Duquesne Light Company

Docket No. R-2021-3024750

DLC Exhibit 5

Direct Testimony – Part II

BOOK 9

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3024750

Duquesne Light Company

Statement No. 10

Direct Testimony of Robert L. O'Brien

Subject: Revenue Requirement

Dated: April 16, 2021

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DIRECT TESTIMONY
OF
ROBERT L. O'BRIEN

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, 2013 and 2018 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, 2022 ("FPFTY"), the future test year ended December 31, 2021 ("FTY") and the historic test year ended December 31, 2020 ("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 Ms. Bachota. 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, 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 Ms. Bachota (DLC St. No. 2), Duquesne Light's Assistant 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, 2022;

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, 2021; and finally, the data for the HTY in DLC Exhibit 4 from the actual data for the year ended December 31, 2020. 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, 2022) 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 for the FPFTY. Because my testimony regarding DLC Exhibit 3, which is Duquesne Light's FTY (December 31, 2021) and DLC Exhibit 4 which is Duquesne Light's HTY (December 31, 2020) are organized in essentially the same format as DLC Exhibit 2, I 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, 2022 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, 2020, added the budgeted capital expenditures that are projected to close to plant in service during twelve months ended December 31, 2021, subtracted the appropriate plant retirements and made any reclassifications or adjustments, which resulted in the plant in service balances at December 31, 2021. The same procedures were followed using plant closings and related plant retirements for the year ended December 31, 2022, which resulted in the plant in service balances at December 31, 2022. The accumulated depreciation at December 31, 2022 was determined in a similar fashion, using the closing balances at December 31, 2020 plus the budgeted and/or pro forma depreciation expense, amortization of net salvage and the plant retirements through December 31, 2021 and for the FPFTY. The measures of value include a reduction for the accumulated deferred income taxes ("ADIT"), which includes an amount for the federal ADIT. The ADIT balance at the end of each of the years 2020, 2021 and 2022 also includes the amortization of the excess ADIT resulting from the reduction of the Federal income tax rate contained in the Tax Cuts and Jobs Act of 2017 ("TCJA"). The claimed levels of materials and supplies and customer deposits are based on 13-month historic averages for the period ended December 31, 2020. In addition, the capitalized pension balance and an amount for cash working capital which was calculated using lead-lag study procedures are added to the measures of value for the FPFTY. 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 analyzed and the portion used to provide distribution service is allocated to the Pennsylvania Jurisdiction with the results 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 distribution operations for the twelve months ending December 31, 2022 to reflect the removal of surcharge revenues that will not be included in base rates when new rates are authorized in this proceeding; to reflect the annualization of customers to year-end levels in the FPFTY and to reflect the other pro forma revenue 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, 2022 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 of expenses actually experienced by the Company during the year ended December 31, 2020. 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 account(s).

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

A. The base amounts were determined by using Company forecasted amounts for the twelve months ended December 31, 2022, 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-20.

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 depreciation rates determined by Mr. Spanos in his depreciation study as described in his testimony (DLC St. No. 11) or by using depreciation rates based on Company data for intangible, leasehold and transportation plant times the year-end plant at December 31, 2022. 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-21 of DLC Exhibit 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. 12). 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-22, page 1 of 3. The income tax expense, as explained by Mr. Simpson in DLC Statement No. 12, was calculated using the provisions and rates under the Tax Cuts and Jobs Act ("TCJA"). In addition, the income tax expense calculation includes the annual amortization of excess deferred income taxes ("EDIT") associated with the change in the Federal Income Tax Rate beginning in 2018, as described by Mr. Simpson.

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 for the FPFTY 2022, 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 pro forma expenses. These total Company amounts were provided to Mr. Gorman and formed 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 PA Jurisdictional annual operating revenues is $85.8 million which is supported by the testimony of Mr. Gorman.

Q. Is the $85.8 million of additional revenue the only increase that will be applied to the present base rates of the PA Jurisdictional customers?

A. No. In addition to the overall revenue increase of $85.8 million, the present base rates will also be increased by the surcharge revenues of $29.2 million which is currently being collected from PA Jurisdictional customers via a surcharge which will be set to zero when the new base rates are established in this proceeding. This combination results in a base rate increase of $115.0 million and a reduction in surcharge revenue of $29.2 million and a net increase in PA Jurisdictional revenue of $85.8 million.

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 and are sponsored by Witnesses Bachota, 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 rate of return at present rates for the total Company and the Pennsylvania jurisdiction and the pro forma rate of 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 $2.998 billion (column 1, line 1) billion and is $2.276 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 $178.5 million (line 4), that is required to attain the target rate of return of 7.84%, 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 for the total Company of $5.313 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, 2022 and is based on utility plant in service at December 31, 2020 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, 2022 by FERC account are shown on page 2 with the detail for plant additions, retirements and adjustments for the year ended December 31, 2022 shown on pages 3 and 4. The total plant in service of $5.313 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, 2022 of $5.300 billion shown on line 42 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, 2021 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, 2022 of $5.300 billion is shown in column 6 on line 51 and is reflected on pages 1 and 2 of Schedule C-2.

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 are not included in the Company's capital expenditure budgets or reflected in the plant in service accounts but are required on a going forward basis. The support for this adjustment is provided by Ms. Bachota in her testimony (DLC St. No. 2). The adjustment, shown in column 1 on page 4, 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 $5.313 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, 2022 for the total Company by FERC account. Duquesne Light's accumulated depreciation at December 31, 2022 is $1.810 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 in column 1. These balances include the accumulated depreciation at December 31, 2021 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. In addition, column 2 shows the accumulated amortization for the cloud expenditures through December 31, 2022 in the amount of $8.037 million, which will be described in more detail in connection with schedule D-11.

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 in the amount of $1.802 billion. Page 3 contains eleven columns showing the changes to the FPFTY accumulated depreciation balances by FERC account from December 31, 2021 (column 2) to December 31, 2022 (column 11). Column 3 shows the depreciation expense for 2022 while column 4 shows the plant retirements, which are equal to the plant retirements shown on the Plant in Service Schedule C-2, page 3, column 4. Columns 5 to 10 show other charges and credits to the accumulated depreciation for 2022. The accumulated depreciation at the end of 2022 is shown in column 11. Page 4, column 2, shows the accumulated amortization adjustment related to the adjustment to plant for Cloud expenditures as shown on DLC Exhibit C-2, page 4. In addition, column 3 reflects an increase in accumulated depreciation of $384,000 to reflect changes in depreciation expense for EV plant for the years 2020 to 2022 as will be described in connection with the adjustment on Section D-1, Schedule 15.

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

A. That amount is $1.810 billion for the total Company as 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 in Schedule C-4. The total of $68.330 million shown on line 6 is included in Duquesne Light's claimed measures of value as CWC 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 $46.162 million as shown on page 3 of 3 in column 2, line 4 of Schedule D-1.

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 57.36 days is shown on line 1; the expense lag days for each of the expense components appear on lines 3 to 6 and in column 3 and the respective amounts are totaled on line 7. The composite O&M expense lag days of 28.22 days is shown on line 8. The net lag in the collection of revenue of 29.14 days (57.36 – 28.22 = 29.14) shown on line 9 is then multiplied by the average daily operating expense balance of $625,000 on line 10 to arrive at the base CWC amount of $18.213 million for operating expenses shown on line 11. The average daily operating expense balance of $625,000 on line 10 was determined by dividing the total pro forma annual operating expenses of $228.002 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 therefore is not included in the determination of working capital as part of the revenue requirement 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 57.36 days were determined by dividing the average month-end accounts receivable balances for the thirteen months ended December 31, 2020 shown in column 2 on line 17 into the annual revenue billed during the 12 months ended December 31, 2020, as shown in column 3 on line 17. This results in an accounts receivable turnover rate of 8.66 (column 4, line 17), which is equivalent to 42.15 lag days (365 days divided by the 8.66 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 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 57.36 days, as shown on line 21. As shown on line 19, there is no lag for the calculation and recording of the bill since it is accomplished on the same day.

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 per month) divided by 2, or a mid-point of 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, 2018 through 2020.

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 108 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 that contract and the most recent 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 25.48 days when subtracted from the revenue lag days of 57.36 calculated on DLC Exhibit C-4, page 3 and shown on line 21 (57.36 days – 33.88 days = 23.48 days). The 23.48 payment lead days is used to calculate the cash working capital requirement related to the purchased energy of $13.797 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 page 2, line 6, is set forth on lines 10 to 14 on 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 of the four months, 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 are not material in total or those which should not be included in a CWC calculation for operating expenses.

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

A. First, using the data for February 2020 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 3,887 (column 1) and a total dollar amount of those disbursements of $46.789 million (column 2) which produced a total-dollar-days of $2.083 billion (column 3). This resulted in expense payment lag days of 44.52 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 3,887 to 500 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 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 2020, shown on line 3, is 47.54 lag-days. A similar process was followed for the months of May, August and November 2020 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 44.90 expense lag-days for other disbursements as shown on line 15, column 4. These data are summarized on page 5, lines 10 to 14 and the average of 44.90 lag-days is reflected on page 2 of 10, column 3, line 6.

Q. Please explain how the average prepayment amount of $18.260 million included on line 12 of Schedule C-4, page 2 was determined.

A. That amount is calculated on page 10 of Schedule C-4 and represents the thirteen-month average of actual amounts recorded for each month end from December 31, 2019 to December 31, 2020. As shown on page 10, the prepayments in question comprise 36 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 as shown on lines 1 to 4. The daily interest expense amount of $164,000, calculated on line 5, is multiplied by the net payment lag of 33.89 days shown on line 8 for a reduction to the working capital allowance of $5.571 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 $37.058 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 can have separate payment dates. For example, as shown on page 9 of Schedule C-4, lines 2 to 5, 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 $68.330 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, 2019 to December 31, 2020 of $33.482 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, 2022 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 $692.225 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-22, pages 1 and 2 of 3. These amounts are supported in the testimony of Mr. Simpson (DLC St. No. 12). The ADIT amounts for CIAC and Non-Utility listed on the schedule on lines 7, 8 and 9 are not included because the related plant in service shown on Schedule C-2 is not included in the measures of value for the FPFTY.

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

A. The amount for the total Company is $692.225 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 for the total Company and $521.809 million for the PA Jurisdiction as shown in column 2.

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, 2020. 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 a recoverable 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 $11.163 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 $532,000 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 included in the Company's measures of value, consistent with the Commission-approved settlements in the Company's 2013 and 2018 rate cases, Docket Nos. R-2013-2372129 and R-2018-3000124. Per the 2018 settlement, the amount to be included as a rate base adjustment is, "…the amount necessary to adjust the Accounting Standards Codification ("ASC") 715 capitalized pension amounts to equal accumulated capitalized pension contributions, net of applicable deferred income taxes, from January 1, 2007 forward." (Settlement in Docket No. R-2018-3000124). 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, $96.687 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 $96.687 million. This amount is also shown on DLC Exhibit 2, Schedule D-1, page 3 of 3, column 1, line 6 for the total Company and $74.408 million for the 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 $2.998 billion, as shown on line 13, page 3 of 3, column 1 of Schedule D-1 for the total Company and $2.276 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 on page 1. The Pennsylvania jurisdictional revenue increase that is calculated by Mr. Gorman is $85.759 million 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 jurisdictional Pennsylvania distribution revenue increase. The various revenue adjustments totaled in column 2 on Schedule D-2 are shown by separate 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-16.

Q. Please describe Schedule D-3.

A. Schedule D-3 summarizes the various adjustments that were made to the FPFTY forecast revenue and expense data to derive the pro forma present rate revenues and expenses 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 11 of page 1 and in columns 14 to 23 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 $31.881 million on line 33 is shown on Schedule D-5, column 3, line 2. In addition, the schedule shows the total amounts for two surcharges that are being included in base rates in the FPFTY. These are the DSIC 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 $29.171 million. The revenue from these two 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 $29.172 million. Once the surcharge revenue of $31.881 million shown in column 3 on line 2 is removed, the remaining $29.172 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. 16).

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 revenues expected to be lost from energy efficiency and conservation activities of the Company and its customers for the years 2023 to 2025 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 2022 to 2025 by customer category on lines 1 to 5. Lines 6 to 20 show the revenue reductions for each year 2023 to 2025 (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 amount to be included as the lost revenue as part of the determination of the FPFTY revenue requirement.

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. 16).

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 2022, the FPFTY, reflect these lost revenues for 2022, the additional lost revenues that will occur in 2023, 2024 and 2025 will reduce the Company's revenue and earnings level. Reflecting 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 4-year period of $8.451 million as shown on Schedule D-5B in column 6 on line 23. The use of the four-year period recognizes that the FPFTY of 2022 already includes a reduction for lost revenue as part of the initial revenue requirement and that the Company currently plans to file another general rate case using a FPFTY of 2025.

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 $573 per year was multiplied by the increase in the number of customers of 615 on line 7 for an annualization adjustment for residential customers of $352,000, as shown on line 8. The total annualization adjustment of

$258,000 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, 2020 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 2020. For example, I determined how much of the payroll cost center expense in 2020 was charged to each FERC account in 2020 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 total FPFTY expense by cost element forecast to a FERC account-based forecast.

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

A. Essentially for two basic reasons. First, the Company's annual reports to the Commission reflect recorded amounts and 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 is necessary to have the FPFTY data available by FERC account for use by Mr. Gorman in his Jurisdictional Separation Study ("JSS") and also for use in his Cost of Service Study ("COSS").

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 several rate cases, I removed the expenses that are recovered through surcharges that will remain in effect and also those expenses that are charged below-the-line from the Cost Elements before the costs element expenses were distributed to the FERC accounts. This process clearly shows that expenses recovered through surcharges that remain in effect and also those that are charged below-the-line are excluded and are not included in the Company's PA Jurisdictional 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 2016 through the FPFTY. The total expenses for the FPFTY are shown in column 7 in the amount of $261.807 million on line 49. From this total amount, the expenses recovered by surcharge (column 8) in the amount of $28.631 million; the expenses charged below-the-line (column 9) in the amount of $3.919 million are removed leaving a net expense for the FPFTY of $229.257 million as shown on line 49 in column 10. The amount of each Cost Element is distributed to FERC accounts and therefore, the amount in column 10, after the removal of the expenses recovered through surcharges and the expenses charged below-the-line, is included in the FPFTY expenses. A similar procedure was used for the FTY and HTY as reflected on Exhibits RLO-3 and RLO-4 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 included in 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 1?

A. Schedule D-6A contains adjustments to remove the expenses, by cost element and FERC account that are 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 20. The total of $28.631 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 or FERC accounts as the remaining surcharge related expenses are in this schedule.

Q. Please describe the adjustment contained on Schedule D-6B, page 1 of 1.

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,

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 $91.473 million on line 16, columns 2 and 4. Column 5 shows the annualization adjustment of $2.189 million distributed to the FERC expense categories, while column 6 lists the pro forma amounts for S&W expense, totaling $93.662 million as shown on line 16 and an annualization adjustment to increase S&W of 2.393 percent as shown on line 17. The adjustment of $2.189 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, 2022 (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, 2023 (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 annualized for the full 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, Duquesne has utilized a vacancy factor in the calculation of the employees during and at the end of the FPFTY and therefore there is no need for an annualization adjustment for the number of employees.

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

A. The amount is $2.189 million, which is an adjustment of 2.393 percent as shown on lines 21 and 22 of page 2 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 $350,000 on this filing through December 31, 2020 (line 3) and has estimated an additional $2.090 million to complete the case. This total, $2.440 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 $813,000, as shown on line 8. This results in an increase of $28,000 from the $785,000 forecasted expense for the FPFTY 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 the end of April 2024 using a FPFTY ended December 31, 2025. 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 pension contributions that the Company forecasts that it will make to its pension funds during the three years ending December 31, 2022, December 31, 2023 and December 31, 2024, which are supported by the testimony of Ms. Bachota. 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 $6.004 million on line 11 is the amount included in the Company's FPFTY forecasted expenses which results in an adjustment of $1.004 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 2 to 7 show the results of the five-year average rate of net uncollectible accounts charged off to total tariff revenue for the 2016-2020 period of 1.10 percent (column 5, line 7), which I would then normally use to determine the level of uncollectible expense at pro forma proposed rates and would be shown in the reference column on line 22 of Schedule D-2.

Q. Are you recommending a different base calculation period for this case?

A. Yes, I am. The data for 2020, which results in a rate of 0.42 percent should not be used because it is an obvious outlier from the data for the prior five years. This 0.42 percent is substantially below all of the previous four years which range from 0.99 percent to 1.57 percent as shown on lines 2 through 5. This is likely due to the COVID-19 pandemic and the various orders issued by the Commission regarding uncollectible accounts and customer disconnections.

Q. **What period are you proposing for this proceeding?**

A. As shown on line 8, I am proposing to use the five-year period 2015 to 2019 for the calculation of the average which results in a 1.30 percent as shown in column 5. This average maintains the five-year calculation period and provides a more consistent base than using the data from 2020, which is unlikely to recur during the years the rates established in this case will be in effect.

Q. Why do you believe that the 1.30 percent reasonable to use in this proceeding?

A. The 1.30 percent average is in line with the actual percentages for the five-year period of 2015 to 2019, which range from 0.99 percent to 1.51 percent as shown on lines 1 to 5 in column 4. This average is more in line with the historic results than the 0.41 percent in 2020 or the resulting 1.10 percent average from the use of the 1996 to 2000 historic data.

Q. Where is the uncollectible factor of 1.30 percent used?

A. First, it is used to calculate the adjustment for uncollectible expense in the FPFTY as shown on lines 9 to 13 of Schedule D-10. It is also used to provide for uncollectible expenses associated with the required revenue increase and included in the Gross Revenue Conversion Factor described in connection with Schedule D-22, page 3 of 3.

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 $12.215 million which is a net increase of $4.760 million from the forecast as shown on line 11 and brought forward to Schedule D-3 in column 13 on line 55 on page 2.

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 Ms. Bachota (DLC St. No. 2). The implementation costs associated with these cloud-based information systems are budgeted by the Company and recorded in accordance with applicable accounting guidance. Column 1 shows expenditures during the years 2016 to 2022 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 amount of the additions to plant while column 4 shows the amortization expense and column 5 the accumulated amortization at the end of each year. Finally, column 6 shows the net amount at the end of the FPFTY.

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

A. First, as shown on line 8, $694,000 is removed from the calculations since that amount which was closed to plant in 2017 (line 2) and would be fully amortized by the end of 2022. Second, the Company is adding $12.553 million to plant in service (column 2, line 9) which is shown on DLC Exhibit 2, Schedule C-2, page 1, column 2, line 1. Third, the Company is adding $7.012 million to accumulated depreciation (column 5, line 9) which is shown on DLC Exhibit 2, Schedule C-3, page 1, column 3, line 1. Finally, $2.511 million is included as amortization expense (column 4, line 12) as shown on DLC Exhibit 2, Schedule D-3, page 2, column 14, line 59.

Q. Please describe the adjustment contained on DLC Exhibit 2, Schedule D-12.

A. This adjustment shows the amortization for the FPFTY of the deferred uncollectible expense and related net costs associated with the Commission's orders related to COVID-19 matters, which are described by Ms. Bachota.

Q. Please describe DLC Exhibit 2, Schedule 12.

A. Lines 1 to 6 show the calculation of the uncollectible expense portion of the adjustment. Lines 7 to 18 show the calculation of the net operating costs to be recovered. The total for the uncollectible and net operating costs of $12.076 million on line 19 is divided by 3 years as the recovery period and the $4.025 million adjustment on line 21 is included in the FPFTY expense.

Q. Please describe the calculation of the uncollectible expense to be recovered.

A. The calculation begins with the actual uncollectible expenses for 2020 of $14.658 million on line 1. This is reduced by the amount of uncollectible expense presumed to be recovered by the Company in rates for 2020 of $10.471 million on line 2 for a net amount of uncollectible expense to be recovered in this adjustment of $4.187 million on line 3.

Q. How was the amount of uncollectible expense recovered in rates calculated?

A. Line 2 shows the amount for uncollectible expense of $10.471 million which was requested by the Company in its FPFTY in its last rate case in Docket No. 2018-3000324. Although the Company did not receive the total revenue increase requested as part of the settlement approved by the Commission in that docket, the uncollectible expense was not contested and therefore the Company is using the full pro forma uncollectible expense of $10.471 million as the amount of uncollectible expense recovered in rates as part of the calculation of this adjustment.

Q. What is contained on lines 4 to 6 of the schedule?

A. Lines 4 to 6 show the Company's estimate of the unrecovered uncollectible accounts related to the COVID-19 orders for 2021 that should be included in the balance to be recovered in this proceeding. The Company is using an estimate based on its 2020 experience and a period of 6 months as shown on lines 4 and 5 in columns 2 to 4. The Company will update this estimate during the proceeding with actual amounts for uncollectible expense in 2021.

Q. How were the operating costs included in the recovery determined?

A. The Company determined incremental costs and revenue losses incurred in 2020 associated with the Commission's COVID-19 orders as described by Ms. Bachota as shown on lines 7 to 13. The Company also identified cost savings associated with the COVID-19 activities in the total amount of $750,000, which is listed on line 15. The net cost of $5.195 million is shown on line 18. In addition, the

Company estimates that it will incur an additional $600,000 of net costs in 2021 resulting from additional costs and savings in these same or similar categories. The total costs to be recovered of $12.076 million is shown on line 19.

Q. Over what period is the Company seeking to recover these costs and expenses?

A. The Company has used the three-year period used to normalize rate case expenses, which is also the period that the Company expects the rates from this case to be in effect. The amount of the adjustment of $4.025 million is shown on line 21.

Q. What is contained on DLC Exhibit 2, Schedule D-13?

A Schedule D-13 contains the adjustment to the FPFTY expense for the COVID-19 New Business Stimulus Rate ("NBSR") as proposed in the testimony of Ms. Krysia Kubiak (DLC St. No. 5). The Company is proposing to establish a NBSR, which, as explained in Ms. Kubiak's testimony, is designed to provide discounts to businesses recovering from the COVID-19 restrictions. As shown on lines 1 to 5, this program will cost $277,000, resulting in an annual expense of $92,000 per year for three years.

The second program, the Crisis Recovery Program ("CRP"), has a total cost of $423,000, as shown on lines 8 to 12 with an annual cost of $141,000 when spread over three years. This program, as described in the testimony of Ms. Kubiak, is designed to provide payment assistance to certain nonresidential customers with delinquent electric bills who, prior to the COVID-19 pandemic, did not have a history of delinquency. The total adjustment for these programs is $233,000 as shown on line 15.

Q. Please describe the adjustment on DLC Exhibit 2, Schedule D-14.

A. This adjustment, as discussed by Ms. Bachota, is to recover deferred costs net of offsetting refunds from programs authorized by the Commission in Docket R-2018-3000124. The $414,000 on line 1 represents payments to customers for infrastructure costs that are "behind the meter" to provide support for the cost of such infrastructure. The customer electric vehicle incentives – not distributed of $140,000 represents the estimated remaining amount from revenues collected for this program that will not be distributed to customers by the end of 2021. The net amount of $275,000 on line 3 is divided by 3 to reflect the normalization of this item over 3 years, similar to the rate case expense normalization.

Q. Please describe the adjustment proposed on Schedule D-15.

A. This adjustment corrects the depreciation expense included in the Company's recorded depreciation for 2020 and also for the depreciation expense included in its forecasts for 2021 and 2022 for the Electronic Vehicle ("EV") plant additions made or forecasted for those years. It also provides for an adjustment to the accumulated depreciation for each year.

Q. What is the nature of the adjustment?

A. Most of the EV equipment has a useful life of 10 years, while a small portion has a useful life of 5 years, which would be equal to depreciation rates of 10 percent and 20 percent respectively. The EV equipment was included in plant account number 390 which has depreciation rates of 2.78 percent for 2020, 3.10 percent for 2021 and 3.18 percent for 2022. The adjustment on Schedule D-15 corrects for the change in depreciation rates for each year.

Q. Please describe the calculations on Schedule D-15.

A. Line 1 shows the plant additions for each year and line 2 shows the depreciation rates that were used to determine the depreciation expense included for each addition in each year. Lines 3 to 5 show the number of months used for the calculation of the depreciation expense in each year. For example, for 2020 as shown in column 1, the plant amount of $874,000 was included in service for one month as shown on line 3. The depreciation expense would be the multiple of lines 1 times line 2 divided by 12 for a total of approximately $2,000. The depreciation expense for 2021 would be based on the same $874,000 times the depreciation rate of 3.10 percent for 2021 (column 2, line 2) or a total of 27,000. Finally, the depreciation expense for 2022 would be based on the $874,000 times the depreciation rate for 2022 of 3.18 percent (column 3, line 2). The total accumulated depreciation for the plant addition through 2022 would be the $57,000 shown on line 9. The same procedures would be followed for each of the plant additions shown on line 1 and result in an accumulated depreciation included in the Company's recorded and forecasted amounts of $170,000 (column 6, line 9). These calculations also provide the amount of depreciation expense included in the forecast for the FPFTY of $120,000 (column 6, line 8).

Q. What is the correct calculation of depreciation expense and accumulated depreciation for the EV plant?

A. The calculation for the accumulated depreciation is shown on lines 10 to 15 and the calculation of the annualized depreciation expense is shown on lines 16 to 18. The correct depreciation rates for each addition are shown on lines 10. As an example, using the plant amounts on line 1 and the in-service months on lines 3 to 5, again, looking at 2020, the $7,000 on line 11 replaces the $2,000 on line 6, as do the other amounts for 2021 and 2022. The updated accumulated depreciation on line 14 for each plant addition is reduced by the amount included in the Company's forecast on line 9, which results in the adjustment on line 15 increasing the accumulated depreciation. The total adjustment of $384,000 is shown on DLC Exhibit 2, Schedule C-3, page 4 of 4, column 3, line 34 for account 390.

Q. What is the adjustment for the pro forma depreciation expense?

A. The depreciation expense adjustment is shown on Schedule D-15, lines 16 to 18. Line 16 shows the amount of depreciation expense included in the Company's forecasts for each plant item, which is the amount calculated on line 8. The pro forma depreciation expense is calculated on line 17 and the difference on line 18 is the adjustment for depreciation expense.

Q. **Where is that adjustment shown?**

A, The adjustment of $437,000 is included on Schedule D-21, column 7, line 48.

Q. **Is the Company proposing a Residential Crisis Recovery Program?**

A. Yes, it is. As described by Ms. Scholl, DLC St. No. 7, the Company is proposing a program to assist certain residential customers with forgiveness of a portion of their arrearage in their electric bills.

Q. **What are the projected costs and how is the Company proposing to recover those costs?**

A. As shown on Schedule D-16, lines 1 to 3, the Company is proposing to provide an estimated forgiveness amount of up to $300 per customer for at least 10,000 residential customers, for a total of $3.0 million. The Company also estimates that it will incur an additional $500,000 for implementation and operational costs not currently included in expenses presented in this proceeding. The Company is proposing to recover this total amount of $3.5 million over three years, or $1.167 million per year, and has included an adjustment to expense for that amount.

C. Taxes – Other Than Income Taxes

Q. **Please describe Schedule D-20 of DLC Exhibit 2.**

A. Schedule D-20 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 increase in

TOTI related to the S&W related changes are made on Schedule D-20, 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 $169,000 as shown on line 4 in column 4. The same procedures were followed for the other related payroll tax items. The total pro forma increase in payroll related taxes of $196,000 is 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 $4.497 million calculated on page 1, lines 11 to 18. The total adjustment is a net decrease of $4.301 million in pro forma FTY expense for TOTI shown in column 4 on line 10. The pro forma TOTI expense is $60.288 million as shown on Schedule D-20, 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-22, page 4, 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-21, pages 1 to 3.

A. Schedule D-21 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 pro forma depreciation expense for the FPFTY was calculated on Schedule D-21, page 1, column 7 using the year-end December 31, 2022 plant balance in column 5 times the depreciation rates shown in column 2.

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. 11). 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 $201.477 million as shown on DLC Exhibit 2, Schedule D-21, column 7, line 47 plus the adjustment for the EV plant discussed in connection with Schedule D-15, which is shown on line 48 of Schedule D-21, page 1 in column 7.

Q. Please describe the calculation of the average net salvage amortization shown on page 2 of DLC Exhibit 2, Schedule D-21.

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. The total of $16.850 million is shown on page 2 of Schedule D-21 in column 7 on line 47.

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

A. The total is $218.327 million as shown DLC Exhibit 2, Schedule D-21, page 3 column 7, line 47 plus the EV depreciation expense adjustment of $437,000 on line 48 in column 7.

E. Income Taxes

Q. Please describe the income tax calculation shown on DLC Exhibit 2, Schedule D-22.

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 on page 1 of 4. Pages 2 and 3 contain 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 4 shows the calculation of the gross revenue conversion factor ("GRCF") which is used to calculate the revenue increase required to recover uncollectible expense, fees and taxes related to revenue once the amount of net operating income increase is determined.

Q. Who is responsible for the calculations and the data contained on Schedule D-22?

A. I am responsible for all of the calculations on Schedule D-22. 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 shown on pages 2 and 3 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. 12), the tax calculations use the 21% Federal income tax rate and other elements of the TCJA.

Q. What is contained on pages 2 and 3 of DLC Exhibit 2, Schedule D-22?

A. Pages 2 and 3 contain the tax depreciation and other tax elements used in the calculation of income tax expense on page 1 of Schedule D-22 for the total Company in columns 2 to 4 and for the PA Jurisdictional operations in column 5.

Q. Please describe page 4 of Schedule D-22.

A. Page 4 shows the calculation of the GRCF on lines 1 to 11 of 1.516558, which includes provision for uncollectible expenses, the GRT and various assessments on revenue which results in an effective composite income tax rate of 26.792% 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 YEAR

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 for the FPFTY, 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. 15).

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, 2021 and are supported by Witnesses Bachota, 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 and the HTY presentation as well as for the FPFTY. Schedules B-6, 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, 2021 as well as the additions, retirements and adjustments for the year ended December 31, 2021. 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, 2021, while page 3 shows the plant additions, retirements and reclassifications for the year 2021. Page 4 reflects any adjustments to plant. The total pro forma plant in service at the end of the FTY, \$5.090 billion, is shown on line 7, column 4 of Schedule C-2, page 1 and also on Schedule D-1, page 3, column 1, line 1 for the total Company. The PA Jurisdictional plant amount is \$3.945 billion as shown on Schedule D-1, page 3, 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, 2021. 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 $1.693 billion as shown on column 4, line 7 and also on Schedule D-1, page 3, column 1, line 2 for the total Company. The PA Jurisdictional accumulated depreciation amount is $1.330 billion as shown in column 2 on line 2 on page 3.

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 $65,978 million (line 6) and also on Schedule D-1, page 3, column 1, line 4. The PA Jurisdictional CWC is $44,539 million as shown on Schedule D-1, page 3, column 2, 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, 2020. The resulting $65,978 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 of $13.189

million 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 and other components may 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 2019 to December 2020 for plant materials and operating supplies. The 13-month average of $33.482 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, 2021 balances were used. The resulting ADIT of $693.8 million for the FTY is shown on line 6 and also on Schedule D-1, page 3, column

1, line 11. The amount for the PA Jurisdiction is $524.8 million as shown on Schedule D-1, page 3, column 2, 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 2019 to December 2020 customer deposits in column 1 and also for the 12-month total for interest expense related to those customer deposits in column 2. The 13-month average of $11.163 million is shown on line 15 in column 1 and also on Schedule D-1, page 3, column 1, line 9. The customer deposit amount is the same for the total Company and for the PA Jurisdictional operations. The interest expense of $532,000 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 $94.008 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 with the PA Jurisdictional amount of $72.865 million shown in column 2.

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 revenue 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 it is similar to Exhibit RLO-1 for the FPFTY. The total Company expenses, net of expenses related to the surcharge revenue that is not being rolled into base rates and also net of below-the-line expenses, are shown in column 10 and 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 2023 to 2025 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 Schedules D-6A and D-6B 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, D-15 and D-20 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-21.

A. Schedule D-21 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 or Company determined depreciation rates for the several accounts normally not included in the analyses provided by Mr. Spanos.

Q. Please describe the income tax calculations on Schedule D-22.

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. Referring now to DLC Exhibit 4, for the HTY, what is contained on Schedules B-1 to B-5?

A. These schedules contain forecast financial data for the year ended December 31, 2020 and are supported by Witnesses Bachota and Simpson, 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 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. These schedules are supported by Mr. Milligan and Mr. Moul as indicated on each schedule.

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 PA Jurisdiction. In addition, it shows the pro forma return at proposed rates for the PA 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, 2020 as well as additions, retirements and adjustments for the year ended December 31, 2020. 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, 2020. Page 3 shows the plant additions, retirements and reclassifications for the year 2020 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, $4.788 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 and $3.703 billion for the PA Jurisdiction as shown on Schedule D-1, page 3, column 2, line 1.

Q. Please describe Schedule C-3.

A. Schedule C-3 contains 4 pages and presents the accumulated depreciation at December 31, 2020. 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 $1.607 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 and $1.261 billion for the PA Jurisdiction as shown on Schedule D-1, page 3, column 2, 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 HTY of $63.453 million (line 6) and also on Schedule D-1, page 3, column 1, line 4 for the total Company and $42.907 million for the PA Jurisdiction as shown on Schedule D-1, page 3, column 2, 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, 2020. The resulting $63.453 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 of $13.081 million 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 2019 to December 2020 for plant materials and operating supplies. The 13-month average of $33.483 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, 2020 balances were used. The resulting ADIT of $697.610 million for the HTY is shown on line 6 and also on Schedule D-1, page 3, column 1, line 11 and $530.082 million for the PA Jurisdiction as shown on Schedule D-1, page 3, column 2, 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 2019 to December 2020 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 $11.163 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 $532,000 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 $95.822 million in column 3 on line 25 is total amount for the capitalized pension adjustment.

Q. What is presented on Schedule D-1?

A. Schedule D-1 contains the PA 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 PA 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 is similar to Exhibit RLO-1 for the FPFTY and Exhibit RLO-2 for the FTY. The net expenses shown in column 10 reflect the base for expenses in the HTY, which as shown in columns 8 and 9 exclude expenses related to surcharge revenues that are not being included in base rates as well as excluding expenses recorded below-the-line.

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 2023 to 2025 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. Does the data shown on Schedules D-6A and D-6B present the same data for the HTY as shown on similar schedules for the FPFTY and FTY?

A. Yes.

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-20 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-21.

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-22.

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. I reserve the right to supplement my testimony through the course of this proceeding.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3024750

Duquesne Light Company

Statement No. 11

Direct Testimony of John J. Spanos

Subject: Depreciation

Dated: April 16, 2021

Direct Testimony of John J. Spanos

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.

Q. What is your position in the firm?

A. I am 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, January 2013 and February 2018.

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

A. I have over 34 years of depreciation experience which includes expert testimony in over 350 cases before approximately 41 regulatory commissions, including the Pennsylvania Public Utility Commission. These cases have included depreciation studies in the electric, gas, water, wastewater and pipeline industries. In addition to cases where I have submitted testimony, I have supervised over 700 other depreciation or valuation assignments. Please refer to Appendix A for my qualifications statement, which includes further information with respect to my work history, case experience, and leadership in the Society of Depreciation Professionals.

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, 2020. Exhibit JJS-2 presents the results of the depreciation study as of December 31, 2021. Exhibit JJS-3 presents the results of the depreciation study as of December 31, 2022. 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, 2020, future test year end, December 31, 2021 and the fully projected future test year end, December 31, 2022.

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

A. Exhibit JJS-1, titled "2020 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2020," includes the results of the depreciation study as related to the original cost at December 31, 2020. The report also includes the detailed depreciation calculations. Exhibit JJS-2, titled "2021 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2021," includes the results of the depreciation study as related to the estimated original cost at December 31, 2021. The report also includes explanatory text, statistics related to the estimation of service life, and the detailed depreciation calculations. Exhibit JJS-3, titled "2022 Depreciation Study – Calculated

Annual Depreciation Accruals Related to Electric Plant as of December 31, 2022," includes the results of the depreciation study as related to the estimated original cost at December 31, 2022.

Q. What was the purpose of your depreciation study?

A. The purpose of the depreciation studies were 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, 2020, December 31, 2021 and December 31, 2022.

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. 2018-3000124.

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. Their 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 in its most recent electric base rate proceeding in Docket No. R-2018-3000124?

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 and for the prior rate cases.

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, 2021 estimated?

A. The book reserve at December 31, 2021, 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, 2020. Annual accruals were estimated using the annual accrual rates calculated as of December 31, 2020. 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 percents 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, 2021.

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

A. No, but the Company's most recent service life study was performed using data through 2019 because this Commission's regulations only require service life studies to be prepared every 5 years. That 2019 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 2019. 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-7 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 as of December 31, 2021, and the book reserve and calculated annual depreciation for each account or subaccount of Electric Plant. Table 2, page V-6, presents the bringforward to December 31, 2021, of the book depreciation reserve as of December 31, 2020. Table 3 on page V-7 sets forth the calculation of the annual accruals used in the bringforward. Table 4, page V-8, presents the experienced and estimated net salvage by function during the five-year period, 2017 through 2021.

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-2 presents the depreciation calculations related to original cost. The tabulations on pages VII-7 through VII-91 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, 2022. 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, 2022, are organized and presented in the same manner as those as of December 31, 2021.

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, 2020. 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, 2020, are organized and presented in the same manner as those as of December 31, 2021.

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, 2021.

The retirement rate method was used to analyze the survivor characteristics of this group. The life table for the 1964-2019 experience band is presented on pages VI-73 through VI-78 of Exhibit JJS-2. The life table, or original survivor curve, is plotted along with the estimated smooth survivor curve, the 50-R0.5, on page VI-72.

The calculation as of December 31, 2021, is presented on pages VII-46 through VII-48 of Exhibit JJS-2 and is based in part on the bringforward 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 V-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, 2019.

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 I-4 of Exhibit JJS-1, page V-5 of Exhibit JJS-2 and on page I-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 2016 through 2020 for the calculation as of December 31, 2020, and on experience during the period 2017 through December 31, 2020, plus estimates for the twelve months of 2021 for the calculation as of December 31, 2021.

The amortization for the December 31, 2022 calculation is based on experience during the period 2018 through December 31, 2020, plus estimates for the period January 2021 through December 2022. The amounts of the five-year amortizations are calculated in Table 2 on page I-5 of Exhibit JJS-1, in Table 4 on page V-8 of Exhibit JJS-2 and in Table 4 on page I-7 of Exhibit JJS-3.

Q. Does this complete your testimony at this time?

A. Yes, it does. I reserve the right to supplement my testimony as may be necessary through the course of this proceeding.

Appendix A

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, January 2013 and February 2018.

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., in April 2012, I was promoted to the 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) and in January of 2019, I was promoted to my present position of President of 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.; Aqua Illinois, 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; Maryland-American Water Company; 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; Northern Illinois Gas Company; Public Service of New Hampshire and Newtown Artesian Water 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; the Public Service Commission of West Virginia; 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 Company	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 Company	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 Company	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Company	Depreciation
18.	2003	FERC	ER03-1274-000	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
32.	2005	IL CC	05-ICC-06	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-ICC-06	Peoples Gas Light and Coke Company	Depreciation
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation

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

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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	US District Court	Cause No. 1:99-CV-1693-LJM/VSS	Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Company	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 Company	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 Company	Depreciation
47.	2006	NC Util Cm.	G-5, Sub522	Pub. Service Company 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	Accounting
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	IS05-82-002, et 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
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

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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 Company	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 Company	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 Company	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	Docket No. 2011-UA-183	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
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

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

	Year	Jurisdiction	Docket No.	Client Utility	Subject
99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Company	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Company	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Company	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 Company	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 Company	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 Company	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 Company	Depreciation
119.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Company - NIFL	Depreciation
120.	2010	IN URC	Cause No. 43894	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	City of Lancaster – 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
130.	2011	IL CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Company	Depreciation
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
133.	2011	FERC	RP11-___-000	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	Borough of Hanover – 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	City of Lancaster – 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 Company	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
154.	2012	TX PUC	SOAH 582-14-1051/ TECQ 2013-2007-UCR	Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Company– 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 Company	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Company	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
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 Company – PEPCO	Depreciation

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

	Year	Jurisdiction	Docket No.	Client Utility	Subject
166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Company	Depreciation
167.	2013	FERC	ER13-2428-0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13-2410-0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Company	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- -0000	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	Borough of Hanover – 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 Water Company	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric Company	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation
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

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

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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	NiSource - 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 Corporation	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	NiSource - 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 Company – Electric	Depreciation
228.	2016	DE PSC	16-0650	Delmarva Power and Light Company – Gas	Depreciation
229.	2016	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation
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

	Year	Jurisdiction	Docket No.	Client Utility	Subject
233.	2016	PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
234.	2016	PA PUC	R-2016-2529660	NiSource - 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	Cause No. 45029	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 UTC	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	Public Service Company of Oklahoma	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	ER17-217-000	Jersey Central Power & Light	Depreciation
259.	2017	FERC	ER17-211-000	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
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

	Year	Jurisdiction	Docket No.	Client Utility	Subject
266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER18-22-000	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	Docket No. 4800	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.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
276.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
277.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
278.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
279.	2018	PA PUC	Docket No. R-2018-2647577	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
280.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
281.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
282.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
283.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
284.	2018	FERC	Docket No. ER18-	Duke Energy Progress	Depreciation
285.	2018	PA PUC	Docket No. R-2018-3000124	Duquesne Light Company	Depreciation
286.	2018	MD PSC	Case No. 948	NiSource - Columbia Gas of Maryland	Depreciation
287.	2018	MA DPU	D.P.U. 18-45	NiSource - Columbia Gas of Massachusetts	Depreciation
288.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
290.	2018	MD PSC	Case No. 9847	Maryland-American Water Company	Depreciation
291.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation
292.	2018	FERC	ER-18-2231-000	Duke Energy Carolinas, LLC	Depreciation
293.	2018	KY PSC	Case No. 2018-00261	Duke Energy Kentucky, Inc.	Depreciation
294.	2018	NJ BPU	BPU Docket No. WR18050593	SUEZ Water New Jersey	Depreciation
295.	2018	WA UTC	Docket No. UE-180778	PacifiCorp	Depreciation
296.	2018	UT PSC	Docket No. 18-035-36	PacifiCorp	Depreciation
297.	2018	OR PUC	Docket No. UM-1968	PacifiCorp	Depreciation
298.	2018	ID PUC	Case No. PAC-E-18-08	PacifiCorp	Depreciation
299.	2018	WY PSC	20000-539-EA-18	PacifiCorp	Depreciation
300.	2018	PA PUC	Docket No. R-2018-3003068	Aqua Pennsylvania, Inc.	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
301.	2018	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
302.	2018	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
303.	2018	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
304.	2018	IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305.	2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306.	2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307.	2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308.	2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309.	2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310.	2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311.	2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312.	2019	NY PSC	Case No. 19-W-0168 & 19-W-0269	SUEZ Water New York	Depreciation
313.	2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314.	2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315.	2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316.	2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317.	2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318.	2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319.	2019	WA UTC	Docket UE-190529 / UG-190530	Puget Sound Energy	Depreciation
320.	2019	PA PUC	Docket No. R-2019-3010955	City of Lancaster	Depreciation
321.	2019	IURC	Cause No. 45253	Duke Energy Indiana	Depreciation
322.	2019	KY PSC	Case No. 2019-00271	Duke Energy Kentucky, Inc.	Depreciation
323.	2019	OH PUC	Case No. 18-1720-GA-AIR	Northeast Ohio Natural Gas Corp	Depreciation
324.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Carolinas	Depreciation
325.	2019	FERC	Docket No. ER20-277-000	Jersey Central Power & Light Company	Depreciation
326.	2019	MA DPU	D.P.U. 19-120	NSTAR Gas Company	Depreciation
327.	2019	SC PSC	Docket No. 2019-290-WS	Blue Granite Water Company	Depreciation
328.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Progress	Depreciation
329.	2019	MD PSC	Case No. 9609	NiSource Columbia Gas of Maryland, Inc.	Depreciation
330.	2020	NJ BPU	Docket No. ER20020146	Jersey Central Power & Light Company	Depreciation
331.	2020	PA PUC	Docket No. R-2020-3018835	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
332.	2020	PA PUC	Docket No. R-2020-3019369	Pennsylvania-American Water Company	Depreciation
333.	2020	PA PUC	Docket No. R-2020-3019371	Pennsylvania-American Water Company	Depreciation
334.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
335.	2020	NM PRC	Case No. 20-00104-UT	El Paso Electric Company	Depreciation
336.	2020	MD PSC	Case No. 9644	Columbia Gas of Maryland, Inc.	Depreciation
337.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
338.	2020	VA St CC	Case No. PUR-2020-00095	Virginia Natural Gas Company	Depreciation

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

	Year	Jurisdiction	Docket No.	Client Utility	Subject
339.	2020	SC PSC	Docket No. 2020-125-E	Dominion Energy South Carolina, Inc.	Depreciation
340.	2020	WV PSC	Case No. 20-0745-G-D	Hope Gas, Inc. d/b/a Dominion Energy West Virginia	Depreciation
341.	2020	VA St CC	Case No. PUR-2020-00106	Aqua Virginia, Inc.	Depreciation
342.	2020	PA PUC	Docket No. R-2020-3020256	City of Bethlehem – Bureau of Water	Depreciation
343.	2020	NE PSC	Docket No. NG-109	Black Hills Nebraska	Depreciation
344.	2020	NY PSC	Case No. 20-E-0428 & 20-G-0429	Central Hudson Gas & Electric Corporation	Depreciation
345.	2020	FERC	ER20-598	Duke Energy Indiana	Depreciation
346.	2020	FERC	ER20-855	Northern Indiana Public Service Company	Depreciation
347.	2020	OR PSC	UE 374	Pacificorp	Depreciation
348.	2020	MD PSC	Case No. 9490 Phase II	Potomac Edison – Maryland	Depreciation
349.	2020	IN URC	Case No. 45447	Southern Indiana Gas and Electric Company	Depreciation
350.	2020	IN URC	IURC Cause No. 45468	Indiana Gas Company, Inc. d/b/a Vectren Energy	Depreciation
351.	2020	KY PSC	Case No. 2020-00349	Kentucky Utilities Company	Depreciation
352.	2020	KY PSC	Case No. 2020-00350	Louisville Gas and Electric Company	Depreciation
353.	2020	FERC	Docket No. ER21- 000	South FirstEnergy Operating Companies	Depreciation
354.	2020	OH PUC	Case Nos 20-1651-EL-AIR, 20-1652-EL-AAM & 20-1653-EL-ATA	Dayton Power and Light Company	Depreciation
355.	2020	OR PSC	UE 388	Northwest Natural Gas Company	Depreciation
356.	2021	KY PSC	Case No. 2021-00103	East Kentucky Power Cooperative	Depreciation
357.	2021	MPUC	Docket No. 2021-00024	Bangor Natural Gas	Depreciation
358.	2021	PA PUC	Docket No. R-2021-3024296	Columbia Gas of Pennsylvania, Inc.	Depreciation
359.	2021	NC Util. Com.	Doc. No. G-5, Sub 632	Public Service of North Carolina	Depreciation
360.	2021	MO PSC	ER-2021-0240	Ameren Missouri	Depreciation

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3024750

Duquesne Light Company

Statement No. 12

Direct Testimony of Matthew L. Simpson

Subject: Taxes

Dated: April 16, 2021

DIRECT TESTIMONY OF MATTHEW L. SIMPSON

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. Yes. I provided written testimony to the Pennsylvania Public Utility Commission for Duquesne Light Company's 2013 and 2018 distribution rate filings, Docket Nos. R-2013-2372129 and R-2018-3000124. I have also provided written testimony to the Federal Energy Regulatory Commission, Docket No. ER13-1220-000 and Docket No. ER21-1012-000, related to a Monthly Deferred Tax Adjustment charge.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to describe and explain Duquesne Light's income tax expense and other tax expense included in the cost of service.

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-20 and D-22. 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 the Tax Cuts and Jobs Act of 2017 ("TCJA")?

A. Yes. Among other things, the TCJA lowered the corporate income tax rate from 35% to 21%, eliminated bonus depreciation for regulated utilities, and provided for the continuation of rate normalization requirements for accelerated depreciation benefits. The Company initially addressed the impacts of the TCJA in its prior base distribution rate case, Docket No. R-2018-3000124. That proceeding resolved distribution rate issues associated with transitioning to the new TCJA framework. I will address the post-transition impacts of the TCJA 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, 2020 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 income tax rate of 21% and a Pennsylvania income 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-22 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 forma 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 16. 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 17. 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 17 and by the federal tax deductions related to property shown on lines 18 through 25 to arrive at the federal taxable income shown on line 26. The Company applied the current federal statutory corporate tax rate of 21% to compute the pro forma current federal income tax expense shown on line 27. Federal deferred income taxes on lines 31 and 32 were also computed at the current federal statutory corporate tax rate of 21%. In addition, the deferred income tax expense calculation was reduced to reflect the flow back 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. Please 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, 2022, 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. 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 deductions 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 did 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. As stated in the 2018 Joint Petition for Settlement, the Company is using ARAM to refund the unamortized EDIT balance recorded in account 282 – Accumulated Deferred Income Taxes and which have reduced the Company's rate base. As shown on Exhibit 2, D-22, line 30, column 9, the Company has lowered its deferred income tax expense by $8.9 million for the refund of EDIT to customers in the Fully Projected Future Test Year.

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. 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.

III. FEDERAL TAX ADJUSTMENT CHARGE

Q. Is the Company proposing an adjustment clause which will adjust base rates for changes in federal corporate income tax rates?

A. Yes, the Company is proposing to add Rider No. 4 to its tariff, named the Federal Tax Adjustment Clause ("FTAC"), to provide for adjustments to base rates to reflect the effects of future increase or decreases in the federal corporate income tax rate. The proposed Rider No. 4 is included within Company witness Mr. Ogden's Exhibit DBO-1.

Q. Why is the Company proposing the FTAC?

A. There several reasons. First, significant changes in the federal corporate income tax rate can dramatically affect the Company's revenue requirement. Second, it is currently difficult to adjust base rates to reflect such changes in a timely manner. Third, the time delay in adjusting base rates under current procedures can result in either significant refunds or significant retroactive recoveries after the effective date of the tax rate change. And, fourth, it is likely that a rate increase is forthcoming as the current federal administration has made numerous statements that an increase in the federal corporate income tax rate from the 21% rate to 28%, among other revenue enhancers, is critical to offsetting the costs of the upcoming infrastructure bill that is being drafted.

Q. Is there specific evidence that the federal administration has given to suggest that an increase in the federal corporate tax rate to 28% is likely to occur?

A. Yes, the White House issued a statement on March 31, 2021. The release, titled "Fact Sheet: The American Jobs Plan", outlines the proposals for significant government spending to invest and rebuild the U.S. infrastructure. As part of this plan, the White House has proposed an increase in the corporate tax rate from 21% to 28% to help pay for the additional government spending. The corporate tax rate increase is one of several proposals intended to roll back some tax reductions enacted only a few years ago with the passage of the TCJA, including the reduction in the corporate tax rate from 35% to the current rate of 21%.

Q. Can you illustrate the effect that an increase in the federal income tax rate increase from 21% to 28% would have on the revenue requirement in this proceeding?

A. Yes, I have done that in Exhibit MLS-3. There are three principal effects. The first is that current federal income taxes on taxable income are increased from 21% to 28%, resulting in an increase of $11.012 million in recoverable income taxes. This is shown on lines 22 to 24 of Exhibit MLS-3, page 1. The second effect is the increase in the required amount to provide for the annual provision for deferred taxes at the 28% rate, which is $0.817 million as shown on lines 2 and 5 of Exhibit MLS-3, page 2. The increase in the corporate tax rate from 21% to 28% represents a 33% tax increase [(28% - 21%) / 21% = 33% tax increase]. The computed increases in both current and deferred federal income expenses shown on Exhibit MLS-3, page 2, lines 7 and 8 are consistent with the proposed 33% tax rate increase. The third component is the reduction of the offset to the deferred tax amount to reduce the amount that provides for the flow back of excess deferred taxes (resulting from the reduction of the federal corporate income tax rate from 35% to 21% under the TCJA), which was reflected in base rates in the Company's 2018 base rate case.

Q. Please explain the calculation of the reduction of the flow back of excess deferred taxes that would result from an increase in the federal corporate income tax rate from 21% to 28%?

A. When there is a change in the federal corporate income tax rate, the IRS normalization rules require that the Company remeasure the accumulated deferred income tax ("ADIT") reserve as of the date of enactment which results in an excess deferred tax reserve (if the rate decreases) or a deficient deferred tax reserve (if the rate increases).[1] After the passage of the TCJA, the Company recorded a regulatory liability to reflect the change in the excess deferred tax reserve for the tax rate increase that went into effect 1/1/18. The amortization of this excess deferred tax reserve to return the amounts previously collected from customers that is no longer due to the IRS is reflected in the flow back of excess deferred taxes on Exhibit MLS-3, page 2, line 3. When there is subsequent change to the federal corporate income tax rate, another remeasurement occurs and the amount of the deferred income tax reserve is once again adjusted to reflect the new tax rate. In the case of a federal tax rate increase from 21% to 28%, this would result in a reduction to the previous balance of the excess deferred tax reserve which then causes a reduction in the amount of the flow back excess deferred taxes as shown on Exhibit MLS-3, page 2, line 6. The computed reduction in excess flow back is $5.809 million as shown on MLS-3, page 2, line 9.

[1] Section 13001(d)(3)(A) of the TCJA defines an "excess tax reserve" to mean the excess of the reserve for deferred taxes (as described in § 168(i)(9)(A)(ii)) as of the day before the corporate rate reductions provided in the amendments made by section 13001(a) take effect, over the amount which would be the balance in such reserve if the amount of such reserve were determined by assuming that the corporate tax rate reductions provided in the TCJA were in effect for all prior periods.

Q. What would be the total income tax effect from an increase in the federal income tax rate from 21% to 28%?

A. Considering the three principal effects described above, the increase in the federal tax rate would increase income tax expense by $17.638 million in the FPFTY as shown on Exhibit MLS-3, page 2, line 10.

Q. What would be the required increase in revenues to reflect the increase from 21% to 28% in this proceeding?

A. The required additional revenues to cover the increased tax expenses will be taxable to the Company. A tax gross up factor must be applied to the net increase in tax expense. To compute the required increase in revenues, the net tax impact shown on Exhibit MLS-3, page 2, line 10 must be multiplied by an adjusted gross revenue conversion that reflects the higher corporate tax rate. Applying the adjusted gross revenue conversion factor, the revenue increase to cover the incremental income tax expense would be $28.923 million as shown on Exhibit MLS-3, page 2, line 12.

Q. Please explain the difficulty of implementing federal corporate tax rate changes under the current system of Pennsylvania rate regulation.

A. The difficulty of implementing federal corporate tax rate changes is illustrated by the implementation of the tax rate reductions created by the TCJA. For companies like Duquesne Light that had planned base rate cases in 2018, the lower tax rate was reflected in those decisions prospectively in early 2019, along with refunds for

2018. The Commission set temporary rates for other companies and implemented surcredits on July 1, 2018 to begin the flow through of the tax rate decrease and required those companies to record regulatory liabilities for the first half of 2018. As noted previously in my testimony, this process delayed receipt of the effects of the tax rate change for some time and required retroactive changes to rates previously charged for service. It is more appropriate to adjust rates as expediently as possible to reflect tax rate changes. The FTAC is designed to accomplish that.

Q. Is there any precedent for changing base rates for tax rate changes in an adjustment mechanism?

A. Yes, Pennsylvania has had a State Tax Adjustment Surcharge ("STAS") in place for major utility companies for many years. It provides for adjustments to base rates for changes in state taxes and specifically for changes in the tax rate under the Pennsylvania Corporate Net Income Tax.

Q. Why is the Company proposing the FTAC now?

A. As I have illustrated, the federal corporate tax rate change contemplated by the current federal administration would have a significant effect on the Company's costs and cause the Company to earn less than a reasonable return in the FPFTY if adopted and not reflected in the Company's rates. Such a situation could occur late in 2021 or in 2022 after the record in this case is closed or when the rates set in this proceeding are in effect. In this regard, my understanding is that the current majorities in the federal Congress make it likely that this could happen by the end of 2022. Adopting the FTAC is an appropriate solution to this potential issue and it would provide symmetrical treatment to the Company to the treatment of the tax rate reduction under the TCJA.

Q Does this conclude your direct testimony?

A. Yes, it does. I reserve the right to supplement my testimony through the course of this proceeding.

EXHIBIT MLS-1

PAGE 1 of 1

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 2017	Taxable Income 2018	Taxable Income 2019	
Tax Loss Companies				
DQE HOLDINGS, LLC	(1,541)	(2,194)	(5,644)	
DUQUESNE LIGHT HOLDINGS, INC.	(67,768)	(79,717)	(58,444)	
TEN CONNECTED SOLUTIONS, INC.	-	-	(33)	
THE EFFICIENCY NETWORK, INC.	-	-	(2,019)	
Total Tax Loss	(69,308)	(81,910)	(66,140)	
Tax Positive Companies				
DUQUESNE LIGHT COMPANY	5,120	93,302	153,693	
MONONGAHELA LIGHT AND POWER	800	-	-	
DUQUESNE FIBER COMPANY	997	-	-	
DES CORPORATE SERVICES, INC.	25	(2)	-	
DQE ENTERPRISES, INC.	52	116	143	
DQE CAPITAL CORPORATION	2	77	(1)	
DQE SYSTEMS, INC.	10,214	-	-	
Total Taxable Income	17,209	93,494	153,834	
Total Consolidated Income/(Loss)	(52,099)	11,583	87,695	
% of Total	29.75%	99.80%	99.91%	
Total Allocated Tax Loss	(20,618)	(81,743)	(66,079)	(56,147)
Distribution allocation				49.290% [a]
Loss allocated to Distribution				(27,675)
Federal Tax rate				21.0%
Consolidated Tax Adjustment				(5,812)

[a] Source: Mr. Gorman testimony, Statement #15, Jurisdictional Separation Study Exhibit 6-8A,
JSS Factors - FedTax_Pres Distribution percentage

DUQUESNE LIGHT COMPANY
CALCULATION OF STATE AND FEDERAL INCOME TAXES
($ in Thousands)
INCOME TAXES

EXHIBIT MLS - 3
PAGE 1

Line #	[1] Description	[2] Reference	[3] Pro forma Proposed Rates FPFTY	[4] Ratemaking Adjustments	[5] Pro forma Proposed Rates FPFTY	Source
1	Operating Revenues		$ 654,141		$ 654,141	
2	Less: O&M Expenses & TOTI		$ 271,825		271,825	
3	Book Depreciation		162,106		162,106	
4	Interest Expense		45,529		45,529	
5	Operating Income before Taxes		$ 174,681	$ -	$ 174,681	Exhibit 2, D-22, L 7, col 9
6	Add: Premature Property Losses/ Amortizations		-			
7	Depr- Straight Line Book Depr - Remaining Life		162,106		$ 162,106	Exhibit 2, D-22, L 13, col 6
8	Taxable Meals & Entertainment		-			
9	Total		$ 162,106	$ -	$ 162,106	
	Deduct:					
10	State Tax Depreciation		123,435	-	123,435	Exhibit 2, D-22, L 14, col 6
11	Normalized Tax Repairs and 263A		59,913		59,913	Exhibit 2, D-22, L 8 + 9, col 9
12	Cost of Removal, net Salvage Amort		1,951		1,951	Exhibit 2, D-22, L 10 + 11, col 9
13	Total		$ 185,299	$ -	$ 185,299	
14	State Taxable Income	L 5 + 9 - 13	151,488	-	151,488	Agrees to Exhibit 2, D-22, L 16, col 9
	State Income At:					
15	Historic, Future and Fully Projected At 9.99%	L 14 x 9.99%	15,134	-	15,134	Exhibit 2, D-22, L 17, col 9
16	Taxable Income after State Income Tax	L 15 - L 16	136,354	-	136,354	
17	Add: Cost Of Removal Non Adr Property					
18	ACRS On Post 1980 Assets		-	-	-	
19	Add: State Tax Depreciation		123,435	-	123,435	Exhibit 2, D-22, L 14, col 6
20	Deduct: Federal Tax Depreciation		102,474	-	102,474	Exhibit 2, D-22, L 24, col 6
21	Income Subject To Federal Income Tax	L 16 + 19 - 20	$ 157,315	$ -	$ 157,315	Agrees to Exhibit 2, D-22, L 26, col 9
22	Federal Income Tax at 21%	L 21 x 21%			$ 33,036	[a]
23	Federal Income Tax at 28%	L 21 x 28%			$ 44,048	[b]
24	**Increase in Federal income tax expense**	**Line 23 - 22**			**$ 11,012**	

DUQUESNE LIGHT COMPANY
CALCULATION OF STATE AND FEDERAL INCOME TAXES
($ in Thousands)
INCOME TAXES

EXHIBIT MLS - 3
PAGE 2

Line #	[1] Description	[2] Reference	[3] Net Tax Effect	Source / Notes:
1	Federal- Current (Page 1, Column 4, Line 23)		33,036	[a]
2	Federal- Deferred		2,456	Exhibit 2, D-22, L 31+32, col 9
3	Federal- EDIT amortization		(8,857)	Exhibit 2, D-22, L 30, col 9
	Adjust: at 28%			
4	Federal- Current (Page 1, Column 4, Line 24)		44,048	[b]
5	Federal- Deferred		3,273	Calculated
6	Federal- EDIT amortization		(3,048)	Calculated
	Total Tax Increase			
7	Federal- Current	L 4 - L1	11,012	Line 1 x 33%
8	Federal- Deferred	L 5 - L 2	817	Line 2 x 33%
9	Federal- EDIT amortization	L 9 - L 6	5,809	
10	**Effect of 28% Tax Increase On Income (A)**	Sum L 7 to 9	17,638	
11	Gross Revenue Conversion Factor	L 22, 28% Rate	1.639785	
12	Revenue Deficiency	L 14 x 15	28,923	

Line #	Description	21% Rate	28% Rate	DIFFERENCE	Rate Increase %
13	Statutory State Tax Rate	9.99%	9.99%	0.00%	
14	Statutory Federal Tax Rate	21.00%	28.00%	7.00%	33.3%
15	1 minus State Tax Rate	90.010%	90.010%	0.00%	
16	Federal Rate multiplied by (1 minus State Tax Rate)	18.902%	25.203%	6.30%	
17	Effective Tax Rate	28.892%	35.193%	6.30%	
18	1 minus Effective Tax Rate (Complement Tax Rate)	0.711079	0.648072	-6.30%	
19	Reciprocal Tax Gross Up Factor	1.406314	1.543038		
20	Effective Tax Rate with GRT	33.088%	39.016%		
21	Income Tax Factor for Gross Revenue (includes GRT)	0.669125	0.609836		
22	Gross Revenue Conversion Factor	1.494489	1.639785		

Statement 13

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Duquesne Light Company	**)**	**Docket No. R-2021-3024750**

DIRECT TESTIMONY OF PAUL R. MOUL

Dated: April 16, 2021

Duquesne Light Company
Direct Testimony of Paul R. Moul
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GLOSSARY OF ACRONYMS AND DEFINED TERMS

ACRONYM	DEFINED TERM
ADIT	Accumulated Deferred Income Taxes
AFUDC	Allowance for Funds Used During Construction
β	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
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
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
ytm	Yield to maturity

DIRECT TESTIMONY OF PAUL R. MOUL

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 appropriate rate of return on common equity is 10.95%. This return falls within the range of results of the cost of equity models. 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. The Company's superior performance in these areas are described in the testimony of Mr. Davis and should be recognized by the Commission in its determination of the Company's rate of return. With this return, I have presented on page 1 of Schedule 1 the weighted average cost of capital, which is 7.84%. The Company's proposed rate of return is shown below:

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	46.65%	4.29%	2.00%
Common Equity	53.35%	10.95%	5.84%
Total	100.00%		7.84%

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. Are there unusual factors that you included in your analysis of the cost of equity for Duquesne Light that make this case unique?

A. Yes. My cost of equity analysis reflects the impact of the coronavirus pandemic. This event had a significant impact on the capital markets -- both debt and equity. Extraordinary events around the COVID-19 pandemic produced significant turmoil that has rocked the stock and bond markets beginning in the February-March 2020 time frame. During this period, we saw abrupt reaction to the coronavirus pandemic and declines in the price of crude oil. These events led to the end of the record-setting 128-month economic expansion. As a recession began in February

2020, extraordinary actions were taken by the Federal Open Market Committee ("FOMC") to address these disruptions. I have considered these events as they impact the inputs that I used in the various models of the cost of equity. That is to say, I have applied the cost of equity models using input data that follows the beginning of the economic recession.

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 to approximately 605,000 customers in Allegheny and Beaver counties. In 2019, electric sales in MWh for Duquesne Light were comprised of approximately 32% to residential, 48% to commercial, 20% to industrial customers. The Company is also the default service provider, or provider of last resort ("POLR"), and 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%.

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 eleven (11) 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?

[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).

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 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	10.52%
RP	10.10%
CAPM	12.54%
Comparable Earnings	12.60%

These returns that provide the range of the cost of equity from 10.10% to 12.54% using the market-based models, i.e., Discounted Cash Flow ("DCF"), Risk Premium, and Capital Asset Pricing Model ("CAPM"). Furthermore, the

Comparable Earnings method confirms the reasonableness of the range defined by the market based 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. The testimony of Mr. Davis and Mr. Morris summarize the many initiatives that the Company has undertaken, which have produced high quality service, along with superior customer service and an exceptional safety record. The Commission should consider these factors when setting the Company's cost of equity in this case. 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 there is always the potential that the Company may not actually achieve its allowed rate of return in the current economic environment. Uncertainty in this regard is related to unanticipated increases in operating and maintenance expenses and the impact on commercial and industrial sales during this recessionary period. My recommendation should be viewed as the minimum necessary to satisfy investors' expectations. It is important that the Company have a reasonable opportunity to earn is cost of capital and that way, sustain its ability to attract and retain capital at the level needed to support the increased demand for capital investment.

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 68% 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. 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., 2021 through 2025), the Company's total capital expenditures are expected to be approximately $1,826.1 million. These expenditures will represent approximately 52.4% ($1,826.1 million ÷ $3,487.3 million) of the net utility plant at December 31, 2020. 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) have publicly-traded common stock, (ii) are contained in The Value Line Investment Survey and are classified in the Electric Utility East group, along with additional companies that are relatively small, (iii) are not currently the target of an announced merger or acquisition, (iv) are not engaged in the construction of a nuclear generating plant, and (v) have not recently reduced their common dividend. 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. This situation is different from the company that initiates the acquisition, which will be the surviving entity. My Electric Group obtained from the Value Line Investment Survey consists of the following companies: AVANGRID, Inc., Consolidated Edison, Duke Energy, Eversource Energy, Exelon Corp., FirstEnergy Corp., MGE Energy, NextEra Energy, Otter Tail Corp., 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 Treasurer, provides further detail on the Company's credit ratings. For the Electric Group, the average LT issuer rating is A2 from Moody's and the average CCR is A- 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 similar to the Electric Group (e.g.

Duquesne Light's Moody's rating is one notch weaker than the Electric Group and its S&P rating is also one notch weaker).

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 2015-2019. The important categories of relative risk may be summarized as follows:

<u>Size.</u> 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.

<u>Market Ratios.</u> 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 similar to the S&P Public Utilities. The five-year average dividend yield was slightly higher for the Electric Group than the S&P Public Utilities. The average market-to-book ratio for the Electric Group was lower than 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 with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 52.5% for Duquesne Light, 49.8% for the Electric Group, and 42.2% for the S&P Public Utilities. The average common equity ratio in 2019 was 48.1% for the Electric Group and reflected a range of common equity ratios from 25.8% to 66.3%. The common equity ratio proposed by Duquesne Light in this case of 53.35%, 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

[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).

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 0.132 (1.5% ÷ 11.4%) for Duquesne Light, 0.084 (0.8% ÷ 9.5%) for the Electric Group, and 0.049 (0.5% ÷ 10.2%) 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.

<u>Operating Ratios.</u> 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 72.3% for Duquesne Light, 77.7% for the Electric Group, and 78.8% 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.

<u>Coverage.</u> 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

[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.

Allowance for Funds Used During Construction ("AFUDC")) was 4.92 times for Duquesne Light, 3.81 times for the Electric Group, and 3.22 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.

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 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.

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 80.0% for Duquesne Light, 77.7% for the Electric Group, and 74.1% for the S&P Public Utilities. The IGF percentages were fairly similar for Duquesne Light, the Electric Group, and the S&P Public Utilities, albeit the Company's ratio was higher.

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 .88 as the average for the Electric Group (see page 2 of Schedule 3), and .91 as the average for the S&P Public Utilities (see page 3 of Schedule 4). The systematic risk was slightly lower for the Electric Group as compared to the S&P Public Utilities.

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. Overall, the results from the Electric Group provide a conservative, albeit an understatement, of the Company's cost of equity. Indeed, the size of Duquesne Light, its much more variable returns, and the somewhat weaker credit rating suggests that the Electric Group provides an understatement of the

[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.

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, 2020, the end of the historic test year ("HTY"). Also shown on Schedule 5 is the Duquesne Light's estimated capital structure at December 31, 2021, which is the end of the future test year ("FTY"), and at December 31, 2022, which is the end of the fully projected future test year ("FPFTY"). During the FPFTY, the Company's capital structure reflects the projected issuance of $150 million of first mortgage bonds and 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 associated with the Company's pension and postretirement plans must be excluded from the common equity because it does not represent funds available to the Company that could be 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 FPFTY capital structure ratios of 46.65% long-term debt and 53.35% 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., $104.3 million average short-term debt in 2022 with an $11.0 million short-term debt balance at December 31, 2022) is less than the associated CWIP balances of $339.7 million at December 31, 2022. 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 4.39% at December 31, 2020. By December 31, 2022, the embedded debt cost rate is estimated to be 4.29%, as shown on page 3 of Schedule 6. For the new issue of debt in the FPFTY, the Company expects this issue to have a 3.50% coupon rate. 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 4.29% embedded cost of long-term debt at December 31, 2022, 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 46.65% 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.

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.

DISCOUNTED CASH FLOW

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-determined 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, which assumes that 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 Schedule 1, page 2, for the Electric Group. The DCF return is 10.52% with the leverage adjustment and 9.06% without the leverage adjustment for the Electric Group. It is apparent that without the leverage adjustment to the DCF that the result is unrealistic. This is obvious due to the

[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.

results of the other models of the cost of equity that provide a considerably higher result.

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 the dividends an investor receives. 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 December 2020, the monthly dividend yields are shown on Schedule 7. The month-end prices were adjusted to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., 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 December 2020 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-month and three-month periods were 3.80% and 3.73%, respectively. For applying the DCF model, I have used the six-month average dividend yield of 3.80% 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 investors' anticipated cash flows. 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 3.91% 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 growth in earnings per share is the DCF model's primary focus because, under the model's assumption that the price-earnings multiple remains constant, the price per share of stock will grow at the same rate as earnings per share. A growth rate analysis considers a variety of variables to reach a consensus of prospective growth, including historical data and widely available analysts' forecasts of earnings, dividends, book value, and cash flow (all stated on a per-share basis). A fundamental growth rate analysis is frequently based upon internal growth ("b x r"), where "r" is the expected rate of return on common equity and "b" is the retention rate (a fraction representing the proportion of earnings not paid out as dividends).

To be complete, the internal growth rate should be modified to account for sales of new common stock (external growth), which is represented by the formula s x v, where "s" is the number of new common shares the firm expects to issue and "v" is the value that accrues to existing shareholders from selling stock at a price above book value. Fundamental growth, which combines internal and external growth, encompasses 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 stabilize 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. 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 should be evaluated using a variety of techniques 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 considered the growth in the financial variables shown on Schedules 8 and 9, which reflect historical (Schedule 8) and projected (Schedule 9) rates of growth 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, earnings per share growth directly influences the expectations of investors for the future performance of utility stocks. Forecasts of earnings growth are required because the DCF model is forward-looking, and, with the constant price-earnings multiple and constant payout ratio that the DCF model assumes, all other measures of growth will mirror earnings growth. The historical growth rates were obtained from the Value Line publication that provides those data. While historical data cannot be ignored, it is much less significant in applying the DCF model than projections of future growth. Investors cannot purchase the past earnings of a utility. To the contrary, they are only entitled to future earnings, which are the focus of growth projections. Furthermore, if significant weight is assigned to historical performance, the historical data are double counted because they are already factored into analysts' forecasts of earnings growth.

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

A. Yes, it is. Although the constant form of the DCF model assumes an infinite stream of cash flows, 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 investors' expected return. The growth in the price per share will equal the growth in earnings per share if, as the DCF model assumes, there is no change in the price-earnings ("P-E") multiple. 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 investors' expectations of their actual total return. Moreover, academic research focuses also on five-year growth rates specifically because market outcomes occurring over that investment horizon are what influence stock prices.

Indeed, if investors required forecasts beyond five years in order to properly value common stocks, then it would be reasonable to expect that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of the marketplace. The absence of such a publication suggests that there is no market for this information because investors do not require forecasts for an infinite series of future data points in order to make informed decisions to purchase and sell stocks.

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, and Value Line. These are all reliable authorities of projected growth that investors use to make buy, sell and hold decisions. The IBES/First Call and Zacks estimates are obtained from the Internet and are widely available to investors. The growth rates reported by IBES/First Call and Zacks are consensus forecasts taken from a survey of analysts that make growth projections for these companies. Notably, First Call's earnings forecasts are frequently quoted in the financial press. 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 and Zacks 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 for the Electric Group are also included on Schedule 9.

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

A. Schedule 9 shows the prospective five-year earnings per share growth rates projected for the Electric Group by IBES/First Call (4.94%), Zacks (4.35%), and Value Line (5.18%).

Q. Are certain growth rate forecasts entitled to greater weight in developing a growth rate for use in the DCF model?

A. Yes. While a variety of factors should be examined to reach a reasonable conclusion on the DCF growth rate, growth in earnings per share should receive the greatest emphasis. Growth in earnings per share is the primary determinant of investors' expectations of the total returns they will obtain from stocks because the capital gains yield (i.e., price appreciation) will track earnings growth if the P-E multiple remains constant, as the DCF model assumes. 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 fact, Professor Myron Gordon, the foremost proponent of the use of the DCF model in setting utility rates, concluded that the best measure of growth for use in the DCF model is a forecast of earnings per-share growth.[6] Consistent with Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, and Value Line, provide the best indication of investor expectations.

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

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

A. The forecasts shown on Schedule 9 for the Electric Group exhibit a range of average earnings per share growth rates from 4.35% to 5.18%. DCF growth rates should not be established by mathematical formulation, and I have not done so. In my opinion, a growth rate of 5.15% is a reasonable estimate of investor-expected growth for the Electric Group. This value is within the array of analysts' forecasts of five-year earnings per share growth rates. The reasonableness of this growth rate is also supported by the expected continuation of accelerated electric utility infrastructure spending.

Q. Are the dividend yield and growth components of the DCF adequate to accurately depict the rate of return on common equity when it is used to calculate a utility's weighted average overall cost of capital?

A. The components of the DCF model are adequate for that purpose only if the capital structure ratios are measured by the market value of debt and equity. In the case of the Electric Group, average capital structure ratios are 37.60% long-term debt, 0.03% preferred stock, and 62.36% 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. If a firm's capitalization, as measured by its stock price, diverges from its capitalization, measured at book value, the potential exists for a financial risk difference. Such a risk difference arises because a market-valued capitalization contains more equity and less debt than a book-value capitalization and, therefore, has less risk than the book-value capitalization. A leverage adjustment properly accounts for the risk differential 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 from the capital structure 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-valued 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 ratios calculated from a firm's book value capitalization, further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the firm's 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 7.31% 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. 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 actually existed.

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: 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. What I label 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) when the DCF return applies to a capital structure used for ratemaking that is computed with book-value weighting rather than market-value weighting. Although I specify a separate factor, which I call the leverage adjustment, there is no need to do so other than to identify this factor. If I expressed my return solely in the context of the book value weighting that we use to calculate the weighted average cost of capital and ignore the familiar D/P + g expression entirely, then a separate element in the DCF cost of equity determination would not be needed to reflect the differential in financial leverage between a market-value and 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 7.31%, which is the return for the Electric Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio) plus 3.20% to compensate investors for the risk of a 52.07% debt ratio and 0.01% associated with the 0.22% preferred stock ratio. Under this approach, the parts sum to 10.52% (7.31% + 3.20% + 0.01%), 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 3.91% dividend yield, the 5.15% growth rate, and 1.46% for the leverage adjustment in order to arrive at the same 10.52% (3.91% + 5.15% + 1.46%) return. I know of no means to mathematically solve for the 1.46% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 1.46% adjustment is merely a convenient way to compare the 10.52% return computed using the Modigliani & Miller formulas to the 9.06% return generated by the DCF model (i.e., $D_1/P_0 + g$, or the traditional form of the DCF shown on Schedule 7, page 1) based on a market-value capital structure. A 9.06% 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. Please provide the DCF return based upon your preceding discussion of dividend yield, growth, and leverage.

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. The resulting DCF cost rate is 10.52%, computed as follows:

	D_1/P_0	+	g	+	$lev.$	=	K
Electric Group	3.91%	+	5.15%	+	1.46%	=	10.52%

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 the results of other models when determining a company's cost of equity. In fact, the DCF result is clearly understated if it is viewed without the leverage adjustment when compared to the results of other models of the cost of equity. Indeed, the Commission has often referenced other models of the cost of equity when deciding the rate of return in rate cases. And when it sets the equity return in the DSIC proceedings, the DSIC return today significantly exceeds the simple yield plus growth formulation of the DCF.

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 Schedule 1, page 2. That result is 10.10%.

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 3.35% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

Q. What historical data are 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 Schedule 11, page 1. For the twelve months ended December 2020, the average monthly yield on Moody's index of A-rated public utility bonds was 3.02%. For the six and three-month periods ended December 2020, the yields were 2.81% and 2.86%, respectively. During the twelve-months ended December 2020, the range of the yields on A-rated public utility bonds was 2.73% to 3.50%. 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 1.45% on a twelve-month average basis, 1.32% on a six-month average basis, and 1.24% on a three-month average basis. Giving greater emphasis to the three-month average spread, which reflects the downtrend, 1.25% represents a reasonable 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. 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 January 1, 2021, and a yield spread of 1.25%, derived from historical data. I should note that after these data were assembled, there was a runup of yields on long-term Treasury bonds beginning in mid-February 2021.

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
2021	First	2.5%	3.5%	1.7%	1.25%	2.95%
2021	Second	2.5%	3.6%	1.8%	1.25%	3.05%
2021	Third	2.6%	3.7%	1.9%	1.25%	3.15%
2021	Fourth	2.7%	3.8%	2.0%	1.25%	3.25%
2022	First	2.8%	3.8%	2.1%	1.25%	3.35%
2022	Second	2.8%	3.8%	2.1%	1.25%	3.35%

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, 2020 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
2022-2026	3.6%	4.6%	2.8%
2027-2031	4.5%	5.4%	3.6%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. A 3.35% yield on A-rated public utility bonds represents a reasonable benchmark for measuring the cost of equity in this case. All the data I used to formulate my conclusion as to a prospective yield on A-rated public utility debt are available to investors, who regularly rely upon those data to make investment decisions.

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

A. To develop an appropriate equity risk premium, I analyzed the results from 2020 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 Schedule 12, page 1.

Common Equity Risk Premiums

Low Interest Rates	6.70%
Average Across All Interest Rates	5.69%
High Interest Rates	4.69%

Based on my analysis of the historical data, the equity risk premium was 6.70% when the marginal cost of long-term government bonds was low (i.e., 2.88%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.09% on average during periods of high interest rates), the spread narrowed to 4.69%. Over the entire spectrum of interest rates, the equity risk premium was 5.69% when the average government bond yield was 4.99%. I have utilized a 6.75% equity risk premium. The equity risk premium of 6.75% that I employed is near the risk premiums associated with low interest rates.

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 10.10%, computed as follows:

	i	+	*RP*	=	*k*
Electric Group	3.35%	+	6.75%	=	10.10%

<u>CAPITAL ASSET PRICING MODEL</u>

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 12.54% for the Electric Group. 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 <u>Value Line</u> betas. As shown on page 2 of Schedule 3, the average beta is 0.88 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 0.63 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 1.08 for the book value capital structure of the Electric Group.

[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.

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 December 2020, the average yield on 30-year Treasury bonds was 1.56%. For the six- and three-months ended December 2020, the yields on 30-year Treasury bonds were 1.49% and 1.62%, respectively. During the twelve-months ended December 2020, the range of the yields on 30-year Treasury bonds was 1.27% to 2.22%. The low yields that existed during recent years can be traced to weakness in business fixed investment and exports due in part to the U.S.'s trade war with China. Thereafter, extraordinary events associated with the COVID-19 pandemic induced significant turmoil that jolted the capital markets in the February-May 2020 time frame. During this period, we saw abrupt reaction to the coronavirus pandemic and significant declines in the price of crude oil. These events led to the end of the record-setting 128-month economic expansion. As the recession unfolded in February 2020, the Federal Open Market Committee ("FOMC") acted to address these disruptions. Presently, the Fed Funds rate is near zero. The FOMC continues to support the money and capital markets during the coronavirus pandemic.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on January 1, 2021 indicate that the yields on long-term Treasury bonds are expected to be in the range of 1.7% to 2.1% during the next six quarters. The forecast for the FPFTY is 2.1% for 30-year Treasury Bonds. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 2.8% from 2022 through 2026 and 3.6% from 2027 to 2031. 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 2.10% risk-free rate of return for CAPM purposes, which considers the Blue Chip forecasts and the trend toward higher Treasury yields that developed in mid-February 2021.

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

A. As shown in the lower panel of data presented on Schedule 13, page 2 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 Schedule 12, page 1. On that schedule, the market return was 11.92% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.88% when interest rates were low. As such, I carried over to Schedule 13, page 2, the average large common stock returns of 11.92% and the average yield on long-term government bonds of 2.88%. The resulting market premium is 9.04% (11.92% - 2.88%) based on historical data, as shown on Schedule 13, page 2. As also shown on Schedule 13, page 2, I calculated the forecast returns, which show a 10.50% total market return. With this forecast, I calculated a market premium of 8.40% (10.50% - 2.10%) using forecast data. The resulting market premium applicable to the CAPM derived from these sources equals 8.72% (8.40% + 9.04% = 17.44% ÷ 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. As noted previously, Duquesne Light is relatively smaller than the Electric Group. To recognize this fact, I used the mid-cap adjustment of 1.02%, as revealed on page 3 of Schedule 13, for the CAPM calculation.

Q. What does your CAPM analysis show?

A. Using the 2.10% risk-free rate of return, the leverage adjusted beta of 1.08 for the Electric Group, the 8.72% market premium, and the 1.02% size adjustment, the following result is indicated.

	Rf	+	*ß*	*x* (	*Rm-Rf*	) +	*size*	=	*k*
Electric Group	2.10%	+	1.08	x (	8.72%	) +	1.02%	=	12.54%

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 Schedule 14, page 3. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on Schedule 14, page 1.

I relied upon Value Line data because they provide 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 Schedule 14, page 2, 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 Bluefield 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 12.2% using only the returns that were less than 20%, as shown on Schedule 14, page 2. The average forecasted rate of return as published by Value Line is 13.0% also using values less than 20%, as provided on Schedule 14, page 2. Using the average of these data my Comparable Earnings result is 12.60%, as shown on Schedule 1, page 2.

CONCLUSION ON COST OF EQUITY

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. My cost of equity recommendation is obtained from a range of the market based models (i.e., 10.10% to 12.54%) and should be considered in the context of the Company's risk characteristics, as well as the general condition of the capital markets. Indeed, as the economy recovers from the pandemic-induced recession, business activity will increase, which will place upward pressure on interest rates. 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.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

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.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

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

Duquesne Light Company
Index of Schedules

Duquesne Light Company
Proposed Rate of Return
Estimated at December 31, 2022

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	46.65%	4.29%	2.00%
Common Equity	53.35%	10.95%	5.84%
Total	100.00%		7.84%

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
(10.21% ÷ 2.00%) 5.11 x

Post-tax coverage of interest expense
(7.84% ÷ 2.00%) 3.92 x

Duquesne Light Company
Cost of Equity
as of December 31, 2020

Discounted Cash Flow (DCF)					***D_1/P_0*** [1]	**+**	***g*** [2]	**+** ***lev.*** [3]	**=** ***k***
Electric Group					3.91%	+	5.15%	+ 1.46%	= 10.52%
Risk Premium (RP)							***I*** [4]	**+** ***RP*** [5]	= ***k***
Electric Group							3.35%	+ 6.75%	= 10.10%
Capital Asset Pricing Model (CAPM)	***Rf*** [6]	**+**	***ß*** [7]	***x (***	***Rm-Rf*** [8]	***) +***	***size*** [9]	=	***k***
Electric Group	2.10%	+	1.08	x (	8.72%	) +	1.02%	=	12.54%
Comparable Earnings (CE) [10]					***Historical***		***Forecast***		***Average***
Comparable Earnings Group					12.2%		13.0%		12.60%

References:
[1] Schedule 07
[2] Schedule 09
[3] Schedule 10
[4] A-rated public utility bond yield comprised of a 2.10% risk-free rate of return (Schedule 13 page 2) and a yield spread of 1.25% (Schedule 11 page 3)
[5] Schedule 12 page 1
[6] Schedule 13 page 2
[7] Schedule 10
[8] Schedule 13 page 2
[9] Schedule 13 page 3
[10] Schedule 14 page 2

Duquesne Light Company
Capitalization and Financial Statistics
2015-2019, Inclusive

	2019	2018	2017	2016	2015	Average
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 2,589.0	$ 2,498.1	$ 2,352.4	$ 2,236.0	$ 2,207.3	
Short-Term Debt	$ -	$ -	$ -	$ -	$ -	
Total Capital	$ 2,589.0	$ 2,498.1	$ 2,352.4	$ 2,236.0	$ 2,207.3	
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	45.1%	48.5%	48.5%	46.0%	46.5%	46.9%
Preferred Stock	0.0%	0.0%	0.0%	1.5%	1.5%	0.6%
Common Equity	54.9%	51.5%	51.5%	52.5%	52.0%	52.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt, incl. Short Term	45.1%	48.5%	48.5%	46.0%	46.5%	46.9%
Preferred Stock	0.0%	0.0%	0.0%	1.5%	1.5%	0.6%
Common Equity	54.9%	51.5%	51.5%	52.5%	52.0%	52.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity	13.6%	12.2%	10.7%	10.1%	10.3%	11.4%
Operating Ratio (1)	70.5%	73.6%	71.2%	73.6%	72.8%	72.3%
Coverage incl. AFUDC (2)						
Pre-tax: All Interest Charges	5.26 x	4.38 x	5.36 x	5.03 x	4.59 x	4.92 x
Post-tax: All Interest Charges	4.38 x	3.73 x	3.62 x	3.43 x	3.12 x	3.66 x
Overall Coverage: All Int. & Pfd. Div.	4.38 x	3.73 x	3.46 x	3.34 x	2.89 x	3.56 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	5.26 x	4.38 x	5.36 x	5.03 x	4.59 x	4.92 x
Post-tax: All Interest Charges	4.38 x	3.73 x	3.62 x	3.43 x	3.12 x	3.66 x
Overall Coverage: All Int. & Pfd. Div.	4.38 x	3.73 x	3.46 x	3.34 x	2.89 x	3.56 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	20.7%	19.4%	39.9%	39.7%	41.0%	32.1%
Internal Cash Generation/Construction (4)	92.6%	71.4%	60.1%	98.6%	77.1%	80.0%
Gross Cash Flow/ Avg. Total Debt(5)	29.4%	27.6%	23.8%	33.1%	29.8%	28.7%
Gross Cash Flow Interest Coverage(6)	7.42 x	6.75 x	6.15 x	7.94 x	5.88 x	6.83 x
Common Dividend Coverage (7)	6.97 x	4.15 x	2.89 x	3.72 x	3.04 x	4.15 x

See Page 2 for Notes.

Duquesne Light Company
Capitalization and Financial Statistics
2015-2019, 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)
2015-2019, Inclusive

	2019	2018	2017	2016	2015	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 41,223.1	$ 37,589.8	$ 35,582.8	$ 33,139.8	$ 31,162.5	
Short-Term Debt	$ 1,257.6	$ 1,754.9	$ 865.8	$ 960.4	$ 988.5	
Total Capital	$ 42,480.7	$ 39,344.7	$ 36,448.6	$ 34,100.2	$ 32,151.0	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	21 x	20 x	20 x	21 x	19 x	20 x
Market/Book Ratio	209.6%	194.7%	198.5%	175.8%	156.5%	187.0%
Dividend Yield	3.3%	3.6%	3.5%	3.7%	3.4%	3.5%
Dividend Payout Ratio	67.9%	72.4%	67.1%	74.1%	59.5%	68.2%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	50.6%	49.5%	50.6%	49.3%	46.9%	49.4%
Preferred Stock	1.3%	1.0%	0.6%	0.5%	0.4%	0.8%
Common Equity (2)	48.1%	49.5%	48.9%	50.2%	52.7%	49.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	51.8%	51.3%	52.1%	50.6%	48.5%	50.9%
Preferred Stock	1.3%	1.0%	0.5%	0.5%	0.4%	0.7%
Common Equity (2)	46.9%	47.7%	47.4%	49.0%	51.1%	48.4%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity (2)	9.5%	10.2%	10.5%	8.6%	8.8%	9.5%
Operating Ratio (3)	78.9%	78.5%	75.5%	77.3%	78.4%	77.7%
Coverage incl. AFUDC (4)						
Pre-tax: All Interest Charges	3.43 x	3.88 x	3.88 x	4.17 x	4.11 x	3.89 x
Post-tax: All Interest Charges	3.02 x	3.28 x	3.55 x	3.12 x	3.08 x	3.21 x
Overall Coverage: All Int. & Pfd. Div.	3.01 x	3.23 x	3.54 x	3.12 x	3.08 x	3.20 x
Coverage excl. AFUDC (4)						
Pre-tax: All Interest Charges	3.35 x	3.79 x	3.79 x	4.09 x	4.03 x	3.81 x
Post-tax: All Interest Charges	2.94 x	3.20 x	3.45 x	3.03 x	3.01 x	3.13 x
Overall Coverage: All Int. & Pfd. Div.	2.93 x	3.14 x	3.45 x	3.03 x	3.01 x	3.11 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	4.4%	5.4%	4.0%	4.8%	5.7%	4.9%
Effective Income Tax Rate	17.1%	20.0%	14.9%	33.2%	30.7%	23.2%
Internal Cash Generation/Construction (5)	65.9%	75.6%	79.2%	83.0%	85.0%	77.7%
Gross Cash Flow/ Avg. Total Debt (6)	19.1%	21.0%	23.0%	24.2%	24.0%	22.3%
Gross Cash Flow Interest Coverage (7)	5.22 x	5.79 x	6.14 x	6.21 x	5.88 x	5.85 x
Common Dividend Coverage (8)	3.44 x	3.69 x	4.04 x	4.20 x	4.01 x	3.88 x

See Page 2 for Notes.

Electric Group
Capitalization and Financial Statistics
2015-2019, 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 along with additional companies that are relatively small, (iii) are not currently the target of an announced merger or acquisition, (iv) are not engaged in the construction of a nuclear generating plant or have not recently cancelled the construction of a nuclear generating plant, and (v) have not recently reduced its common dividend.

		Corporate Credit Ratings		Stock	Value Line
Ticker	Company	Moody's	S&P	Traded	Beta
AGR	Avangrid, Inc.	A3	BBB+	NYSE	0.85
ED	Consol. Edison	Baa1	A-	NYSE	0.75
DUK	Duke Energy	A1	BBB+	NYSE	0.85
ES	Eversource Energy	A3	A	NYSE	0.90
EXC	Exelon Corp.	A2	BBB+	NASDQ	0.95
FE	FirstEnergy Corp.	A3	BB+	NYSE	0.85
MGEE	MGE Energy	A1	AA-	NASDQ	0.70
NEE	NextEra Energy	A1	A	NYSE	0.90
OTTR	Otter Tail Corp.	A3	BBB+	NASDQ	0.85
PPL	PPL Corp.	A3	A-	NYSE	1.15
PEG	Public Serv. Enterprise	A2	A-	NYSE	0.90
	Average	A2	A-		0.88

Note: Ratings are those of utility subsidiaries

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)
2015-2019, Inclusive

	2019	2018	2017	2016	2015	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 36,567.1	$ 32,871.6	$ 30,827.6	$ 29,173.1	$ 26,655.9	
Short-Term Debt	$ 1,221.9	$ 1,420.3	$ 1,076.1	$ 1,032.2	$ 875.5	
Total Capital	$ 37,789.0	$ 34,291.9	$ 31,903.7	$ 30,205.3	$ 27,531.4	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	20 x	21 x	21 x	21 x	18 x	20 x
Market/Book Ratio	220.8%	204.7%	214.4%	196.0%	181.1%	203.4%
Dividend Yield	3.2%	3.5%	3.3%	3.5%	3.6%	3.4%
Dividend Payout Ratio	62.7%	71.7%	74.4%	74.6%	68.8%	70.4%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	56.7%	55.0%	56.8%	56.6%	54.7%	55.9%
Preferred Stock	2.2%	2.5%	1.4%	1.9%	1.6%	1.9%
Common Equity (2)	41.1%	42.5%	41.8%	41.6%	43.8%	42.2%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	58.2%	57.0%	58.4%	58.2%	56.1%	57.6%
Preferred Stock	2.1%	2.4%	1.4%	1.8%	1.5%	1.8%
Common Equity (2)	39.7%	40.7%	40.3%	40.1%	42.4%	40.6%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity (2)	10.3%	10.3%	10.8%	9.7%	9.7%	10.2%
Operating Ratio (3)	79.3%	79.8%	77.0%	78.2%	79.7%	78.8%
Coverage incl. AFUDC (4)						
Pre-tax: All Interest Charges	3.05 x	2.94 x	3.42 x	3.38 x	3.80 x	3.32 x
Post-tax: All Interest Charges	3.10 x	2.59 x	2.86 x	2.55 x	2.79 x	2.78 x
Overall Coverage: All Int. & Pfd. Div.	3.04 x	2.55 x	2.84 x	2.52 x	2.75 x	2.74 x
Coverage excl. AFUDC (4)						
Pre-tax: All Interest Charges	2.95 x	2.84 x	3.31 x	3.28 x	3.70 x	3.22 x
Post-tax: All Interest Charges	3.00 x	2.48 x	2.75 x	2.44 x	2.69 x	2.67 x
Overall Coverage: All Int. & Pfd. Div.	2.94 x	2.44 x	2.73 x	2.41 x	2.65 x	2.63 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	5.8%	7.3%	7.3%	6.5%	5.5%	6.5%
Effective Income Tax Rate	12.2%	19.0%	28.2%	29.0%	32.5%	24.2%
Internal Cash Generation/Construction (5)	66.0%	75.7%	78.7%	78.0%	71.9%	74.1%
Gross Cash Flow/ Avg. Total Debt (6)	17.5%	17.4%	19.9%	20.5%	20.0%	19.1%
Gross Cash Flow Interest Coverage (7)	4.97 x	4.98 x	5.57 x	5.54 x	5.41 x	5.29 x
Common Dividend Coverage (8)	5.56 x	4.80 x	4.33 x	4.31 x	4.24 x	4.65 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2015-2019, 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	S&P	Common Stock Traded	Value Line Beta
Alliant Energy Corporation	LNT	Baa1	A-	NYSE	0.85
Ameren Corporation	AEE	Baa1	BBB+	NYSE	0.85
American Electric Power	AEP	Baa1	A-	NYSE	0.75
American Water Works	AWK	Baa1	A	NYSE	0.85
CenterPoint Energy	CNP	Baa1	BBB+	NYSE	1.15
CMS Energy	CMS	A3	A-	NYSE	0.80
Consolidated Edison	ED	Baa1	A-	NYSE	0.75
Dominion Energy	D	A2	BBB+	NYSE	0.80
DTE Energy Co.	DTE	A2	A-	NYSE	0.95
Duke Energy	DUK	A1	BBB+	NYSE	0.85
Edison Int'l	EIX	Baa2	BBB	NYSE	0.95
Entergy Corp.	ETR	Baa1	A-	NYSE	0.95
Evergy, Inc.	EVRG	Baa1	A-	NYSE	1.00
Eversource	ES	A3	A	NYSE	0.90
Exelon Corp.	EXC	A2	BBB+	NYSE	0.95
FirstEnergy Corp.	FE	A3	BB+	NYSE	0.85
NextEra Energy Inc.	NEE	A1	A	NYSE	0.90
NiSource Inc.	NI	Baa2	BBB+	NYSE	0.85
NRG Energy Inc.	NRG	Ba1	BB+	NYSE	1.25
Pinnacle West Capital	PNW	A2	A-	NYSE	0.90
PPL Corp.	PPL	A3	A-	NYSE	1.15
Public Serv. Enterprise Inc.	PEG	A2	A-	NYSE	0.90
Sempra Energy	SRE	Baa1	BBB+	NYSE	1.00
Southern Co.	SO	Baa1	A-	NYSE	0.90
WEC Energy Corp.	WEC	A2	A-	NYSE	0.80
Xcel Energy Inc	XEL	A2	A-	NYSE	0.80
Average for S&P Utilities		A3	BBB+		0.91

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, 2020 and Estimated at December 31, 2021 and December 31, 2022

	Actual at December 31, 2020			Estimated at December 31, 2021			Estimated at December 31, 2022		
	Amount Outstanding	Ratios Excl. S-T Debt	Ratios Incl. S-T Debt	Amount Outstanding	Ratios Excl. S-T Debt	Ratios Incl. S-T Debt	Amount Outstanding	Ratios Excl. S-T Debt	Ratios Incl. S-T Debt
Long-Term Debt	$ 1,377,771,607	47.71%	47.55%	$ 1,379,800,430 (2)	46.39%	46.03%	$ 1,506,814,759 (2)	46.65%	46.30%
Common Equity									
Common Stock	-			-			-		
Capital Surplus	988,426,521			988,426,521			988,426,521		
Retained earnings(1)	521,503,160			606,171,160 (3)			734,862,160 (3)		
Total Common Equity	1,509,929,681	52.29%	52.11%	1,594,597,681	53.61%	53.19%	1,723,288,681	53.35%	52.95%
Total Permanent Capital	2,887,701,288	100.00%	99.66%	2,974,398,111	100.00%	99.22%	3,230,103,440	100.00%	99.25%
Short-term Debt	10,000,000		0.34%	23,400,000		0.78%	24,200,000		0.75%
Total Capital Employed	$ 2,897,701,288		100.00%	$ 2,997,798,111		100.00%	$ 3,254,303,440		100.00%

Notes:

	2020	2021	2022
(1) Excluding Accumulated Other Comprehensive Income ("OCI") of:	$ (2,690,662)	$ (2,690,662)	$ (2,690,662)
(2) Reflects changes in the principal amount of long-term debt of:			
1st Mortgage Bond 3.38% due 3/31/52			$ 125,000,000
Net change in Loss on Reacquired Debt		$ 2,028,822	2,014,329
(3) Projection of retained earnings consisting of:			
Net Income		$ 158,668,000	$ 173,191,000
Distributions		(74,000,000)	(44,500,000)

Source of Information: Company provided data

Duquesne Light Company
Calculation of the Embedded Cost of Long-Term Debt
Actual at December 31, 2020

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	14.34%	4.81%	0.69%
1st Mortgage Bond 4.97% due 11/14/43	160,000,000	11.47%	5.01%	0.57%
1st Mortgage Bond 5.02% due 2/4/44	45,000,000	3.23%	5.06%	0.16%
1st Mortgage Bond 5.12% due 2/4/54	85,000,000	6.09%	5.16%	0.31%
1st Mortgage Bond 3.78% due 3/2/45	100,000,000	7.17%	3.81%	0.27%
1st Mortgage Bond 3.93% due 3/2/55	200,000,000	14.34%	3.95%	0.57%
1st Mortgage Bond 3.93% due 7/15/45	160,000,000	11.47%	3.96%	0.45%
1st Mortgage Bond 3.82% due 10/3/47	60,000,000	4.30%	3.86%	0.17%
1st Mortgage Bond 3.89% due 2/1/48	60,000,000	4.30%	3.93%	0.17%
1st Mortgage Bond 4.04% due 2/1/58	125,000,000	8.96%	4.07%	0.36%
1st Mortgage Bond 3.11% due 5/5/50	200,000,000	14.34%	3.14%	0.45%
Total Long -Term Debt	1,395,000,000	100.00%		4.19%
Unamortized Call Premium	(17,228,393)			
Long Term- Debt	$ 1,377,771,607			
Annualized Cost	$ 58,387,136			
Amortization of Loss on Reacquired Debt	2,033,556			
Total Cost	$ 60,420,692			4.39%

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, 2021

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	14.34%	4.81%	0.69%
1st Mortgage Bond 4.97% due 11/14/43	160,000,000	11.47%	5.01%	0.57%
1st Mortgage Bond 5.02% due 2/4/44	45,000,000	3.23%	5.06%	0.16%
1st Mortgage Bond 5.12% due 2/4/54	85,000,000	6.09%	5.16%	0.31%
1st Mortgage Bond 3.78% due 3/2/45	100,000,000	7.17%	3.81%	0.27%
1st Mortgage Bond 3.93% due 3/2/55	200,000,000	14.34%	3.95%	0.57%
1st Mortgage Bond 3.93% due 7/15/45	160,000,000	11.47%	3.96%	0.45%
1st Mortgage Bond 3.82% due 10/3/47	60,000,000	4.30%	3.86%	0.17%
1st Mortgage Bond 3.89% due 2/1/48	60,000,000	4.30%	3.93%	0.17%
1st Mortgage Bond 4.04% due 2/1/58	125,000,000	8.96%	4.07%	0.36%
1st Mortgage Bond 4.04% due 2/1/58	200,000,000	14.34%	3.14%	0.45%
Total Long -Term Debt	1,395,000,000	100.00%		4.19%
Unamortized Call Premium	(15,199,570)			
Long Term- Debt	$ 1,379,800,430			
Annualized Cost	$ 58,387,136			
Amortization of Loss on Reacquired Debt	2,028,823			
Total Cost	$ 60,415,959			4.38%

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, 2022

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	13.16%	4.81%	0.63%
1st Mortgage Bond 4.97% due 11/14/43	160,000,000	10.53%	5.01%	0.53%
1st Mortgage Bond 5.02% due 2/4/44	45,000,000	2.96%	5.06%	0.15%
1st Mortgage Bond 5.12% due 2/4/54	85,000,000	5.59%	5.16%	0.29%
1st Mortgage Bond 3.78% due 3/2/45	100,000,000	6.58%	3.81%	0.25%
1st Mortgage Bond 3.93% due 3/2/55	200,000,000	13.16%	3.95%	0.52%
1st Mortgage Bond 3.93% due 7/15/45	160,000,000	10.53%	3.96%	0.42%
1st Mortgage Bond 3.82% due 10/3/47	60,000,000	3.95%	3.86%	0.15%
1st Mortgage Bond 3.89% due 2/1/48	60,000,000	3.95%	3.93%	0.16%
1st Mortgage Bond 4.04% due 2/1/58	125,000,000	8.22%	4.07%	0.33%
1st Mortgage Bond 3.11% due 5/5/50	200,000,000	13.16%	3.14%	0.41%
1st Mortgage Bond 3.38% due 3/31/52	125,000,000	8.22%	3.41%	0.28%
Total Long -Term Debt	1,520,000,000	100.00%		4.12%
Unamortized Call Premium	(13,185,241)			
Long Term- Debt	$ 1,506,814,759			
Annualized Cost	$ 62,648,995			
Amortization of Loss on Reacquired Debt	2,014,329			
Total Cost	$ 64,663,324			4.29%

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%	02/03/12	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%	11/14/13	11/14/43	30.0	160,000,000	962,455	159,037,545	99.40%	5.01%
1st Mortgage Bond 5.02% due 2/4/44	5.02%	02/04/14	02/04/44	30.0	45,000,000	273,501	44,726,499	99.39%	5.06%
1st Mortgage Bond 5.12% due 2/4/54	5.12%	02/04/14	02/04/54	40.0	85,000,000	543,463	84,456,537	99.36%	5.16%
1st Mortgage Bond 3.78% due 3/2/45	3.78%	03/02/15	03/02/45	30.0	100,000,000	446,281	99,553,719	99.55%	3.81%
1st Mortgage Bond 3.93% due 3/2/55	3.93%	03/02/15	03/02/55	40.0	200,000,000	891,394	199,108,606	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	781,258	159,218,742	99.51%	3.96%
1st Mortgage Bond 3.82% due 10/3/47	3.82%	10/03/17	10/03/47	30.0	60,000,000	437,811	59,562,189	99.27%	3.86%
1st Mortgage Bond 3.89% due 2/1/48	3.89%	02/01/18	02/01/48	30.0	60,000,000	377,534	59,622,466	99.37%	3.93%
1st Mortgage Bond 4.04% due 2/1/58	4.04%	02/01/18	02/01/58	40.0	125,000,000	786,529	124,213,471	99.37%	4.07%
1st Mortgage Bond 3.11% due 5/5/50	3.11%	05/01/20	05/05/50	30.0	200,000,000	1,114,869	198,885,131	99.44%	3.14%
1st Mortgage Bond 3.38% due 3/31/52	3.38%	03/31/22	03/31/52	30.0	125,000,000	750,000	124,250,000	99.40%	3.41%

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 December 2020

Company	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	12-Month Average	6-Month Average	3-Month Average
AVANGRID, Inc (AGR)	3.32%	3.57%	4.03%	4.12%	3.99%	4.21%	3.56%	3.66%	3.50%	3.59%	3.82%	3.88%			
Consolidated Edison Inc (ED)	3.28%	3.89%	3.94%	3.91%	4.09%	4.28%	4.02%	4.30%	3.95%	3.93%	4.02%	4.26%			
Duke Energy Corporation (DUK)	3.90%	4.13%	4.70%	4.51%	4.42%	4.76%	4.60%	4.82%	4.38%	4.23%	4.17%	4.24%			
Eversource Energy (ES)	2.46%	2.64%	2.91%	2.83%	2.71%	2.73%	2.53%	2.67%	2.72%	2.61%	2.61%	2.63%			
Exelon Corp (EXC)	3.24%	3.55%	4.18%	4.16%	4.00%	4.24%	4.00%	4.15%	4.30%	3.87%	3.73%	3.64%			
FirstEnergy Corp (FE)	3.09%	3.51%	3.92%	3.81%	3.70%	4.05%	5.45%	5.48%	5.48%	5.31%	5.90%	5.14%			
MGE Energy Inc (MGEE)	1.77%	1.98%	2.16%	2.19%	2.08%	2.19%	2.24%	2.28%	2.37%	2.28%	2.16%	2.12%			
NextEra Energy Inc (NEE)	2.10%	2.22%	2.33%	2.43%	2.20%	2.34%	2.00%	2.01%	2.02%	1.92%	1.90%	1.82%			
Otter Tail Corp (OTTR)	2.78%	3.05%	3.34%	3.36%	3.45%	3.83%	3.90%	3.82%	4.11%	3.89%	3.72%	3.49%			
PPL Corp (PPL)	4.62%	5.60%	6.75%	6.59%	6.02%	6.45%	6.29%	6.09%	6.12%	6.09%	5.92%	5.91%			
Public Service Enterprise Group Inc (PEG)	3.33%	3.85%	4.38%	3.89%	3.87%	4.00%	3.52%	3.78%	3.58%	3.39%	3.39%	3.37%			
Average	**3.08%**	**3.45%**	**3.88%**	**3.80%**	**3.68%**	**3.92%**	**3.83%**	**3.91%**	**3.87%**	**3.74%**	**3.76%**	**3.68%**	**3.72%**	**3.80%**	**3.73%**

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: https://finance.yahoo.com
https://www.nasdaq.com

Forward-looking Dividend Yield

1/2 Growth	D_0/P_0	(.5g)	D_1/P_0	$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$
	3.80%	1.025750	3.90%	
Discrete	D_0/P_0	Adj.	D_1/P_0	$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$
	3.80%	1.031985	3.92%	
Quarterly	D_0/P_0	Adj.	D_1/P_0	$K = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$
	0.9500%	1.012634	3.90%	
Average			3.91%	
Growth rate			5.15%	
K			9.06%	

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

	Earnings per Share		**Dividends per Share**		**Book Value per Share**		**Cash Flow per Share**	
	Value Line		Value Line		Value Line		Value Line	
Electric Group	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year
AVANGRID, Inc.	-	-	-	-	-	-	-	-
Consol. Edison	2.00%	2.50%	3.00%	2.00%	4.50%	4.00%	4.00%	4.00%
Duke Energy	2.50%	3.00%	3.00%	3.00%	1.00%	2.00%	6.00%	3.50%
Eversource Energy	7.00%	6.00%	7.00%	9.00%	3.50%	6.50%	6.50%	2.00%
Exelon Corp.	4.50%	-4.50%	-3.00%	-3.50%	4.00%	6.50%	5.00%	1.00%
FirstEnergy Corp.	-	-7.00%	-2.00%	-3.00%	-17.50%	-8.50%	-3.00%	-6.00%
MGE Energy	2.50%	4.50%	4.00%	3.50%	5.50%	5.50%	5.00%	4.50%
NextEra Energy	7.00%	6.50%	11.00%	9.50%	10.50%	9.00%	7.00%	6.50%
Otter Tail Corp.	9.00%	5.50%	2.50%	1.50%	4.50%	-	6.00%	2.50%
PPL Corp.	-1.00%	1.00%	2.00%	2.00%	-3.50%	1.00%	-3.50%	-1.00%
Public Serv. Enterprise	4.00%	1.00%	4.50%	3.50%	4.50%	6.00%	2.00%	2.00%
Average	4.17%	1.85%	3.20%	2.75%	1.70%	3.56%	3.50%	1.90%

Source of Information: Value Line Investment Survey November 13, 2020

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**	**Earnings Per Share**	**Dividends Per Share**	**Book Value Per Share**	**Cash Flow Per Share**	**Percent Retained to Common Equity**
AVANGRID, Inc.	4.00%	4.70%	4.00%	0.50%	1.00%	4.50%	1.50%
Consol. Edison	2.54%	2.00%	3.00%	3.50%	3.00%	4.00%	2.50%
Duke Energy	2.80%	3.60%	5.00%	2.50%	2.50%	5.00%	2.50%
Eversource Energy	6.51%	6.50%	5.50%	6.00%	5.50%	5.50%	3.50%
Exelon Corp.		2.40%	3.50%	5.50%	3.50%	4.00%	4.00%
FirstEnergy Corp.		NA	8.50%	2.00%	10.00%	3.00%	6.50%
MGE Energy	4.80%	4.80%	4.00%	5.50%	5.00%	5.00%	4.00%
NextEra Energy	8.73%	7.90%	9.50%	10.50%	6.50%	7.50%	4.00%
Otter Tail Corp.	9.00%	NA	6.50%	5.00%	5.00%	5.00%	4.50%
PPL Corp.		NA	2.50%	2.00%	4.50%	4.00%	4.00%
Public Serv. Enterprise	1.10%	2.90%	5.00%	4.00%	5.00%	5.00%	5.00%
Average	4.94%	4.35%	5.18%	4.27%	4.68%	4.77%	3.82%

Note: Negative growth rates removed for Exelon of -2.40%, FirstEnergy of -2.40%, and PPL Corp. of -16.20%.

Source of Information : Yahoo Finance, January 5, 2021
Zacks, January 5, 2021
Value Line Investment Survey, November 13, 2020

Electric Group
Financial Risk Adjustment

		AVANGRID Inc (AGR)	Consolidated Edison Inc (ED)	Duke Energy Corporation (DUK)	Eversource Energy (ES)	Exelon Corp(EXC)	FirstEnergy Corp (FE)	MGE Energy Iinc. (MGEE)	NextEra Energy Inc (NEE)	Otter Tail Corp. (OTTR)	PPL Corp (PPL)	Public Service Enterprise Group Inc	Average
Fiscal Year		12/31/19	12/31/19	12/31/19	12/31/19	12/31/19	12/31/19	12/31/19	12/31/19	12/31/19	12/31/19	12/31/19	
Capitalization at Fair Values													
	Debt(D)	8,168,000	22,738,000	63,062,000	15,796,100	41,516,000	22,928,000	611,909	42,928,000	742,279	25,481,000	16,723,000	23,699,481
	Preferred(P)	0	0	0	162,000	0	0	0	0	0	0	0	14,727
	Equity(E)	15,846,919	28,045,700	66,856,930	28,062,946	44,267,890	26,275,698	2,732,532	118,416,240	2,059,683	27,528,320	29,761,200	35,441,278
	Total	24,014,919	50,783,700	129,918,930	44,021,046	85,783,890	49,203,698	3,344,441	161,344,240	2,801,962	53,009,320	46,484,200	59,155,486
Capital Structure Ratios													
	Debt(D)	34.01%	44.77%	48.54%	35.88%	48.40%	46.60%	18.30%	26.61%	26.49%	48.07%	35.98%	37.60%
	Preferred(P)	0.00%	0.00%	0.00%	0.37%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.03%
	Equity(E)	65.99%	55.23%	51.46%	63.75%	51.60%	53.40%	81.70%	73.39%	73.51%	51.93%	64.02%	62.36%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.99%
Common Stock													
	Issued		333,000.000			973,000.000						534,000.000	
	Treasury		23,000.000			2,000.000						30,000.000	
	Outstanding	309,752.140	310,000.000	733,000.000	329,880.645	971,000.000	540,652.222	34,668.000	489,000.000	40,157.591	767,233.000	504,000.000	
	Market Price	$51.16	$90.47	$91.21	$85.07	$45.59	$48.60	$78.82	$242.16	$51.29	$35.88	$59.05	
Capitalization at Carrying Amounts													
	Debt(D)	7,446,000	19,973,000	58,126,000	14,681,500	37,628,000	20,074,000	547,879	39,667,000	689,764	21,893,000	15,108,000	21,439,468
	Preferred(P)	0	0	1,962,000	155,600	0	0	0	0	0	0	0	192,509
	Equity(E)	15,237,000	18,022,000	44,860,000	12,629,994	32,224,000	6,975,000	855,676	37,005,000	781,482	12,991,000	15,089,000	17,879,105
	Total	22,683,000	37,995,000	104,948,000	27,467,094	69,852,000	27,049,000	1,403,555	76,672,000	1,471,246	34,884,000	30,197,000	39,511,081
Capital Structure Ratios													
	Debt(D)	32.83%	52.57%	55.39%	53.45%	53.87%	74.21%	39.04%	51.74%	46.88%	62.76%	50.03%	52.07%
	Preferred(P)	0.00%	0.00%	1.87%	0.57%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.22%
	Equity(E)	67.17%	47.43%	42.74%	45.98%	46.13%	25.79%	60.96%	48.26%	53.12%	37.24%	49.97%	47.71%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Betas	Value Line	0.85	0.75	0.85	0.90	0.95	0.85	0.70	0.90	0.85	1.15	0.90	0.88

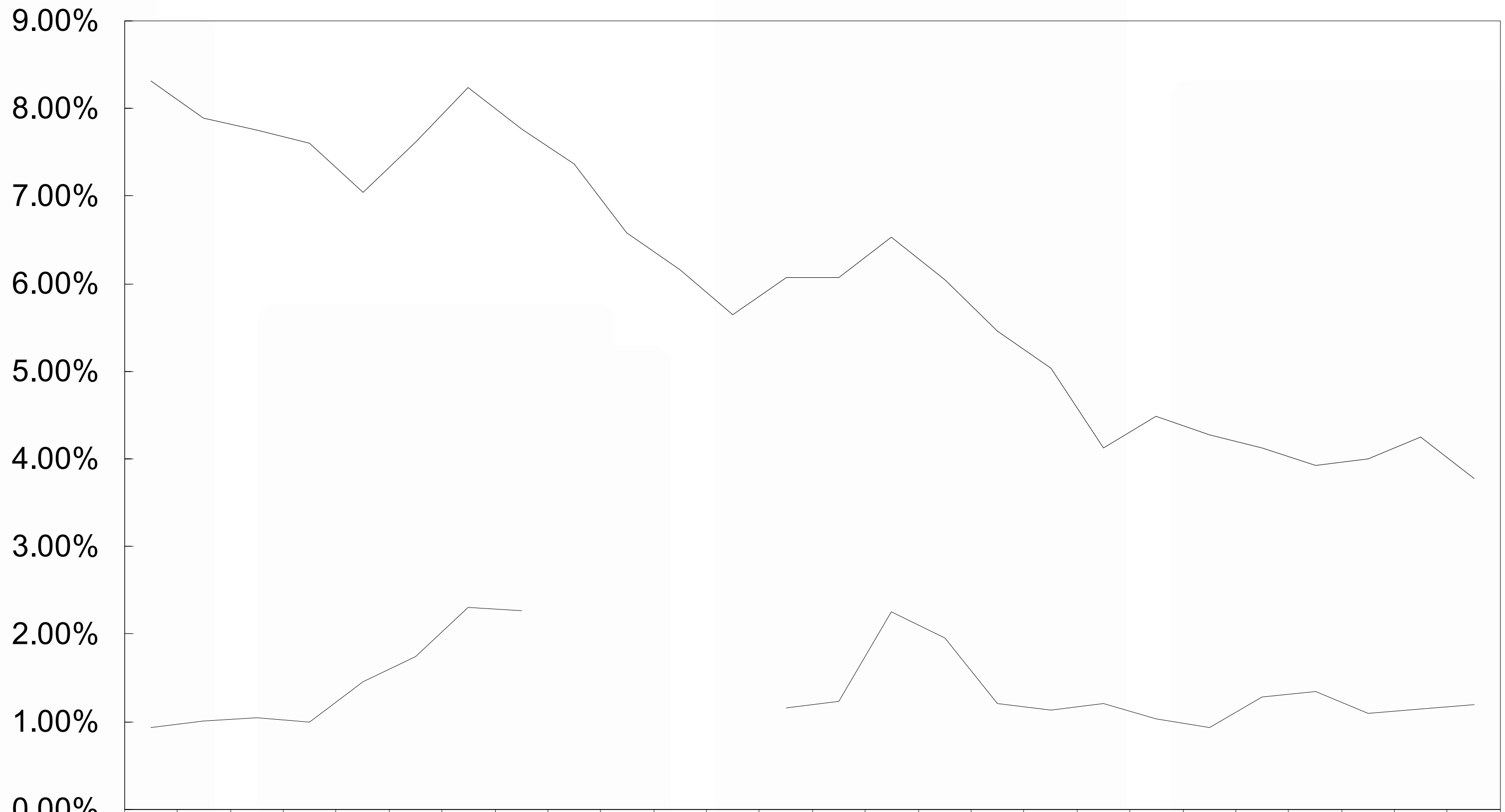
Hamada	Bl	=	Bu	[1+	(1 - t)	D/E	+	P/E	]
	0.88	=	Bu	[1+	(1-0.35)	0.6030	+	0.0005	]
	0.88	=	Bu	[1+	0.65	0.6030	+	0.0005	]
	0.88	=	Bu	1.3925					
	0.63	=	Bu						
Hamada	Bl	=	0.63	[1+	(1 - t)	D/E	+	P/E	]
	Bl	=	0.63	[1+	0.65	1.0914	+	0.0046	]
	Bl	=	0.63	1.7140					
	Bl	=	1.08						

M&M	ku	=	ke	-	(((	ku	-	i	)	1-t	)	D	/	E	) - (	ku	-	d	)	P	/	E
	7.31%	=	9.06%	-	(((	7.31%	-	2.81%	)	0.65	)	37.60%	/	62.36%	) - (	7.31%	-	5.68%	)	0.03%	/	62.36%
	7.31%	=	9.06%	-	(((	4.50%			)	0.65	)	0.6030			) - (	1.63%			)	0.0005		
	7.31%	=	9.06%	-	((	2.93%					)	0.6030			) - (	1.63%			)	0.0005		
	7.31%	=	9.06%	-		1.77%									-	0.00%						
M&M	ke	=	ku	+	(((	ku	-	i	)	1-t	)	D	/	E	) + (	ku	-	d	)	P	/	E
	10.52%	=	7.31%	+	(((	7.31%	-	2.81%	)	0.65	)	52.07%	/	47.71%	) + (	7.31%	-	5.68%	)	0.22%	/	47.71%
	10.52%	=	7.31%	+	(((	4.50%			)	0.65	)	1.0914			) + (	1.63%			)	0.0046		
	10.52%	=	7.31%	+	((	2.93%					)	1.0914			) + (	1.63%			)	0.0046		
	10.52%	=	7.31%	+		3.20%									+	0.01%						

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2015-2019
and the Twelve Months Ended December 2020

Years	Aa Rated	A Rated	Baa Rated	Average
2015	4.00%	4.12%	5.03%	4.38%
2016	3.73%	3.93%	4.68%	4.11%
2017	3.82%	4.00%	4.38%	4.07%
2018	4.09%	4.25%	4.67%	4.34%
2019	3.61%	3.77%	4.19%	3.86%
Five-Year Average	3.85%	4.01%	4.59%	4.15%
Months				
Jan-20	3.12%	3.29%	3.60%	3.34%
Feb-20	2.96%	3.11%	3.42%	3.16%
Mar-20	3.30%	3.50%	3.96%	3.59%
Apr-20	2.93%	3.19%	3.82%	3.31%
May-20	2.89%	3.14%	3.63%	3.22%
Jun-20	2.80%	3.07%	3.44%	3.10%
Jul-20	2.46%	2.74%	3.09%	2.77%
Aug-20	2.49%	2.73%	3.06%	2.76%
Sep-20	2.62%	2.84%	3.17%	2.88%
Oct-20	2.72%	2.95%	3.27%	2.98%
Nov-20	2.63%	2.85%	3.17%	2.89%
Dec-20	2.57%	2.77%	3.05%	2.80%
Twelve-Month Average	2.79%	3.02%	3.39%	3.07%
Six-Month Average	2.58%	2.81%	3.14%	2.85%
Three-Month Average	2.64%	2.86%	3.16%	2.89%

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	2018	2019
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%	4.25%	3.77%
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%	1.14%	1.19%

Exhibit PRM-1
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A rated Public Utility Bonds over 30-Year Treasuries

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries 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%		
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%		

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
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%
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%
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%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
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%
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%
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%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
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%
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%
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%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
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%
Feb-18	4.09%	3.13%	0.96%
Mar-18	4.13%	3.09%	1.04%
Apr-18	4.17%	3.07%	1.10%
May-18	4.28%	3.13%	1.15%
Jun-18	4.27%	3.05%	1.22%
Jul-18	4.27%	3.01%	1.26%
Aug-18	4.26%	3.04%	1.22%
Sep-18	4.32%	3.15%	1.17%
Oct-18	4.45%	3.34%	1.11%
Nov-18	4.52%	3.36%	1.16%
Dec-18	4.37%	3.10%	1.27%
Jan-19	4.35%	3.04%	1.31%
Feb-19	4.25%	3.02%	1.23%
Mar-19	4.16%	2.98%	1.18%
Apr-19	4.08%	2.94%	1.14%
May-19	3.98%	2.82%	1.16%
Jun-19	3.82%	2.57%	1.25%
Jul-19	3.69%	2.57%	1.12%
Aug-19	3.29%	2.12%	1.17%
Sep-19	3.37%	2.16%	1.21%
Oct-19	3.39%	2.19%	1.20%
Nov-19	3.43%	2.28%	1.15%
Dec-19	3.40%	2.30%	1.10%
Jan-20	3.29%	2.22%	1.07%
Feb-20	3.11%	1.97%	1.14%
Mar-20	3.50%	1.46%	2.04%
Apr-20	3.19%	1.27%	1.92%
May-20	3.14%	1.38%	1.76%
Jun-20	3.07%	1.49%	1.58%
Jul-20	2.74%	1.31%	1.43%
Aug-20	2.73%	1.36%	1.37%
Sep-20	2.84%	1.42%	1.42%
Oct-20	2.95%	1.57%	1.38%
Nov-20	2.85%	1.62%	1.23%
Dec-20	2.77%	1.67%	1.10%
Average:	12-months		1.45%
	6-months		1.32%
	3-months		1.24%

Common Equity Risk Premiums
Years 1926-2019

	Large Common Stocks	Long-Term Corp. Bonds	Equity Risk Premium	Long-Term Govt. Bonds Yields
Low Interest Rates	11.92%	5.22%	6.70%	2.88%
Average Across All Interest Rates	12.09%	6.40%	5.69%	4.99%
High Interest Rates	12.26%	7.57%	4.69%	7.09%

Source of Information: 2020 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%
2019	31.49%	19.95%	2.25%
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%
2017	21.83%	12.25%	2.54%
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%
2018	-4.38%	-4.73%	2.84%
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 2015-2019
and the Twelve Months Ended December 2020

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year	30-Year
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%
2017	1.20%	1.40%	1.58%	1.91%	2.16%	2.33%	2.65%	2.90%
2018	2.33%	2.53%	2.63%	2.75%	2.85%	2.91%	3.02%	3.11%
2019	2.05%	1.97%	1.94%	1.96%	2.05%	2.14%	2.40%	2.58%
Five-Year Average	1.30%	1.49%	1.64%	1.90%	2.12%	2.27%	2.57%	2.81%
Months								
Jan-20	1.53%	1.52%	1.52%	1.56%	1.67%	1.76%	2.07%	2.22%
Feb-20	1.41%	1.33%	1.31%	1.32%	1.42%	1.50%	1.81%	1.97%
Mar-20	0.33%	0.45%	0.50%	0.59%	0.78%	0.87%	1.26%	1.46%
Apr-20	0.18%	0.22%	0.28%	0.39%	0.55%	0.66%	1.06%	1.27%
May-20	0.16%	0.17%	0.22%	0.34%	0.53%	0.67%	1.12%	1.38%
Jun-20	0.18%	0.19%	0.22%	0.34%	0.55%	0.73%	1.27%	1.49%
Jul-20	0.15%	0.15%	0.17%	0.28%	0.46%	0.62%	1.09%	1.31%
Aug-20	0.13%	0.14%	0.16%	0.27%	0.46%	0.65%	1.14%	1.36%
Sep-20	0.13%	0.13%	0.16%	0.27%	0.46%	0.68%	1.21%	1.42%
Oct-20	0.13%	0.15%	0.19%	0.34%	0.55%	0.79%	1.34%	1.57%
Nov-20	0.12%	0.17%	0.22%	0.39%	0.63%	0.87%	1.40%	1.62%
Dec-20	0.10%	0.14%	0.19%	0.39%	0.66%	0.93%	1.47%	1.67%
Twelve-Month Average	0.38%	0.40%	0.43%	0.54%	0.73%	0.89%	1.35%	1.56%
Six-Month Average	0.13%	0.15%	0.18%	0.32%	0.54%	0.76%	1.28%	1.49%
Three-Month Average	0.12%	0.15%	0.20%	0.37%	0.61%	0.86%	1.40%	1.62%

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 December 1, 2020 and January 1, 2021

		Treasury					Corporate	
Year	Quarter	1-Year Bill	2-Year Note	5-Year Note	10-Year Note	30-Year Bond	Aaa Bond	Baa Bond
2021	First	0.1%	0.2%	0.4%	0.9%	1.7%	2.5%	3.5%
2021	Second	0.2%	0.2%	0.5%	1.0%	1.8%	2.5%	3.6%
2021	Third	0.2%	0.3%	0.6%	1.1%	1.9%	2.6%	3.7%
2021	Fourth	0.2%	0.3%	0.6%	1.2%	2.0%	2.7%	3.8%
2022	First	0.2%	0.4%	0.7%	1.3%	2.1%	2.8%	3.8%
2022	Second	0.3%	0.4%	0.8%	1.4%	2.1%	2.8%	3.8%
Long-range CONSENSUS								
2022		0.3%	0.4%	0.8%	1.3%	2.1%	2.8%	3.9%
2023		0.6%	0.8%	1.2%	1.7%	2.4%	3.2%	4.3%
2024		1.0%	1.2%	1.6%	2.0%	2.8%	3.6%	4.7%
2025		1.4%	1.6%	2.0%	2.4%	3.1%	4.0%	5.0%
2026		1.8%	1.9%	2.3%	2.6%	3.4%	4.2%	5.2%
Averages:								
	2022-2026	1.0%	1.2%	1.5%	2.0%	2.8%	3.6%	4.6%
	2027-2031	2.1%	2.3%	2.5%	2.8%	3.6%	4.5%	5.4%

Measures of the Market Premium

Value Line Return

As of:	Dividend Yield		Median Appreciation Potential		Median Total Return
25-Dec-20	2.0%	+	7.79%	=	9.79%

DCF Result for the S&P 500 Composite

D/P	(	1+.5g	)	+	g	=	k
1.73%	(	1.0470	)	+	9.40%	=	11.21%

Summary

Value Line			9.79%
S&P 500			11.21%
Average			10.50%
Risk-free Rate of Return (Rf)			2.10%
Forecast Market Premium			8.40%
Historical Market Premium			
Low Interest Rates	(Rm)	(Rf)	
1926-2019 Arith. mean	11.92%	2.88%	9.04%
Average - Forecast/Historical			8.72%

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; Safety Rank of 1, 2 & 3; Financial Strength of B+, B++, A, A+ & A++;
Price Stability of 75 to 95; Betas of .75 to 1.15; and Technical Rank of 3, 4 & 5

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
Abbott Laboratories	Med Supp Non-Invasive	3	1	A·	85	0.95	3
Adobe Inc.	Computer Software	2	2	A·	85	0.75	3
Agilent Technologies	Precision Instrument	2	2	A	95	0.90	3
Air Products and Chemicals Inc	Chemical (Diversified)	2	1	A·	95	0.90	3
Alleghany Corp	Insurance (Prop/Cas.)	1	2	A	85	1.10	4
Allstate Corporation	Insurance (Prop/Cas.)	2	1	A·	95	1.00	4
Altria Group Inc	Tobacco	2	3	B·	90	0.90	4
Amazon com	Internet	1	1	A·	75	0.75	3
AMERCO	Trucking	3	2	B·	90	0.95	3
AMETEK Inc.	Diversified Co.	3	2	A	90	1.15	3
Amgen Inc	Biotechnology	2	1	A·	95	0.75	3
Analog Devices Inc	Semiconductor	2	1	A·	90	0.95	3
ANSYS Inc	Computer Software	2	2	A·	90	0.85	4
Apple Inc	Computers/Peripherals	2	1	A·	80	0.90	3
Arthur J Gallagher and Company	Financial Svcs. (Div.)	2	1	A	95	1.00	3
Balchem Corp.	Chemical (Specialty)	1	3	B·	80	0.75	4
BancorpSouth Bank	Bank	2	3	B·	75	1.05	4
Bank of Hawaii	Bank	3	2	B·	75	1.10	3
Becton Dickinson and Company	Med Supp Invasive	2	1	A·	95	0.80	5
Bio Rad Laboratories Inc	Med Supp Non-Invasive	1	2	A	90	0.80	3
Bio-Techne Corp.	Biotechnology	2	2	A	85	0.80	3
Boston Scientific Corp	Med Supp Invasive	2	3	B·	85	1.05	5
Broadridge Fin'l	Information Services	2	2	B·	95	0.85	3
Brown Forman Corp (Class B)	Beverage	3	1	A	95	0.85	3
CACI International Inc	IT Services	3	3	B·	80	0.95	3
Cadence Design Systems Inc	Computer Software	1	2	A·	85	0.90	5
Carlisle Companies Inc	Diversified Co.	3	2	A	80	1.10	3
Caseys General Stores Inc	Retail/Wholesale Food	3	3	B·	85	0.85	3
Cboe Global Markets	Brokers & Exchanges	2	2	A	85	0.90	5
Cerner Corp	Healthcare Information	3	2	A·	85	0.95	3
Charter Communic.	Cable TV	1	3	B·	85	0.90	3
Chemed Corporation	Diversified Co.	3	2	A	95	0.85	4
Cisco Systems Inc	Telecom. Equipment	2	1	A·	95	0.95	5
CNA Financial Corporation	Insurance (Prop/Cas.)	2	2	B·	80	1.10	5
Cognizant Technology Solutions Corp	IT Services	2	2	A·	80	1.05	3
Cooper Companies Inc	Med Supp Non-Invasive	2	2	A	85	0.95	3
Copart Inc	Retail Automotive	2	2	A	75	1.05	4
CoStar Group Inc	Information Services	3	2	A·	80	0.95	3
CSG Systems International Inc	IT Services	3	3	B·	85	0.75	5
CVS Caremark Corporation	Retail Store	1	2	A·	80	0.90	3
Deere and Co	Heavy Truck & Equip	2	1	A·	75	1.15	3
Dolby Laboratories Inc	Entertainment Tech	3	2	A	90	0.95	3
Donaldson Co	Machinery	3	2	A	80	1.15	3
Eli Lilly and Co	Drug	3	1	A·	95	0.75	3
ESCO Technologies Inc	Diversified Co.	3	3	B·	90	1.00	3
Estee Lauder Companies Inc	Toiletries/Cosmetics	2	2	A	90	0.90	3
Expeditors International of Washington	Industrial Services	2	1	A·	95	0.95	3
Exponent Inc.	Information Services	3	3	B·	90	0.85	4
F5 Networks	Telecom. Equipment	2	3	A	75	0.90	3
FactSet Research Systems Inc	Information Services	3	2	A·	85	1.00	3
Fastenal Co	Retail Building Supply	2	2	A·	80	0.95	3
First Republic Bank	Bank	1	3	B·	80	1.00	3
Franklin Electric Co Inc	Electrical Equipment	3	3	A	75	1.00	3
Gartner Inc	Information Services	2	3	B·	75	1.15	3
GATX Corp	Railroad	3	3	B·	75	1.00	3
General Dynamics Corporation	Aerospace/Defense	2	1	A·	85	1.15	3
Gentex Corp	Auto Parts	3	3	B·	85	0.95	3
Goldman Sachs Group Inc	Investment Banking	2	2	A·	80	1.15	3
Graco Inc	Machinery	2	2	A	90	1.05	4
Graphic Packaging	Packaging & Container	3	3	B·	80	1.00	3
Hanover Insurance Group Inc	Insurance (Prop/Cas.)	3	2	B·	95	0.95	3
Heartland Express Inc	Trucking	3	2	A	90	0.75	3
Hershey Company	Food Processing	3	1	A·	95	0.85	3
Huntington Ingalls Industries Inc	Aerospace/Defense	3	3	B·	75	1.05	4
IDEX Corporation	Machinery	3	2	B·	95	1.05	3
IDEXX Laboratories Inc	Med Supp Non-Invasive	1	3	B·	75	1.05	4
Integra LifeSciences Holdings Corporati	Med Supp Invasive	3	3	B·	75	1.00	4
Intel Corporation	Semiconductor	2	1	A·	80	0.85	4
Intercontinental Exch.	Brokers & Exchanges	3	2	A	95	0.90	4
International Business Machines Corp	Computers/Peripherals	3	1	A	90	1.05	4
Intuit Inc	Computer Software	2	2	A·	85	1.00	3
Investors Bancorp Inc	Thrift	3	3	B·	80	1.10	5
Iron Mountain Inc	Industrial Services	2	3	B·	80	0.95	4
Jack Henry and Associates Inc	IT Services	2	1	A·	95	0.85	3
JP Morgan Chase and Co	Bank	2	1	A·	85	1.10	3
Juniper Networks Inc	Telecom. Equipment	2	2	A	80	1.00	5
Kadant Inc	Diversified Co.	3	3	B·	75	1.05	3
Lindsay Corporation	Machinery	1	3	B·	75	0.85	5
Littelfuse Inc	Electrical Equipment	3	3	B·	75	1.10	3
Lockheed Martin Corp	Aerospace/Defense	2	1	A·	90	0.95	3
ManTech International Corporation	IT Services	3	3	B·	85	0.85	3
Markel Corp	Insurance (Prop/Cas.)	1	2	A	85	1.15	3
Masimo Corporation	Med Supp Non-Invasive	1	3	A	75	0.80	3
Mastercard Incorporated	Financial Svcs. (Div.)	2	1	A·	90	1.05	3
MAXIMUS Inc	Industrial Services	2	2	A·	85	0.80	3
McCormick and Co	Food Processing	2	1	A·	95	0.85	3
Mercury General Corp	Insurance (Prop/Cas.)	3	3	B·	75	0.95	5
Mettler Toledo International Inc	Precision Instrument	2	2	B·	95	0.95	3
Monolithic Power Sys.	Semiconductor	3	3	A	75	1.00	4
Monster Beverage Corporation	Beverage	3	2	A·	80	0.85	4
Moodys Corp	Information Services	3	3	B·	80	1.15	3
MSCI Inc	Information Services	2	3	B·	85	0.95	4
Nasdaq Inc.	Brokers & Exchanges	3	3	A	85	1.05	3
New York Times Co	Publishing	3	3	B·	75	0.80	3
Nike Inc	Shoe	3	1	A·	75	1.15	3
Northern Trust Corp	Bank (Midwest)	2	3	B·	80	1.10	3
Northrop Grumman Corp Holding Co	Aerospace/Defense	2	1	A·	90	0.85	3
Old National Bancorp	Bank (Midwest)	2	3	B·	80	1.00	4
Old Republic International Corp	Insurance (Prop/Cas.)	2	3	B·	80	1.15	4
Packaging Corp	Packaging & Container	2	2	A	80	1.00	3
Peoples United Financial Inc	Thrift	2	3	B·	80	1.00	4
PerkinElmer Inc	Precision Instrument	1	2	B·	90	0.95	3
Philip Morris International Inc	Tobacco	2	3	B·	80	0.95	3
Plexus Corp	Electronics	3	3	B·	75	1.05	3
Pool Corporation	Recreation	2	2	B·	85	0.90	3
Post Holdings Inc	Food Processing	3	3	B	85	0.95	5
Progressive Corp.	Insurance (Prop/Cas.)	1	1	A	95	0.80	4
Rayonier Inc	Paper/Forest Products	3	3	B·	85	1.05	3
Regal Beloit Corp	Machinery	3	3	B·	75	1.15	3
RLI Corp	Insurance (Prop/Cas.)	3	2	B·	95	0.75	3
Rollins Inc	Industrial Services	1	2	A	90	0.85	3
Roper Tech.	Machinery	3	1	A·	95	1.00	3
RPM International Inc	Chemical (Specialty)	2	3	B·	75	1.10	3
Selective Insurance Group Inc	Insurance (Prop/Cas.)	2	3	B·	90	0.85	3
Sherwin Williams	Retail Building Supply	1	1	A·	90	0.95	3
Starbucks Corporation	Restaurant	2	1	A·	90	0.95	3
Stryker Corp	Med Supp Invasive	1	1	A·	80	1.10	3
Synopsys Inc	Computer Software	1	1	A·	90	0.95	4
Teledyne Technologies	Aerospace/Defense	2	3	A·	80	1.15	3
Texas Instruments Incorporated	Semiconductor	3	1	A·	95	0.85	3
The Travelers Companies Inc	Insurance (Prop/Cas.)	2	1	A·	95	1.00	3
TJX Companies Inc	Retail (Softlines)	2	3	B·	80	1.15	3
Toro Co	Machinery	2	2	B·	90	1.05	3
Tractor Supply Co	Retail Building Supply	2	2	A·	75	0.80	3
Transmission Holdings Inc	Auto Parts	3	3	B·	80	1.10	4
Trimas Corporation	Diversified Co.	3	3	B·	80	0.90	3
UniFirst Corp	Industrial Services	3	2	A	90	0.95	4
UnitedHealth Group	Medical Services	3	1	A·	80	1.05	3
US Bancorp	Bank (Midwest)	3	2	A	85	1.15	4
Valmont Industries	Diversified Co.	3	2	A	80	1.05	3
VeriSign Inc	Internet	3	3	B	90	0.95	4
Visa Inc	Financial Svcs. (Div.)	3	1	A·	95	1.00	3
Walt Disney Co	Entertainment	2	3	A	95	0.95	4
Waters Corp	Precision Instrument	2	2	A	90	0.95	4
Watts Water Technologies Inc	Machinery	3	2	B·	95	1.00	3
West Pharmaceutical Services Inc	Med Supp Non-Invasive	1	2	A	85	0.80	3
Western Union Company	Financial Svcs. (Div.)	2	3	B·	95	0.80	3
Wiley John and Sons Inc (Class A)	Publishing	2	3	B·	85	0.90	5
Xylem Inc	Machinery	2	2	B·	85	1.05	3
Yum Brands Inc	Restaurant	3	3	B·	85	1.05	3
Zoetis Inc	Drug	3	2	B·	90	1.00	3
Average		2	2	A	85	0.96	3
Electric Group	Average	3	2	A	87	0.90	4

Source of Information: Value Line Investment Survey for Windows, January 20021

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2015-2019 and
Projected 3-5 Year Returns

Company	2015	2016	2017	2018	2019	Average	Projected 2023-25
Abbott Laboratories	15.4%	16.0%	14.2%	16.8%	18.7%	16.2%	23.0%
Adobe Inc.	9.0%	15.7%	20.0%	27.7%	28.0%	20.1%	22.0%
Agilent Technologies	14.1%	15.4%	15.9%	19.9%	20.8%	17.2%	17.5%
Air Products and Chemicals Inc	19.7%	23.3%	13.7%	15.1%	16.5%	17.7%	18.5%
Alleghany Corp	7.4%	5.8%	1.1%	0.5%	9.8%	4.9%	6.5%
Allstate Corporation	10.6%	9.0%	11.0%	13.9%	12.8%	11.5%	14.0%
Altria Group Inc	182.0%	46.4%	42.5%	51.0%	NMF	80.5%	NMF
Amazon com	4.5%	12.3%	8.1%	23.1%	18.7%	13.3%	18.0%
AMERCO	21.7%	15.2%	9.0%	10.0%	7.0%	12.6%	6.5%
AMETEK Inc.	18.2%	16.5%	14.6%	18.3%	16.8%	16.9%	21.0%
Amgen Inc	28.3%	29.4%	36.5%	76.6%	93.3%	52.8%	59.5%
Analog Devices Inc	19.7%	18.6%	16.6%	20.4%	16.3%	18.3%	18.5%
ANSYS Inc	14.3%	14.6%	15.5%	19.4%	16.4%	16.0%	17.0%
Apple Inc	44.7%	35.6%	36.1%	55.6%	61.1%	46.6%	60.0%
Arthur J Gallagher and Company	9.8%	11.5%	11.3%	13.9%	12.8%	11.9%	14.0%
Balchem Corp.	12.9%	10.7%	14.6%	11.4%	10.7%	12.1%	17.5%
BancorpSouth Bank	7.7%	7.7%	8.9%	10.1%	8.7%	8.6%	8.0%
Bank of Hawaii	15.0%	15.6%	15.0%	17.3%	17.6%	16.1%	15.0%
Becton Dickinson and Company	20.7%	24.5%	16.0%	13.6%	15.2%	18.0%	20.0%
Bio Rad Laboratories Inc	4.5%	3.7%	2.2%	4.4%	3.7%	3.7%	5.5%
Bio-Techne Corp.	12.7%	11.9%	9.2%	9.8%	8.2%	10.4%	19.0%
Boston Scientific Corp	12.8%	15.8%	18.0%	17.7%	13.0%	15.5%	22.0%
Broadridge Fin'l	30.9%	29.4%	32.6%	46.1%	49.1%	37.6%	32.8%
Brown Forman Corp (Class B)	45.3%	48.8%	56.7%	50.7%	41.9%	48.7%	60.0%
CACI International Inc	8.5%	8.9%	9.1%	9.4%	11.2%	9.4%	11.0%
Cadence Design Systems Inc	24.8%	47.4%	39.7%	40.8%	29.4%	36.4%	22.0%
Carlisle Companies Inc	13.6%	15.6%	13.9%	13.8%	17.9%	15.0%	16.0%
Caseys General Stores Inc	20.9%	14.9%	11.2%	14.5%	16.1%	15.5%	15.0%
Cboe Global Markets	79.0%	58.4%	12.9%	13.1%	11.1%	34.9%	12.5%
Cerner Corp	19.1%	20.1%	16.8%	16.6%	20.0%	18.5%	20.0%
Charter Communic.	-	8.8%	1.5%	3.4%	5.3%	4.8%	18.5%
Chemed Corporation	21.5%	20.7%	26.1%	33.9%	31.7%	26.8%	28.5%
Cisco Systems Inc	19.0%	18.9%	18.2%	29.4%	41.1%	25.3%	32.5%
CNA Financial Corporation	4.4%	6.9%	7.5%	7.6%	8.0%	6.9%	11.5%
Cognizant Technology Solutions Corp	20.2%	19.3%	21.0%	23.4%	20.3%	20.8%	16.0%
Cooper Companies Inc	7.6%	10.1%	11.7%	10.3%	12.9%	10.5%	13.0%
Copart Inc	22.8%	33.0%	27.6%	26.3%	30.1%	28.0%	31.5%
CoStar Group Inc	4.3%	8.3%	5.8%	10.0%	11.0%	7.9%	11.0%
CSG Systems International Inc	18.7%	25.0%	17.9%	18.3%	20.9%	20.2%	22.0%
CVS Caremark Corporation	15.7%	17.2%	16.1%	12.7%	14.5%	15.2%	12.5%
Deere and Co	28.8%	23.4%	22.6%	27.1%	27.9%	26.0%	21.5%
Dolby Laboratories Inc	10.0%	9.4%	9.4%	12.6%	11.1%	10.5%	13.5%
Donaldson Co	26.9%	24.9%	26.6%	31.0%	29.9%	27.9%	28.5%
Eli Lilly and Co	25.1%	26.7%	39.1%	58.3%	NMF	37.3%	71.5%
ESCO Technologies Inc	7.1%	8.3%	8.6%	9.0%	9.9%	8.6%	9.5%
Estee Lauder Companies Inc	29.9%	31.2%	28.5%	36.2%	45.1%	34.2%	59.0%
Expeditors International of Washington Inc	27.0%	23.4%	22.7%	31.1%	26.9%	26.2%	28.0%
Exponent Inc.	16.6%	17.4%	14.3%	23.0%	23.5%	19.0%	30.0%
F5 Networks	27.7%	30.9%	34.2%	35.3%	24.3%	30.5%	19.0%
FactSet Research Systems Inc	45.3%	49.7%	46.1%	50.8%	52.5%	48.9%	43.5%
Fastenal Co	28.7%	25.8%	27.6%	32.7%	29.7%	28.9%	32.0%
First Republic Bank	9.2%	9.7%	9.7%	9.8%	9.4%	9.6%	9.5%
Franklin Electric Co Inc	13.2%	12.8%	12.5%	14.6%	12.3%	13.1%	12.5%
Gartner Inc	-	NMF	30.3%	41.1%	37.8%	36.4%	26.5%
GATX Corp	18.1%	17.6%	10.4%	11.2%	10.9%	13.6%	8.0%
General Dynamics Corporation	27.6%	27.9%	25.5%	28.6%	25.7%	27.1%	16.5%
Gentex Corp	18.5%	18.2%	18.0%	23.5%	21.9%	20.0%	25.0%
Goldman Sachs Group Inc	10.3%	8.5%	10.6%	11.6%	9.4%	10.1%	9.5%
Graco Inc	30.3%	35.2%	34.9%	43.6%	31.7%	35.1%	22.0%
Graphic Packaging	22.4%	21.6%	23.2%	11.9%	13.2%	18.5%	17.5%
Hanover Insurance Group Inc	9.8%	6.5%	6.8%	9.9%	11.4%	8.9%	10.0%
Heartland Express Inc	15.5%	11.1%	7.4%	11.8%	10.7%	11.3%	12.0%
Hershey Company	91.2%	NMF	NMF	80.8%	70.1%	80.7%	32.5%
Huntington Ingalls Industries Inc	27.1%	34.7%	27.2%	55.1%	36.5%	36.1%	19.5%
IDEX Corporation	18.7%	18.5%	17.9%	21.1%	19.6%	19.2%	21.5%
IDEXX Laboratories Inc	-	-	-	NMF	NMF	-	55.5%
Integra LifeSciences Holdings Corporation	13.6%	16.1%	15.9%	14.8%	16.8%	15.4%	21.0%
Intel Corporation	18.4%	19.6%	24.0%	28.8%	28.1%	23.8%	28.5%
Intercontinental Exch.	9.2%	10.6%	10.4%	12.1%	12.7%	11.0%	12.0%
International Business Machines Corp	93.7%	65.1%	72.8%	75.4%	54.9%	72.4%	26.5%
Intuit Inc	31.7%	86.5%	84.9%	62.2%	47.5%	62.6%	25.5%
Investors Bancorp Inc	5.5%	6.2%	5.7%	7.7%	7.5%	6.5%	8.5%
Iron Mountain Inc	49.9%	13.7%	13.3%	16.8%	20.0%	22.7%	42.0%
Jack Henry and Associates Inc	21.3%	25.0%	23.8%	22.3%	19.0%	22.3%	24.0%
JP Morgan Chase and Co	9.9%	9.7%	10.4%	12.7%	13.9%	11.3%	10.0%
Juniper Networks Inc	14.1%	12.9%	17.3%	13.8%	13.0%	14.2%	30.0%
Kadant Inc	13.1%	12.2%	15.3%	16.3%	14.4%	14.3%	11.5%
Lindsay Corporation	9.1%	11.4%	8.6%	11.4%	5.8%	9.3%	12.5%
Littelfuse Inc	11.1%	17.5%	19.1%	16.1%	11.3%	15.0%	16.5%
Lockheed Martin Corp	NMF	NMF	-	NMF	NMF	-	45.0%
ManTech International Corporation	4.3%	4.5%	4.7%	5.9%	7.6%	5.4%	9.0%
Markel Corp	6.0%	4.4%	0.6%	NMF	16.2%	6.8%	6.0%
Masimo Corporation	30.2%	21.5%	24.2%	20.0%	16.8%	22.5%	15.5%
Mastercard Incorporated	63.2%	71.8%	89.5%	126.0%	134.7%	97.0%	27.0%
MAXIMUS Inc	25.8%	23.8%	22.3%	20.4%	19.3%	22.3%	25.0%
McCormick and Co	26.9%	29.7%	21.4%	20.9%	20.8%	23.9%	17.0%
Mercury General Corp	7.1%	5.4%	5.1%	6.2%	8.0%	6.4%	14.5%
Mettler Toledo International Inc	60.8%	88.4%	81.9%	83.6%	NMF	78.7%	NMF
Monolithic Power Sys.	9.5%	12.2%	15.1%	16.4%	14.1%	13.5%	23.0%
Monster Beverage Corporation	13.4%	21.4%	20.0%	27.5%	26.6%	21.8%	33.5%
Moodys Corp	-	-	-	NMF	NMF	-	27.5%
MSCI Inc	25.5%	82.1%	75.8%	NMF	NMF	61.1%	NMF
Nasdaq Inc.	10.4%	11.4%	11.7%	14.9%	14.8%	12.6%	11.0%
New York Times Co	7.7%	3.7%	0.5%	12.1%	11.9%	7.2%	20.5%
Nike Inc	25.8%	30.7%	34.2%	40.5%	44.6%	35.2%	70.0%
Northern Trust Corp	11.2%	10.6%	11.2%	14.8%	13.5%	12.3%	11.5%
Northrop Grumman Corp Holding Co	36.0%	41.8%	28.6%	39.4%	40.9%	37.3%	19.5%
Old National Bancorp	7.8%	7.4%	6.0%	7.1%	8.4%	7.3%	8.5%
Old Republic International Corp	9.4%	9.4%	7.4%	10.9%	9.1%	9.2%	13.0%
Packaging Corp	26.7%	25.5%	25.0%	27.6%	22.7%	25.5%	20.0%
Peoples United Financial Inc	5.5%	5.5%	5.7%	7.2%	6.5%	6.1%	7.0%
PerkinElmer Inc	13.7%	13.3%	12.9%	15.6%	16.3%	14.4%	25.5%
Philip Morris International Inc	NMF	NMF	NMF	NMF	NMF	-	NMF
Plexus Corp	11.4%	9.9%	10.9%	11.9%	12.3%	11.3%	12.0%
Pool Corporation	50.2%	72.6%	74.9%	NMF	63.8%	65.4%	60.0%
Post Holdings Inc	1.8%	7.2%	7.6%	10.1%	12.7%	7.9%	11.5%
Progressive Corp.	15.2%	11.8%	16.7%	27.2%	23.1%	18.8%	22.5%
Rayonier Inc	3.4%	15.0%	9.3%	6.6%	4.1%	7.7%	15.0%
Regal Beloit Corp	12.4%	10.0%	9.1%	11.4%	9.9%	10.6%	11.5%
RLI Corp	13.6%	11.3%	8.7%	11.4%	11.8%	11.4%	15.0%
Rollins Inc	29.0%	29.4%	29.2%	32.5%	24.9%	29.0%	35.5%
Roper Tech.	12.8%	11.4%	11.0%	15.9%	14.4%	13.1%	12.0%
RPM International Inc	25.0%	25.8%	23.2%	24.2%	25.9%	24.8%	25.0%
Selective Insurance Group Inc	11.2%	10.6%	10.8%	12.2%	12.0%	11.4%	11.5%
Sherwin Williams	NMF	60.3%	38.7%	47.1%	47.9%	48.5%	38.5%
Starbucks Corporation	41.1%	48.2%	55.2%	NMF	NMF	48.2%	NMF
Stryker Corp	16.9%	17.2%	18.6%	23.7%	24.5%	20.2%	20.0%
Synopsys Inc	14.0%	14.6%	16.4%	17.2%	17.2%	15.9%	22.5%
Teledyne Technologies	14.6%	12.3%	11.9%	15.0%	14.8%	13.7%	12.0%
Texas Instruments Incorporated	30.0%	34.3%	42.9%	62.0%	56.3%	45.1%	37.0%
The Travelers Companies Inc	14.5%	12.8%	8.6%	11.0%	9.8%	11.3%	11.5%
TJX Companies Inc	52.9%	52.0%	48.5%	60.6%	55.0%	53.8%	30.0%
Toro Co	43.6%	42.0%	43.4%	40.7%	31.9%	40.3%	35.5%
Tractor Supply Co	29.5%	30.1%	30.1%	34.1%	36.0%	32.0%	35.0%
Transmission Holdings Inc (Allison)	15.3%	19.9%	50.7%	NMF	77.3%	40.8%	61.0%
Trimas Corporation	10.7%	11.6%	11.8%	13.1%	9.5%	11.3%	14.0%
UniFirst Corp	10.0%	8.5%	7.4%	10.2%	10.0%	9.2%	7.5%
UnitedHealth Group	17.2%	20.4%	20.8%	24.5%	25.3%	21.6%	26.0%
US Bancorp	12.9%	12.4%	12.4%	13.9%	13.3%	13.0%	10.0%
Valmont Industries	4.4%	18.4%	14.2%	16.1%	13.8%	13.4%	12.5%
VeriSign Inc	-	-	-	-	-	-	NMF
Visa Inc	21.6%	20.8%	25.4%	30.3%	34.8%	26.6%	35.0%
Walt Disney Co	18.8%	21.7%	21.7%	25.8%	11.7%	19.9%	11.5%
Waters Corp	22.8%	22.7%	27.0%	39.9%	NMF	28.1%	36.0%
Watts Water Technologies Inc	12.0%	12.5%	12.5%	14.4%	14.2%	13.1%	14.0%
West Pharmaceutical Services Inc	9.3%	12.9%	11.8%	14.8%	15.4%	12.8%	18.0%
Western Union Company	59.6%	91.4%	NMF	NMF	NMF	75.5%	NMF
Wiley John and Sons Inc (Class A)	15.3%	17.4%	16.6%	14.2%	NMF	15.9%	13.0%
Xylem Inc	16.1%	11.9%	17.1%	18.9%	18.5%	16.5%	16.0%
Yum Brands Inc	NMF	-	-	-	-	-	NMF
Zoetis Inc	83.2%	65.4%	66.8%	69.8%	64.8%	70.0%	46.5%
Average						23.8%	22.4%
Median						17.2%	18.5%
Average (excluding companies with values >20%)						12.2%	13.0%

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-2021-3024750

Duquesne Light Company

Statement No. 14

Direct Testimony of James Milligan

Subjects: Capital Structure, Cost of Long-Term Debt, Credit Ratings, Liability Driven Investment Strategy for Pension Assets

Dated: April 16, 2021

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 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, and financial planning, analysis, and valuation.

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 2018. 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 and Duquesne Light's 2018 distribution rate case Docket No. 2018-3000124.

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 are challenged by the economic impacts related to the COVID-19 pandemic. 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.

Company's Current and Future Capital Structure

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

A. The capital structure as of December 31, 2020 was approximately 47.7% debt and 52.3% equity. In May 2020, Duquesne Light issued $200.0 million of 3.11% 30-year first mortgage bonds ("FMB") to fund capital expenditures, repay existing indebtedness and other general corporate purposes. During 2021, the Company plans to use $131.7 million of retained earnings, or nearly 82% of projected net income, and short-term borrowings to support the Company's funding needs. During 2022, the Company anticipates further using retained earnings of $109.5 million, or nearly 79% of projected net income, as well as issuing $150 million of long-term debt to fund its needs. Funding needs during 2021 and 2022 include capital expenditures, some of which are directly related to the Company's long-term infrastructure improvement plan (LTIIP). In addition, the proceeds from the 2022 long-term debt issuance will be used to repay outstanding short-term borrowings accumulated during 2021. As a result of the increased retained earnings balances expected during the FTY and FPFTY, partially offset by the increased long-term debt, the Company's equity as a percentage of total capitalization is projected to increase to 53.35% by the end of the FPFTY. The increased retained earnings and higher equity capitalization will provide further credit support to the Company through the impacts of the COVID-19 pandemic.

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 46.65% debt and 53.35% equity, which represents the Company's estimated equity capitalization on December 31, 2022. This capital structure is largely in line with the average of the prior three years, as provided in DFR III A-2, and is consistent with Duquesne Light's capital structure in the FPFTY. Further, as described by Mr. Paul Moul in his testimony, DLC St. No. 13, this capital structure is within a range of capital structures employed by 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 the COVID-19 pandemic.

Cost of Long-term Debt

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

A. The total adjusted long-term cost of debt requested in the Company's 2018 distribution rate case was 4.60%. Given current rates, future anticipated long-term debt issuances, 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 further decrease to approximately 4.29% by the end of the FPFTY.

Importance of Maintaining Duquesne Light's Credit Ratings

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 a generally accepted indication of creditworthiness used by the capital markets. A low credit rating reduces the availability of capital and makes capital more expensive. 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 fund many uses, most notably its capital expenditures needed to maintain reliable service to its customers. 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. In its Credit Opinion released on June 29, 2020, 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. Moody's also notes that Duquesne Light is operating in the credit supportive Pennsylvania regulatory environment.

Standard and Poor's upgraded Duquesne Light's rating on December 19, 2019 from BBB to BBB+. On November 20, 2020, Standard & Poor's affirmed the BBB+ issuer credit rating noting the Company's excellent business risk profile and stable credit metrics. Standard & Poor's also notes that the Company operates in a constructive regulatory environment, noting the existence of several regulatory mechanisms, including future test years and distribution system improvement charge rider.

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 three 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 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.

In addition to maintaining financial credit metrics consistent with the expectations for investment grade ratings, the rating agencies also consider qualitative factors, such as the regulatory environment in which Duquesne Light operates. As noted above, both Moody's and Standard & Poor's view Pennsylvania as supportive and constructive. The Company's ability to earn a fair and reasonable return and reduce regulatory lag is supportive to the Company's existing investment grade credit ratings.

Q. What impact did the COVID-19 pandemic have on the Company's creditworthiness and how have the rating agencies reacted to these negative consequences?

A. The Company's credit metrics were harmed by both the lower revenue as a result of lower customer usage and an increase in customer payment delinquency. Moody's and Standard & Poor's are closely monitoring these developments, including the regulatory response to the challenges created by the pandemic. In its June 29, 2020 Credit Opinion, Moody's noted that it "is monitoring customer usage declines, utility bill payment delinquency, and the regulatory response to counter any negative impacts on earnings and cash flow. The effects of the pandemic could result in financial metrics that are temporarily weaker than expected but not reflective of the companies' core operations or long-term financial or credit profile." In short, the rating agencies are remaining patient with utilities to improve their lower than expected financial metrics in anticipation of a supportive regulatory response to the COVID-19 pandemic.

Q. Are the results of this rate proceeding important to the Company's ability to maintain its current credit ratings?

A. Yes, as noted, the ability to recover costs and earn a reasonable return is an important criterion used by the rating agencies in determining the Company's creditworthiness. As noted, the support of the regulatory bodies is an important qualitative factor considered by the rating agencies. Regulatory support is always an important piece of rating agencies' creditworthiness criteria for utilities and is even more important during this period of uncertainty as utilities respond to the challenges created by the COVID-19 pandemic.

In addition to the regulatory environment, the rating agencies assess 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 of the COVID-19 pandemic. 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, 2020 levels in response to these developments.

<u>Liability Driven Investment Strategy for the Company's Pension Assets</u>

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 several years to realize. It took until 2020 to reach the point at which less than half of the active employees were in the pension plan and accruing 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. The Company also executed two lump sum buyouts of terminated and vested employees over the last five years. These lump sum buyouts reduced the size of the pension plan liability, while providing a beneficial option to those former employees.

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 93% funded and has nearly 65% 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 eliminated.

The market volatility at the beginning of the pandemic created a good test for the funded status of the pension plan and the Company's LDI strategy. Despite the S&P 500 index decreasing in value by nearly 23% from December 31, 2019 to March 30, 2020, the funded status of the Duquesne Light pension plan decreased less than 5% from 92.1% to 87.3%. Since that time, the funded status has more than fully recovered to 93.8% at year-end 2020.

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
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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
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53.53-III-B-3	Bank notes
53.53-III-B-4	Short term debt
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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-F	**General Financial Data**
53.53-III-F-3	Coverage requirements
53.53-III-F-4	Comparative financial data - 4 yrs.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3024750

Duquesne Light Company

Statement No. 15

Direct Testimony of Howard S. Gorman

Subjects: Jurisdictional Separation and Allocated Cost of Service

Dated: April 16, 2021

SECTION 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 presented 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, 2020 (Historic Test Year or HTY), for the year ended December 31, 2021 (Future Test Year or FTY) and for the year ended December 31, 2022 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:

Section I (this section)- Introduction and purpose of testimony

Section II- Overview of ACOS

Section III- Identification and discussion of exhibits included with my testimony

Section IV- Jurisdictional Separation Studies

Section V- Allocated Cost of Service Study

Section VI- Development of Allocators for FPFTY ACOS

SECTION 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 $1,036.279 million, which includes a return on distribution rate base, as well as overall total company rate base, of 7.84%. 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 Small (GS)
General Service Medium<25 (GM<25)
General Service Medium>25 (GM>25)
General Service Medium Heating<25 (GMH<25)
General Service Medium Heating>25 (GMH>25)
General Service Large (GL)
General Service Large Heating (GLH)
Large (L)
High-Voltage Power Service (HVPS)

Street Lighting Energy (SE)
Street Lighting (SM)
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.

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 No. R-2018-3000124?

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 No. R-2018-3000124?

A. Yes, the same methodology was used.

SECTION III- IDENTIFICATION AND DESCRIPTION OF EXHIBITS

Q. Please identify the exhibits that are included with your testimony.

A. My testimony includes exhibits identified in the Index to Exhibit 6. The JSS for the FPFTY, FTY and HTY are presented in Exhibits 6-1, 6-1A and 6-1B respectively. The ACOS for the FPFTY is presented in Exhibits 6-2 through 6-9, including Development of Allocator values on Exhibit 6-9. Exhibit 6-10 shows the proposed Revenue Allocation, which is described in Mr. Ogden's testimony, including Distribution ROR at Proposed Revenue Allocation. Exhibit 6-11 presents the SL- Distribution-only 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 77-137), depreciation expense (lines 138-159) and taxes (lines 160-177). Revenues (lines 181-189) are compared to total expenses (line 179, also line 191) to compute net income at present rates (line 192, also line 210) and return on rate base (line 212).

The distribution revenue required to produce a rate of return of 7.84% in the FPFTY is computed on lines 214-230, and the difference between the revenue requirement and revenue at present rates is shown on line 233.

The distribution revenue requirement for the FPFTY is $654.1 million, an increase of $85.76 million over Distribution revenue at present 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, 7.84%.

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 7.84% 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 7.84% return (line 27), and the percentage of total revenue (line 28) and distribution tariff revenue (line 29) this increase represents.

The exhibit demonstrates that to produce the return on rate base of 7.84% an increase in distribution revenue of $85.76 million, or 15.58% of distribution tariff revenue (15.09% of total distribution revenue), 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 6-5.

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* show 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 Exhibit 6-7. 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.

SECTION 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. 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, AMI initiative 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 214-230. It is the amount required to recover all jurisdictional costs, and to provide an after-tax return on jurisdictional rate base of 7.84%.

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, presented in Exhibit 6-1?

A. Yes.

<u>SECTION V - ALLOCATED COST OF SERVICE (ACOS) STUDY</u>

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.

<u>Functionalization</u>

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 components 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 230. 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) were functionalized between Primary Distribution and Secondary Distribution based on a review of purchases over the period 1999-2019.

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 1999-2019.

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.

<u>Classification</u>

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. Therefor 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. Therefor 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 computed by 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 Overhead 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, which include the costs of 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). A separate allocator was developed for AMI costs, which are included in Intangible Assets. 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). A special study was used to develop the allocator 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 through 6-7D show 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 DSIC and STAS 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 revenue 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 is shown on Exhibit 6-7, line 230, 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.

SECTION 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 Overhead 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 demands for each class.

The PLCC adjustment was made for OH Transformers and Radial Transformers, comprising approximately 57% 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.

<u>SECTION VII- RATES OF RETURN AT PROPOSED REVENUE ALLOCATION</u>

Q. Please describe Exhibit 6-10.

A. <u>*Exhibit 6-10*</u> 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. <u>*Exhibit 6-11*</u> 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. I reserve the right to supplement my testimony through the course of this proceeding.

RESUME OF
HOWARD S. GORMAN
PRESIDENT – HSG GROUP, INC.

Mr. Gorman has more than 30 years of experience in the energy industry, including 20 years in rate and regulatory proceedings. His areas of expertise include embedded class cost of service studies, marginal cost studies, revenue allocation, rate design and revenue requirements, for both electric and gas utilities. He has testified as an expert witness before the Massachusetts Department of Public Utilities, New Jersey Board of Public Utilities, New Hampshire Public Utilities Commission, New York State Public Service 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, and treasury and financial management.

PROFESSIONAL EMPLOYMENT

2010 - Present	HSG Group, Inc. *President*	
1997 - 2010	Black & Veatch Corporation (R.J. Rudden Associates, Inc. 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*; IPO with NYSE listing in 1994
1982 - 1987	Coleco Industries, Inc. *Director, Treasury*	
1976 - 1979	Touche Ross & Co. *Staff Accountant*	

PROFESSIONAL EXPERIENCE

Utility Accounting and Costing

Mr. Gorman has performed numerous class cost of service studies, and has developed and supported revenue requirements, revenue allocation, rate designs and marginal cost studies, in rate cases before regulatory commissions in several jurisdictions, for electric and gas utilities. These assignments included development of test year data, forecasts for the rate year, establishment of cost causality, selection of allocation bases, development of allocators, and analysis of customer impacts and policy considerations.

Energy Project Financing and Analysis

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 performed financial analyses of energy-related assets, including electric and gas distribution companies, power plants and transmission operators. These analyses 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.

Accounting and Financial Management

Mr. Gorman 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. He managed the corporate insurance portfolios and the benefit plans for Trigen Energy Corporation and for Coleco Industries, and has bought and sold interest rate and currency forward contracts for the purpose of managing risk.

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			
Utility	**Jurisdiction**	**Docket**	**Subject Matter**
Niagara Mohawk (Gas)	New York 2020	20-G-0381	Gas class cost of service; revenue allocation; rate design; marginal cost
Niagara Mohawk (Electric)	New York 2020	20-E-0380	Electric class cost of service; revenue allocation; rate design; marginal cost
Citizens' Electric of Lewisburg, PA	Pennsylvania 2019	R-2019-3008212	Electric revenue requirements, class cost of service, revenue allocation, rate design
Wellsboro Electric Company	Pennsylvania 2019	R-2019-3008208	Electric revenue requirements, class cost of service, revenue allocation, rate design
Valley Energy, Inc.	Pennsylvania 2019	R-2019-3008209	Gas revenue requirements, rate design
Brooklyn Union Gas / KeySpan Gas East	New York 2019	19-G-0309 /0310	Gas class cost of service; revenue allocation; rate design; marginal cost
Massachusetts / Nantucket Electric	Massachusetts 2018	DPU 18-150	Electric class cost of service; revenue allocation; rate design; marginal cost Monthly Minimum Reliability Contribution
Duquesne Light	Pennsylvania 2018	R-2018-30000124	Electric class cost of service; revenue allocation; rate design
Narragansett Electric	Rhode Island 2017	RIPUC 4770	Electric class cost of service; revenue allocation; rate design
Veolia Energy Philadelphia	Pennsylvania 2017	R-2017-2593142	Steam system revenue requirements; sales forecast
Niagara Mohawk (Gas)	New York 2017	17-G-0239	Gas class cost of service; revenue allocation; rate design; marginal cost
Niagara Mohawk (Electric)	New York 2017	17-E-0238	Electric class cost of service; revenue allocation; rate design; marginal cost
Citizens' Electric of Lewisburg, PA	Pennsylvania 2016	R-2016-2531550	Electric revenue requirements, class cost of service, revenue allocation, rate design
Wellsboro Electric Company	Pennsylvania 2016	R-2016-2531551	Electric revenue requirements, class cost of service, revenue allocation, rate design
Granite State Electric	New Hampshire 2016	DE 16-383	Electric revenue requirement
Brooklyn Union Gas / KeySpan Gas East	New York 2016	16-G-0058 /0059	Gas class cost of service; revenue allocation; rate design; marginal cost
Massachusetts / Nantucket Electric	Massachusetts 2015	DPU 15-155	Marginal cost
Jamestown Board of Public Utilities	New York 2015	15-E-0184	Electric revenue requirements
Energy North Natural Gas	New Hampshire 2015	DE14-180	Gas revenue requirements
Village of Freeport	New York 2014	14-E-0035	Electric revenue requirements; sales forecast; rate design
Veolia Energy Philadelphia	Pennsylvania 2014	R-2013-2386293	Steam system revenue requirements and sales forecast

Relevant Projects			
Utility	**Jurisdiction**	**Docket**	**Subject Matter**
Duquesne Light	Pennsylvania 2014	R-2013-2372129	Electric class cost of service; revenue allocation; rate design
Granite State Electric	New Hampshire 2013	DE13-063	Electric class cost of service (marginal cost); revenue allocation; rate design
Hydro One Networks Inc.	Ontario 2005-2013	EB-2005-0378 et al	Electric Transmission and Distribution cost allocation; OH capitalization rates (2013, 2012, 2010, 2009, 2008, 2006, 2005)
Ontario Power Generation	Ontario 2006-2013	EB-2007-0905 et al	Electric cost allocation methodology (2013, 2010, 2006)
Niagara Mohawk (Electric)	New York 2012	12-E-0201	Electric class cost of service; revenue allocation
Narragansett Electric	Rhode Island 2012	RIPUC 4323	Electric class cost of service
Village of Rockville Centre	New York 2011	11-E-0590	Electric revenue requirements; rate design; sales forecast
Chautauqua Utilities, Inc.	New York 2011	11-G-0142	Gas revenue requirements, rate design
Kellogg (intervenor)	Pennsylvania 2010	R-2010-2179103	Water class cost of service; revenue allocation
Duquesne Light	Pennsylvania 2010	R-2010-2179522	Electric class cost of service; revenue allocation; rate design
Wellsboro Electric	Pennsylvania 2010	R-2010-2172662	Electric revenue requirements, class cost of service, revenue allocation, rate design
Citizens' Electric of Lewisburg, PA	Pennsylvania 2010	R-2010-2172665	Electric revenue requirements, class cost of service, revenue allocation, rate design
Valley Energy, Inc.	Pennsylvania 2010	R-2010-2174470	Gas revenue requirements, rate design
PECO Energy (Gas)	Pennsylvania 2010	R-2010-2161592	Gas class cost of service; revenue allocation; rate design
PECO Energy (Electric)	Pennsylvania 2010	R-2010-2161575	Electric class cost of service; revenue allocation; rate design
Niagara Mohawk (Electric)	New York 2010	10-E-0050	Electric class cost of service
Jamestown Board of Public Utilities	New York 2009	09-E-0862	Electric revenue requirements
Philadelphia Gas Works	Pennsylvania 2001-2009	R-2139884 R-00061931 M-00021612 R- 00017034 R- 00006042	Gas class cost of service; revenue allocation; rate design; rate unbundling; recovery of fixed costs (2006, 2002, 2001)
Narragansett Electric	Rhode Island 2009	RIPUC 4065	Electric class cost of service; revenue allocation; rate design

Relevant Projects			
Utility	**Jurisdiction**	**Docket**	**Subject Matter**
Massachusetts / Nantucket Electric	Massachusetts 2009	DPU 09-39	Electric revenue requirements; adjustment mechanisms; class cost of service; revenue allocation; rate design
PECO Energy (Gas)	Pennsylvania 2008	R-2008-2028394	Gas class cost of service; revenue allocation; rate design
Wellsboro Electric	Pennsylvania 2007	R-00072350	Electric revenue requirements; rate design
Citizens' Electric of Lewisburg, PA	Pennsylvania 2007	R-00072348	Electric revenue requirements; rate design
Valley Energy, Inc.	Pennsylvania 2007	R-00072349	Gas revenue requirements; rate design
Village of Freeport	New York 2006	06-E-0911	Electric revenue requirements; rate design
Duquesne Light	Pennsylvania 2006	R-00061346	Electric class cost of service; revenue allocation; rate design
Village of Rockville Centre	New York 2003	03-E-1568	Electric revenue requirements; rate design; sales forecast
AmeriSteel aka Co-Steel (intervenor)	New Jersey 2002	ER02080506, ER02050303 et al	Electric cost allocation and rate design; industrial rates

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3024750

Duquesne Light Company

Statement No. 16

Direct Testimony of David B. Ogden

Subjects: Revenue Allocation, Rate Design, Bill Impact, Proof of Revenue, and Tariff Changes

Date: April 16, 2021

INTRODUCTION

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 twelve (12) 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 twelve 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 VIII ("DSP VIII") proceeding at Docket No. P-2016-2543140, the Company's Distribution System Improvement Charge ("DSIC") proceeding at Docket No. P-2016-2540046, the Company's 2018 base rate proceeding at Docket No. R-2018-3000124, the Company's Default Service Plan IX ("DSP IX") proceeding at Docket No. P-2020-3019522, and the Company's Energy Efficiency and Conservation ("EEC") Phase IV Plan at Docket No. M-2020-3020818.

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. 25 implementing the proposed rates, riders and tariff revisions in this proceeding. Certain of the tariff revisions included in Exhibit DBO-1 are addressed by other Company witnesses, namely:

- Rule No. 41.1 (Residential Master Metering for New Low-Income Supportive Housing) is addressed by Ms. Phillips at DLC Statement No. 6.
- Revised Rider No. 16 – Service to Non-Utility Generating Facilities, Rider No. 7 - Residential Subscription Rate Pilot, and Rider No. 19 - Community Development are addressed by Ms. Everett at DLC Statement No. 17.
- Rider No. 23 - Home Charging Pilot Program and Rider No. 24 - Fleet Charging Pilot Program are addressed by Ms. Olexsak at DLC Statement No. 8.
- Rider No. 25 - New Business Stimulus and Rider No. 26 – Crisis Recovery Program are addressed by Ms. Kubiak at DLC Statement No. 5.

- 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 tariff supplement
- Exhibit DBO-4, which contains the calculations supporting the proposed LED street light rates
- Exhibit DBO-5, which contains an updated unbundling schedule
- Exhibit DBO-6, which contains an illustrative example to calculate the Federal Tax Adjustment Charge ("FTAC") rate

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 base 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 those proposed changes to the Rules and Regulations section and Riders of the tariff that are not addressed by other Company witnesses, as discussed above.

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 Rules 41 and 41.1 and Rider Nos. 7, 16, 19, and 23 through 26, as discussed above.

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 revenue allocation objectives it established in its 2006, 2010, 2013 and 2018 distribution rate case proceedings. The Company's primary goal in this rate case, as in its 2006, 2010, 2013 and 2018 rate cases, is for the proposed revenue allocation to move each rate class closer to the proposed overall return of 7.84%, which would recover the class's full cost of service (including return). Each class's return at present rates is determined in the class cost allocation study ("ACOS") prepared by Mr. Gorman in Exhibit 6 at DLC Statement No. 15. Each class relative return is equal to its return at present rates (Exhibit 6-2, line 11) divided by the overall return at present rates of 5.36%. The proposed revenue allocation moves a class closer to recovering its full cost of service, when its relative return moves closer to 1.0, or unity.

The second overall revenue allocation objective is to mitigate the rate impact both on rate classes and on individual customer subgroups, while continuing to progress to the rate class's fully allocated cost of service. 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. 15, 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 and return at present rates, 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 7.84 %).

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 13-20. The class returns at proposed revenue are computed on lines 21-32. The relative returns at proposed revenue and progress toward unity are on lines 34-38.

Class distribution revenue at proposed rates is shown on line 40. These are the revenue targets that the proposed new rates will be designed to produce.

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 5.36% at current rates, equal to returns of 4.02 to 6.70 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 $85.76 million, or 15.58% of distribution revenue at present rates, is required to produce the proposed return of 7.84%. In Step 1 of the revenue allocation (Exhibit 6-10, line 16), classes within the tolerance band but above the average (i.e. RS, GS, GM<25, GMH<25, GL) received an initial increase of 15.03% (0.965X average); GM<25 was included in this group because it is just above the tolerance band, at 1.29X. Classes within the tolerance band but below average (i.e. GM>25, L) received an initial increase of 16.50% (1.059X average). Classes below the tolerance band (i.e. RH, RA, GMH>25, GLH, UMS) received an initial increase of 21.5% (1.38X average). Classes above the tolerance band (i.e. SE and SL) received an initial increase of 5.0% (0.321X average). HVPS class received an initial increase of zero because it had a very high return at present rates. The use of the tolerance band results in a revenue increase of $85.76 million (line 17), which equals the required increase.

In Step 2 of the revenue allocation, the Company judgmentally reduced the allocation to RS in order to move it closer to unity at proposed rates, and also adjusted GS and L (line 19). The difference was spread among the classes in proportion to the initial increase (line 20).

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 13-20. The class returns at proposed revenue are computed on lines 21-32. The relative returns at proposed revenue and progress toward unity are on lines 34-38.

Class distribution revenue at proposed rates is shown on line 40. These are the revenue targets that the proposed new rates will be designed to produce.

Q. Does the proposed revenue allocation achieve the goals?

A. The Company substantially achieved its goals. Except for RS and L, each class moves closer to unity (line 35), which compares relative return at present (line 4) and relative return at proposed (line 34). Both RS and L will be very close to unity at both present and proposed rates; to move RS closer to unity would have required a further net decrease of $2.05M, and to move L to unity would have required a further net increase of $0.4 million. In addition, no class received an increase greater than 1.5X average (line 38), which meets the constraint which I described earlier.

Q. Why does RS not make progress toward the system average return?

A. RS is currently producing a return 1.01X average, and the proposed rates produce a return for RS of 1.028X average. When classes are so close to the average, it can be challenging to move the returns even closer. In the case of RS, the proposed increase is 14.35% compared to the average proposed increase of 15.58%; reducing the RS revenue allocation any further would raise the targets for other classes. The proposed revenue allocation fairly balances moving most classes closer to average return, mitigating increases and keeping RS very close to its present relative return.

Q. Why does L not make progress toward the system average return?

A. L is currently producing a return 0.98X average, and the proposed rates produce a return for L of 0.94X average. As discussed above regarding class RS, when classes are so close to the average, it can be challenging to move the returns even closer. In the case of L, the proposed increase is 18.25% compared to the average proposed increase of 15.58%. The proposed revenue allocation fairly balances moving most classes closer to average return, mitigating increases and keeping L close to its present relative return.

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 base 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. Finally, the Company has tried to mitigate extreme bill impacts on customers within each class. 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. I also note that a higher fixed charge provides some revenue stability for the Company and cost stability for customers.

Recovery of the remaining revenue (that is, target revenue less the amount recovered through the fixed monthly charge) will be through a single volumetric charge per kWh.

Q. Please describe the rate design for customers on Rates 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 (which is off-peak for most of the Company's customers). Currently, Rates RH and RA have the same rates 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 51,900 commercial and industrial ("C&I") customers. This group consists of approximately 24,900 non-demand-billed customers on Rate GS, approximately 20,200 customers on Rate GM with monthly demand less than 25 kW and approximately 6,800 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, 2013 and 2018 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 single volumetric charge per kWh, 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. Demand is the customer's peak 15-minute usage each month. 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 Rate GM under 25 kW ($7.89 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. Rate GMH under 25 kW and Rate 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 3,200 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-related costs identified in Exhibit 6-4E and the demand-related costs identified in Exhibit 6-3. The proposed $63.00 fixed monthly charge is the same as proposed for Rate 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 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 percentage increase. The balance of the target revenues is 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 single volumetric 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 20 customers. These customers represent some of the largest customers served by the Company and are diverse in size (demand). The Company offers the Rate L Service Voltage Less than 138 kW 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.

Q. What is the distribution rate design that is being proposed for Rate L?

A. The Company is proposing to continue the same rate structure for Rate L. The existing rate structure uses 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 fixed charge, which includes the first block of demand (5,000 kW), was increased by approximately the rate class revenue percentage increase. The balance of the target revenues is recovered through the charge for demand over 5,000 kW.

Q. Please describe the current distribution rate design for Rate HVPS.

A. There are currently nine (9) customers on Rate HVPS each served at 69 kV or more and with a monthly demand greater than 5,000 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. The Company is proposing to continue 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 increased by the same percentage, as needed to produce the class revenue target.

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 increase to each rate. These changes, when combined with the elimination of surcharges that are being rolled into rates (e.g. DSIC) will produce the revenue targets.

For Rate SE, the Company is proposing a rate which, when combined with the elimination of surcharges that are being rolled into rates (e.g. DSIC) will produce the revenue target.

For Rate UMS, the Company is proposing to continue the same rate structure for Rate UMS. The fixed charge was increased by approximately the rate class revenue percentage increase. Recovery of the remaining revenue (that is, target revenue less the amount recovered through the fixed monthly charge) will be through a single volumetric charge per kWh.

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 rate. 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's 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 IV Energy Efficiency and Conservation Surcharge (“EEC IV”), 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 DSIC and STAS, revenue shown. The STAS is proposed to be set at 0% with the associated taxes recovered in the proposed distribution charges. Schedule D-5D, Line 29, 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. 10 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 G, 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, 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 and other factors 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 ministerial changes as well as changes to reflect current business practices that are described in the list of modifications within Exhibit 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. The Company is not proposing changes to the base distribution rate structure in this proceeding.

Q. Please describe the proposed revisions to Rate AL – Architectural Lighting Service and Rate SH – Street Lighting Highway options to the tariff.

A. Beginning January 1, 2022, Rate AL and Rate SH will no longer be available to new customers, applicants and/or for new installations. The Company will continue to maintain and replace defective or broken fixtures for existing customers.

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 rates to municipal, highway, and non-municipal customers, respectively. The street light rates correspond to mercury vapor, high pressure sodium ("HPS") fixtures and LED fixture options. The Company closed the mercury vapor rate and stopped installing new mercury vapor fixtures in 2019, and proposes to do the same for HPS fixtures in this proceeding. Moving forward, the Company will install only LED street lighting fixtures. The Company proposes to add one new LED fixture option and remove one LED fixture option to/from Rate SM, Rate SH and Rate PAL, and update the supporting calculations for the existing LED fixtures as described below.

Q. Please describe the proposed revisions to the tariff to implement the new LED street light rate?

A. Rate SM, Rate SH and Rate PAL have been revised to include, in tabular format, the new LED fixture option and applicable distribution rates. These rates are a fixed charge per fixture per month similar to the existing LED fixtures. The updated rate is based on the calculations in Exhibit DBO-4.

In addition, Rider No. 8, Default Service Supply ("DSS"), has been revised to show the new LED fixture option. 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 option.

Q. What DSS and TSC rate will the new LED street lighting fixture reflect?

A. The Company proposes to charge the new 30 watt LED street lighting option the same rate as the 45 wattage LED option 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. How did the Company calculate the fixed charges for the new and existing LED street lighting options?

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 and existing 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 changes to existing riders in the tariff?

A. Yes, in addition to the above-mentioned changes to rules and riders that are sponsored by Ms. Kubiak, Ms. Phillips, Ms. Olexsak, and Ms. Everett, there are four (4) riders and one (1) appendix that the Company is proposing to revise. First, the Company is proposing to update the tables in the lighting sections of Rider No. 8 – DSS to accommodate the revised LED street light fixture in Rate Schedules SM, SH and PAL. Second, 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. Third, the Company is proposing to reset Rider No. 10 - STAS to zero to reflect recovery of these charges in base rates. Fourth, the Company is proposing to reset Rider No. 22 – DSIC to zero to reflect recovery of these charges in base rates. Finally, the Company is proposing to update Appendix A – TSC accommodate the revised LED street lighting fixtures offered.

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 fixture that is 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, 2021 to May 31, 2025 at Docket No. P-2020-3019522. 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, 2022, the first effective default service supply rate change for all classes after new distribution rates become effective January 15, 2022.

Q. Please explain the change to Rider No. 9 – Day-Ahead Hourly Price Service ("HPS")

A. Rider No. 9 provides eligible C&I 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 HPS eligible 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, 2022, the first effective FRA rate change after new distribution rates become effective January 15, 2022.

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 2021, for any state tax changes not reflected in the base rate filing.

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, 2022, rate base in the present case.

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 F, Page 2. As described earlier, the distribution revenues in Schedule D-5D, Column G, 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. 10.

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 fixture offered.

Q. Are there any new or revised riders in the tariff?

A. Including the Riders sponsored by other witnesses, as discussed above, the Company is proposing the following additional riders to the tariff:

- Rider No. 4 – Federal Tax Adjustment Charge (“FTAC”)
- Rider No. 7 - Residential Subscription Rate Pilot
- Rider No. 16 – Service to Non-Utility Generating Facilities
- Rider No. 19 - Community Development
- Rider No. 23 - Home Charging Pilot Program
- Rider No. 24 - Fleet Charging Pilot Program
- Rider No. 25 – New Business Stimulus
- Rider No. 26 - Crisis Recovery Program

Q. Please explain the new Rider No. 4 – FTAC.

A. As Company witness Simpson describes in further detail in his direct testimony, DLC Statement No. 12, the Federal Tax Adjustment Charge (FTAC) will provide for adjustments to base distribution revenue to reflect the effects of future increases or decreases in the federal corporate income tax rate.

Q. Please describe the Company’s proposed FTAC.

A. The FTAC is a reconcilable Section 1307(e) adjustment clause that will function similar to the Company’s existing STAS that provides for adjustments to base rates for changes in state taxes and specifically for changes in the tax rate under the Pennsylvania Corporate Net Income Tax. The Company’s proposed methodology to quantify the federal income tax adjustment (“FITA”) before and after implementing the federal corporate income tax rate change is presented in an illustrative example within witness Simpson’s Exhibit MLS-3.

The increase/decrease in required revenues will be divided by the estimated annual base distribution revenues to develop the FTAC that will be applied to customers' bills for service rendered during the applicable twelve-month period. The difference between the actual increase/decrease in required revenue and the increase/decrease produced by the FTAC as applied will be subject to refund or recovery in an annual true-up to the FTAC.

An annual reconciliation statement will be submitted to the Commission each year, and a final reconciliation statement will be filed within 30 days after the completion of the final over/under collection. The Company may file interim rate adjustments to eliminate any over or under recovery of the surcharge outside of their respective filing periods. The FTAC revenues and reconciliation will be subject to audit by the Commission's Bureau of Audits. The FTAC has been included in the Company's proposed Tariff within Exhibits DBO-1 and DBO-2.

Q. Please describe the computation of the FTAC.

A. The computation of the FTAC is as follows:

$$FTAC = \frac{(((FITA * GRCF) + e) * GRT)}{PAR}$$

$$GRCF = (1/((1-SIT)*(1-FIT)))$$

$$GRT = 1/(1-T)$$

Where:

FITA = Reflects the federal income tax adjustment, if any, and may be a positive or negative value.

GRCF = Gross Revenue Conversion Factor

SIT = State Income Tax rate in effect at the time of the filing

FIT = Federal income tax rate in effect at the time of the filing

T = Pennsylvania gross receipts tax rate in effect during the billing month

e = Amount calculated (+/-) under the annual reconciliation feature or Commission audit.

PAR = Projected annual revenues for base distribution service (excluding all applicable clauses and riders) from existing customers

Q. What constitutes distribution revenue for purposes of the FTAC calculation?

A. For purposes of calculating the FTAC charge, distribution revenue includes all amounts that are billed to customers for distribution service (i.e. fixed customer charge, kWh, kW), excluding all applicable clauses and riders. As a result, the FTAC, expressed as a percentage, will be applied to the total base distribution charges of a customer's bill, before all other clauses and riders have been calculated.

Q. What customers will be charged the FTAC?

A. The Company's FTAC will be applied as an equal percentage to all distribution customers.

Q. Will the FTAC appear as a separate charge on customers' bills?

A. Yes. The Company is proposing to present the FTAC mechanism as a separate line item, distinct from the other customer charges.

Q. What is the projected impact of the FTAC on customers' rates?

A. Per the illustrative FTAC rate calculation provided in Exhibit DBO-6, Duquesne Light estimates that a change in the federal corporate income tax rate from 21% to 28% would be approximately 4.49% increase in distribution charges. This is based on the illustrative FITA example within witness Mr. Simpson's Exhibit MLS-3. The incremental total bill impact to the average residential default service customer would be $2.63 or 2.44% on a total bill basis.

Q. When would the FTAC go into effect?

A. The Company is requesting permission to implement its FTAC on January 15, 2022. The FTAC would be filed to become effective on 10 days' notice as soon as practicable following the effective date of any federal corporate income tax change. After the initial filing, the FTAC shall be filed with the Commission by April 1st of each year that it is in place. The FTAC will be reset to zero upon application of new base rates. Thereafter, only the residual over/under collection or E-factor amount can continue to be collected or credited, until a subsequent change occurs in the future that impacts the federal corporate income tax rate.

Q. The Commission's Policy Statement on alternative distribution ratemaking mechanisms, 52 Pa. Code §§ 69.3301 and 69.3302, identifies a number of factors the Commission may consider when evaluating an alternative distribution rate mechanism. Has the Company considered these factors with respect to the FTAC?

A. Yes. I address each of them below.

(1) How the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.

The FTAC advances cost-causation principles because it aligns the Company's incurrence and recovery of federal tax liability, as Mr. Simpson explains in his direct testimony.

(2) How the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.

(3) Whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.

(4) How the ratemaking mechanism and rate design limit or eliminate interclass and intraclass cost shifting.

(5) How the ratemaking mechanism and rate design limit or eliminate disincentives for the promotion of efficiency programs.

(6) How the ratemaking mechanism and rate design impact customer incentives to employ efficiency measures and distributed energy resources.

(7) How the ratemaking mechanism and rate design impact low-income customers and support consumer assistance programs.

Items #2 through #7 are not applicable to the FTAC. The FTAC adjusts the Company's total revenue requirement, but does not affect customer programs, rate design, or revenue allocation among or within any customer groups.

(8) How the ratemaking mechanism and rate design impact customer rate stability principles.

The FTAC supports customer rate stability by reducing regulatory lag between a change in federal tax rates and the corresponding adjustment in distribution rates. Absent the FTAC, a change in federal tax rates could cause the Company to over- or under-collect until its distribution rates are reset. The longer these over- or under-collections accumulate, the more rate disruption they will produce when ultimate refunded or recouped from customers. The FTAC mitigates the accumulation of over- or under-collections by adjusting the Company's distribution rates in tandem with federal corporate income tax rates.

(9) How weather impacts utility revenue under the ratemaking mechanism and rate design.

Item #9 is not applicable to the FTAC.

(10) How the ratemaking mechanism and rate design impact the frequency of rate case filings and affect regulatory lag.

Please see my response to item #8 above. As discussed, the FTAC mitigates regulatory lag associated with changes in federal corporate income tax rates, and thereby may reduce the need for or frequency of future rate case filings.

(11) If or how the ratemaking mechanism and rate design interact with other revenue sources, such as Section 1307 automatic adjustment surcharges, 66 Pa.C.S. § 1307 (relating to sliding scale of rates; adjustments), riders such as 66 Pa.C.S. § 2804(9) (relating to standards for restructuring of electric industry) or system improvement charges, 66 Pa.C.S. § 1353 (relating to distribution system improvement charge).

Item #11 is not applicable. As described above, the FTAC is being proposed as a reconcilable Section 1307(e) adjustment clause, but it will only interact with base distribution revenue, and will not apply to any other revenue sources.

(12) Whether the alternative ratemaking mechanism and rate design include appropriate consumer protections.

The FTAC includes appropriate customer protections. Any adjustment to the Company's rates via the FTAC is subject to prior Commission review and approval. As Mr. Simpson explains in his direct testimony, and as the proposed FTAC Rider indicates, the Company must provide full factual support for any proposed rate adjustment through the FTAC, which will be provided to statutory advocates as well as the Commission. In addition, as described above, the FTAC revenues and reconciliation will be subject to audit by the Commission's Bureau of Audits.

(13) Whether the alternative ratemaking mechanism and rate design are understandable to consumers.

This item is not directly applicable to the FTAC, as the FTAC only modifies the Company's revenue requirement, not any customers' rate design. However, it is intuitive that as federal corporate income tax rates change, the Company's costs recovered through rates must also change.

(14) How the ratemaking mechanism and rate design will support improvements in utility reliability.

The FTAC advances the Company's ongoing efforts to improve reliability by reducing regulatory lag, as I discussed above. By aligning tax liability incurrence with recovery thereof, the FTAC helps to ensure the Company can continue to invest in programs that support system reliability and resiliency.

Q. Please explain the new Rider No. 7 – Residential Subscription Rate Pilot.

A. As sponsored by Company witness Everett, she describes in further detail in her direct testimony, DLC Statement No. 17, the Company's proposal to implement a pilot to test the feasibility and acceptance of a Residential Subscription tariff. This subscription rate would offer customers the option to select a specified level of grid access for a set monthly charge.

Q. Please explain the new Rider No. 16 – Service to Non-Utility Generating Facilities.

A. As sponsored by Company witness Everett, which she describes in further detail in her direct testimony, DLC Statement No. 17, the Company is proposing to change the structure of Rider No. 16.

Q. Please explain the new Rider No. 19 – Community Development Rider.

A. As sponsored by Company witness Everett, which she describes in further detail in her direct testimony, DLC Statement No. 17, the Company is proposing to provide incentives for customers to bring operations to the Company's service territory.

Q. Please explain the new Rider No. 23 – Home Charging Pilot Program and Rider No. 24 – Fleet Charging Pilot Program.

A. As sponsored by Company witness Olexsak (DLC Statement No. 8) and Everett (DLC Statement No. 17), the Company's pilot proposals include rates charged to participating customers to recover the costs of the chargers, and some of the costs incurred to establish charging solutions, for customers who are using electric vehicles.

Q. Please explain the new Rider No. 25 – New Business Stimulus Rider.

A. As sponsored by Company witness Kubiak, which she describes in further detail in her direct testimony, DLC Statement No. 5, the Company is proposing to help support the rebuilding of small communities' business districts by incentivizing new businesses to occupy and operate from vacant storefronts in certain communities in Duquesne Light's service territory by providing them with a reduced distribution rate for 2 years.

Q. Please explain the new Rider No. 26 – Crisis Recovery Program.

A. As sponsored by Company witness Kubiak, which she describes in further detail in her direct testimony, DLC Statement No. 5, the Company is proposing to provide a relief program for existing nonresidential customers who have accumulated a delinquent balance because of COVID-19 business restrictions.

Q. Does this conclude your direct testimony?

A. Yes, it does. I reserve the right to supplement my testimony through the course of this proceeding.

Exhibit No. DBO-1

SUPPLEMENT NO. 25
TO ELECTRIC – PA. P.U.C. NO. 25

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

Mark E. Kaplan
Interim President and Chief Executive Officer

ISSUED: April 16, 2021 EFFECTIVE: June 15, 2021

Filed at Docket No. R-2021-3024750

NOTICE

THIS TARIFF SUPPLEMENT ADDS PAGES AND RIDERS, MAKES CHANGES TO THE TABLE OF CONTENTS, RULES AND REGULATIONS, RATE SCHEDULES, RIDER MATRIX, RIDERS AND APPENDIX A AND MAKES INCREASES AND DECREASES TO THE RATES CONTAINED IN THE RATE SCHEDULES AND RIDERS.

See Page Two

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES

List of Modifications Made by this Tariff

First Revised Pages No. 2A through Original Page No. 2G
Cancelling Original Pages No. 2A – 2G

Original Pages No. 2H – 2L

Original Page No. 2H through Original Page No. 2L have been added to Tariff No. 25 to accommodate the List of Modifications.

Original Page No. 3A has been added to the Table of Contents and therefore to Tariff No. 25.

Original Page No. 26A has been added to the rules section and therefore to Tariff No. 25.

Original Page No. 34A has been added to the rules section and therefore to Tariff No. 25.

Original Page No. 87A has been added to the Rider Matrix section and therefore to Tariff No. 25.

Original Page No. 92A has been added to the rider section and therefore to Tariff No. 25.

Original Page No. 92B has been added to the rider section and therefore to Tariff No. 25.

Original Page No. 97A has been added to the rider section and therefore to Tariff No. 25.

Original Page No. 124A has been added to the rider section and therefore to Tariff No. 25.

Original Page No. 128A has been added to the rider section and therefore to Tariff No. 25.

Original Page No. 141A through Original Page No. 141G have been added to the rider section and therefore to Tariff No. 25.

Table of Contents

Fourth Revised Page No. 3
Cancelling Third Revised Page No. 3

Original Page No. 2H through Original Page No. 2L have been added to Tariff No. 25 to accommodate the List of Modifications.

Rider No. 4 – Federal Tax Adjustment Clause has been added to Tariff No. 25 and to the Table of Contents.

Original Page No. 87A has been added to the Table of Contents to reflect the additional page added to the Rider Matrix (Pages No. 87-87A).

Original Page No. 92B has been added to the Table of Contents to reflect the addition of Rider No. 4 – Federal Tax Adjustment Clause (Pages No. 92–92B).

Rider No. 7 – Residential Subscription Service Pilot has been added to Tariff No. 25 and to the Table of Contents.

Original Page No. 97A has been added to the Table of Contents to reflect the additional page added to Rider No. 7 – Residential Subscription Service Pilot (Pages No. 97-97A).

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Table of Contents — **Fourth Revised Page No. 3**
Cancelling Third Revised Page No. 3

Table of Contents information previously found on Third Revised Page No. 3, Cancelling Second Revised Page No. 3 has been moved to Original Page No. 3A to accommodate the additional Riders added to Tariff No. 25.

Table of Contents — **Original Page No. 3A**

Table of Contents information previously found on Third Revised Page No. 3, Cancelling Second Revised Page No. 3 has been moved to Original Page No. 3A to accommodate the additional Riders added to Tariff No. 25.

Original Page No. 124A has been added to the Table of Contents to reflect the additional page added to Rider No. 16 – Service to Non-Utility Generating Facilities (Pages No. 123-124A).

Rider No. 19 – Community Development for New Load has been added to Tariff No. 25 and to the Table of Contents.

Administerial update to the page numbering on the Table of Contents page. Rider No. 21 - Net Metering Service now reflects the addition of Page No. 136A which was added and approved in the Company's DSP IX proceeding at Docket No. P-2020-3019522, Order entered January 14, 2021.

Rider No. 23 - Home Charging Pilot Program has been added to Tariff No. 25 and to the Table of Contents.

Rider No. 24 – Fleet Charging Pilot Program has been added to Tariff No. 25 and to the Table of Contents.

Rider No. 25 – New Business Stimulus has been added to Tariff No. 25 and to the Table of Contents.

Rider No. 26 – Crisis Recovery Program has been added to Tariff No. 25 and to the Table of Contents.

Rules and Regulations — **First Revised Page No. 7**
The Electric Service Tariff — **Cancelling Original Page No. 7**
3.1 Definitions
(2) Applicant

Language has been added to clarify that the definition of "Applicant" includes non-residential applicants.

Rules and Regulations — **First Revised Page No. 11**
Contracts, Deposits and Advance Payments — **Cancelling Original Page No. 11**
Rule No. 5 - Deposits and Advance Payments

Language has been modified to reflect that residential customers/applicants are permitted to pay their deposit in four (4) twenty-five percent (25%) installments.

Language has been modified to clarify security deposits for non-residential customers/applicants.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rules and Regulations
Installation of Service
Rule No. 6.1 - Service Point

First Revised Page No. 13
Cancelling Original Page No. 13

Language has been revised to accommodate the Company's proposed transportation electrification programs.

Rules and Regulations
Installation of Service
Rule No. 7 - Supply Line Extensions

First Revised Page No. 14
Cancelling Original Page No. 14

First Revised Page No. 15
Cancelling Original Page No. 15

First Revised Page No. 16
Cancelling Original Page No. 16

Language has been modified to clarify that both customers and applicants for service are subject to tariff cost commitment requirements.

Language has been modified to allow applicants (e.g., developers) to pay Contribution in Aid of Construction ("CIAC") on behalf of the ultimate customer.

Rules and Regulations
Installation of Service
Rule No 10 - One Service of A Kind

First Revised Page No. 19
Cancelling Original Page No. 19

Language has been modified to remove obsolete cross-reference.

Rules and Regulations
Measurement and Use of Service
Rule No. 16.1 - Interconnection, Safety and Reliability Requirements

Second Revised Page No. 26
Cancelling First Revised Page No. 26

New Rule No. 16.1 Interconnection, Safety and Reliability Requirements has been added to the tariff to clarify and memorialize the Company's existing process for customer generation interconnection (including facilities not eligible for net metering).

Rule No. 18.1 – Electric Vehicle Charging and Rule No. 19 – Continuity and Safety, previously found on First Revised Page No. 26, Cancelling Original Page No. 26 have been moved to Original Page No. 26A to accommodate the addition of Rule No. 16.1 – Interconnection, Safety and Reliability Requirements on Second Revised Page No. 26, Cancelling First Revised Page No. 26.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rules and Regulations **Original Page No. 26A**
Measurement and Use of Service

Rule No. 18.1 – Electric Vehicle Charging and Rule No. 19 – Continuity and Safety, previously found on First Revised Page No. 26, Cancelling Original Page No. 26 have been moved to Original Page No. 26A to accommodate the addition of Rule No. 16.1 – Interconnection, Safety and Reliability Requirements.

Rules and Regulations **First Revised Page No. 29**
Company Property on Customer's Premises **Cancelling Original Page No. 29**
Rule No. 22.1 - Vegetation Management and Right-of-Way

Language has been added to clarify a customer's responsibility to manage vegetation around the Company's service facilities.

Rules and Regulations **First Revised Page No. 33**
Discontinuance, Curtailment or Interruption of Electric Service **Cancelling Original Page No. 33**
Rule No. 40 - Reconnection Charge

Language has been added to expand reconnection charge applicability to customers who apply for reconnection at the same premises more than thirty (30) days following disconnection (i.e., when then former customer now constitutes an "applicant").

Rules and Regulations **First Revised Page No. 34**
Discontinuance, Curtailment or Interruption of Electric Service **Cancelling Original Page No. 34**
Rule No. 41 - Prohibition of Residential Master Metering

Language has been modified to allow residential master metering for certain low-income supportive housing pursuant to Rule No. 41.1.

Rules and Regulations **First Revised Page No. 34**
Discontinuance, Curtailment or Interruption of Electric Service **Cancelling Original Page No. 34**
Rule No. 41.1 - Residential Master Metering for New Low-Income Supportive Housing

New Rule No. 41.1 Residential Master Metering for New Low-Income Supportive Housing has been added to the tariff to establish eligibility and conditions for master metering of certain low-income supportive housing.

Rules and Regulations **First Revised Page No. 34**
General Provisions **Cancelling Original Page No. 34**

Rule No. 42 – Meter Testing, Rule No. 43 – Other Services, Rule No. 44 – This Rule Intentionally Left Blank and Rule No. 45 – Supplier Switching, previously found on Original Page No. 34, have been moved to Original Page No. 34A to accommodate the addition of Rule No. 41.1 – Residential Master Metering for New Low-Income Supportive Housing on First Revised Page No. 34, Cancelling Original Page No. 34.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rules and Regulations
General Provisions — **Original Page No. 34A**

Rule No. 42 – Meter Testing, Rule No. 43 – Other Services, Rule No. 44 – This Rule Intentionally Left Blank and Rule No. 45 – Supplier Switching, previously found on Original Page No. 34, have been moved to Original Page No. 34A to accommodate the addition of Rule No. 41.1 – Residential Master Metering for New Low-Income Supportive Housing.

Rate RS – Residential Service — **First Revised Page No. 38**
Cancelling Original Page No. 38

Administerial revision to add the word “cents” back to the Energy Charge line to indicate “cents per kilowatt hour.”

Rate GS/GM – General Service Small and Medium — **First Revised Page No. 46**
Cancelling Original Page No. 46

Language has been added to clarify eligibility.

Rate GS/GM – General Service Small and Medium — **First Revised Page No. 48**
Cancelling Original Page No. 48

Language has been modified to reflect current business practice.

Rate GL – General Service Large — **First Revised Page No. 53**
Cancelling Original Page No. 53

Language has been added to clarify eligibility.

Rate GLH – General Service Large Heating — **First Revised Page No. 56**
Cancelling Original Page No. 56

Language has been reorganized on the Rate Schedule to clarify that the Customer Distribution Charge is only applicable to the billing months of October through May.

Rate L –Large Power Service — **First Revised Page No. 60**
Cancelling Original Page No. 60

Language has been modified to reflect current business practice.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rate HVPS –High Voltage Power Service — **First Revised Page No. 62**
Cancelling Original Page No. 62

Language has been added to clarify eligibility.

Rate HVPS –High Voltage Power Service — **First Revised Page No. 63**
Cancelling Original Page No. 63

Language has been modified to reflect current business practice.

Rate AL – Architectural Lighting Service — **First Revised Page No. 66**
Cancelling Original Page No. 66

Language has been added to reflect that beginning January 15, 2022, Rate AL will no longer be available to new customers or applicants, or to new installations for existing customers.

Rate SE – Street Lighting Energy — **First Revised Page No. 71**
Special Provisions – No. 5 — **Cancelling Original Page No. 71**

Language has been modified to replace the word “men” with “workers.”

Rate SM – Street Lighting Municipal — **First Revised Page No. 72**
Cancelling Original Page No. 72

Language has been added to reflect that beginning January 15, 2022, only LED lighting options will be installed for customers being served under Rate SM.

Language has been added to reflect that beginning January 15, 2022, the Company may replace existing high pressure sodium lights with LED lights or that a customer may request to exchange functioning high pressure sodium lights with LEDs with advance payment to cover the costs of the Company’s estimated removal costs of such replacement. Both will be at the Company’s discretion.

Rate SM – Street Lighting Municipal — **First Revised Page No. 73**
Cancelling Original Page No. 73

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted under Cobra Head, Colonial and Contemporary fixtures.

Rate SM – Street Lighting Municipal — **First Revised Page No. 74**
Cancelling Original Page No. 74

Language has been modified to replace the word “his” with “its.”

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rate SH – Street Lighting Highway

First Revised Page No. 76
Cancelling Original Page No. 76

Language has been added to reflect that beginning January 15, 2022, Rate SH will no longer be available to new customers or applicants, or to new installations for existing customers.

Language has been added to reflect that beginning January 15, 2022, replacement of high pressure sodium 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 LED lighting options.

Language has been added to reflect that due to the limited availability of high pressure sodium lighting, the Company will replace existing high pressure sodium lights with LED lights or a customer may request to exchange functioning high pressure sodium lights with LEDs with advance payment to cover the costs of the Company's estimated removal costs of such replacement. Both will be at the Company's discretion.

Rate SH – Street Lighting Highway

First Revised Page No. 76
Cancelling Original Page No. 76

New LED lamp wattages have been inserted under Cobra Head fixtures.

Rate PAL – Private Area Lighting

First Revised Page No. 82
Cancelling Original Page No. 82

Language has been added to reflect that beginning January 15, 2022, replacement of high pressure sodium 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 LED lighting options.

Language has been added to reflect that due to the limited availability of high pressure sodium lighting, the Company will replace existing high pressure sodium lights with LED lights or a customer may request to exchange functioning high pressure sodium lights with LEDs with advance payment to cover the costs of the Company's estimated removal costs of such replacement. Both will be at the Company's discretion.

Rate PAL – Private Area Lighting

First Revised Page No. 82
Cancelling Original Page No. 82

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted under Cobra Head, Colonial and Contemporary fixtures.

Rate PAL – Private Area Lighting

First Revised Page No. 84
Cancelling Original Page No. 84

Language has been modified to replace the word "his" with "its."

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Standard Contract Riders — **Second Revised Page No. 87**
Rider Matrix — **Cancelling First Revised Page No. 87**

The Rider Matrix has been updated to reflect the addition of the following Riders:

Rider No. 4 – Federal Tax Adjustment Clause
Rider No. 7 – Residential Subscription Service Pilot
Rider No. 19 – Community Development for New Load

Standard Contract Riders — **Second Revised Page No. 87**
Rider Matrix — **Cancelling First Revised Page No. 87**

Riders No. 20 through Appendix A, previously found in the Rider Matrix on First Revised Page No. 87, Cancelling Original Page No. 87, have been moved to Original Page No. 87A to accommodate the additional Riders placed into the Tariff.

"Continued on Original Page No. 87A" has been added to the bottom of Second Revised Page No. 87, Cancelling First Revised Page No. 87, to indicate that the Rider Matrix continues onto the next page.

Standard Contract Riders — **Original Page No. 87A**
Rider Matrix

A Rider Matrix for Riders No. 20 through Appendix A, previously found on First Revised Page No. 87, Cancelling Original Page No. 87, has been created and is now found on Original Page No. 87A to accommodate the additional Riders placed into the Tariff.

Standard Contract Riders — **Original Page No. 87A**
Rider Matrix

The Rider Matrix has been updated to reflect the addition of the following Riders:

Rider No. 23 – Home Charging Pilot Program
Rider No. 24 – Fleet Charging Pilot Program
Rider No. 25 – New Business Stimulus
Rider No. 26 – Crisis Recovery Program

Standard Contract Riders — **First Revised Page No. 92**
Rider No. 4 – Federal Tax Adjustment Clause — **Cancelling Original Page No. 92**

Original Page No. 92A

Original Page No. 92B

Rider No. 4 – Federal Tax Adjustment Clause ("FTAC") is being added to Tariff No. 25 to provide for adjustments to base distribution revenue to reflect the effects of future increases or decreases in the federal corporate income tax rate.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Standard Contract Riders
Rider No. 5 – Universal Service Charge

First Revised Page No. 94
Cancelling Original Page No. 94

The CAP participation level has been reset as per the provisions of Rider No. 5.

Standard Contract Riders
Rider No. 7 – Residential Subscription Service Pilot

First Revised Page No. 97
Cancelling Original Page No. 97

Rider No. 7 – Residential Subscription Service Pilot is being added to Tariff No. 25 to offer eligible customers the option to select a specified level of grid access for a set monthly charge.

Standard Contract Riders
Rider No. 8 – Default Service Supply

Second Revised Page No. 100
Cancelling First Revised Page No. 100

Fourth Revised Page No. 101
Cancelling First Revised Page No. 101

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted under Cobra Head, Colonial and Contemporary fixtures.

Standard Contract Riders
Rider No. 8 – Default Service Supply

Second Revised Page No. 103
Cancelling First Revised Page No. 103

In the “Calculation of Rates” section, the Docket No. has been updated in DSSa.

Standard Contract Riders
Rider No. 9 – Day-Ahead Hourly Price Service

Third Revised Page No. 108
Cancelling Second Revised Page No. 108

Under the “Fixed Retail Administrative Charge” section, the Docket No. has been updated in FRA.

Standard Contract Riders
Rider No. 10 – State Tax Adjustment

Third Revised Page No. 112
Cancelling Second Revised Page No. 112

Rider No. 10 – State Tax Adjustment has been modified to reflect that Part 1 of the STAS has been set to zero.

Standard Contract Riders
Rider No. 16 – Service to Non-Utility Generating Facilities

First Revised Page No. 123
Cancelling Original Page No. 123

First Revised Page No. 124
Cancelling Original Page No. 124

Rider No. 16 – Service to Non-Utility Generating Facilities has been modified to reflect changes in applicable terms, rules, and rates.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Standard Contract Riders
Rider No. 19 – Community Development

First Revised Page No. 128
Cancelling Original Page No. 128

Original Page No. 128A

Rider No. 19 – Community Development for New Load is being added to Tariff No. 25 to provide incentives to eligible customers to move and/or expand their operations within the Company's service territory.

Standard Contract Riders
Rider No. 21 – Net Metering Service

First Revised Page No. 133
Cancelling Original Page No. 133

First Revised Page No. 134
Cancelling Original Page No. 134

Second Revised Page No. 135
Cancelling First Revised Page No. 135

Second Revised Page No. 136
Cancelling First Revised Page No. 136

First Revised Page No. 136A
Cancelling Original Page No. 136A

Rider No. 21 – Net Metering Service has been revised to include Rate Schedule GLH and Rate Schedule L.

Standard Contract Riders
Rider No. 21 – Net Metering Service

First Revised Page No. 134
Cancelling Original Page No. 134

Language has been modified to reflect current business practice.

Standard Contract Riders
Rider No. 22 – Distribution System Improvement Charge

Seventh Revised Page No. 137
Cancelling Sixth Revised Page No. 137

Rider No. 22 – Distribution System Improvement Charge ("DSIC") has been modified to reflect that it has been set to zero.

Standard Contract Riders
Rider No. 23 – Home Charging Pilot Program

Original Page No. 141A-141B

Rider No. 23 – Home Charging Pilot Program is being added to Tariff No. 25 to set forth the eligibility, terms, and conditions applicable to residential customers participating in the Company's voluntary Home Charging Pilot.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Standard Contract Riders **Original Page No. 141C-141E**
Rider No. 24 – Fleet Charging Pilot Program

Rider No. 24 – Fleet Charging Pilot Program is being added to Tariff No. 25 to set forth the eligibility, terms, and conditions applicable to non-residential customers participating in the Company's voluntary Fleet Charging Pilot.

Standard Contract Riders **Original Page No. 141F**
Rider No. 25 – New Business Stimulus

Rider No. 25 – New Business Stimulus is being added to Tariff No. 25 to incent eligible new small or medium businesses by providing them with a reduced distribution rate for two (2) years.

Standard Contract Riders **Original Page No. 141G**
Rider No. 26 – Crisis Recovery Program

Rider No. 26 – Crisis Recovery Program is being added to Tariff No. 25 to provide a relief program for eligible existing small or medium business customers who have accumulated a delinquent balance because of COVID-19 business restrictions.

Appendix A – Transmission Service Charges **Second Revised Page No. 143**
Cancelling First Revised Page No. 143

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted under Cobra Head, Colonial and Contemporary fixtures.

INCREASES

Rate RS – Residential Service **First Revised Page No. 38**
Cancelling Original Page No. 38

Rate RH – Residential Service Heating **First Revised Page No. 40**
Cancelling Original Page No. 40

Rate RA – Residential Service Add-On Heat Pump **First Revised Page No. 43**
Cancelling Original Page No. 43

Rate GS/GM – General Service Small and Medium **First Revised Page No. 46**
Cancelling Original Page No. 46

LIST OF MODIFICATIONS MADE BY THIS TARIFF

INCREASES – (Continued)

Rate GMH – General Service Medium Heating	**First Revised Page No. 50 Cancelling Original Page No. 50**
	First Revised Page No. 51 Cancelling Original Page No. 51
Rate GL – General Service Large	**First Revised Page No. 53 Cancelling Original Page No. 53**
Rate GLH – General Service Large Heating	**First Revised Page No. 56 Cancelling Original Page No. 56**
	First Revised Page No. 57 Cancelling Original Page No. 57
Rate L – Large Power Service	**First Revised Page No. 59 Cancelling Original Page No. 59**
Rate HVPS – High Voltage Power Service	**First Revised Page No. 62 Cancelling Original Page No. 62**
Rate AL – Architectural Lighting Service	**First Revised Page No. 66 Cancelling Original Page No. 66**
Rate SE – Street Lighting Energy	**First Revised Page No. 69 Cancelling Original Page No. 69**
Rate SM – Street Lighting Municipal	**First Revised Page No. 72 Cancelling Original Page No. 72**
	First Revised Page No. 73 Cancelling Original Page No. 73
	First Revised Page No. 74 Cancelling Original Page No. 74
Rate SH – Street Lighting Highway	**First Revised Page No. 76 Cancelling Original Page No. 76**
Rate UMS – Unmetered Service	**First Revised Page No. 80 Cancelling Original Page No. 80**
Rate PAL – Private Area Lighting	**First Revised Page No. 82 Cancelling Original Page No. 82**
	First Revised Page No. 84 Cancelling Original Page No. 84

Unit pricing has changed resulting in increases.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

INCREASES – (Continued)

Rider No. 10 – State Tax Adjustment — **Third Revised Page No. 112**
Cancelling Second Revised Page No. 112

Rider No. 10 – State Tax Adjustment has been modified to reflect that Part 1 of the STAS has been set to zero.

DECREASES

Rate SM – Street Lighting Municipal — **First Revised Page No. 73**
Cancelling Original Page No. 73

Rate PAL – Private Area Lighting — **First Revised Page No. 82**
Cancelling Original Page No. 82

Unit pricing has changed resulting in decreases.

Rider No. 22 – Distribution System Improvement Charge — **Seventh Revised Page No. 137**
Cancelling Sixth Revised Page No. 137

Rider No. 22 – Distribution System Improvement Charge has been modified to reflect that it has been set to zero.

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RULES AND REGULATIONS – (Continued)

<u>THE ELECTRIC SERVICE TARIFF</u> – (Continued)

3. APPLICATION – (Continued

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.

3.1 DEFINITIONS

(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.

(2) Applicant – An entity that applies for service provided by the Company. With respect to residential applicants, "applicant" means 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)** **(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.

(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.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

CONTRACTS, DEPOSITS AND ADVANCE PAYMENTS - (Continued)

5. DEPOSITS AND ADVANCE PAYMENTS - (Continued)

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 from a residential customer or applicant, the amount of the deposit will be **(C)**
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. The minimum deposit amount for **(C)**
non-residential customers and applicants shall be $250.00. When the Company determines a deposit is required **(C)**
for new service or for reconnection of service as described in Rule No. 40, such deposit shall be payable within a **(C)**
reasonable time period after commencing or reconnecting electric service. Failure to pay a required deposit may **(C)**
result in termination of service consistent with Commission regulations. An applicant or existing customer may **(C)**
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.

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.

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.

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) – Indicates Change

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

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:

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 electric vehicle pilot **(C)**
program(s) for electric vehicle charging stations. **(C)**

The Company shall not be required to install or maintain any conductors, meter base, equipment or apparatus beyond the Service Point except meter and meter accessories, as applicable; and electric vehicle charging stations **(C)**
and/or make-ready infrastructure, as applicable, for customers participating in the Company's applicable electric **(C)**
vehicle pilot program(s). **(C)**

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.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

7. SUPPLY LINE EXTENSIONS – (Continued)

A. Definitions – (Continued)

(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 or applicant. **(C)**

(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 or applicant's property line without a **(C)** guarantee of revenue.

(2) In areas where the existing supply lines are overhead, the Company will construct and maintain extensions of all three-phase overhead supply lines, operating at 23,000 volts or less, which are usable as a part of its general supply system without a guarantee of revenue. When the three-phase supply line extension is to supply service exclusively to a single customer or applicant, such a supply line will be extended to the customer's or applicant's **(C)** property line only if a guarantee of revenue is provided by the customer or applicant over a **(C)** 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 or applicant represents a credit **(C)** risk, the Company may require an up-front contribution in aid of construction (CIAC) from the customer or applicant to recover the total cost of construction. A customer or applicant **(C)** 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.

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

7. SUPPLY LINE EXTENSIONS - (Continued)

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 or applicant, such a supply line will be extended to the customer's or applicant's property line **(C)** only if a guarantee of revenue is provided by the customer or applicant, over a period of five **(C)** 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 or applicant represents a credit risk, the Company **(C)** may require an up-front contribution in aid of construction (CIAC) from the customer or **(C)** applicant to recover the total cost of construction. A customer or applicant may choose the **(C)** 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 or applicant, such a supply line will be extended to the customer's or applicant's property line **(C)** only if a guarantee of revenue is provided by the customer or applicant over a period of five **(C)** 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 or applicant represents a credit risk, the Company **(C)** may require an up-front contribution in aid of construction (CIAC) from the customer or **(C)** applicant to recover the total cost of construction. A customer or applicant may choose the **(C)** 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.

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 or applicant agrees to pay the Company any initial and **(C)** 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 and (ii) other new Company facilities necessary to serve the customer or applicant. 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)**

(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.

(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.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

9. RELOCATIONS OF FACILITIES – (Continued)

C. 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.

10. ONE SERVICE OF A KIND Only one service of each type as to voltage and phase will be provided to a customer under one contract; provided, however, that when, in the judgment of the Company, standard electric **(C)** service may be most economically effected by establishing a separate service connection for a portion of the **(C)** customer's load, such separate service connection may, at the option of the customer, be combined, notwithstanding similarity as to voltage and phase, with other service connections under a single contract for the customer's entire electric delivery service requirements at the affected location. Electric service at different premises, regardless of voltage or phase, shall never be combined for billing under one account for the purpose of reducing Company charges.

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

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

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

13.1 UNDERGROUND DISTRIBUTION

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

(C) – Indicates Change

MEASUREMENT AND USE OF SERVICE - (Continued)

16.1 INTERCONNECTION, SAFETY AND RELIABILITY REQUIREMENTS In order to assure the integrity and safe operation of the Company's system and to permit the continuation of reliable service to other customers, the following requirements and standards apply to all types of Generating Facilities, including customer owned generation and customer owned energy storage systems, desiring to interconnect with the Company's system. **(C)**

All generation operations shall be performed in a safe, reasonable and competent manner in accordance with prudent electric practices in order to, among other things, preserve and protect the Company's electric system.

All Generating Facilities shall submit a written application to the Company for acceptance of interconnected operation of their facilities with the Company's system prior to engaging in such interconnected operations. The Company may require, among other things, the following as part of any application submitted by an Applicant/Customer for service under this Rule No. 16.1.

1. Plans, specifications and location of the proposed installation.
2. Single line diagrams and details, including relay settings, of the proposed protection schemes.
3. Instruction manuals for all protective components.
4. Component specifications and internal wiring diagrams of protective components, if not provided in instruction manuals.
5. Generator data required to analyze fault contributions and load current flows including, but not limited to, equivalent impedances, time constants and harmonic distortions.
6. The rating of all protective equipment if not provided in instruction manuals.
7. All such other information that may be required by the Company.

Paralleling customer generation with the Company's system, including closed transition of customer back-up generation, shall be permitted only upon the written consent of the Company.

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

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.

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.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued) **(C)**

MEASUREMENT AND USE OF SERVICE - (Continued)

18.1 ELECTRIC VEHICLE CHARGING Electricity sales by a person, corporation or other entity, not a public utility, owning and operating an electric vehicle charging facility for the sole purpose of recharging an electric vehicle battery for compensation are not construed to be sales to residential consumers and therefore do not fall under the pricing requirements of 66 Pa.C.S. § 1313. Further, 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. For the purposes of this Rule No. 18.1, 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.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

COMPANY PROPERTY ON CUSTOMER'S PREMISES – (Continued)

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. Notwithstanding the foregoing, the customer/applicant/property owner shall be responsible for vegetation management on the customer/applicant/property owner's property, as necessary, to prevent vegetation from interfering with the service line(s) on the premises. Any vegetation management within ten (10) feet of an energized electric utility line must be performed by qualified line clearance personnel. **(C) (C) (C) (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.

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.

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."

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.

(C) – Indicates Change

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

39.2 EMERGENCY ENERGY CONSERVATION - (Continued)

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

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

40. RECONNECTION CHARGE Where service has been discontinued under the terms of Rules No. 26 through 36, inclusive, the Company reserves the right as a condition precedent to the reconnection of service to require the payment of all arrearages for Company charges and payment of a deposit as described in Rule No. 5, and to require the payment of the following appropriate reconnection charge:

A. $50.00 for resumption of electric service to the same customer or applicant within a year of the service disconnection or termination where service has been disconnected at the meter. **(C)**

B. $250.00 for resumption of electric service to the same customer or applicant within a year of the service disconnection or termination where service has been disconnected at the pole. **(C)**

C. $250.00 for resumption of electric service to the same customer or applicant within a year of the service disconnection or termination when the connection is an aerial tap. **(C)**

D. $89.00 for reconnection of a transformer to the same General Service customer or applicant within a year of the service disconnection or termination. **(C)**

E. $20.00 for resumption of electric service where a remote capable meter has been installed and in which resumption of service is to the same customer or applicant within a year of the service disconnection or termination where service has been disconnected at the meter. **(C)**

When a residential customer or residence or residential applicant 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)**

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

Where electric service to a non-residential customer or applicant has been terminated under the terms of Rules No. 30 and/or 34, and such condition was the direct result of tampering, the Company reserves the right as a condition precedent to the reconnection of service to require payment of all costs incurred by the Company for investigations and inspections, and for such protective equipment deemed necessary by the Company. **(C)**

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

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

41. PROHIBITION OF RESIDENTIAL MASTER METERING Except as provided in Rule No. 41.1 herein, each residential dwelling unit in a building must be individually metered by the Company for buildings connected after January 1, 1981. For the purposes of the Rule, a dwelling unit is defined as: **(C)**

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

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

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

41.1 RESIDENTIAL MASTER METERING FOR NEW LOW-INCOME SUPPORTIVE HOUSING Notwithstanding anything in Rule No. 41 to the contrary, a single meter may be used for certain multi-tenant premises ("master metering"), where the premises: **(C)**

1. Is a new service;
2. Is master-metered through entire premises (i.e., no individual tenant meters);
3. Has a minimum of four (4) dwelling units; and
4. Is low-income supportive housing (i.e., housing that is permanently available to low-income tenants where the housing provider is responsible for utility bills).

To be eligible to master-meter a given residential building, in addition to satisfying the other criteria herein, a provider of low-income housing must either:

1. Show that the building is a Public Housing Authority development, or
2. Certify that all tenants are (i) eligible for a Housing Choice Voucher (HCV), available to residents who make 50% or less of the median family income, or (ii) have household incomes equal to or less than 150% of federal poverty guidelines.

Customers permitted to use master metering under this Rule must also, on a continuing basis:

1. Annually certify their on-going conformance to the above criteria; and
2. Participate in each of the Company's applicable energy efficiency, conservation, and/or usage reduction programs.

The Company may retain the customer's security deposit, paid pursuant to Rule No. 5, for the entire duration of the master metering arrangement.

If a customer using master metering under this Rule fails to comply with any of the foregoing eligibility criteria or on-going requirements, the Company may require the customer to reconfigure the customer's electrical equipment, at customer expense, to allow the Company to separately meter each dwelling unit.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued) **(C)**

GENERAL PROVISIONS

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

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

44. THIS RULE INTENTIALLY LEFT BLANK

45. SUPPLIER SWITCHING The Company will accommodate requests by customers to switch EGSs in accordance with 52 Pa. Code, Chapter 57, Subchapter M "Standards for Changing a Customers Electricity Generation Supplier."

Customers who elect to return to the Company from an EGS will return at the charges of the applicable rate.

In compliance with the Commission's Order at Docket No. L-2014-2409383, the Company shall preserve all records relating to unauthorized change of EGS or change to Default Service disputes for three (3) years from the date the customer filed the dispute. These records shall be made available to the Commission or its staff upon request.

Switching by customers shall occur in accordance with the direct access procedures and in accordance with the provisions contained in this Tariff and the Company's EGS Coordination Tariff.

(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 .... 7.0564 cents per kilowatt hour **(I)(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 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 **(C) – Indicates Change**

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 .... 6.3410 cents per kilowatt hour **(I)**

Summer Monthly Rate — For the Billing Months of May through October:

Energy Charge .... 7.0564 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 .... 2.7631 cents per kilowatt hour **(I)**

Summer Monthly Rate — For the Billing Months of May through October:

Energy Charge .... 7.0564 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 and where the demand is less than 300 kW. **(C)**

MONTHLY RATE FOR NON-DEMAND CUSTOMERS

DISTRIBUTION CHARGES — RATE GS

Customer Charge .... $16.25 **(I)**

Energy Charge — All kWh .... 8.4241 cents per kilowatt-hour **(I)**

MONTHLY RATE FOR DEMAND CUSTOMERS

DISTRIBUTION CHARGES — RATE GM < 25 kW

Customer Charge .... $63.00 **(I)**

Energy Charge — All kWh .... 1.8390 cents per kilowatt-hour **(I)**

Demand Charge — First five (5) kilowatts or less .... No Charge

— Additional kilowatts of Demand .... $7.89 per kilowatt **(I)**

DISTRIBUTION CHARGES — RATE GM ≥ 25 kW

Customer Charge .... $76.00 **(I)**

Energy Charge — All kWh .... 1.2661 cents per kilowatt-hour **(I)**

Demand Charge — First five (5) kilowatts or less .... No Charge

— Additional kilowatts of Demand .... $7.89 per kilowatt **(I)**

MONTHLY RATE FOR NON-DEMAND AND DEMAND CUSTOMERS

DISTRIBUTION RATE ASSIGNMENT

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 < 25 kW or Rate GM ≥ 25 kW at a time.

(C) – Indicates Change **(I) – Indicates Increase**

RATE GS/GM - GENERAL SERVICE SMALL AND MEDIUM - (Continued)

MONTHLY RATE FOR NON-DEMAND AND DEMAND CUSTOMERS - (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 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 30% **(C)**
of the highest Billing Demand during the preceding eleven months plus the current billing period charges for **(C)**
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.

(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

WINTER MONTHLY RATE — FOR THE BILLING MONTHS OF OCTOBER THROUGH MAY

DISTRIBUTION CHARGES

Customer Charge .... $63.00 **(I)**

Energy Charge — All kWh .... 3.8382 cents per kilowatt-hour **(I)**

SUMMER MONTHLY RATE — FOR THE BILLING MONTHS OF JUNE THROUGH SEPTEMBER

DISTRIBUTION CHARGES

Customer Charge .... $63.00 **(I)**

Energy Charge — All kWh .... 1.8390 cents per kilowatt-hour **(I)**

Demand Charge — First five (5) kilowatts or less .... No Charge

— Additional kilowatts of Demand .... $7.89 per kilowatt **(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 or Rider No. 9 – Day-Ahead Hourly Price Service, as applicable, and will be billed in accordance with the terms contained therein.

Rider No. 8 – Default Service Supply – Applicable to customers with monthly demand less than 25 kW and customers with monthly demand greater than or equal to 25 kW but less than 200 kW, on average, who elect to purchase their electric supply requirements from the Company. The Supply rate shall be determined based on the formula described in the “Calculation of Rate” section in Rider No. 8. Supply Charges will be updated through competitive requests for proposal and will be effective for the periods as defined and described in Rider No. 8.

(I) – Indicates Increase

RATE GMH - GENERAL SERVICE MEDIUM HEATING - (Continued)

MONTHLY RATE - (Continued)

SUPPLY CHARGES – (Continued)

Rider No. 9 – Day-Ahead Hourly Price Service – Customers with monthly demand of 200 kW, on average, or greater and elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 9 and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

For purposes of determining the monthly rate for demand customers, Duquesne Light shall evaluate the customer's twelve (12) most recent months of monthly billing demand for that customer available in October of the preceding year. If the customer's average monthly billing demand is less than 25 kW in the twelve (12) months, then that customer shall be charged the monthly rate for demand 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 demand is 25 kW or greater in the twelve (12) month period, then that customer shall be charged the monthly rate for demand 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 average monthly billing demand for the next twelve (12) month period.

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 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 $7.89 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.

(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 greater than or equal to 300 kilowatts (≥ 300 kW) and less than 5,000 kilowatts (< 5,000 kW). **(C)** **(C)**

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.

DISTRIBUTION

DEMAND CHARGES

First 300 kilowatts or less of Demand	$3,675.00	**(I)**
Additional kilowatts of Demand	$10.66 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.

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 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

DISTRIBUTION **(C)**

For the Billing Months of October through May:

CUSTOMER CHARGE

Customer Distribution Charge .... $77.50 **(I)**

ENERGY CHARGES

All kilowatt-hours 3.0162 cents per kWh **(I)**

DISTRIBUTION **(C)**

For the Billing Months of June through September:

Rate GL shall apply. **(I)**

SUPPLY **(C)**

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.

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.

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 $10.66 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.

(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.

DISTRIBUTION

DEMAND CHARGES

Service Voltage Less than 138 kV:

First 5,000 kilowatts or less of Demand	$41,800.00	**(I)**
Additional kilowatts of Demand	$16.63 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.

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

(I) – Indicates Increase

RATE L - LARGE POWER SERVICE - (Continued)

MONTHLY RATE - (Continued)

UNTRANSFORMED SERVICE CREDIT

Where the customer furnishes all necessary equipment to take untransformed service at 11,500 volts or higher, in strict accordance with the Company's standards and specifications, a credit of $0.75 per kW based upon the individual demand of the untransformed circuit shall be applied to the customer's account.

MINIMUM CHARGE

The Minimum Charge shall be the sum of a Demand Charge based on 70% of the Contract On-Peak Demand for **(C)**
distribution plus the charges for Company supplied transmission and supply, if any. The Demand Charge shall be **(C)**
determined using the Distribution Charge, and, in total, shall not be less than the demand charges associated with **(C)**
the first 5,000 kWs or less of demand. For Company supplied transmission and supply, the transmission charges **(C)**
shall be calculated as set forth in Appendix A – Transmission Service Charges and the supply charges shall be **(C)**
calculated as set forth under Rider No. 9 – Day-Ahead Hourly Price Service. **(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 which exceed 30 kilowatts will be adjusted for power factor by multiplying by

$$\left\{0.8 + \left[0.6 \ \frac{\text{Reactive Kilovolt - ampere hours}}{\text{Kilowatt - hours}}\right]\right\},$$

where such multiplier will be not less than 1.00 nor more than 2.00. The Billing Demand will be the sum of the individual demands of each metered service adjusted for power factor as defined above, but not less than 70% of the Contract On-Peak Demand nor less than 5,000 kilowatts, whichever is the greater.

STANDARD CONTRACT RIDERS

For modifications of the above rate under special conditions, see "Standard Contract Riders".

(C) – Indicates Change

RATE HVPS - HIGH VOLTAGE POWER SERVICE

AVAILABILITY

Available to customers with Contract On-Peak Demands greater than or equal to 5,000 kilowatts (≥ 5,000 kW) 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.

DISTRIBUTION

FIXED MONTHLY CHARGE

Up to and Including 50,000 kW Billing Demand	$2,503.20	**(I)**
50,001 kW to 100,000 kW Billing Demand	$3,910.17	**(I)**
Greater than 100,000 kW Billing Demand	$5,545.24	**(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.

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 customer's Fixed Distribution Monthly Charge. For Company supplied transmission and supply, the transmission charges shall be calculated as set forth in Appendix A – Transmission Service Charges and the supply charges shall be calculated as set forth under Rider No. 9 – Day-Ahead Hourly Price Service. **(C)** **(C)** **(C)** **(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.

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 AL - ARCHITECTURAL LIGHTING SERVICE

AVAILABILITY

Beginning January 15, 2022, Rate AL will no longer be available to new customers or applicants, or to new installations for existing customers. **(C)**

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

Demand Charge .... $1.83 per kilowatt **(I)**

Energy Charge .... 0.2396 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.

(C) – Indicates Change **(I) – Indicates Increase**

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.. $3.23 **(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 SE - STREET LIGHTING ENERGY - (Continued)

MONTHLY RATE - (Continued)

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.

SPECIAL PROVISIONS

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

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

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

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

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

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

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

TERM OF CONTRACT

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

(C) – Indicates Change

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.

Beginning January 15, 2022, only LED lighting options will be installed. Replacement of mercury vapor or high pressure sodium lamps, fixtures or luminaries, including brackets and ballasts, will not be available. **(C)**

Beginning January 15, 2022, the Company may replace existing high pressure sodium lights with LED lights, and place the customer on the corresponding rate schedule, at the Company's discretion. The Company may exchange functioning high pressure sodium lights with LEDs upon customer request and upon receipt, in advance, of the Company's estimated removal costs of such replacement. Such elective replacements shall be at the Company's discretion. **(C)**

(C)

MONTHLY RATE

DISTRIBUTION CHARGE — Monthly Rate Per Unit

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	
Mercury Vapor				
100	44	$14.19	$3.03	**(I)(I)**
175	74	$14.48	$3.03	**(I)(I)**
250	102	$14.76	$3.03	**(I)(I)**
400	161	$15.36	$3.03	**(I)(I)**
1,000	386	$17.66	$3.03	**(I)(I)**
Sodium Vapor				
70	29	$14.66	$3.03	**(I)(I)**
100	50	$14.77	$3.03	**(I)(I)**
150	71	$14.99	$3.03	**(I)(I)**
250	110	$15.38	$3.03	**(I)(I)**
400	170	$15.99	$3.03	**(I)(I)**
1,000	387	$18.39	$3.03	**(I)(I)**

(C) – Indicates Change **(I) – Indicates Increase**

RATE SM - STREET LIGHTING MUNICIPAL - (Continued)

MONTHLY RATE – (Continued)

DISTRIBUTION CHARGE — Monthly Rate Per Unit - (Continued)

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				
30	11	$12.91	$3.03	**(C)**
45	16	$12.91	$3.03	**(D)(I)**
60	21	$13.33	$3.03	**(D)(I)**
95	34	$14.71	$3.03	**(I)(I)**
139	49	$15.37	$3.03	**(I)(I)**
219	77	$15.65	$3.03	**(D)(I)**
				(C)
Light-Emitting Diode (LED) — Colonial				
20	7	$16.89	$3.03	**(C)**
45	16	$17.23	$3.03	**(C)**
Light-Emitting Diode (LED) — Contemporary				
40	14	$15.59	$3.03	**(C)**
55	20	$15.59	$3.03	**(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 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.

RATE SM - STREET LIGHTING MUNICIPAL - (Continued)

MONTHLY RATE – (Continued)

ELECTRIC CHARGES – (Continued)

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 its own expense in accordance with SPECIAL TERM AND CONDITION NO. 2 or the **(C)**
Company will install, own and maintain the pole(s) and bill the customer at the monthly rate of $11.54 for each pole **(I)**
required.

CUSTOMER OWNED AND MAINTAINED EQUIPMENT CHARGE

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 SH - STREET LIGHTING HIGHWAY

AVAILABILITY

Beginning January 15, 2022, Rate SH will no longer be available to new customers or applicants, or to new installations for existing customers. **(C)**

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.

Beginning January 15, 2022, replacement of high pressure sodium 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 LED lighting options listed below. **(C)**

Due to the limited availability of high pressure sodium lighting, the Company will be replacing existing high pressure sodium lights with LED lights at its discretion. The Company may exchange functioning high pressure sodium lights with LEDs upon customer request and upon receipt, in advance, of the Company's estimated removal costs of such replacement. Such elective replacements shall be at the Company's discretion. **(C)**

MONTHLY RATE

DISTRIBUTION CHARGE — Monthly Rate Per Unit

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	
Sodium Vapor				
100	50	$14.02	$3.03	**(I)(I)**
150	71	$14.22	$3.03	**(I)(I)**
200	95	$14.42	$3.03	**(I)(I)**
400	170	$15.99	$3.03	**(I)(I)**
Light-Emitting Diode (LED) — Cobra Head				
30	11	$12.91	$3.03	**(C)**
45	16	$12.91	$3.03	**(C)**
60	21	$15.12	$3.03	**(I)(I)**
95	34	$15.65	$3.03	**(I)(I)**
139	49	$16.87	$3.03	**(I)(I)**
219	77	$19.62	$3.03	**(I)(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.

(C) – Indicates Change **(I) – Indicates Increase**

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 .... $11.50 **(I)**

Energy Charge .... 2.7761 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 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.

(I) – Indicates Increase

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.

Beginning January 15, 2022, replacement of high pressure sodium 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 LED lighting options listed below. **(C)**

Due to the limited availability of high pressure sodium lighting, the Company will be replacing existing high pressure sodium lights with LED lights at its discretion. The Company may exchange functioning high pressure sodium lights with LEDs upon customer request and upon receipt, in advance, of the Company's estimated removal costs of such replacement. Such elective replacements shall be at the Company's discretion. **(C)**

MONTHLY RATE

DISTRIBUTION CHARGE - Monthly Rate Per Unit

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	
High Pressure Sodium				
70	29	$14.66	$3.03	**(I)(I)**
100	50	$14.77	$3.03	**(I)(I)**
150	71	$14.99	$3.03	**(I)(I)**
250	110	$15.38	$3.03	**(I)(I)**
400	170	$15.99	$3.03	**(I)(I)**
Flood Lighting				
100	46	$14.66	$3.03	**(I)(I)**
250	100	$15.34	$3.03	**(I)(I)**
400	155	$16.04	$3.03	**(I)(I)**
Light-Emitting Diode (LED) — Cobra Head				
30	11	$12.91	$3.03	**(C)**
45	16	$12.91	$3.03	**(D)(I)**
60	21	$13.33	$3.03	**(D)(I)**
95	34	$14.71	$3.03	**(I)(I)**
139	49	$15.37	$3.03	**(I)(I)**
219	77	$15.65	$3.03	**(D)(I)**
				(C)
Light-Emitting Diode (LED) — Colonial				
20	7	$16.89	$3.03	**(C)**
45	16	$17.23	$3.03	**(C)**
Light-Emitting Diode (LED) — Contemporary				
40	14	$15.59	$3.03	**(C)**
55	20	$15.59	$3.03	**(C)**

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 its 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 $11.54 for each pole required. **(C)** **(I)**

CUSTOMER OWNED AND MAINTAINED EQUIPMENT CHARGE

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.

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	X	X	X	X	X	X	X	X	X	X	X	**(C)**
Rider No. 5	X	X	X													
Rider No. 6				X												
Rider No. 7	X															**(C)**
Rider No. 8	X	X	X	X	X					X	X	X	X	X	X	
Rider No. 9				X	X	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				X		X		X								**(C)**

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 — Federal Tax Adjustment Clause **(C)**
Rider No. 5 — Universal Service Charge
Rider No. 6 — Temporary Service
Rider No. 7 — Residential Subscription Service Pilot **(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 IV 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 — Community Development for New Load **(C)**

Continued on Original Page No. 87A **(C)**

STANDARD CONTRACT RIDERS – (Continued) **(C)**

RIDER MATRIX – (Continued) **(C)**

	RS	RH	RA	GS/GM	GMH	GL	GLH	L	HVPS	AL	SE	SM	SH	UMS	PAL	
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	
Rider No. 23	X	X	X													**(C)**
Rider No. 24				X	X	X	X	X								**(C)**
Rider No. 25				X	X											**(C)**
Rider No. 26				X	X											**(C)**
Appendix A	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	

Rider Titles:

Rider No. 20 — Smart Meter Charge
Rider No. 21 — Net Metering Service
Rider No. 22 — Distribution System Improvement Charge (“DSIC”)
Rider No. 23 — Home Charging Pilot Program **(C)**
Rider No. 24 — Fleet Charging Pilot Program **(C)**
Rider No. 25 — New Business Stimulus **(C)**
Rider No. 26 — Crisis Recovery Program **(C)**
Appendix A — Transmission Service Charges

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 4 – FEDERAL TAX ADJUSTMENT CLAUSE (C)

(Applicable to all Rates)

The Federal Tax Adjustment Clause ("FTAC") is instituted as a mechanism to adjust for changes in the federal corporate income tax rate that are not reflected in the Company's most recent general base rate proceeding. The FTAC is applicable to all base distribution rates under this Tariff. The amount of the adjustment will be determined as provided below.

A. Determination of the Change in Recoverable Federal Income Taxes Resulting from Increases or Decreases in the Federal Corporate Income Tax Rate ("FITA").

   1. FITA shall include the effect of the increase or decrease in the federal corporate income tax rate on:

      a. the provision in rates for recovery of current federal income taxes;
      b. the provision in rates for recovery of deferred federal income taxes; and
      c. any provision in rates for adjustment of previously deferred federal income taxes recorded at a different federal income tax rate.

   2. The increases/decreases in annual revenues under this Rider will be calculated based on either the federal tax amounts associated with distribution utility investments, revenues and expenses allowed in the Company's most recent general base rate proceeding if fully determined in a Final Order, if available, or on the federal tax amounts associated with distribution utility investments, revenues and expenses incurred by the Company in the calendar year preceding the effective date of the tax rate change. If any base distribution rate revenue increase is granted during such calendar year or thereafter, the actual federal tax amounts will be adjusted to reflect the annualized increase in federal corporate income taxes resulting from the allowed increase in base distribution rate revenues.

B. Allocation of Increased/ Decreased Revenues to Rate Classes

   1. The required increase/decrease in revenues to reflect the change in the federal corporate income tax rate calculated pursuant to this Rider shall be applied by equal percentage to all base distribution rates.

C. Calculation and Filing of Adjusted Rates For Changes in the Federal Corporate Income Tax Rate

   1. To calculate the FTAC, the required increase/decrease in revenues will be divided by the Company's projected annual revenue for base distribution service for the period during which the charge will be collected, exclusive of State Tax Adjustment Surcharge (STAS) and automatic adjustment clause revenues.

   2. The surcharge will be expressed as a percentage carried to two decimal places and will be applied to the total base distribution charges that are billed to each customer for distribution service.

   3. The surcharge will be filed to become effective on ten (10) days' notice as soon as practicable following the effective date of the federal corporate income tax change, including appropriate supporting data demonstrating the calculation of the revenue adjustment and determination of the surcharge.

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued) **(C)**

RIDER NO. 4 – FEDERAL TAX ADJUSTMENT CLAUSE – (Continued)

(Applicable to all Rates)

C. Calculation and Filing of Adjusted Rates For Changes in the Federal Corporate Income Tax Rate – (Continued)

4. After the initial filing, the FTAC surcharge shall be filed with the Commission by April 1 of each year that it is in place.

5. The FTAC shall be applied on a bills rendered basis.

D. Formula

The computation of the FTAC is as follows:

$$FTAC = \frac{(((FITA * GRCF) + e) * GRT)}{PAR}$$

$$GRCF = (1/((1-SIT)*(1-FIT)))$$

$$GRT = 1/(1-T)$$

Where:

FITA = Reflects the federal income tax adjustment, if any, as defined in Part A of this Rider and may be a positive or negative value.

GRCF = Gross Revenue Conversion Factor.

SIT = State Income Tax rate in effect at the time of the filing.

FIT = Federal income tax rate in effect at the time of the filing.

T = Pennsylvania gross receipts tax rate in effect during the billing month.

e = Amount calculated (+/-) under the annual reconciliation feature or Commission audit.

PAR = Projected annual revenues for base distribution service (excluding all applicable clauses and riders) from existing customers plus netted revenue from any customers which will be acquired or lost by the beginning of the applicable service period.

STANDARD CONTRACT RIDERS - (Continued) **(C)**

RIDER NO. 4 – FEDERAL TAX ADJUSTMENT CLAUSE – (Continued)

(Applicable to all Rates)

E. Reconciliation

1. The surcharge shall be reconciled on an annual basis to provide for over/under-recoveries of the revised revenues to be recovered. The revenue received under the FTAC for the reconciliation period will be compared to the Company's required increase/decrease in revenues as defined in Part A. The difference will be recouped or refunded, as appropriate, over a one-year period commencing on April 1 of each year. The surcharge will be reconciled at the end of each calendar year and will remain in place until the Company files and the Commission approves new base distribution rates for the Company pursuant to Section 1308(d).

2. Under- or over-recoveries of the required revenue changes to reflect a delay in implementation of the surcharge following the effective date of the federal corporate income tax rate, including the effect of implementation of a federal corporate income tax rate change on a retroactive basis, will be reconciled in the first annual reconciliation filing.

3. Upon determination that the surcharge, if left unchanged, would result in a material over- or under-collection, the Company may file with the Commission, on at least ten (10) days' notice, for an interim revision of the FTAC.

4. Interest will not be applied to reconciled amounts.

5. The FTAC will not be included in the calculation of the Distribution System Improvement Charge ("DSIC").

(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)

- 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 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.

- 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 35,853 customers. Specifically, the recoverable CAP discounts **(C)** will be reduced by the number of CAP participants in excess of 35,853 times the average CAP **(C)** 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.

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)

RIDER NO. 7 – RESIDENTIAL SUBSCRIPTION SERVICE PILOT (C)

(Applicable to Rate Schedule RS)

AVAILABILITY

Available to customers served under Rate RS – Residential Service who are not enrolled in the Customer Assistance Program (CAP) and are not billed under Rider No. 21 (Net Energy Metering). Enrollment in the Residential Subscription Service Pilot ("Pilot") provided under this Rider will be limited to 2,000 customers who request enrollment during the period January 15, 2022, through December 31, 2022. The Company may decline to enroll a customer at its sole discretion.

This Rider applies only to base distribution services. All other applicable charges and Riders will be charged as designed.

DEFINITIONS

Subscription Unit. Incremental size of subscription that is equal to 1 kW.

Subscribed Units. Total number of Subscription Units chosen by customer. (For example, a customer who wants to cover 5 kW of demand will choose 5 Subscription Units.)

Subscription Level. Total demand (kW) of subscription based on the Subscribed Units chosen by customer times the Subscription Unit, plus 1 kW minimum subscription included in the Customer Charge.

Overage Bandwidth. Amount by which customer can exceed their Subscription Level without incurring Overage Fees. This is set to one-half of one Subscription Unit, or 0.5 kW.

Overage Amount. The positive amount of customer's monthly maximum billed demand less Subscription Level less Overage Bandwidth.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge $28.48

Subscription Unit Charge .... $12.23 per unit

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued) **(C)**

RIDER NO. 7 – RESIDENTIAL SUBSCRIPTION SERVICE PILOT – (Continued)

(Applicable to Rate RS)

SUBSCRIPTION SERVICE LEVEL

Upon enrollment in the Pilot, customers shall select the number of Subscription Units the customer will purchase every month to cover their electric distribution needs. The Company will provide the customer with information regarding their previous peak energy use in the past year to aid the customer in selecting the appropriate Subscription Service Level. The customer's Distribution Charges will then be computed as the Customer Charge, plus the Subscribed Units multiplied by the Subscription Unit Charge, plus any applicable Overage Amount or other charges.

Where a customer's demand exceeds their Subscription Level plus the Overage Bandwidth, the customer shall pay an overage fee equal to the Overage Amount multiplied by two times the Subscription Unit Charge. If a customer has an Overage Amount more than three times during the previous six billing periods, or the customer's Overage Amount exceeds 3 kW, the customer's Subscribed Units will automatically be reset to the customer's maximum demand from the past six months rounded up to the nearest 1 kW.

DETERMINATION OF DEMAND FOR DISTRIBUTION

Individual demand, except in unusual cases, will be determined by measurement of the sixty-minute period of greatest kilowatt-hour use during the billing period.

SPECIAL PROVISIONS

CUSTOMER ENROLLMENT

A customer may exit the Pilot and this Rider at any time for any reason. A customer who exits the Pilot will be removed from this Rider effective with the billing cycle that commences three (3) business days after the date the customer notified the Company of their election to leave the Pilot.

BILL PROTECTION

A customer who exits the Pilot may request a refund for the positive difference between their billed distribution charges under this Rider and the amount of such charges if billed under Rate Schedule RS for up to three months prior to exiting, but no longer than the customer's actual enrollment in the program. The Company will provide such refund within 60 days of customer request.

(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.

		Application Period						
Wattage	Nominal kWh Energy Usage per Unit per Month	06/01/2021 through 11/30/2021	12/01/2021 through 05/31/2022	06/01/2022 through 11/30/2022	12/01/2022 through 05/31/2023	06/01/2023 through 11/30/2023	12/01/2023 through 05/31/2023	
Supply Charge ¢ per kWh		3.0953	X.XXXX	X.XXXX	X.XXXX	X.XXXX	X.XXXX	
		Fixture Charge — $ per Month						
Mercury Vapor								
100	44	1.36	X.XX	X.XX	X.XX	X.XX	X.XX	
175	74	2.29	X.XX	X.XX	X.XX	X.XX	X.XX	
250	102	3.16	X.XX	X.XX	X.XX	X.XX	X.XX	
400	161	4.98	X.XX	X.XX	X.XX	X.XX	X.XX	
1000	386	11.95	X.XX	X.XX	X.XX	X.XX	X.XX	
High Pressure Sodium								
70	29	0.90	X.XX	X.XX	X.XX	X.XX	X.XX	
100	50	1.55	X.XX	X.XX	X.XX	X.XX	X.XX	
150	71	2.20	X.XX	X.XX	X.XX	X.XX	X.XX	
200	95	2.94	X.XX	X.XX	X.XX	X.XX	X.XX	
250	110	3.40	X.XX	X.XX	X.XX	X.XX	X.XX	
400	170	5.26	X.XX	X.XX	X.XX	X.XX	X.XX	
1000	387	11.98	X.XX	X.XX	X.XX	X.XX	X.XX	
Flood Lighting - Unmetered								
70	29	0.90	X.XX	X.XX	X.XX	X.XX	X.XX	
100	46	1.42	X.XX	X.XX	X.XX	X.XX	X.XX	
150	67	2.07	X.XX	X.XX	X.XX	X.XX	X.XX	
250	100	3.10	X.XX	X.XX	X.XX	X.XX	X.XX	
400	155	4.80	X.XX	X.XX	X.XX	X.XX	X.XX	
Light-Emitting Diode (LED) — Cobra Head								
30	11	X.XX	X.XX	X.XX	X.XX	X.XX	X.XX	(C)
45	16	0.50	X.XX	X.XX	X.XX	X.XX	X.XX	
60	21	0.65	X.XX	X.XX	X.XX	X.XX	X.XX	
95	34	1.05	X.XX	X.XX	X.XX	X.XX	X.XX	
139	49	1.52	X.XX	X.XX	X.XX	X.XX	X.XX	
219	77	2.38	X.XX	X.XX	X.XX	X.XX	X.XX	
								(C)
Light-Emitting Diode (LED) — Colonial								
20	7	X.XX	X.XX	X.XX	X.XX	X.XX	X.XX	(C)
45	16	X.XX	X.XX	X.XX	X.XX	X.XX	X.XX	(C)
Light-Emitting Diode (LED) — Contemporary								
40	14	X.XX	X.XX	X.XX	X.XX	X.XX	X.XX	(C)
55	20	X.XX	X.XX	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)

DEFAULT SERVICE SUPPLY RATE – (Continued)

Lighting — (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**	**06/01/2023 through 11/30/2023**	**12/01/2023 through 05/31/2024**	**06/01/2024 through 11/30/2024**	**12/01/2024 through 05/31/2025**	
Supply Charge ¢ per kWh		X.XXXX	X.XXXX	X.XXXX	X.XXXX	
		Fixture Charge — $ per Month				
Mercury Vapor						
100	44	X.XX	X.XX	X.XX	X.XX	
175	74	X.XX	X.XX	X.XX	X.XX	
250	102	X.XX	X.XX	X.XX	X.XX	
400	161	X.XX	X.XX	X.XX	X.XX	
1000	386	X.XX	X.XX	X.XX	X.XX	
High Pressure Sodium						
70	29	X.XX	X.XX	X.XX	X.XX	
100	50	X.XX	X.XX	X.XX	X.XX	
150	71	X.XX	X.XX	X.XX	X.XX	
200	95	X.XX	X.XX	X.XX	X.XX	
250	110	X.XX	X.XX	X.XX	X.XX	
400	170	X.XX	X.XX	X.XX	X.XX	
1000	387	X.XX	X.XX	X.XX	X.XX	
Flood Lighting - Unmetered						
70	29	X.XX	X.XX	X.XX	X.XX	
100	46	X.XX	X.XX	X.XX	X.XX	
150	67	X.XX	X.XX	X.XX	X.XX	
250	100	X.XX	X.XX	X.XX	X.XX	
400	155	X.XX	X.XX	X.XX	X.XX	
Light-Emitting Diode (LED) — Cobra Head						
30	11	X.XX	X.XX	X.XX	X.XX	**(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	
						(C)
Light-Emitting Diode (LED) — Colonial						
20	7	X.XX	X.XX	X.XX	X.XX	**(C)**
45	16	X.XX	X.XX	X.XX	X.XX	**(C)**
Light-Emitting Diode (LED) — Contemporary						
40	14	X.XX	X.XX	X.XX	X.XX	**(C)**
55	20	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:

$$DSS = [(CA + SLR + (DSS_a + E)/S) * F + (DSS_b/S)] * [1/(1 – T)]$$

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.

CA = The weighted average of the winning bids received in a competitive auction 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 competitive auction shall be conducted as described in "Procurement Process."

DSS_a = 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. 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-2021-3024750. **(C)**

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 9 – DAY-AHEAD HOURLY PRICE SERVICE – (Continued)

(Applicable to Rates GS/GM, GMH, 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-2021- (C)
3024750. (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 Medium (≥ 200 kW) Customer Class and 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, 2021 through May 31, 2022	$3.60
June 1, 2022 through May 31, 2023	$X.XX
June 1, 2023 through May 31, 2024	$X.XX
June 1, 2024 through May 31, 2025	$X.XX

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. **(I)**

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.

(I) – Indicates Increase

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 16 - SERVICE TO NON-UTILITY GENERATING FACILITIES

(Applicable to Rates GM < 25, GM ≥ 25, GMH, GL, GLH and L) **(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

Contract is the signed agreement between the customer and the Company that is executed upon the customer's request to select Rider No. 16 service. Among other things, the Contract specifies the contractual demand levels for Back-Up Service and Supplementary Service that are defined below. **(C)**

Supplementary Service is distribution service provided by the Company, inclusive of distribution services included in the applicable monthly customer charge, 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)** **(C)** **(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)** **(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.

Supplementary Contract Demand may be established and represents the threshold demand for Supplementary Service to the customer's facility. **(C)**

Maintenance 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 and is in addition to Supplementary Contract Demand. **(C)** **(C)**

Peak Period is the period between 12pm and 10pm EST on all days in the months of June through September. **(C)**

Supplementary Service Billing Determinants is the kW specified in the Contract with the customer for Supplementary Service. **(C)** **(C)**

Maintenance Demand Service Billing Determinants is the kW specified in the Contract as Maintenance Contract Demand with the customer for Back-Up Service. This Billing Determinant applied every billing period regardless of whether the customer calls upon Back-Up Service during the billing period. **(C)** **(C)** **(C)**

As-Used Demand Billing Determinant is the kW specified in the Contract as Maintenance Contract Demand that applies if the customer calls upon Back-Up Services during the Peak Period. As-Used Demand Billing Determinant will be set to the Maintenance Contact Demand level if the customer's maximum demand during the Peak Period of the billing period exceeds the Supplementary Contract Demand specified in the Contract. **(C)**

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 16 - SERVICE TO NON-UTILITY GENERATING FACILITIES - (Continued)

(Applicable to Rates GM < 25, GM ≥ 25, GMH, GL, GLH and L) **(C)**

A. DEFINITIONS – (Continued)

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)** **(C)**

Supply Billing Determinants for customers not being served by an Electric Generation Supplier ("EGS"). Rate 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 for customers on Rate GS/GM and GMH shall be the billing determinants for the current billing month then in effect under Rider No. 8 – Default Service Supply or Rider No. 9 – Day-Ahead Hourly Price Service, as applicable. **(C)** **(C)** **(C)**

B. BACK-UP SERVICE **(C)**

The Company will supply Back-Up Service at the following rates: **(C)**

DISTRIBUTION

A distribution charge of $3.09 per kW shall be applied to the Back-Up Service Maintenance Demand Billing Determinants. **(C)** **(C)**

The Maintenance Contract Demand distribution charges will be applied in each month based on the customer's Maintenance Contract Demand without regard to actual usage. **(C)** **(C)**

An additional distribution charge of $6.79 per kW shall be applied to the Back-Up Service As-Used Contract Demand Billing Determinants. The As-Used Contract Demand distribution charge will be applied in each month based on the customer's As-Used Contract Demand if the customer calls upon Back-Up service during the Peak Period. **(C)**

Overage charges will also apply if the customer exceeds Maintenance Demand by 10% or more. The Maintenance Overage Charge of $9.88 per kW shall be applied to the difference in actual maximum kW during the billing period and the customer's Maintenance Contact Demand. No additional charges will apply to the As-Used Contract Demand Charge. **(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 rates, including all ratchets applicable. **(C)** **(C)**

STANDARD CONTRACT RIDERS - (Continued) **(C)**

RIDER NO. 16 - SERVICE TO NON-UTILITY GENERATING FACILITIES - (Continued)

(Applicable to Rates GM < 25, GM ≥ 25, GMH, GL, GLH and L)

B. BACK-UP SERVICE – (Continued)

If a customer's Back-Up Service requirement at any time exceeds the customer's Maintenance Contract Demand by 5% or more, the actual Back-Up Service requirement provided, measured in kW demand will become the customer's new Maintenance Contract Demand for the remaining term of the back-up contract. If a customer's actual Back-Up Service requirement provided at any time exceeds the customer's Maintenance Contract Demand by 10% or more, the customer will be assessed a fee equal to the difference between the actual Back-Up Service provided at the time during the billing period and the Maintenance Contract Demand multiplied by the Overage Charge ($9.88). **(C)**

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 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)**

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 19 – COMMUNITY DEVELOPMENT FOR NEW LOAD **(C)**

(Applicable to Rate Schedules GS/GM, GL, and L)

AVAILABILITY

This Rider is available to customers taking distribution service under Rate GM < 25, GM ≥ 25, GL, or L. For new services, the customer or applicant must have a projected load of at least 10 kW and must apply for the Rider prior to the service being energized. For existing services, the customer must reasonably project a peak load increase of at least 10 kW and apply for the Rider before the load growth occurs. The Rider will apply no sooner than thirty (30) days after the customer provides to the Company written notice of its desire to be placed on the Rider. The Company reserves the right to decline to enroll any customer or applicant in this Rider, at the Company’s sole discretion. Customers taking service under this Rider are not eligible for any other distribution rate discount.

DEFINITIONS

Service Location. A single or contiguous premises that has or will have one or more delivery points for distribution service billed by the Company under a single account.

Brownfield Site. A Service Location where the expansion, redevelopment, or reuse of which may be complicated by the presence or potential presence of a hazardous substance, pollutant, or contaminant. Requires documentation either by providing a copy of the pertinent sections of the ASTM E1903-97 Phase II Site Assessment documenting the site contamination or by providing a letter from a local, state or federal regulatory agency confirming the site is classified as a Brownfield by that agency.

Site Expansion. A Service Location where the Company has not previously provided service, or where the service previously provided by the Company was not used for substantially the same type of operation or was terminated at least twelve (12) months before the customer's contractually specified effective date for service under this rider. This condition is waived for existing Service Locations where an entity has assumed operation of a Service Location from a customer which has ceased operations as a result of dissolution, so long as the formation of the entity did not occur as a result of merger, joint venture, acquisition and/or any other variation of combined business structures with the former customer at the service location. In any event, the completed application for the rider must be made within six (6) months from the later of the date: (1) the customer first received service from the Company; or (2) the date the customer received its sales tax exemption certificate from the Commonwealth of Pennsylvania.

Manufacturing Sales Tax Exemption Certificate. Pennsylvania Sales Tax Blanket Exemption Certificate filed by the customer with the Company showing the address of the Service Location and certifying that more than fifty (50) percent (on an annual basis) of the service purchased by the customer for the Service Location is exempt from sales tax because it is used in manufacturing operations, shipbuilding operations, or ship cleaning operations.

Employment Report. The "Employer's Report for Unemployment Compensation" (PA Form UC-2) as filed by the customer with the Office of Employment Security, Department of Labor and Industry, Commonwealth of Pennsylvania and as defined by 43 P.S. 753 [d].

STANDARD CONTRACT RIDERS - (Continued) **(C)**

RIDER NO. 19 – COMMUNITY DEVELOPMENT FOR NEW LOAD – (Continued)

(Applicable to Rate Schedules GS/GM, GL, and L)

MONTHLY RATE

DISTRIBUTION CHARGES

Rider No. 19 provides a percent discount to monthly demand charges for base distribution services included in Rates GM < 25, GM ≥ 25, GL, and L during the months of January through May and October through November. The percent discount declines ratably over five years as follows.

2022 Percent Discount	25%
2023 Percent Discount	20%
2024 Percent Discount	15%
2025 Percent Discount	10%
2026 Percent Discount	5%

This Rider applies only to base distribution services. All other applicable charges and Riders will be charged as designed.

QUALIFICATIONS

Customers and applicants requesting service under this Rider shall file with the Company, before the effective date of the Rider for the Service Location, a Manufacturing Sales Tax Exemption Certificate, as defined above, for the Service Location. Customer also files with the Company copies of the Employment Reports, as defined above, for the Service Location at the time of application.

TRANSFER OF OWNERSHIP

The Company will only apply the Rider to the customer's base distribution charges for the term of contract. If, during the term of contract, the ownership of the Service Location changes, the Company may continue to apply the Rider to the new owner's bills for the Service Location. If the Company continues to apply the Rider in such circumstances, the Company shall apply the Rider to the new owner's bills for the Service Location as if the new owner had been on the Rider for the Service Location for the same period of time as was the previous owner.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 21 – NET METERING SERVICE

(Applicable to Rates RS, RH, RA, GS/GM, GMH, GL, GLH and L) **(C)**

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, GL, GLH and L 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, GL, GLH and L), 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. **(C)** **(C)**

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, GL, GLH and L. **(C)**

1. A customer-generator facility used for net metering shall be equipped with a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. A dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense.

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 21 – NET METERING SERVICE – (Continued)

(Applicable to Rates RS, RH, RA, GS/GM, GMH, GL, GLH and L) **(C)**

METERING PROVISIONS - (Continued)

2. If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator’s expense. Additional metering equipment for the purpose of qualifying alternative energy credits owned by the customer-generator shall be paid for by the customer-generator. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The Company shall, prior to taking title to any alternative energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for their disposition.

3. Meter aggregation on properties owned or leased and operated by a customer-generator shall be allowed for purposes of net metering. Meter aggregation shall be limited to meters located on properties within two (2) miles of the boundaries of the customer-generator’s property. Meter aggregation shall only be available for properties located within the Company’s service territory. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis.

BILLING PROVISIONS

The following billing provisions apply to customer-generators in conjunction with service under applicable Rate Schedule RS, RH, RA, GS/GM, GMH, GL, GLH and L: **(C)**

1. The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at the full retail rate consistent with Commission regulations. If a customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator’s usage in subsequent billing periods at the full retail rate. Any excess kilowatt hours shall continue to accumulate for the 12 month period ending May 31. On an annual basis, the Company will compensate the customer-generator for kilowatt-hours received from the customer-generator in excess of the kilowatt hours delivered by the Company to the customer-generator during the preceding year at the Company’s Price To Compare consistent with Commission regulations. For customer-generators on Rider No. 9 – Day-Ahead Hourly Price Service, the Price To Compare shall be determined as an average for the twelve (12) month period in accordance with Rider No. 9 and Appendix A – Transmission Service Charges. The customer-generator is responsible for the **(C)** customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 21 – NET METERING SERVICE – (Continued)

(Applicable to Rates RS, RH, RA, GS/GM, GMH, GL, GLH and L) **(C)**

BILLING PROVISIONS - (Continued)

2. If the Company supplies more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

3. For customer-generators involved in virtual meter aggregation programs, a credit shall be applied first to the meter through which the generating facility supplies electricity to the distribution system, then through the remaining meters for the customer-generator's account equally at each meter's designated rate. Virtual meter aggregation is the combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-generator by means of the Company's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. The customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

BILLING PROVISIONS FOR
ELECTRIC VEHICLE TIME-OF-USE PILOT PROGRAM ("EV-TOU") CUSTOMER GENERATORS

(Applicable to Rates RS, RH, RA, GS/GM and GMH)

The following billing provisions apply to customer-generators that take service on Rider No 8 – Default Service Supply and are on EV-TOU rates.

1. The EV-TOU customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at the full retail rate consistent with Commission regulations. If an EV-TOU customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator in a given billing period, the Company will maintain an active record of the excess kilowatt hours produced at the customer-generators premise in a "bank". If an EV-TOU customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the EV-TOU customer generator's usage in a subsequent billing period at the full retail rate. If, in a subsequent billing period, a customer consumes more electricity than produced, kilowatt-hours will be pulled from the customer's bank on a first in first out basis. Any excess kilowatt hours shall continue to accumulate and credit against usage for the 12 month period ending May 31st. On an annual basis, the Company will compensate the customer-generator for kilowatt-hours remaining in the bank on May 31st, at the applicable Price To Compare at the time the excess kilowatt-hours were banked. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 21 – NET METERING SERVICE – (Continued)

(Applicable to Rates RS, RH, RA, GS/GM, GMH, GL, GLH and L) **(C)**

BILLING PROVISIONS FOR
ELECTRIC VEHICLE TIME-OF-USE PILOT PROGRAM ("EV-TOU") CUSTOMER GENERATORS

(Applicable to Rates RS, RH, RA, GS/GM and GMH)

- (Continued)

1. If the Company supplies more kilowatt-hours of electricity than the customer-generator supplies during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

3. If an eligible customer-generator wishes to no longer be enrolled in the EV-TOU Pilot Program and switches to the standard default service supply product, any excess kilowatt hours banked and remaining from the EV-TOU period will be used, as applicable, for the remaining portion of the 12 month period ending May 31 and the Company shall compensate for any excess kilowatt hours that are banked at the Price To Compare in effect at the time.

NET METERING PROVISIONS FOR SHOPPING CUSTOMERS

1. Customer-generators may take net metering services from EGSs that offer such services.

2. If a net-metering customer takes service from an EGS, the Company will credit the customer for distribution charges for each kilowatt hour produced by the customer-generator, up to the total amount of kilowatt-hours delivered to the customer by the Company during the billing period. If a customer-generator supplies more electricity to the electric distribution system than the Company delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the Company's distribution rates. Any excess kilowatt hours shall continue to accumulate for the 12 month period ending May 31. Any excess kilowatt hours at the end of the 12 month period will not carry over to the next year for distribution charge purposes. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

3. If the Company delivers more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the applicable rate schedule shall be applied to the net kilowatt-hours of electricity that the Company delivered. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 21 – NET METERING SERVICE – (Continued)

(Applicable to Rates RS, RH, RA, GS/GM, GMH, GL, GLH and L) **(C)**

NET METERING PROVISIONS FOR SHOPPING CUSTOMERS – (Continued)

4. Pursuant to Commission regulations, the credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs shall be stated in the service agreement between the customer-generator and the EGS. The Company will provide the customer-generator with a statement of monthly kilowatt hour usage for the 12 month period ending May 31 for the purpose of the customer-generator seeking credit or compensation from the EGS.

5. If a customer-generator switches electricity suppliers, the Company shall treat the end of the service period as if it were the end of the year.

APPLICATION

Customer-generators seeking to receive service under the provisions of this Rider must submit a written application to the Company demonstrating compliance with the Net Metering Rider provisions and quantifying the total rated generating capacity of the customer-generator facility.

MINIMUM CHARGE

The Minimum Charges under Rate Schedule RS, RH, RA, GS/GM, GMH, GL, GLH and L apply for installations under this Rider. **(C)**

RIDERS

Bills rendered by the Company under this Rider shall be subject to charges stated in any other applicable Rider.

(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

STANDARD CONTRACT RIDERS - (Continued) **(C)**

RIDER NO. 23 – HOME CHARGING PILOT PROGRAM

(Applicable to Rates RS, RH and RA)

PURPOSE

This Rider sets forth the eligibility, terms, and conditions applicable to customers participating in the Company's voluntary residential Home Charging Pilot (the "Program").

APPLICABILITY

Available to residential customers served under Rate Schedules RS, RH and RA who:

a. own a single-family home, defined as a detached single-family home, townhome/row house, or duplex ("Service Address");

b. have an active Duquesne Light residential electric service account with no past due bills at the Service Address;

c. have a personal garage or private driveway at Service Address suitable, in the Company's sole judgment, for the installation and operation of an electric vehicle ("EV") level 2 charging station ("Charging Station") and related equipment; and

d. own or lease an EV which is registered to the customer's Service Address.

The Program is available to up to 125 new participants per calendar year on a first-come, first-served basis. The Company may decline to enroll any customer at the Company's sole discretion.

MONTHLY RATE

In addition to any applicable charges for electric delivery and supply, participating customers shall pay a monthly Program Charge of $21.17.

PROGRAM DESCRIPTION

Through the Program, Duquesne Light shall provide, own, and maintain a Charging Station at the participating customer's Service Address for the duration of the customer's participation in the Program. The customer shall select the Charging Station from a list of options approved by Duquesne Light. The Charging Station shall be installed at a mutually-agreeable location at the Service Address by Duquesne Light's third-party contractor(s). The Company shall pay the Covered Amount (as defined below) toward costs associated with installing the Charging Station. Any costs above the Covered Amount shall be at the customer's expense.

STANDARD CONTRACT RIDERS - (Continued) **(C)**

RIDER NO. 23 – HOME CHARGING PILOT PROGRAM – (Continued)

(Applicable to Rates RS, RH and RA)

PROGRAM DESCRIPTION – (Continued)

"Covered Amount:" The Covered Amount shall be up to $2,000 for customers with household incomes equal to or less than 150% of the Federal Poverty Level, or up to $500 for all other customers. For customers with household incomes equal to or less than 150% of the Federal Poverty Level, the Covered Amount may apply to Charging Station installation costs, as well as costs of electrical upgrades at the customer's residence (e.g., new electrical panel or breakers) necessary to support Charging Station installation and operation. For all other customers, the Covered Amount may apply only to Charging Station installation costs.

In addition to the foregoing requirements, participating customers shall:

a. Execute and abide by the Home Charging Pilot Customer Agreement, with a minimum term of five years.

b. Have and maintain wireless internet ("Wi-Fi") service at the Service Address with sufficient signal at the Charging Station location.

c. Share charging data with Duquesne Light (and provide any authorizations required to accommodate such sharing) via the applicable Charging Station vendor.

d. Promptly notify Duquesne Light in the event the Charging Station fails to operate or otherwise requires repair, except for minor issues remedied by the customer pursuant to (e) herein.

e. Make reasonable efforts to remedy minor issues with the Charging Station that do not require qualified technicians to address, including but not limited to, the resetting of a tripped circuit breaker or assisting with software or Wi-Fi interconnectivity issues.

f. Establish and maintain an account with the applicable Charging Station vendor and for wireless internet connectivity to enable communication between the Charging Station and Charging Station vendor's hardware and software.

g. Use the Charging Station only in accordance with the manufacturer's applicable recommendations.

h. Maintain the area surrounding the Charging Station. See also Rule No. 23 herein.

i. Provide Duquesne Light with reasonable access to the Charging Station. See also Rule No. 22 herein.

j. Upon Duquesne Light's request, participate in surveys and provide feedback about the Program.

Upon conclusion of the Home Charging Pilot Customer Agreement Term, except in the event of customer default or early termination as discussed below, ownership of the Charging Station shall pass automatically to customer.

In the event of customer default or early termination, the customer shall pay a sum equal to the number of months remaining in the Home Charging Pilot Customer Agreement Term multiplied by the Monthly Charge per Charging Station, plus a one-time fee of $200; and Duquesne Light may remove the Charging Station from the Service Address.

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued) **(C)**

RIDER NO. 24 – FLEET CHARGING PILOT PROGRAM

(Applicable to Rates GS/GM, GMH, GL, GLH and L)

PURPOSE

This Rider sets forth the eligibility, terms, and conditions applicable to customers participating in the Company's voluntary Fleet Charging Pilot (the "Program").

APPLICABILITY

Available to customers served under Rate Schedules GS/GM, GMH, GL GLH, and L that:

a. own, lease, or operate a fleet of at least six on-road vehicles;

b. demonstrate that electric vehicles are currently in-use or have been purchased for use at the customer's premises ("Service Address");

c. own or lease the Service Address, and demonstrate site control, suitable, in the Company's sole judgement, for the installation and operation of level 2 electric vehicle charging stations ("Charging Stations") and related equipment.

The Program is available to up to twelve (12) new customers per calendar year on a first-come, first-served basis. The Company may decline to enroll any customer at the Company's sole discretion.

MONTHLY RATE

In addition to any applicable charges for electric delivery and supply, participating customers shall pay the following applicable monthly charge per charging station port:

- Bundled Option: $63.24
- Pre-Pay Option: $28.82
- Customer-Supplied Charging Station Option: No charge

Customers will select one Program Option for all charging ports subject to the Program at the Service Address for the duration of the customer's participation in the Program.

STANDARD CONTRACT RIDERS - (Continued) (C)

RIDER NO. 24 – FLEET CHARGING PILOT PROGRAM – (Continued)

(Applicable to Rates GS/GM, GMH, GL, GLH and L)

PROGRAM DESCRIPTION

Through the Program, Duquesne Light shall provide electric vehicle charging services consistent with the Program Option selected by the customer.

- For customers participating in the Bundled Option and the Pre-Pay Option, Duquesne Light shall provide, own, and maintain Charging Stations at the Service Address, as well as electrical equipment reasonably necessary to connect the Charging Stations to the customer's Service Point ("Make-Ready Infrastructure"), for the duration of the customer's participation in the Program. The customer shall select the Charging Stations from a list of options approved by Duquesne Light. The Charging Stations shall be installed at a mutually-agreeable location at the Service Address by Duquesne Light's third-party contractor(s). Additionally, for customers participating in the Pre-Pay Option, the customer shall pay the Company's costs of the Charging Station in addition to the applicable monthly charge identified herein.

- For customers participating in the Customer-Supplied Charging Station Option, the customer shall provide, install, own, and maintain the Charging Stations at a mutually-agreeable location at the Service Address; and the Company shall own and maintain the Make-Ready Infrastructure.

In addition to the foregoing requirements, participating customers shall:

a. Execute and abide by the Fleet Charging Pilot Customer Agreement, with a minimum term of ten (10) years.

b. Host Charging Stations with a minimum total of four (4) charging station ports per participating Service Address.

c. Share charging data with Duquesne Light (and provide any authorizations required to accommodate such sharing) via the applicable Charging Station vendor.

d. Promptly notify Duquesne Light in the event the Charging Station fails to operate or otherwise requires repair, except for minor issues remedied by the customer pursuant to (e) herein.

e. Make reasonable efforts to remedy minor issues with the Charging Station that do not require qualified technicians to address, including but not limited to, the resetting of a tripped circuit breaker or assisting with software or Wi-Fi interconnectivity issues.

f. Use the Charging Station only in accordance with the manufacturer's applicable recommendations.

g. Grant Duquesne Light any rights-of-way or easements deemed necessary. See also Rule No. 22.1 herein.

h. Maintain the area surrounding the Charging Station. See also Rule No. 23 herein.

i. Provide Duquesne Light with reasonable access to the Charging Station. See also Rule No. 22 herein.

j. Upon Duquesne Light's request, participate in surveys and provide feedback about the Program.

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued) **(C)**

RIDER NO. 24 – FLEET CHARGING PILOT PROGRAM – (Continued)

(Applicable to Rates GS/GM, GMH, GL, GLH and L)

PROGRAM DESCRIPTION – (Continued)

For customers participating in the Bundled and Pre-Pay Options: Upon conclusion of the Fleet Charging Pilot Agreement Term, except in the event of customer default or early termination as discussed below, ownership of the Charging Station and Make Ready shall pass automatically to customer.

For all customers: Customers that leave the program prematurely will be required to purchase the Make Ready and Charging Stations, as applicable, at the remaining undepreciated value of the equipment; or alternatively, to have the Company remove the infrastructure, and reimburse the Company's costs of removal and stranded equipment (if any).

STANDARD CONTRACT RIDERS - (Continued) **(C)**

RIDER NO. 25 – NEW BUSINESS STIMULUS

(Applicable to Rates GS/GM and GMH)

AVAILABILITY

The New Business Stimulus Rider ("NBSR") is available to new small and medium business customers who start new electric service for a retail business in a Vacant Retail Storefront located within a Local Neighborhood Commercial (LNC) district, a Qualified Low-Income Census Tracts (QCT) district, and/or a Neighborhood Assistance Program (NAP) district.

PROGRAM TERMS

Enrolled customers will receive a 30% discount on variable base distribution charges for a period of no more than two (2) years from commencing service or until December 31, 2024, whichever occurs earlier. Customers taking service under the NBSR are not eligible for any other distribution rate discount.

DEFINITIONS

Vacant Retail Storefront: a brick-and-mortar location intended for retail business operations that: (a) will be open to the public, (b) has not received active electric service for thirty (30) or more days prior to the request to commence service, and (c) will receive service at the same voltage and phase as the previous customer. For the purposes of the NBSR, retail business operations will include businesses that offer goods and/or services using in-person storefront locations. These businesses will include boutiques, cafes, restaurants, bars or taverns, gyms, fitness centers, professional services providers, childcare and early education centers, salons and barber shops, and other retailers which are typically found in Main Street business districts.

Local Neighborhood Commercial (LNC) District: area(s) identified as LNC by the City of Pittsburgh Code of Ordinances.

Qualified Low-Income Census Tracts (QCT) District: area(s) identified as QCT by the United States Department of Housing and Urban Development.

Neighborhood Assistance Program (NAP) District: area(s) identified as NAP by the United States Department of Housing and Urban Development.

STANDARD CONTRACT RIDERS - (Continued) **(C)**

RIDER NO. 26 – CRISIS RECOVERY PROGRAM

(Applicable to Rates GS/GM and GMH)

AVAILABILITY

The Crisis Recovery Program ("CRP") is available to existing small and medium business customers that meet the eligibility requirements listed in the Program Terms and Conditions of this Rider. The CRP provides eligible customers with a 25% waiver of their delinquent account balance and/or an 18-month payment arrangement on the delinquent account balance.

DEFINITIONS

COVID-19 pandemic: The World Health Organization (WHO) and the Centers for Disease Control and Prevention's (CDC) declaration of a novel coronavirus (COVID-19), which resulted in a state-wide disaster emergency proclamation by the Pennsylvania Governor pursuant to 35 Pa. C.S. § 7301(c) on or about March 6, 2020.

Frozen period: The time in which the customer's delinquent balance will not become due, beginning with the first bill issued six (6) or more days following enrollment, and ending the calendar day following the due date of the sixth bill issued since enrollment.

PROGRAM TERMS AND CONDITIONS

Eligible customers are required to demonstrate that they accumulated an account balance as a result of the COVID-19 pandemic.

Enrolled customers will have their delinquent account balance frozen at the time of enrollment, which will remain frozen for six (6) billing cycles.

If the enrolled customer pays the non-frozen portion of their account balance in full by the due date of the sixth bill issued during the frozen period, 25% of the customer's delinquent account balance will be waived, and the customer will be issued an 18-month payment arrangement on the remaining account balance. Customers can agree to shorter payment arrangement terms.

Failure to pay the non-frozen portion in full by the due date of the sixth bill issued during the frozen period will result in the customer receiving an 18-month payment arrangement on the full delinquent balance. Customers can agree to shorter payment arrangement terms.

Enrollment into the CRP shall end on June 30, 2022.

Customers who are actively enrolled into the CRP are not eligible for any other rate discount.

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			—	$0.01	—	
100			—	$0.02	—	
150			—	$0.02	—	
250			—	$0.04	—	
400			—	$0.06	—	
Light-Emitting Diode (LED) — Cobra Head						
30			$0.00	$0.00	$0.00	**(C) (C) (C)**
45			$0.00	$0.01	$0.01	**(C)**
60			$0.02	$0.01	$0.01	
95			$0.03	$0.01	$0.01	
139			$0.04	$0.02	$0.02	
219			$0.06	$0.03	$0.03	
						(C)
Light-Emitting Diode (LED) — Colonial						
20			—	$0.00	$0.00	**(C) (C)**
45			—	$0.00	$0.00	**(C) (C)**
Light-Emitting Diode (LED) — Contemporary						
40			—	$0.00	$0.00	**(C) (C)**
55			—	$0.00	$0.00	**(C) (C)**

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 kW. 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

(C) – Indicates Change

Exhibit No. DBO-2

SUPPLEMENT NO. 25
TO ELECTRIC – PA. P.U.C. NO. 25

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

Mark E. Kaplan
Interim President and Chief Executive Officer

ISSUED: April 16, 2021 EFFECTIVE: June 15, 2021

Filed at Docket No. R-2021-3024750

NOTICE

THIS TARIFF SUPPLEMENT ADDS PAGES AND RIDERS, MAKES CHANGES TO THE TABLE OF CONTENTS, RULES AND REGULATIONS, RATE SCHEDULES, RIDER MATRIX, RIDERS AND APPENDIX A AND MAKES INCREASES AND DECREASES TO THE RATES CONTAINED IN THE RATE SCHEDULES AND RIDERS.

See Page Two

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES

List of Modifications Made by this Tariff — **First Revised Pages No. 2A through Original Page No. 2G**
Cancelling Original Pages No. 2A – 2G

Original Pages No. 2H – 2L

Original Page No. 2H through Original Page No. 2L have been added to Tariff No. 25 to accommodate the List of Modifications.

Original Page No. 3A has been added to the Table of Contents and therefore to Tariff No. 25.

Original Page No. 26A has been added to the rules section and therefore to Tariff No. 25.

Original Page No. 34A has been added to the rules section and therefore to Tariff No. 25.

Original Page No. 87A has been added to the Rider Matrix section and therefore to Tariff No. 25.

Original Page No. 92A has been added to the rider section and therefore to Tariff No. 25.

Original Page No. 92B has been added to the rider section and therefore to Tariff No. 25.

Original Page No. 97A has been added to the rider section and therefore to Tariff No. 25.

Original Page No. 124A has been added to the rider section and therefore to Tariff No. 25.

Original Page No. 128A has been added to the rider section and therefore to Tariff No. 25.

Original Page No. 141A through Original Page No. 141G have been added to the rider section and therefore to Tariff No. 25.

Table of Contents — **Fourth Revised Page No. 3**
Cancelling Third Revised Page No. 3

Original Page No. 2H through Original Page No. 2L have been added to Tariff No. 25 to accommodate the List of Modifications.

Rider No. 4 – Federal Tax Adjustment Clause has been added to Tariff No. 25 and to the Table of Contents.

Original Page No. 87A has been added to the Table of Contents to reflect the additional page added to the Rider Matrix (Pages No. 87-87A).

Original Page No. 92B has been added to the Table of Contents to reflect the addition of Rider No. 4 – Federal Tax Adjustment Clause (Pages No. 92–92B).

Rider No. 7 – Residential Subscription Service Pilot has been added to Tariff No. 25 and to the Table of Contents.

Original Page No. 97A has been added to the Table of Contents to reflect the additional page added to Rider No. 7 – Residential Subscription Service Pilot (Pages No. 97-97A).

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Table of Contents — **Fourth Revised Page No. 3**
Cancelling Third Revised Page No. 3

Table of Contents information previously found on Third Revised Page No. 3, Cancelling Second Revised Page No. 3 has been moved to Original Page No. 3A to accommodate the additional Riders added to Tariff No. 25.

Table of Contents — **Original Page No. 3A**

Table of Contents information previously found on Third Revised Page No. 3, Cancelling Second Revised Page No. 3 has been moved to Original Page No. 3A to accommodate the additional Riders added to Tariff No. 25.

Original Page No. 124A has been added to the Table of Contents to reflect the additional page added to Rider No. 16 – Service to Non-Utility Generating Facilities (Pages No. 123-124A).

Rider No. 19 – Community Development for New Load has been added to Tariff No. 25 and to the Table of Contents.

Administerial update to the page numbering on the Table of Contents page. Rider No. 21 - Net Metering Service now reflects the addition of Page No. 136A which was added and approved in the Company's DSP IX proceeding at Docket No. P-2020-3019522, Order entered January 14, 2021.

Rider No. 23 - Home Charging Pilot Program has been added to Tariff No. 25 and to the Table of Contents.

Rider No. 24 – Fleet Charging Pilot Program has been added to Tariff No. 25 and to the Table of Contents.

Rider No. 25 – New Business Stimulus has been added to Tariff No. 25 and to the Table of Contents.

Rider No. 26 – Crisis Recovery Program has been added to Tariff No. 25 and to the Table of Contents.

Rules and Regulations — **First Revised Page No. 7**
The Electric Service Tariff — **Cancelling Original Page No. 7**
3.1 Definitions
(2) Applicant

Language has been added to clarify that the definition of "Applicant" includes non-residential applicants.

Rules and Regulations — **First Revised Page No. 11**
Contracts, Deposits and Advance Payments — **Cancelling Original Page No. 11**
Rule No. 5 - Deposits and Advance Payments

Language has been modified to reflect that residential customers/applicants are permitted to pay their deposit in four (4) twenty-five percent (25%) installments.

Language has been modified to clarify security deposits for non-residential customers/applicants.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rules and Regulations — **First Revised Page No. 13**
Installation of Service — **Cancelling Original Page No. 13**
Rule No. 6.1 - Service Point

Language has been revised to accommodate the Company's proposed transportation electrification programs.

Rules and Regulations — **First Revised Page No. 14**
Installation of Service — **Cancelling Original Page No. 14**
Rule No. 7 - Supply Line Extensions
First Revised Page No. 15
Cancelling Original Page No. 15

First Revised Page No. 16
Cancelling Original Page No. 16

Language has been modified to clarify that both customers and applicants for service are subject to tariff cost commitment requirements.

Language has been modified to allow applicants (e.g., developers) to pay Contribution in Aid of Construction ("CIAC") on behalf of the ultimate customer.

Rules and Regulations — **First Revised Page No. 19**
Installation of Service — **Cancelling Original Page No. 19**
Rule No 10 - One Service of A Kind

Language has been modified to remove obsolete cross-reference.

Rules and Regulations — **Second Revised Page No. 26**
Measurement and Use of Service — **Cancelling First Revised Page No. 26**
Rule No. 16.1 - Interconnection, Safety and Reliability Requirements

New Rule No. 16.1 Interconnection, Safety and Reliability Requirements has been added to the tariff to clarify and memorialize the Company's existing process for customer generation interconnection (including facilities not eligible for net metering).

Rule No. 18.1 – Electric Vehicle Charging and Rule No. 19 – Continuity and Safety, previously found on First Revised Page No. 26, Cancelling Original Page No. 26 have been moved to Original Page No. 26A to accommodate the addition of Rule No. 16.1 – Interconnection, Safety and Reliability Requirements on Second Revised Page No. 26, Cancelling First Revised Page No. 26.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rules and Regulations — **Original Page No. 26A**
Measurement and Use of Service

Rule No. 18.1 – Electric Vehicle Charging and Rule No. 19 – Continuity and Safety, previously found on First Revised Page No. 26, Cancelling Original Page No. 26 have been moved to Original Page No. 26A to accommodate the addition of Rule No. 16.1 – Interconnection, Safety and Reliability Requirements.

Rules and Regulations — **First Revised Page No. 29**
Company Property on Customer's Premises — **Cancelling Original Page No. 29**
Rule No. 22.1 - Vegetation Management and Right-of-Way

Language has been added to clarify a customer's responsibility to manage vegetation around the Company's service facilities.

Rules and Regulations — **First Revised Page No. 33**
Discontinuance, Curtailment or Interruption of Electric Service — **Cancelling Original Page No. 33**
Rule No. 40 - Reconnection Charge

Language has been added to expand reconnection charge applicability to customers who apply for reconnection at the same premises more than thirty (30) days following disconnection (i.e., when then former customer now constitutes an "applicant").

Rules and Regulations — **First Revised Page No. 34**
Discontinuance, Curtailment or Interruption of Electric Service — **Cancelling Original Page No. 34**
Rule No. 41 - Prohibition of Residential Master Metering

Language has been modified to allow residential master metering for certain low-income supportive housing pursuant to Rule No. 41.1.

Rules and Regulations — **First Revised Page No. 34**
Discontinuance, Curtailment or Interruption of Electric Service — **Cancelling Original Page No. 34**
Rule No. 41.1 - Residential Master Metering for New Low-Income Supportive Housing

New Rule No. 41.1 Residential Master Metering for New Low-Income Supportive Housing has been added to the tariff to establish eligibility and conditions for master metering of certain low-income supportive housing.

Rules and Regulations — **First Revised Page No. 34**
General Provisions — **Cancelling Original Page No. 34**

Rule No. 42 – Meter Testing, Rule No. 43 – Other Services, Rule No. 44 – This Rule Intentionally Left Blank and Rule No. 45 – Supplier Switching, previously found on Original Page No. 34, have been moved to Original Page No. 34A to accommodate the addition of Rule No. 41.1 – Residential Master Metering for New Low-Income Supportive Housing on First Revised Page No. 34, Cancelling Original Page No. 34.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rules and Regulations – General Provisions — **Original Page No. 34A**

Rule No. 42 – Meter Testing, Rule No. 43 – Other Services, Rule No. 44 – This Rule Intentionally Left Blank and Rule No. 45 – Supplier Switching, previously found on Original Page No. 34, have been moved to Original Page No. 34A to accommodate the addition of Rule No. 41.1 – Residential Master Metering for New Low-Income Supportive Housing.

Rate RS – Residential Service — **First Revised Page No. 38**
Cancelling Original Page No. 38

Administerial revision to add the word “cents” back to the Energy Charge line to indicate “cents per kilowatt hour.”

Rate GS/GM – General Service Small and Medium — **First Revised Page No. 46**
Cancelling Original Page No. 46

Language has been added to clarify eligibility.

Rate GS/GM – General Service Small and Medium — **First Revised Page No. 48**
Cancelling Original Page No. 48

Language has been modified to reflect current business practice.

Rate GL – General Service Large — **First Revised Page No. 53**
Cancelling Original Page No. 53

Language has been added to clarify eligibility.

Rate GLH – General Service Large Heating — **First Revised Page No. 56**
Cancelling Original Page No. 56

Language has been reorganized on the Rate Schedule to clarify that the Customer Distribution Charge is only applicable to the billing months of October through May.

Rate L –Large Power Service — **First Revised Page No. 60**
Cancelling Original Page No. 60

Language has been modified to reflect current business practice.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rate HVPS –High Voltage Power Service **First Revised Page No. 62**
Cancelling Original Page No. 62

Language has been added to clarify eligibility.

Rate HVPS –High Voltage Power Service **First Revised Page No. 63**
Cancelling Original Page No. 63

Language has been modified to reflect current business practice.

Rate AL – Architectural Lighting Service **First Revised Page No. 66**
Cancelling Original Page No. 66

Language has been added to reflect that beginning January 15, 2022, Rate AL will no longer be available to new customers or applicants, or to new installations for existing customers.

Rate SE – Street Lighting Energy **First Revised Page No. 71**
Special Provisions – No. 5 **Cancelling Original Page No. 71**

Language has been modified to replace the word “men” with “workers.”

Rate SM – Street Lighting Municipal **First Revised Page No. 72**
Cancelling Original Page No. 72

Language has been added to reflect that beginning January 15, 2022, only LED lighting options will be installed for customers being served under Rate SM.

Language has been added to reflect that beginning January 15, 2022, the Company may replace existing high pressure sodium lights with LED lights or that a customer may request to exchange functioning high pressure sodium lights with LEDs with advance payment to cover the costs of the Company’s estimated removal costs of such replacement. Both will be at the Company’s discretion.

Rate SM – Street Lighting Municipal **First Revised Page No. 73**
Cancelling Original Page No. 73

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted under Cobra Head, Colonial and Contemporary fixtures.

Rate SM – Street Lighting Municipal **First Revised Page No. 74**
Cancelling Original Page No. 74

Language has been modified to replace the word “his” with “its.”

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rate SH – Street Lighting Highway **First Revised Page No. 76**
Cancelling Original Page No. 76

Language has been added to reflect that beginning January 15, 2022, Rate SH will no longer be available to new customers or applicants, or to new installations for existing customers.

Language has been added to reflect that beginning January 15, 2022, replacement of high pressure sodium 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 LED lighting options.

Language has been added to reflect that due to the limited availability of high pressure sodium lighting, the Company will replace existing high pressure sodium lights with LED lights or a customer may request to exchange functioning high pressure sodium lights with LEDs with advance payment to cover the costs of the Company's estimated removal costs of such replacement. Both will be at the Company's discretion.

Rate SH – Street Lighting Highway **First Revised Page No. 76**
Cancelling Original Page No. 76

New LED lamp wattages have been inserted under Cobra Head fixtures.

Rate PAL – Private Area Lighting **First Revised Page No. 82**
Cancelling Original Page No. 82

Language has been added to reflect that beginning January 15, 2022, replacement of high pressure sodium 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 LED lighting options.

Language has been added to reflect that due to the limited availability of high pressure sodium lighting, the Company will replace existing high pressure sodium lights with LED lights or a customer may request to exchange functioning high pressure sodium lights with LEDs with advance payment to cover the costs of the Company's estimated removal costs of such replacement. Both will be at the Company's discretion.

Rate PAL – Private Area Lighting **First Revised Page No. 82**
Cancelling Original Page No. 82

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted under Cobra Head, Colonial and Contemporary fixtures.

Rate PAL – Private Area Lighting **First Revised Page No. 84**
Cancelling Original Page No. 84

Language has been modified to replace the word "his" with "its."

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Standard Contract Riders **Second Revised Page No. 87**
Rider Matrix **Cancelling First Revised Page No. 87**

The Rider Matrix has been updated to reflect the addition of the following Riders:

Rider No. 4 – Federal Tax Adjustment Clause
Rider No. 7 – Residential Subscription Service Pilot
Rider No. 19 – Community Development for New Load

Standard Contract Riders **Second Revised Page No. 87**
Rider Matrix **Cancelling First Revised Page No. 87**

Riders No. 20 through Appendix A, previously found in the Rider Matrix on First Revised Page No. 87, Cancelling Original Page No. 87, have been moved to Original Page No. 87A to accommodate the additional Riders placed into the Tariff.

"Continued on Original Page No. 87A" has been added to the bottom of Second Revised Page No. 87, Cancelling First Revised Page No. 87, to indicate that the Rider Matrix continues onto the next page.

Standard Contract Riders **Original Page No. 87A**
Rider Matrix

A Rider Matrix for Riders No. 20 through Appendix A, previously found on First Revised Page No. 87, Cancelling Original Page No. 87, has been created and is now found on Original Page No. 87A to accommodate the additional Riders placed into the Tariff.

Standard Contract Riders **Original Page No. 87A**
Rider Matrix

The Rider Matrix has been updated to reflect the addition of the following Riders:

Rider No. 23 – Home Charging Pilot Program
Rider No. 24 – Fleet Charging Pilot Program
Rider No. 25 – New Business Stimulus
Rider No. 26 – Crisis Recovery Program

Standard Contract Riders **First Revised Page No. 92**
Rider No. 4 – Federal Tax Adjustment Clause **Cancelling Original Page No. 92**

Original Page No. 92A

Original Page No. 92B

Rider No. 4 – Federal Tax Adjustment Clause ("FTAC") is being added to Tariff No. 25 to provide for adjustments to base distribution revenue to reflect the effects of future increases or decreases in the federal corporate income tax rate.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Standard Contract Riders — **First Revised Page No. 94**
Rider No. 5 – Universal Service Charge — **Cancelling Original Page No. 94**

The CAP participation level has been reset as per the provisions of Rider No. 5.

Standard Contract Riders — **First Revised Page No. 97**
Rider No. 7 – Residential Subscription Service Pilot — **Cancelling Original Page No. 97**

Rider No. 7 – Residential Subscription Service Pilot is being added to Tariff No. 25 to offer eligible customers the option to select a specified level of grid access for a set monthly charge.

Standard Contract Riders — **Second Revised Page No. 100**
Rider No. 8 – Default Service Supply — **Cancelling First Revised Page No. 100**

Fourth Revised Page No. 101
Cancelling First Revised Page No. 101

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted under Cobra Head, Colonial and Contemporary fixtures.

Standard Contract Riders — **Second Revised Page No. 103**
Rider No. 8 – Default Service Supply — **Cancelling First Revised Page No. 103**

In the “Calculation of Rates” section, the Docket No. has been updated in DSSa.

Standard Contract Riders — **Third Revised Page No. 108**
Rider No. 9 – Day-Ahead Hourly Price Service — **Cancelling Second Revised Page No. 108**

Under the “Fixed Retail Administrative Charge” section, the Docket No. has been updated in FRA.

Standard Contract Riders — **Third Revised Page No. 112**
Rider No. 10 – State Tax Adjustment — **Cancelling Second Revised Page No. 112**

Rider No. 10 – State Tax Adjustment has been modified to reflect that Part 1 of the STAS has been set to zero.

Standard Contract Riders — **First Revised Page No. 123**
Rider No. 16 – Service to Non-Utility Generating Facilities — **Cancelling Original Page No. 123**

First Revised Page No. 124
Cancelling Original Page No. 124

Rider No. 16 – Service to Non-Utility Generating Facilities has been modified to reflect changes in applicable terms, rules, and rates.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Standard Contract Riders — **First Revised Page No. 128**
Rider No. 19 – Community Development — **Cancelling Original Page No. 128**

Original Page No. 128A

Rider No. 19 – Community Development for New Load is being added to Tariff No. 25 to provide incentives to eligible customers to move and/or expand their operations within the Company's service territory.

Standard Contract Riders — **First Revised Page No. 133**
Rider No. 21 – Net Metering Service — **Cancelling Original Page No. 133**

First Revised Page No. 134
Cancelling Original Page No. 134

Second Revised Page No. 135
Cancelling First Revised Page No. 135

Second Revised Page No. 136
Cancelling First Revised Page No. 136

First Revised Page No. 136A
Cancelling Original Page No. 136A

Rider No. 21 – Net Metering Service has been revised to include Rate Schedule GLH and Rate Schedule L.

Standard Contract Riders — **First Revised Page No. 134**
Rider No. 21 – Net Metering Service — **Cancelling Original Page No. 134**

Language has been modified to reflect current business practice.

Standard Contract Riders — **Seventh Revised Page No. 137**
Rider No. 22 – Distribution System Improvement Charge — **Cancelling Sixth Revised Page No. 137**

Rider No. 22 – Distribution System Improvement Charge ("DSIC") has been modified to reflect that it has been set to zero.

Standard Contract Riders — **Original Page No. 141A-141B**
Rider No. 23 – Home Charging Pilot Program

Rider No. 23 – Home Charging Pilot Program is being added to Tariff No. 25 to set forth the eligibility, terms, and conditions applicable to residential customers participating in the Company's voluntary Home Charging Pilot.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Standard Contract Riders **Original Page No. 141C-141E**
Rider No. 24 – Fleet Charging Pilot Program

Rider No. 24 – Fleet Charging Pilot Program is being added to Tariff No. 25 to set forth the eligibility, terms, and conditions applicable to non-residential customers participating in the Company's voluntary Fleet Charging Pilot.

Standard Contract Riders **Original Page No. 141F**
Rider No. 25 – New Business Stimulus

Rider No. 25 – New Business Stimulus is being added to Tariff No. 25 to incent eligible new small or medium businesses by providing them with a reduced distribution rate for two (2) years.

Standard Contract Riders **Original Page No. 141G**
Rider No. 26 – Crisis Recovery Program

Rider No. 26 – Crisis Recovery Program is being added to Tariff No. 25 to provide a relief program for eligible existing small or medium business customers who have accumulated a delinquent balance because of COVID-19 business restrictions.

Appendix A – Transmission Service Charges **Second Revised Page No. 143**
Cancelling First Revised Page No. 143

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted under Cobra Head, Colonial and Contemporary fixtures.

INCREASES

Rate RS – Residential Service **First Revised Page No. 38**
Cancelling Original Page No. 38

Rate RH – Residential Service Heating **First Revised Page No. 40**
Cancelling Original Page No. 40

Rate RA – Residential Service Add-On Heat Pump **First Revised Page No. 43**
Cancelling Original Page No. 43

Rate GS/GM – General Service Small and Medium **First Revised Page No. 46**
Cancelling Original Page No. 46

LIST OF MODIFICATIONS MADE BY THIS TARIFF

INCREASES – (Continued)

Rate GMH – General Service Medium Heating	First Revised Page No. 50
	Cancelling Original Page No. 50
	First Revised Page No. 51
	Cancelling Original Page No. 51
Rate GL – General Service Large	First Revised Page No. 53
	Cancelling Original Page No. 53
Rate GLH – General Service Large Heating	First Revised Page No. 56
	Cancelling Original Page No. 56
	First Revised Page No. 57
	Cancelling Original Page No. 57
Rate L – Large Power Service	First Revised Page No. 59
	Cancelling Original Page No. 59
Rate HVPS – High Voltage Power Service	First Revised Page No. 62
	Cancelling Original Page No. 62
Rate AL – Architectural Lighting Service	First Revised Page No. 66
	Cancelling Original Page No. 66
Rate SE – Street Lighting Energy	First Revised Page No. 69
	Cancelling Original Page No. 69
Rate SM – Street Lighting Municipal	First Revised Page No. 72
	Cancelling Original Page No. 72
	First Revised Page No. 73
	Cancelling Original Page No. 73
	First Revised Page No. 74
	Cancelling Original Page No. 74
Rate SH – Street Lighting Highway	First Revised Page No. 76
	Cancelling Original Page No. 76
Rate UMS – Unmetered Service	First Revised Page No. 80
	Cancelling Original Page No. 80
Rate PAL – Private Area Lighting	First Revised Page No. 82
	Cancelling Original Page No. 82
	First Revised Page No. 84
	Cancelling Original Page No. 84

Unit pricing has changed resulting in increases.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

INCREASES – (Continued)

Rider No. 10 – State Tax Adjustment — **Third Revised Page No. 112**
Cancelling Second Revised Page No. 112

Rider No. 10 – State Tax Adjustment has been modified to reflect that Part 1 of the STAS has been set to zero.

DECREASES

Rate SM – Street Lighting Municipal — **First Revised Page No. 73**
Cancelling Original Page No. 73

Rate PAL – Private Area Lighting — **First Revised Page No. 82**
Cancelling Original Page No. 82

Unit pricing has changed resulting in decreases.

Rider No. 22 – Distribution System Improvement Charge — **Seventh Revised Page No. 137**
Cancelling Sixth Revised Page No. 137

Rider No. 22 – Distribution System Improvement Charge has been modified to reflect that it has been set to zero.

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APPENDIX A:

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RULES AND REGULATIONS – (Continued)

THE ELECTRIC SERVICE TARIFF – (Continued)

3. APPLICATION – (Continued

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.

3.1 DEFINITIONS

(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.

(2) Applicant – An entity that applies for service provided by the Company. With respect to residential applicants, "applicant" means a ~~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) (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.

(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.

RULES AND REGULATIONS - (Continued)

CONTRACTS, DEPOSITS AND ADVANCE PAYMENTS - (Continued)

5. DEPOSITS AND ADVANCE PAYMENTS - (Continued)

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 from a residential customer or applicant, the amount of the deposit will be **(C)**
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~~ ~~t~~The minimum deposit **(C)**
amount for non-residential customers and applicants shall be $250.00. ~~In accordance with Commission regulations,~~ **(C)**
~~the deposit shall be payable during the 90-day period commencing w~~When the Company determines a deposit is **(C)**
required ~~whether~~ for new service or for ~~deposits required upon~~ reconnection of service as described in Rule No. **(C)**
40,~~.~~ such deposit shall be payable within a reasonable time period after commencing or reconnecting electric **(C)**
service. Failure to pay a required deposit ~~within the time period noted above~~ may result in termination of service **(C)**
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.

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.

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.

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.

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

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:

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~~ electric vehicle pilot program(s) for electric vehicle charging stations. **(C)** **(C)**

The Company shall not be required to install or maintain any conductors, meter base, equipment or apparatus beyond the Service Point except meter and meter accessories, as applicable; ~~, beyond the Service Point~~ and electric vehicle charging stations and/or make-ready infrastructure, as applicable, for customers participating in the Company's applicable electric vehicle pilot program(s). **(C)** **(C)** **(C)**

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.

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

7. SUPPLY LINE EXTENSIONS – (Continued)

A. Definitions – (Continued)

(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 or applicant. **(C)**

(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 or applicant's property line without a **(C)** guarantee of revenue.

(2) In areas where the existing supply lines are overhead, the Company will construct and maintain extensions of all three-phase overhead supply lines, operating at 23,000 volts or less, which are usable as a part of its general supply system without a guarantee of revenue. When the three-phase supply line extension is to supply service exclusively to a single customer or applicant, such a supply line will be extended to the customer's or applicant's **(C)**
property line only if a guarantee of revenue is provided by the customer or applicant over a **(C)**
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 or applicant represents a credit **(C)**
risk, the Company may require an up-front contribution in aid of construction (CIAC) from the customer or applicant to recover the total cost of construction. A customer or applicant **(C)**
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) – Indicates Change

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

7. SUPPLY LINE EXTENSIONS - (Continued)

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 or applicant, such a supply line will be extended to the customer's or applicant's property line **(C)**
only if a guarantee of revenue is provided by the customer or applicant, over a period of five **(C)**
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 or applicant represents a credit risk, the Company **(C)**
may require an up-front contribution in aid of construction (CIAC) from the customer or **(C)**
applicant to recover the total cost of construction. A customer or applicant may choose the **(C)**
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 or applicant, such a supply line will be extended to the customer's or applicant's property line **(C)**
only if a guarantee of revenue is provided by the customer or applicant over a period of five **(C)**
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 or applicant represents a credit risk, the Company **(C)**
may require an up-front contribution in aid of construction (CIAC) from the customer or **(C)**
applicant to recover the total cost of construction. A customer or applicant may choose the **(C)**
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.

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 or applicant agrees to pay the Company any initial and **(C)**
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 and (ii) other new Company facilities necessary to serve the customer or applicant. 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)**

(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.

(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.

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

9. RELOCATIONS OF FACILITIES – (Continued)

C. 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.

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

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

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

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

13.1 UNDERGROUND DISTRIBUTION

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

RULES AND REGULATIONS - (Continued)

MEASUREMENT AND USE OF SERVICE - (Continued)

16.1 INTERCONNECTION, SAFETY AND RELIABILITY REQUIREMENTS In order to assure the integrity and safe operation of the Company's system and to permit the continuation of reliable service to other customers, the following requirements and standards apply to all types of Generating Facilities, including customer owned generation and customer owned energy storage systems, desiring to interconnect with the Company's system. **(C)**

All generation operations shall be performed in a safe, reasonable and competent manner in accordance with prudent electric practices in order to, among other things, preserve and protect the Company's electric system.

All Generating Facilities shall submit a written application to the Company for acceptance of interconnected operation of their facilities with the Company's system prior to engaging in such interconnected operations. The Company may require, among other things, the following as part of any application submitted by an Applicant/Customer for service under this Rule No. 16.1.

1. Plans, specifications and location of the proposed installation.
2. Single line diagrams and details, including relay settings, of the proposed protection schemes.
3. Instruction manuals for all protective components.
4. Component specifications and internal wiring diagrams of protective components, if not provided in instruction manuals.
5. Generator data required to analyze fault contributions and load current flows including, but not limited to, equivalent impedances, time constants and harmonic distortions.
6. The rating of all protective equipment if not provided in instruction manuals.
7. All such other information that may be required by the Company.

Paralleling customer generation with the Company's system, including closed transition of customer back-up generation, shall be permitted only upon the written consent of the Company.

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

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.

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.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued) (C)

MEASUREMENT AND USE OF SERVICE - (Continued)

18.1 ELECTRIC VEHICLE CHARGING Electricity sales by a person, corporation or other entity, not a public utility, owning and operating an electric vehicle charging facility for the sole purpose of recharging an electric vehicle battery for compensation are not construed to be sales to residential consumers and therefore do not fall under the pricing requirements of 66 Pa.C.S. § 1313. Further, 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. For the purposes of this Rule No. 18.1, 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.

RULES AND REGULATIONS - (Continued)

COMPANY PROPERTY ON CUSTOMER'S PREMISES – (Continued)

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. Notwithstanding the foregoing, the customer/applicant/property owner shall be responsible for vegetation management on the customer/applicant/property owner's property, as necessary, to prevent vegetation from interfering with the service line(s) on the premises. Any vegetation management within ten (10) feet of an energized electric utility line must be performed by qualified line clearance personnel. (C) (C) (C) (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.

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.

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."

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.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

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

39.2 EMERGENCY ENERGY CONSERVATION - (Continued)

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

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

40. RECONNECTION CHARGE Where service has been discontinued under the terms of Rules No. 26 through 36, inclusive, the Company reserves the right as a condition precedent to the reconnection of service to require the payment of all arrearages for Company charges and payment of a deposit as described in Rule No. 5, and to require the payment of the following appropriate reconnection charge:

A. $50.00 for resumption of electric service to the same customer or applicant within a year of the service disconnection or termination where service has been disconnected at the meter. **(C)**

B. $250.00 for resumption of electric service to the same customer or applicant within a year of the service disconnection or termination where service has been disconnected at the pole. **(C)**

C. $250.00 for resumption of electric service to the same customer or applicant within a year of the service disconnection or termination when the connection is an aerial tap. **(C)**

D. $89.00 for reconnection of a transformer to the same General Service customer or applicant within a year of the service disconnection or termination. **(C)**

E. $20.00 for resumption of electric service where a remote capable meter has been installed and in which resumption of service is to the same customer or applicant within a year of the service disconnection or termination where service has been disconnected at the meter. **(C)**

When a residential customer or residence or residential applicant 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)**

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

Where electric service to a non-residential customer or applicant has been terminated under the terms of Rules No. 30 and/or 34, and such condition was the direct result of tampering, the Company reserves the right as a condition precedent to the reconnection of service to require payment of all costs incurred by the Company for investigations and inspections, and for such protective equipment deemed necessary by the Company. **(C)**

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

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

41. PROHIBITION OF RESIDENTIAL MASTER METERING Except as provided in Rule No. 41.1 herein, ~~E~~each residential dwelling unit in a building must be individually metered by the Company for buildings connected after January 1, 1981. For the purposes of the Rule, a dwelling unit is defined as: **(C)**

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

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

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

41.1 RESIDENTIAL MASTER METERING FOR NEW LOW-INCOME SUPPORTIVE HOUSING Notwithstanding anything in Rule No. 41 to the contrary, a single meter may be used for certain multi-tenant premises ("master metering"), where the premises: **(C)**

1. Is a new service;
2. Is master-metered through entire premises (i.e., no individual tenant meters);
3. Has a minimum of four (4) dwelling units; and
4. Is low-income supportive housing (i.e., housing that is permanently available to low-income tenants where the housing provider is responsible for utility bills).

To be eligible to master-meter a given residential building, in addition to satisfying the other criteria herein, a provider of low-income housing must either:

1. Show that the building is a Public Housing Authority development, or
2. Certify that all tenants are (i) eligible for a Housing Choice Voucher (HCV), available to residents who make 50% or less of the median family income, or (ii) have household incomes equal to or less than 150% of federal poverty guidelines.

Customers permitted to use master metering under this Rule must also, on a continuing basis:

1. Annually certify their on-going conformance to the above criteria; and
2. Participate in each of the Company's applicable energy efficiency, conservation, and/or usage reduction programs.

The Company may retain the customer's security deposit, paid pursuant to Rule No. 5, for the entire duration of the master metering arrangement.

If a customer using master metering under this Rule fails to comply with any of the foregoing eligibility criteria or on-going requirements, the Company may require the customer to reconfigure the customer's electrical equipment, at customer expense, to allow the Company to separately meter each dwelling unit.

RULES AND REGULATIONS - (Continued) (C)

GENERAL PROVISIONS

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

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

44. THIS RULE INTENTIALLY LEFT BLANK

45. SUPPLIER SWITCHING The Company will accommodate requests by customers to switch EGSs in accordance with 52 Pa. Code, Chapter 57, Subchapter M "Standards for Changing a Customers Electricity Generation Supplier."

Customers who elect to return to the Company from an EGS will return at the charges of the applicable rate.

In compliance with the Commission's Order at Docket No. L-2014-2409383, the Company shall preserve all records relating to unauthorized change of EGS or change to Default Service disputes for three (3) years from the date the customer filed the dispute. These records shall be made available to the Commission or its staff upon request.

Switching by customers shall occur in accordance with the direct access procedures and in accordance with the provisions contained in this Tariff and the Company's EGS Coordination Tariff.

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 .... ~~$12.50~~$16.25 (I)

Energy Charge .... ~~6.0233~~ 7.0564 cents per kilowatt hour (I)(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 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.

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 .... ~~$12.50~~$16.25 **(I)**

Winter Monthly Rate — For the Billing Months of November through April:

Energy Charge .... ~~4.5677~~ 6.3410 cents per kilowatt hour **(I)**

Summer Monthly Rate — For the Billing Months of May through October:

Energy Charge .... ~~6.0233~~ 7.0564 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 .... ~~$12.50~~$16.25 **(I)**

Winter Monthly Rate — For the Billing Months of November through April:

Energy Charge .... ~~1.6394~~ 2.7631 cents per kilowatt hour **(I)**

Summer Monthly Rate — For the Billing Months of May through October:

Energy Charge .... ~~6.0233~~ 7.0564 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 and where the demand is less than 300 kW. **(C)**

MONTHLY RATE FOR NON-DEMAND CUSTOMERS

DISTRIBUTION CHARGES — RATE GS

Customer Charge .... ~~$12.50~~$16.25 **(I)**

Energy Charge — All kWh .... ~~7.3313~~ 8.4241 cents per kilowatt-hour **(I)**

MONTHLY RATE FOR DEMAND CUSTOMERS

DISTRIBUTION CHARGES — RATE GM < 25 kW

Customer Charge .... ~~$54.50~~$63.00 **(I)**

Energy Charge — All kWh .... ~~1.3961~~ 1.8390 cents per kilowatt-hour **(I)**

Demand Charge — First five (5) kilowatts or less .... No Charge

— Additional kilowatts of Demand .... ~~$6.54~~ $7.89 per kilowatt **(I)**

DISTRIBUTION CHARGES — RATE GM ≥ 25 kW

Customer Charge .... ~~$65.65~~$76.00 **(I)**

Energy Charge — All kWh .... ~~0.9685~~ 1.2661 cents per kilowatt-hour **(I)**

Demand Charge — First five (5) kilowatts or less .... No Charge

— Additional kilowatts of Demand .... ~~$6.54~~ $7.89 per kilowatt **(I)**

MONTHLY RATE FOR NON-DEMAND AND DEMAND CUSTOMERS

DISTRIBUTION RATE ASSIGNMENT

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 < 25 kW or Rate GM ≥ 25 kW at a time.

(C) – Indicates Change **(I) – Indicates Increase**

RATE GS/GM - GENERAL SERVICE SMALL AND MEDIUM - (Continued)

MONTHLY RATE FOR NON-DEMAND AND DEMAND CUSTOMERS - (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 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. (C) (C) (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.

(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

WINTER MONTHLY RATE — FOR THE BILLING MONTHS OF OCTOBER THROUGH MAY

DISTRIBUTION CHARGES

Customer Charge .... ~~$54.50~~$63.00 **(I)**

Energy Charge — All kWh .... ~~2.9609~~ 3.8382 cents per kilowatt-hour **(I)**

SUMMER MONTHLY RATE — FOR THE BILLING MONTHS OF JUNE THROUGH SEPTEMBER

DISTRIBUTION CHARGES

Customer Charge .... ~~$54.50~~$63.00 **(I)**

Energy Charge — All kWh .... ~~1.3961~~ 1.8390 cents per kilowatt-hour **(I)**

Demand Charge — First five (5) kilowatts or less .... No Charge

— Additional kilowatts of Demand .... ~~$6.54~~ $7.89 per kilowatt **(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 or Rider No. 9 – Day-Ahead Hourly Price Service, as applicable, and will be billed in accordance with the terms contained therein.

Rider No. 8 – Default Service Supply – Applicable to customers with monthly demand less than 25 kW and customers with monthly demand greater than or equal to 25 kW but less than 200 kW, on average, who elect to purchase their electric supply requirements from the Company. The Supply rate shall be determined based on the formula described in the “Calculation of Rate” section in Rider No. 8. Supply Charges will be updated through competitive requests for proposal and will be effective for the periods as defined and described in Rider No. 8.

(I) – Indicates Increase

RATE GMH - GENERAL SERVICE MEDIUM HEATING - (Continued)

MONTHLY RATE - (Continued)

SUPPLY CHARGES – (Continued)

Rider No. 9 – Day-Ahead Hourly Price Service – Customers with monthly demand of 200 kW, on average, or greater and elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 9 and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

For purposes of determining the monthly rate for demand customers, Duquesne Light shall evaluate the customer's twelve (12) most recent months of monthly billing demand for that customer available in October of the preceding year. If the customer's average monthly billing demand is less than 25 kW in the twelve (12) months, then that customer shall be charged the monthly rate for demand 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 demand is 25 kW or greater in the twelve (12) month period, then that customer shall be charged the monthly rate for demand 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 average monthly billing demand for the next twelve (12) month period.

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 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 ~~$6.54~~ $7.89 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)**

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~~greater than or equal to 300 kilowatts (≥ 300 kW) and less than 5,000 kilowatts (< 5,000 kW). **(C)** **(C)**

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.

DISTRIBUTION

DEMAND CHARGES

First 300 kilowatts or less of Demand	~~$3,180.00~~$3,675.00	**(I)**
Additional kilowatts of Demand	~~$8.41~~ $10.66 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.

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

DISTRIBUTION (C)

For the Billing Months of October through May:

CUSTOMER CHARGE

Customer Distribution Charge .... ~~$67.00~~$77.50 (I)

ENERGY CHARGES

All kilowatt-hours ~~2.3145~~ 3.0162 cents per kWh (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.~~

~~**DISTRIBUTION**~~

~~For the Billing Months of October through May:~~

~~**ENERGY CHARGES**~~

~~Al kilowatt-hours 2.3145 cents per kWh~~

DISTRIBUTION (C)

For the Billing Months of June through September:

Rate GL shall apply. (I)

SUPPLY (C)

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) – Indicates Change **(I) – Indicates Increase**

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.

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 ~~$8.41~~ $10.66 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.

(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.

DISTRIBUTION

DEMAND CHARGES

Service Voltage Less than 138 kV:

First 5,000 kilowatts or less of Demand	~~$34,900.00~~$41,800.00	(I)
Additional kilowatts of Demand	~~$13.12~~ $16.63 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.

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

(I) – Indicates Increase

RATE L - LARGE POWER SERVICE - (Continued)

MONTHLY RATE - (Continued)

UNTRANSFORMED SERVICE CREDIT

Where the customer furnishes all necessary equipment to take untransformed service at 11,500 volts or higher, in strict accordance with the Company's standards and specifications, a credit of $0.75 per kW based upon the individual demand of the untransformed circuit shall be applied to the customer's account.

MINIMUM CHARGE

The Minimum Charge shall be the sum of a Demand Charge based on 70% of the Contract On-Peak Demand for ~~transmission and~~ distribution ~~and~~ plus the charges ~~Demand Charge as calculated under Rider No. 9~~ for Company supplied transmission and supply, if any. 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, shall not be less than the demand charges associated with the first 5,000 kWs or less of demand. For Company supplied transmission and supply, the transmission charges shall be calculated as set forth in Appendix A – Transmission Service Charges and the supply charges shall be calculated as set forth under Rider No. 9 – Day-Ahead Hourly Price Service. (C) (C) (C) (C) (C) (C) (C) (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 which exceed 30 kilowatts will be adjusted for power factor by multiplying by

$$\left\{0.8 + \left[0.6 \frac{\text{Reactive Kilovolt - ampere hours}}{\text{Kilowatt - hours}}\right]\right\},$$

where such multiplier will be not less than 1.00 nor more than 2.00. The Billing Demand will be the sum of the individual demands of each metered service adjusted for power factor as defined above, but not less than 70% of the Contract On-Peak Demand nor less than 5,000 kilowatts, whichever is the greater.

STANDARD CONTRACT RIDERS

For modifications of the above rate under special conditions, see "Standard Contract Riders".

RATE HVPS - HIGH VOLTAGE POWER SERVICE

AVAILABILITY

Available to customers with Contract On-Peak Demands greater than or equal to 5,000 kilowatts (≥ 5,000 kW) 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.

DISTRIBUTION

FIXED MONTHLY CHARGE

Up to and Including 50,000 kW Billing Demand	~~$2,050.31~~$2,503.20	**(I)**
50,001 kW to 100,000 kW Billing Demand	~~$3,202.72~~$3,910.17	**(I)**
Greater than 100,000 kW Billing Demand	~~$4,541.96~~$5,545.24	**(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.

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 customer's Fixed Distribution Monthly Charge~~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~~ For 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~~ the transmission charges shall be calculated as set forth in Appendix A – Transmission Service Charges and the supply charges shall be calculated as set forth under Rider No. 9 – Day-Ahead Hourly Price Service. **(C)** **(C)** **(C)** **(C)** **(C)** **(C)** **(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.

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 AL - ARCHITECTURAL LIGHTING SERVICE

AVAILABILITY

Beginning January 15, 2022, Rate AL will no longer be available to new customers or applicants, or to new installations for existing customers. **(C)**

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

Demand Charge .... ~~$1.59~~ $1.83 per kilowatt **(I)**

Energy Charge .... ~~0.2110~~ 0.2396 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.

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... ~~$2.92~~$3.23 **(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 SE - STREET LIGHTING ENERGY - (Continued)

MONTHLY RATE - (Continued)

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.

SPECIAL PROVISIONS

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

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

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

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

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

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

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

TERM OF CONTRACT

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

(C) – Indicates Change

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 December 29, 2018, 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)

Beginning January 15, 2022, only LED lighting options will be installed. Replacement of mercury vapor or high pressure sodium lamps, fixtures or luminaries, including brackets and ballasts, will not be available. (C)

Beginning January 15, 2022, the Company may replace existing high pressure sodium lights with LED lights, and place the customer on the corresponding rate schedule, at the Company's discretion. The Company may exchange functioning high pressure sodium lights with LEDs upon customer request and upon receipt, in advance, of the Company's estimated removal costs of such replacement. Such elective replacements shall be at the Company's discretion. (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

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	
Mercury Vapor				
100	44	~~$12.69~~$14.19	~~$2.71~~$3.03	(I)(I)
175	74	~~$12.95~~$14.48	~~$2.71~~$3.03	(I)(I)
250	102	~~$13.20~~$14.76	~~$2.71~~$3.03	(I)(I)
400	161	~~$13.73~~$15.36	~~$2.71~~$3.03	(I)(I)
1,000	386	~~$15.79~~$17.66	~~$2.71~~$3.03	(I)(I)
Sodium Vapor				
70	29	~~$13.11~~$14.66	~~$2.71~~$3.03	(I)(I)
100	50	~~$13.21~~$14.77	~~$2.71~~$3.03	(I)(I)
150	71	~~$13.40~~$14.99	~~$2.71~~$3.03	(I)(I)
250	110	~~$13.75~~$15.38	~~$2.71~~$3.03	(I)(I)
400	170	~~$14.30~~$15.99	~~$2.71~~$3.03	(I)(I)
1,000	387	~~$16.44~~$18.39	~~$2.71~~$3.03	(I)(I)

RATE SM - STREET LIGHTING MUNICIPAL - (Continued)

MONTHLY RATE – (Continued)

DISTRIBUTION CHARGE — Monthly Rate Per Unit - (Continued)

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				
30	11	$12.91	$3.03	(C)
45	16	~~$13.01~~$12.91	~~$2.71~~$3.03	(D)(I)
60	21	~~$13.52~~$13.33	~~$2.71~~$3.03	(D)(I)
95	34	~~$13.99~~$14.71	~~$2.71~~$3.03	(I)(I)
139	49	~~$15.08~~$15.37	~~$2.71~~$3.03	(I)(I)
219	77	~~$17.54~~$15.65	~~$2.71~~$3.03	(D)(I)
~~275~~	~~97~~	~~$19.24~~	~~$2.71~~	(C)
Light-Emitting Diode (LED) — Colonial				
~~48~~20	~~17~~7	$16.89	$3.03	(C)
~~83~~45	~~29~~16	$17.23	$3.03	(C)
Light-Emitting Diode (LED) — Contemporary				
~~47~~40	~~17~~14	$15.59	$3.03	(C)
~~62~~55	~~22~~20	$15.59	$3.03	(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 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.

RATE SM - STREET LIGHTING MUNICIPAL - (Continued)

MONTHLY RATE – (Continued)

ELECTRIC CHARGES – (Continued)

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~~ its 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~~$11.54 for each pole required. (C) (I)

CUSTOMER OWNED AND MAINTAINED EQUIPMENT CHARGE

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 SH - STREET LIGHTING HIGHWAY

AVAILABILITY

Beginning January 15, 2022, Rate SH will no longer be available to new customers or applicants, or to new installations for existing customers. **(C)**

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.

Beginning January 15, 2022, replacement of high pressure sodium 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 LED lighting options listed below. **(C)**

Due to the limited availability of high pressure sodium lighting, the Company will be replacing existing high pressure sodium lights with LED lights at its discretion. The Company may exchange functioning high pressure sodium lights with LEDs upon customer request and upon receipt, in advance, of the Company's estimated removal costs of such replacement. Such elective replacements shall be at the Company's discretion. **(C)**

MONTHLY RATE

DISTRIBUTION CHARGE — Monthly Rate Per Unit

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	
Sodium Vapor				
100	50	~~$12.54~~$14.02	~~$2.71~~$3.03	(I)(I)
150	71	~~$12.71~~$14.22	~~$2.71~~$3.03	(I)(I)
200	95	~~$12.89~~$14.42	~~$2.71~~$3.03	(I)(I)
400	170	~~$13.57~~$15.99	~~$2.71~~$3.03	(I)(I)
Light-Emitting Diode (LED) — Cobra Head				
30	11	$12.91	$3.03	(C)
45	16	$12.91	$3.03	(C)
60	21	~~$13.52~~$15.12	~~$2.71~~$3.03	(I)(I)
95	34	~~$13.99~~$15.65	~~$2.71~~$3.03	(I)(I)
139	49	~~$15.08~~$16.87	~~$2.71~~$3.03	(I)(I)
219	77	~~$17.54~~$19.62	~~$2.71~~$3.03	(I)(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.

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~~$11.50 (I)

Energy Charge .... ~~1.8171~~ 2.7761 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 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.

(I) – Indicates Increase

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.

Beginning January 15, 2022, replacement of high pressure sodium 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 LED lighting options listed below. (C)

Due to the limited availability of high pressure sodium lighting, the Company will be replacing existing high pressure sodium lights with LED lights at its discretion. The Company may exchange functioning high pressure sodium lights with LEDs upon customer request and upon receipt, in advance, of the Company's estimated removal costs of such replacement. Such elective replacements shall be at the Company's discretion. (C)

MONTHLY RATE

DISTRIBUTION CHARGE - Monthly Rate Per Unit

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	
High Pressure Sodium				
70	29	~~$13.11~~$14.66	~~$2.71~~$3.03	(I)(I)
100	50	~~$13.21~~$14.77	~~$2.71~~$3.03	(I)(I)
150	71	~~$13.40~~$14.99	~~$2.71~~$3.03	(I)(I)
250	110	~~$13.75~~$15.38	~~$2.71~~$3.03	(I)(I)
400	170	~~$14.30~~$15.99	~~$2.71~~$3.03	(I)(I)
Flood Lighting				
100	46	~~$13.11~~$14.66	~~$2.71~~$3.03	(I)(I)
250	100	~~$13.72~~$15.34	~~$2.71~~$3.03	(I)(I)
400	155	~~$14.34~~$16.04	~~$2.71~~$3.03	(I)(I)
Light-Emitting Diode (LED) — Cobra Head				
30	11	$12.91	$3.03	(C)
45	16	~~$13.01~~$12.91	~~$2.71~~$3.03	(D)(I)
60	21	~~$13.52~~$13.33	~~$2.71~~$3.03	(D)(I)
95	34	~~$13.99~~$14.71	~~$2.71~~$3.03	(I)(I)
139	49	~~$15.08~~$15.37	~~$2.71~~$3.03	(I)(I)
219	77	~~$17.54~~$15.65	~~$2.71~~$3.03	(D)(I)
~~275~~	~~97~~	~~$19.24~~	~~$2.71~~	(C)
Light-Emitting Diode (LED) — Colonial				
~~48~~20	~~17~~7	$16.89	$3.03	(C)
~~83~~45	~~29~~16	$17.23	$3.03	(C)
Light-Emitting Diode (LED) — Contemporary				
~~47~~40	~~17~~14	$15.59	$3.03	(C)
~~62~~55	~~22~~20	$15.59	$3.03	(C)

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~~ its 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~~ $11.54 for each pole required. **(C)** **(I)**

CUSTOMER OWNED AND MAINTAINED EQUIPMENT CHARGE

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.

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	X	X	X	X	X	X	X	X	X	X	X	(C)
Rider No. 5	X	X	X													
Rider No. 6				X												
Rider No. 7	X															(C)
Rider No. 8	X	X	X	X	X					X	X	X	X	X	X	
Rider No. 9				X	X	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				X		X		X								(C)

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 — Federal Tax Adjustment Clause~~Intentionally Left Blank~~ (C)
Rider No. 5 — Universal Service Charge
Rider No. 6 — Temporary Service
Rider No. 7 — Residential Subscription Service Pilot~~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 IV 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 — Community Development for New Load~~Intentionally Left Blank~~ (C)

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STANDARD CONTRACT RIDERS – (Continued) (C)

RIDER MATRIX – (Continued) (C)

	RS	RH	RA	GS/GM	GMH	GL	GLH	L	HVPS	AL	SE	SM	SH	UMS	PAL	
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	
Rider No. 23	X	X	X													(C)
Rider No. 24				X	X	X	X	X								(C)
Rider No. 25				X	X											(C)
Rider No. 26				X	X											(C)
Appendix A	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	

Rider Titles:

Rider No. 20 — Smart Meter Charge
Rider No. 21 — Net Metering Service
Rider No. 22 — Distribution System Improvement Charge (“DSIC”)
Rider No. 23 — Home Charging Pilot Program (C)
Rider No. 24 — Fleet Charging Pilot Program (C)
Rider No. 25 — New Business Stimulus (C)
Rider No. 26 — Crisis Recovery Program (C)
Appendix A — Transmission Service Charges

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 4 – FEDERAL TAX ADJUSTMENT CLAUSE **(C)**
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(Applicable to all Rates)

The Federal Tax Adjustment Clause ("FTAC") is instituted as a mechanism to adjust for changes in the federal corporate income tax rate that are not reflected in the Company's most recent general base rate proceeding. The FTAC is applicable to all base distribution rates under this Tariff. The amount of the adjustment will be determined as provided below.

A. Determination of the Change in Recoverable Federal Income Taxes Resulting from Increases or Decreases in the Federal Corporate Income Tax Rate ("FITA").

1. FITA shall include the effect of the increase or decrease in the federal corporate income tax rate on:

a. the provision in rates for recovery of current federal income taxes;
b. the provision in rates for recovery of deferred federal income taxes; and
c. any provision in rates for adjustment of previously deferred federal income taxes recorded at a different federal income tax rate.

2. The increases/decreases in annual revenues under this Rider will be calculated based on either the federal tax amounts associated with distribution utility investments, revenues and expenses allowed in the Company's most recent general base rate proceeding if fully determined in a Final Order, if available, or on the federal tax amounts associated with distribution utility investments, revenues and expenses incurred by the Company in the calendar year preceding the effective date of the tax rate change. If any base distribution rate revenue increase is granted during such calendar year or thereafter, the actual federal tax amounts will be adjusted to reflect the annualized increase in federal corporate income taxes resulting from the allowed increase in base distribution rate revenues.

B. Allocation of Increased/ Decreased Revenues to Rate Classes

1. The required increase/decrease in revenues to reflect the change in the federal corporate income tax rate calculated pursuant to this Rider shall be applied by equal percentage to all base distribution rates.

C. Calculation and Filing of Adjusted Rates For Changes in the Federal Corporate Income Tax Rate

1. To calculate the FTAC, the required increase/decrease in revenues will be divided by the Company's projected annual revenue for base distribution service for the period during which the charge will be collected, exclusive of State Tax Adjustment Surcharge (STAS) and automatic adjustment clause revenues.

2. The surcharge will be expressed as a percentage carried to two decimal places and will be applied to the total base distribution charges that are billed to each customer for distribution service.

3. The surcharge will be filed to become effective on ten (10) days' notice as soon as practicable following the effective date of the federal corporate income tax change, including appropriate supporting data demonstrating the calculation of the revenue adjustment and determination of the surcharge.

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued) (C)

RIDER NO. 4 – FEDERAL TAX ADJUSTMENT CLAUSE – (Continued)

(Applicable to all Rates)

C. Calculation and Filing of Adjusted Rates For Changes in the Federal Corporate Income Tax Rate – (Continued)

4. After the initial filing, the FTAC surcharge shall be filed with the Commission by April 1 of each year that it is in place.

5. The FTAC shall be applied on a bills rendered basis.

D. Formula

The computation of the FTAC is as follows:

$$FTAC = \frac{(((FITA * GRCF) + e) * GRT)}{PAR}$$

$$GRCF = (1/((1-SIT)*(1-FIT)))$$

$$GRT = 1/(1-T)$$

Where:

FITA = Reflects the federal income tax adjustment, if any, as defined in Part A of this Rider and may be a positive or negative value.

GRCF = Gross Revenue Conversion Factor.

SIT = State Income Tax rate in effect at the time of the filing.

FIT = Federal income tax rate in effect at the time of the filing.

T = Pennsylvania gross receipts tax rate in effect during the billing month.

e = Amount calculated (+/-) under the annual reconciliation feature or Commission audit.

PAR = Projected annual revenues for base distribution service (excluding all applicable clauses and riders) from existing customers plus netted revenue from any customers which will be acquired or lost by the beginning of the applicable service period.

STANDARD CONTRACT RIDERS - (Continued) (C)

RIDER NO. 4 – FEDERAL TAX ADJUSTMENT CLAUSE – (Continued)

(Applicable to all Rates)

E. Reconciliation

1. The surcharge shall be reconciled on an annual basis to provide for over/under-recoveries of the revised revenues to be recovered. The revenue received under the FTAC for the reconciliation period will be compared to the Company's required increase/decrease in revenues as defined in Part A. The difference will be recouped or refunded, as appropriate, over a one-year period commencing on April 1 of each year. The surcharge will be reconciled at the end of each calendar year and will remain in place until the Company files and the Commission approves new base distribution rates for the Company pursuant to Section 1308(d).

2. Under- or over-recoveries of the required revenue changes to reflect a delay in implementation of the surcharge following the effective date of the federal corporate income tax rate, including the effect of implementation of a federal corporate income tax rate change on a retroactive basis, will be reconciled in the first annual reconciliation filing.

3. Upon determination that the surcharge, if left unchanged, would result in a material over- or under-collection, the Company may file with the Commission, on at least ten (10) days' notice, for an interim revision of the FTAC.

4. Interest will not be applied to reconciled amounts.

5. The FTAC will not be included in the calculation of the Distribution System Improvement Charge ("DSIC").

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 5 – UNIVERSAL SERVICE CHARGE - (Continued)

(Applicable to Rate Schedules RS, RH and RA)

CALCULATION OF CHARGE – (Continued)

- 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 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.

- 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~~ 35,853 customers. Specifically, the recoverable CAP discounts will be reduced by the number of CAP participants in excess of ~~39,088~~ 35,853 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)

RIDER NO. 7 – RESIDENTIAL SUBSCRIPTION SERVICE PILOT (C)
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(Applicable to Rate Schedule RS)

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AVAILABILITY

Available to customers served under Rate RS – Residential Service who are not enrolled in the Customer Assistance Program (CAP) and are not billed under Rider No. 21 (Net Energy Metering). Enrollment in the Residential Subscription Service Pilot ("Pilot") provided under this Rider will be limited to 2,000 customers who request enrollment during the period January 15, 2022, through December 31, 2022. The Company may decline to enroll a customer at its sole discretion.

This Rider applies only to base distribution services. All other applicable charges and Riders will be charged as designed.

DEFINITIONS

Subscription Unit. Incremental size of subscription that is equal to 1 kW.

Subscribed Units. Total number of Subscription Units chosen by customer. (For example, a customer who wants to cover 5 kW of demand will choose 5 Subscription Units.)

Subscription Level. Total demand (kW) of subscription based on the Subscribed Units chosen by customer times the Subscription Unit, plus 1 kW minimum subscription included in the Customer Charge.

Overage Bandwidth. Amount by which customer can exceed their Subscription Level without incurring Overage Fees. This is set to one-half of one Subscription Unit, or 0.5 kW.

Overage Amount. The positive amount of customer's monthly maximum billed demand less Subscription Level less Overage Bandwidth.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge $28.48

Subscription Unit Charge .... $12.23 per unit

STANDARD CONTRACT RIDERS - (Continued) (C)

RIDER NO. 7 – RESIDENTIAL SUBSCRIPTION SERVICE PILOT – (Continued)

(Applicable to Rate RS)

SUBSCRIPTION SERVICE LEVEL

Upon enrollment in the Pilot, customers shall select the number of Subscription Units the customer will purchase every month to cover their electric distribution needs. The Company will provide the customer with information regarding their previous peak energy use in the past year to aid the customer in selecting the appropriate Subscription Service Level. The customer's Distribution Charges will then be computed as the Customer Charge, plus the Subscribed Units multiplied by the Subscription Unit Charge, plus any applicable Overage Amount or other charges.

Where a customer's demand exceeds their Subscription Level plus the Overage Bandwidth, the customer shall pay an overage fee equal to the Overage Amount multiplied by two times the Subscription Unit Charge. If a customer has an Overage Amount more than three times during the previous six billing periods, or the customer's Overage Amount exceeds 3 kW, the customer's Subscribed Units will automatically be reset to the customer's maximum demand from the past six months rounded up to the nearest 1 kW.

DETERMINATION OF DEMAND FOR DISTRIBUTION

Individual demand, except in unusual cases, will be determined by measurement of the sixty-minute period of greatest kilowatt-hour use during the billing period.

SPECIAL PROVISIONS

CUSTOMER ENROLLMENT

A customer may exit the Pilot and this Rider at any time for any reason. A customer who exits the Pilot will be removed from this Rider effective with the billing cycle that commences three (3) business days after the date the customer notified the Company of their election to leave the Pilot.

BILL PROTECTION

A customer who exits the Pilot may request a refund for the positive difference between their billed distribution charges under this Rider and the amount of such charges if billed under Rate Schedule RS for up to three months prior to exiting, but no longer than the customer's actual enrollment in the program. The Company will provide such refund within 60 days of customer request.

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.

		Application Period						
Wattage	**Nominal kWh Energy Usage per Unit per Month**	**06/01/2021 through 11/30/2021**	**12/01/2021 through 05/31/2022**	**06/01/2022 through 11/30/2022**	**12/01/2022 through 05/31/2023**	**06/01/2023 through 11/30/2023**	**12/01/2023 through 05/31/2023**	
Supply Charge ¢ per kWh		3.0953	X.XXXX	X.XXXX	X.XXXX	X.XXXX	X.XXXX	
		Fixture Charge — $ per Month						
Mercury Vapor								
100	44	1.36	X.XX	X.XX	X.XX	X.XX	X.XX	
175	74	2.29	X.XX	X.XX	X.XX	X.XX	X.XX	
250	102	3.16	X.XX	X.XX	X.XX	X.XX	X.XX	
400	161	4.98	X.XX	X.XX	X.XX	X.XX	X.XX	
1000	386	11.95	X.XX	X.XX	X.XX	X.XX	X.XX	
High Pressure Sodium								
70	29	0.90	X.XX	X.XX	X.XX	X.XX	X.XX	
100	50	1.55	X.XX	X.XX	X.XX	X.XX	X.XX	
150	71	2.20	X.XX	X.XX	X.XX	X.XX	X.XX	
200	95	2.94	X.XX	X.XX	X.XX	X.XX	X.XX	
250	110	3.40	X.XX	X.XX	X.XX	X.XX	X.XX	
400	170	5.26	X.XX	X.XX	X.XX	X.XX	X.XX	
1000	387	11.98	X.XX	X.XX	X.XX	X.XX	X.XX	
Flood Lighting - Unmetered								
70	29	0.90	X.XX	X.XX	X.XX	X.XX	X.XX	
100	46	1.42	X.XX	X.XX	X.XX	X.XX	X.XX	
150	67	2.07	X.XX	X.XX	X.XX	X.XX	X.XX	
250	100	3.10	X.XX	X.XX	X.XX	X.XX	X.XX	
400	155	4.80	X.XX	X.XX	X.XX	X.XX	X.XX	
Light-Emitting Diode (LED) — Cobra Head								
30	11	X.XX	X.XX	X.XX	X.XX	X.XX	X.XX	(C)
45	16	0.50	X.XX	X.XX	X.XX	X.XX	X.XX	
60	21	0.65	X.XX	X.XX	X.XX	X.XX	X.XX	
95	34	1.05	X.XX	X.XX	X.XX	X.XX	X.XX	
139	49	1.52	X.XX	X.XX	X.XX	X.XX	X.XX	
219	77	2.38	X.XX	X.XX	X.XX	X.XX	X.XX	
~~275~~	~~97~~	~~3.00~~	~~X.XX~~	~~X.XX~~	~~X.XX~~	~~X.XX~~	~~X.XX~~	(C)
Light-Emitting Diode (LED) — Colonial								
~~48~~20	~~17~~7	~~0.53~~X.XX	X.XX	X.XX	X.XX	X.XX	X.XX	(C)
~~83~~45	~~29~~16	~~0.90~~X.XX	X.XX	X.XX	X.XX	X.XX	X.XX	(C)
Light-Emitting Diode (LED) — Contemporary								
~~47~~40	~~17~~14	~~0.53~~X.XX	X.XX	X.XX	X.XX	X.XX	X.XX	(C)
~~62~~55	~~22~~20	~~0.68~~X.XX	X.XX	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)

DEFAULT SERVICE SUPPLY RATE – (Continued)

Lighting — (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**	**06/01/2023 through 11/30/2023**	**12/01/2023 through 05/31/2024**	**06/01/2024 through 11/30/2024**	**12/01/2024 through 05/31/2025**	
Supply Charge ¢ per kWh		X.XXXX	X.XXXX	X.XXXX	X.XXXX	
		Fixture Charge — $ per Month				
Mercury Vapor						
100	44	X.XX	X.XX	X.XX	X.XX	
175	74	X.XX	X.XX	X.XX	X.XX	
250	102	X.XX	X.XX	X.XX	X.XX	
400	161	X.XX	X.XX	X.XX	X.XX	
1000	386	X.XX	X.XX	X.XX	X.XX	
High Pressure Sodium						
70	29	X.XX	X.XX	X.XX	X.XX	
100	50	X.XX	X.XX	X.XX	X.XX	
150	71	X.XX	X.XX	X.XX	X.XX	
200	95	X.XX	X.XX	X.XX	X.XX	
250	110	X.XX	X.XX	X.XX	X.XX	
400	170	X.XX	X.XX	X.XX	X.XX	
1000	387	X.XX	X.XX	X.XX	X.XX	
Flood Lighting - Unmetered						
70	29	X.XX	X.XX	X.XX	X.XX	
100	46	X.XX	X.XX	X.XX	X.XX	
150	67	X.XX	X.XX	X.XX	X.XX	
250	100	X.XX	X.XX	X.XX	X.XX	
400	155	X.XX	X.XX	X.XX	X.XX	
Light-Emitting Diode (LED) — Cobra Head						
30	11	X.XX	X.XX	X.XX	X.XX	(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~~	(C)
Light-Emitting Diode (LED) — Colonial						
~~48~~20	~~17~~7	X.XX	X.XX	X.XX	X.XX	(C)
~~83~~45	~~29~~16	X.XX	X.XX	X.XX	X.XX	(C)
Light-Emitting Diode (LED) — Contemporary						
~~47~~40	~~17~~14	X.XX	X.XX	X.XX	X.XX	(C)
~~62~~55	~~22~~20	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:

$$DSS = [(CA + SLR + (DSS_a + E)/S) * F + (DSS_b/S)] * [1/(1 - T)]$$

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.

CA = The weighted average of the winning bids received in a competitive auction 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 competitive auction shall be conducted as described in "Procurement Process."

DSS_a = 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. 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-2020-3019522~~ R-2021-3024750. (C)

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 9 – DAY-AHEAD HOURLY PRICE SERVICE – (Continued)

(Applicable to Rates GS/GM, GMH, 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-2020-3019522~~ R-2021-3024750. (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 Medium (≥ 200 kW) Customer Class and 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, 2021 through May 31, 2022	$3.60
June 1, 2022 through May 31, 2023	$X.XX
June 1, 2023 through May 31, 2024	$X.XX
June 1, 2024 through May 31, 2025	$X.XX

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 ~~(0.0080%)~~ 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. **(I)**

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.

(I) – Indicates Increase

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 16 - SERVICE TO NON-UTILITY GENERATING FACILITIES

~~**(Applicable to all General Service Rates Except Non-Demand Metered GS/GM Customers)**~~ (C)
(Applicable to Rates GM < 25, GM ≥ 25, GMH, GL, GLH and L) (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

Contract is the signed agreement between the customer and the Company that is executed upon the customer's request to select Rider No. 16 service. Among other things, the Contract specifies the contractual demand levels for Back-Up Service and Supplementary Service that are defined below. (C)

Supplementary ~~**Power**~~ **Service** is ~~electric energy and capacity supplied~~distribution service provided by the Company, inclusive of distribution services included in the applicable monthly customer charge, ~~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) (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.

Supplementary Contract Demand may be established and represents the threshold demand for Supplementary Service to the customer's facility. (C)

Maintenance 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 and is in addition to Supplementary Contract Demand. ~~A Contract Demand may be established for Supplementary Power to the customer's facility.~~ (C) (C) (C)

Peak Period is the period between 12pm and 10pm EST on all days in the months of June through September. (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 ~~Supplementary~~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) (C) (C)

Maintenance Demand ~~**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 as Maintenance Contract Demand with the customer for Back-Up ~~Billing Determinants~~Service. ~~are the kW and kWh in excess of the Supplementary Power Contract Demand.~~This Billing Determinant applied every billing period regardless of whether the customer calls upon Back-Up Service during the billing period. (C) (C) (C) (C) (C) (C)

RIDER NO. 16 - SERVICE TO NON-UTILITY GENERATING FACILITIES - (Continued)

~~(Applicable to all General Service Rates Except Non-Demand Metered GS/GM Customers)~~ **(C)**
(Applicable to Rates GM < 25, GM ≥ 25, GMH, GL, GLH and L) **(C)**

A. DEFINITIONS – (Continued)

As-Used Demand Billing Determinant is the kW specified in the Contract as Maintenance Contract Demand that applies if the customer calls upon Back-Up Services during the Peak Period. As-Used Demand Billing Determinant will be set to the Maintenance Contact Demand level if the customer's maximum demand during the Peak Period of the billing period exceeds the Supplementary Contract Demand specified in the Contract. **(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 GS/GM (GM ≥ 200 kW), GMH (GMH ≥ 200 kW),~~ GL, GLH, and L ~~and HVPS~~ 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 ~~not being served by an Electric Generation Supplier ("EGS") on Rate Schedule~~for customers on Rate GS/GM ~~(GM < 200 kW)~~ and GMH ~~(GMH < 200 kW)~~ shall be the billing determinants for the current billing month then in effect under Rider No. 8 – Default Service Supply or Rider No. 9 – Day-Ahead Hourly Price Service, as applicable~~.~~ **(C)**

B. BACK-UP ~~POWER~~SERVICE **(C)**

The Company will supply Back-Up ~~such s~~Service ~~each month~~ at the following rates: **(C)**

DISTRIBUTION

A distribution charge of ~~$2.50~~ $3.09 per kW shall be applied to the Back-Up ~~Power~~ Service maintenance ~~Billing~~Demand Billing Determinants ~~for Back-Up Power.~~. **(C)** **(C)**

The Maintenance Contract Demand distribution charges will be applied in each month based on the customer's Maintenance Contract Demand without regard to actual usage~~whether or not back-up energy is supplied~~. **(C)** **(C)** **(C)**

An additional distribution charge of $6.79 per kW shall be applied to the Back-Up Service As-Used Contract Demand Billing Determinants. The As-Used Contract Demand distribution charge will be applied in each month based on the customer's As-Used Contract Demand if the customer calls upon Back-Up service during the Peak Period. **(C)**

Overage charges will also apply if the customer exceeds Maintenance Demand by 10% or more. The Maintenance Overage Charge of $9.88 per kW shall be applied to the difference in actual maximum kW during the billing period and the customer's Maintenance Contract Demand. No additional charges will apply to the As-Used Contract Demand Charge. **(C)**

STANDARD CONTRACT RIDERS - (Continued) (C)

RIDER NO. 16 - SERVICE TO NON-UTILITY GENERATING FACILITIES - (Continued)

(Applicable to Rates GM < 25, GM ≥ 25, GMH, GL, GLH and L)

B. BACK-UP SERVICE – (Continued)

~~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 – Day-Ahead Hourly Price Service for customers with an average Contract Demand of 200 kW or more. For customers having an average Contract Demand of less than 200 kW, the Company will bill the applicable supply demand and energy charges then in effect under Rider No. 8 – Default Service Supply.~~ (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 ~~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 rates, including all ratchets applicable. (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 Maintenance ~~back-up~~ Contract Demand by 5% or more, the actual Back-Up Service requirement provided, measured in kW demand ~~as established~~ will become the customer's new Maintenance ~~back-up~~ Contract Demand for the remaining term of the back-up contract. If a customer's actual ~~kW demand at the time~~ ~~b~~Back-U~~u~~p ~~service~~ Service requirement provided at any time ~~is being supplied~~ exceeds the customer's Maintenance ~~back-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-~~up~~ Up ~~service~~ Service provided at the time during the billing period ~~is being supplied~~ and the Maintenance ~~backup~~ Contract Demand multiplied by the Overage Charge ($9.88). ~~two times the applicable charge per kilowatt.~~ (C)

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 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)

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 19 – COMMUNITY DEVELOPMENT FOR NEW LOAD (C)

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(Applicable to Rate Schedules GS/GM, GL, and L)

AVAILABILITY

This rider is available to customers taking distribution service under Rate GM < 25, GM ≥ 25, GL, or L. For new services, the customer or applicant must have a projected load of at least 10 kW and must apply for the rider prior to the service being energized. For existing services, the customer must reasonably project a peak load increase of at least 10 kW and apply for the rider before the load growth occurs. The rider will apply no sooner than 30 days after the customer provides to the Company written notice of its desire to be placed on the rider. The Company reserves the right to decline to enroll any customer or applicant in this rider, at the Company's sole discretion. Customers taking service under this rider are not eligible for any other distribution rate discount.

DEFINITIONS

Service Location. A single or contiguous premises that has or will have one or more delivery points for distribution service billed by the Company under a single account.

Brownfield Site. A Service Location where the expansion, redevelopment, or reuse of which may be complicated by the presence or potential presence of a hazardous substance, pollutant, or contaminant. Requires documentation either by providing a copy of the pertinent sections of the ASTM E1903-97 Phase II Site Assessment documenting the site contamination or by providing a letter from a local, state or federal regulatory agency confirming the site is classified as a Brownfield by that agency.

Site Expansion. A Service Location where the Company has not previously provided service, or where the service previously provided by the Company was not used for substantially the same type of operation or was terminated at least twelve (12) months before the customer's contractually specified effective date for service under this rider. This condition is waived for existing Service Locations where an entity has assumed operation of a Service Location from a customer which has ceased operations as a result of dissolution, so long as the formation of the entity did not occur as a result of merger, joint venture, acquisition and/or any other variation of combined business structures with the former customer at the service location. In any event, the completed application for the rider must be made within six (6) months from the later of the date: (1) the customer first received service from the Company; or (2) the date the customer received its sales tax exemption certificate from the Commonwealth of Pennsylvania.

Manufacturing Sales Tax Exemption Certificate. Pennsylvania Sales Tax Blanket Exemption Certificate filed by the customer with the Company showing the address of the Service Location and certifying that more than fifty (50) percent (on an annual basis) of the service purchased by the customer for the Service Location is exempt from sales tax because it is used in manufacturing operations, shipbuilding operations, or ship cleaning operations.

Employment Report. The "Employer's Report for Unemployment Compensation" (PA Form UC-2) as filed by the customer with the Office of Employment Security, Department of Labor and Industry, Commonwealth of Pennsylvania and as defined by 43 P.S. 753 [d].

STANDARD CONTRACT RIDERS - (Continued) (C)

RIDER NO. 19 – COMMUNITY DEVELOPMENT FOR NEW LOAD – (Continued)

(Applicable to Rate Schedules GS/GM, GL, and L)

MONTHLY RATE

DISTRIBUTION CHARGES

Rider No. 19 provides a percent discount to monthly demand charges for base distribution services included in Rates GM < 25, GM ≥ 25, GL, and L during the months of January through May and October through November. The percent discount declines ratably over five years as follows.

2022 Percent Discount	25%
2023 Percent Discount	20%
2024 Percent Discount	15%
2025 Percent Discount	10%
2026 Percent Discount	5%

This Rider applies only to base distribution services. All other applicable charges and Riders will be charged as designed.

QUALIFICATIONS

Customers and applicants requesting service under this rider shall file with the Company, before the effective date of the rider for the Service Location, a Manufacturing Sales Tax Exemption Certificate, as defined above, for the Service Location. Customer also files with the Company copies of the Employment Reports, as defined above, for the Service Location at the time of application.

TRANSFER OF OWNERSHIP

The Company will only apply the rider to the customer's base distribution charges for the term of contract. If, during the term of contract, the ownership of the Service Location changes, the Company may continue to apply the rider to the new owner's bills for the Service Location. If the Company continues to apply the rider in such circumstances, the Company shall apply the rider to the new owner's bills for the Service Location as if the new owner had been on the rider for the Service Location for the same period of time as was the previous owner.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 21 – NET METERING SERVICE

(Applicable to Rates RS, RH, RA, GS/GM, GMH, ~~and~~ GL, GLH and L) (C)

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, GLH and L 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, GLH and L), 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. (C) (C) (C)

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, GLH and L. (C)

1. A customer-generator facility used for net metering shall be equipped with a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. A dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense.

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 21 – NET METERING SERVICE – (Continued)

(Applicable to Rates RS, RH, RA, GS/GM, GMH, ~~and~~ GL, GLH and L) **(C)**

METERING PROVISIONS - (Continued)

2. If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator's expense. Additional metering equipment for the purpose of qualifying alternative energy credits owned by the customer-generator shall be paid for by the customer-generator. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The Company shall, prior to taking title to any alternative energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for their disposition.

3. Meter aggregation on properties owned or leased and operated by a customer-generator shall be allowed for purposes of net metering. Meter aggregation shall be limited to meters located on properties within two (2) miles of the boundaries of the customer-generator's property. Meter aggregation shall only be available for properties located within the Company's service territory. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis.

BILLING PROVISIONS

The following billing provisions apply to customer-generators in conjunction with service under applicable Rate Schedule RS, RH, RA, GS/GM, GMH, ~~and~~ GL, GLH and L: **(C)**

1. The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at the full retail rate consistent with Commission regulations. If a customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the full retail rate. Any excess kilowatt hours shall continue to accumulate for the 12 month period ending May 31. On an annual basis, the Company will compensate the customer-generator for kilowatt-hours received from the customer-generator in excess of the kilowatt hours delivered by the Company to the customer-generator during the preceding year at the Company's Price To Compare consistent with Commission regulations. For customer-generators on Rider No. 9 – Day-Ahead Hourly Price Service, the Price To Compare shall be determined as an average for the twelve (12) month period in accordance with Rider No. 9 and Appendix A – Transmission Service Charges. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule. **(C)**

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 21 – NET METERING SERVICE – (Continued)

(Applicable to Rates RS, RH, RA, GS/GM, GMH, ~~and~~ GL, GLH and L) **(C)**

BILLING PROVISIONS - (Continued)

2. If the Company supplies more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

3. For customer-generators involved in virtual meter aggregation programs, a credit shall be applied first to the meter through which the generating facility supplies electricity to the distribution system, then through the remaining meters for the customer-generator's account equally at each meter's designated rate. Virtual meter aggregation is the combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-generator by means of the Company's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. The customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

BILLING PROVISIONS FOR
ELECTRIC VEHICLE TIME-OF-USE PILOT PROGRAM ("EV-TOU") CUSTOMER GENERATORS

(Applicable to Rates RS, RH, RA, GS/GM and GMH)

The following billing provisions apply to customer-generators that take service on Rider No 8 – Default Service Supply and are on EV-TOU rates.

1. The EV-TOU customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at the full retail rate consistent with Commission regulations. If an EV-TOU customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator in a given billing period, the Company will maintain an active record of the excess kilowatt hours produced at the customer-generators premise in a "bank". If an EV-TOU customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the EV-TOU customer generator's usage in a subsequent billing period at the full retail rate. If, in a subsequent billing period, a customer consumes more electricity than produced, kilowatt-hours will be pulled from the customer's bank on a first in first out basis. Any excess kilowatt hours shall continue to accumulate and credit against usage for the 12 month period ending May 31st. On an annual basis, the Company will compensate the customer-generator for kilowatt-hours remaining in the bank on May 31st, at the applicable Price To Compare at the time the excess kilowatt-hours were banked. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 21 – NET METERING SERVICE – (Continued)

(Applicable to Rates RS, RH, RA, GS/GM, GMH, ~~and~~ GL, GLH and L) **(C)**

BILLING PROVISIONS FOR
ELECTRIC VEHICLE TIME-OF-USE PILOT PROGRAM ("EV-TOU") CUSTOMER GENERATORS

(Applicable to Rates RS, RH, RA, GS/GM and GMH)

- (Continued)

1. If the Company supplies more kilowatt-hours of electricity than the customer-generator supplies during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

3. If an eligible customer-generator wishes to no longer be enrolled in the EV-TOU Pilot Program and switches to the standard default service supply product, any excess kilowatt hours banked and remaining from the EV-TOU period will be used, as applicable, for the remaining portion of the 12 month period ending May 31 and the Company shall compensate for any excess kilowatt hours that are banked at the Price To Compare in effect at the time.

NET METERING PROVISIONS FOR SHOPPING CUSTOMERS

1. Customer-generators may take net metering services from EGSs that offer such services.

2. If a net-metering customer takes service from an EGS, the Company will credit the customer for distribution charges for each kilowatt hour produced by the customer-generator, up to the total amount of kilowatt-hours delivered to the customer by the Company during the billing period. If a customer-generator supplies more electricity to the electric distribution system than the Company delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the Company's distribution rates. Any excess kilowatt hours shall continue to accumulate for the 12 month period ending May 31. Any excess kilowatt hours at the end of the 12 month period will not carry over to the next year for distribution charge purposes. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

3. If the Company delivers more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the applicable rate schedule shall be applied to the net kilowatt-hours of electricity that the Company delivered. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 21 – NET METERING SERVICE – (Continued)

(Applicable to Rates RS, RH, RA, GS/GM, GMH, ~~and~~ GL, GLH and L) **(C)**

NET METERING PROVISIONS FOR SHOPPING CUSTOMERS – (Continued)

4. Pursuant to Commission regulations, the credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs shall be stated in the service agreement between the customer-generator and the EGS. The Company will provide the customer-generator with a statement of monthly kilowatt hour usage for the 12 month period ending May 31 for the purpose of the customer-generator seeking credit or compensation from the EGS.

5. If a customer-generator switches electricity suppliers, the Company shall treat the end of the service period as if it were the end of the year.

APPLICATION

Customer-generators seeking to receive service under the provisions of this Rider must submit a written application to the Company demonstrating compliance with the Net Metering Rider provisions and quantifying the total rated generating capacity of the customer-generator facility.

MINIMUM CHARGE

The Minimum Charges under Rate Schedule RS, RH, RA, GS/GM, GMH, ~~and~~ GL, GLH and L apply for installations under this Rider. **(C)**

RIDERS

Bills rendered by the Company under this Rider shall be subject to charges stated in any other applicable Rider.

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 ~~4.01%~~ 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.

STANDARD CONTRACT RIDERS - (Continued) (C)

RIDER NO. 23 – HOME CHARGING PILOT PROGRAM

(Applicable to Rates RS, RH and RA)

PURPOSE

This Rider sets forth the eligibility, terms, and conditions applicable to customers participating in the Company's voluntary residential Home Charging Pilot (the "Program").

APPLICABILITY

Available to residential customers served under Rate Schedules RS, RH and RA who:

a. own a single-family home, defined as a detached single-family home, townhome/row house, or duplex ("Service Address");

b. have an active Duquesne Light residential electric service account with no past due bills at the Service Address;

c. have a personal garage or private driveway at Service Address suitable, in the Company's sole judgment, for the installation and operation of an electric vehicle ("EV") level 2 charging station ("Charging Station") and related equipment; and

d. own or lease an EV which is registered to the customer's Service Address.

The Program is available to up to 125 new participants per calendar year on a first-come, first-served basis. The Company may decline to enroll any customer at the Company's sole discretion.

MONTHLY RATE

In addition to any applicable charges for electric delivery and supply, participating customers shall pay a monthly Program Charge of $21.17.

PROGRAM DESCRIPTION

Through the Program, Duquesne Light shall provide, own, and maintain a Charging Station at the participating customer's Service Address for the duration of the customer's participation in the Program. The customer shall select the Charging Station from a list of options approved by Duquesne Light. The Charging Station shall be installed at a mutually-agreeable location at the Service Address by Duquesne Light's third-party contractor(s). The Company shall pay the Covered Amount (as defined below) toward costs associated with installing the Charging Station. Any costs above the Covered Amount shall be at the customer's expense.

STANDARD CONTRACT RIDERS - (Continued) (C)

RIDER NO. 23 – HOME CHARGING PILOT PROGRAM – (Continued)

(Applicable to Rates RS, RH and RA)

PROGRAM DESCRIPTION – (Continued)

"Covered Amount:" The Covered Amount shall be up to $2,000 for customers with household incomes equal to or less than 150% of the Federal Poverty Level, or up to $500 for all other customers. For customers with household incomes equal to or less than 150% of the Federal Poverty Level, the Covered Amount may apply to Charging Station installation costs, as well as costs of electrical upgrades at the customer's residence (e.g., new electrical panel or breakers) necessary to support Charging Station installation and operation. For all other customers, the Covered Amount may apply only to Charging Station installation costs.

In addition to the foregoing requirements, participating customers shall:

a. Execute and abide by the Home Charging Pilot Customer Agreement, with a minimum term of five years.

b. Have and maintain wireless internet ("Wi-Fi") service at the Service Address with sufficient signal at the Charging Station location.

c. Share charging data with Duquesne Light (and provide any authorizations required to accommodate such sharing) via the applicable Charging Station vendor.

d. Promptly notify Duquesne Light in the event the Charging Station fails to operate or otherwise requires repair, except for minor issues remedied by the customer pursuant to (e) herein.

e. Make reasonable efforts to remedy minor issues with the Charging Station that do not require qualified technicians to address, including but not limited to, the resetting of a tripped circuit breaker or assisting with software or Wi-Fi interconnectivity issues.

f. Establish and maintain an account with the applicable Charging Station vendor and for wireless internet connectivity to enable communication between the Charging Station and Charging Station vendor's hardware and software.

g. Use the Charging Station only in accordance with the manufacturer's applicable recommendations.

h. Maintain the area surrounding the Charging Station. See also Rule No. 23 herein.

i. Provide Duquesne Light with reasonable access to the Charging Station. See also Rule No. 22 herein.

j. Upon Duquesne Light's request, participate in surveys and provide feedback about the Program.

Upon conclusion of the Home Charging Pilot Customer Agreement Term, except in the event of customer default or early termination as discussed below, ownership of the Charging Station shall pass automatically to customer.

In the event of customer default or early termination, the customer shall pay a sum equal to the number of months remaining in the Home Charging Pilot Customer Agreement Term multiplied by the Monthly Charge per Charging Station, plus a one-time fee of $200; and Duquesne Light may remove the Charging Station from the Service Address.

STANDARD CONTRACT RIDERS - (Continued) (C)

RIDER NO. 24 – FLEET CHARGING PILOT PROGRAM

(Applicable to Rates GS/GM, GMH, GL, GLH and L)

PURPOSE

This Rider sets forth the eligibility, terms, and conditions applicable to customers participating in the Company's voluntary Fleet Charging Pilot (the "Program").

APPLICABILITY

Available to customers served under Rate Schedules GS/GM, GMH, GL GLH, and L that:

a. own, lease, or operate a fleet of at least six on-road vehicles;

b. demonstrate that electric vehicles are currently in-use or have been purchased for use at the customer's premises ("Service Address");

c. own or lease the Service Address, and demonstrate site control, suitable, in the Company's sole judgement, for the installation and operation of level 2 electric vehicle charging stations ("Charging Stations") and related equipment.

The Program is available to up to twelve (12) new customers per calendar year on a first-come, first-served basis. The Company may decline to enroll any customer at the Company's sole discretion.

MONTHLY RATE

In addition to any applicable charges for electric delivery and supply, participating customers shall pay the following applicable monthly charge per charging station port:

- Bundled Option: $63.24
- Pre-Pay Option: $28.82
- Customer-Supplied Charging Station Option: No charge

Customers will select one Program Option for all charging ports subject to the Program at the Service Address for the duration of the customer's participation in the Program.

STANDARD CONTRACT RIDERS - (Continued) (C)

RIDER NO. 24 – FLEET CHARGING PILOT PROGRAM – (Continued)

(Applicable to Rates GS/GM, GMH, GL, GLH and L)

PROGRAM DESCRIPTION

Through the Program, Duquesne Light shall provide electric vehicle charging services consistent with the Program Option selected by the customer.

- For customers participating in the Bundled Option and the Pre-Pay Option, Duquesne Light shall provide, own, and maintain Charging Stations at the Service Address, as well as electrical equipment reasonably necessary to connect the Charging Stations to the customer's Service Point ("Make-Ready Infrastructure"), for the duration of the customer's participation in the Program. The customer shall select the Charging Stations from a list of options approved by Duquesne Light. The Charging Stations shall be installed at a mutually-agreeable location at the Service Address by Duquesne Light's third-party contractor(s). Additionally, for customers participating in the Pre-Pay Option, the customer shall pay the Company's costs of the Charging Station in addition to the applicable monthly charge identified herein.

- For customers participating in the Customer-Supplied Charging Station Option, the customer shall provide, install, own, and maintain the Charging Stations at a mutually-agreeable location at the Service Address; and the Company shall own and maintain the Make-Ready Infrastructure.

In addition to the foregoing requirements, participating customers shall:

a. Execute and abide by the Fleet Charging Pilot Customer Agreement, with a minimum term of ten (10) years.

b. Host Charging Stations with a minimum total of four (4) charging station ports per participating Service Address.

c. Share charging data with Duquesne Light (and provide any authorizations required to accommodate such sharing) via the applicable Charging Station vendor.

d. Promptly notify Duquesne Light in the event the Charging Station fails to operate or otherwise requires repair, except for minor issues remedied by the customer pursuant to (e) herein.

e. Make reasonable efforts to remedy minor issues with the Charging Station that do not require qualified technicians to address, including but not limited to, the resetting of a tripped circuit breaker or assisting with software or Wi-Fi interconnectivity issues.

f. Use the Charging Station only in accordance with the manufacturer's applicable recommendations.

g. Grant Duquesne Light any rights-of-way or easements deemed necessary. See also Rule No. 22.1 herein.

h. Maintain the area surrounding the Charging Station. See also Rule No. 23 herein.

i. Provide Duquesne Light with reasonable access to the Charging Station. See also Rule No. 22 herein.

j. Upon Duquesne Light's request, participate in surveys and provide feedback about the Program.

STANDARD CONTRACT RIDERS - (Continued) (C)

RIDER NO. 24 – FLEET CHARGING PILOT PROGRAM – (Continued)

(Applicable to Rates GS/GM, GMH, GL, GLH and L)

PROGRAM DESCRIPTION – (Continued)

For customers participating in the Bundled and Pre-Pay Options: Upon conclusion of the Fleet Charging Pilot Agreement Term, except in the event of customer default or early termination as discussed below, ownership of the Charging Station and Make Ready shall pass automatically to customer.

For all customers: Customers that leave the program prematurely will be required to purchase the Make Ready and Charging Stations, as applicable, at the remaining undepreciated value of the equipment; or alternatively, to have the Company remove the infrastructure, and reimburse the Company's costs of removal and stranded equipment (if any).

STANDARD CONTRACT RIDERS - (Continued) (C)

RIDER NO. 25 – NEW BUSINESS STIMULUS

(Applicable to Rates GS/GM and GMH)

AVAILABILITY

The New Business Stimulus Rider ("NBSR") is available to new small and medium business customers who start new electric service for a retail business in a Vacant Retail Storefront located within a Local Neighborhood Commercial (LNC) district, a Qualified Low-Income Census Tracts (QCT) district, and/or a Neighborhood Assistance Program (NAP) district.

PROGRAM TERMS

Enrolled customers will receive a 30% discount on variable base distribution charges for a period of no more than two (2) years from commencing service or until December 31, 2024, whichever occurs earlier. Customers taking service under the NBSR are not eligible for any other distribution rate discount.

DEFINITIONS

Vacant Retail Storefront: a brick-and-mortar location intended for retail business operations that: (a) will be open to the public, (b) has not received active electric service for thirty (30) or more days prior to the request to commence service, and (c) will receive service at the same voltage and phase as the previous customer. For the purposes of the NBSR, retail business operations will include businesses that offer goods and/or services using in-person storefront locations. These businesses will include boutiques, cafes, restaurants, bars or taverns, gyms, fitness centers, professional services providers, childcare and early education centers, salons and barber shops, and other retailers which are typically found in Main Street business districts.

Local Neighborhood Commercial (LNC) District: area(s) identified as LNC by the City of Pittsburgh Code of Ordinances.

Qualified Low-Income Census Tracts (QCT) District: area(s) identified as QCT by the United States Department of Housing and Urban Development.

Neighborhood Assistance Program (NAP) District: area(s) identified as NAP by the United States Department of Housing and Urban Development.

STANDARD CONTRACT RIDERS - (Continued) (C)

RIDER NO. 26 – CRISIS RECOVERY PROGRAM

(Applicable to Rates GS/GM and GMH)

AVAILABILITY

The Crisis Recovery Program ("CRP") is available to existing small and medium business customers that meet the eligibility requirements listed in the Program Terms and Conditions of this Rider. The CRP provides eligible customers with a 25% waiver of their delinquent account balance and/or an 18-month payment arrangement on the delinquent account balance.

DEFINITIONS

COVID-19 pandemic: The World Health Organization (WHO) and the Centers for Disease Control and Prevention's (CDC) declaration of a novel coronavirus (COVID-19), which resulted in a state-wide disaster emergency proclamation by the Pennsylvania Governor pursuant to 35 Pa. C.S. § 7301(c) on or about March 6, 2020.

Frozen period: The time in which the customer's delinquent balance will not become due, beginning with the first bill issued six (6) or more days following enrollment, and ending the calendar day following the due date of the sixth bill issued since enrollment.

PROGRAM TERMS AND CONDITIONS

Eligible customers are required to demonstrate that they accumulated an account balance as a result of the COVID-19 pandemic.

Enrolled customers will have their delinquent account balance frozen at the time of enrollment, which will remain frozen for six (6) billing cycles.

If the enrolled customer pays the non-frozen portion of their account balance in full by the due date of the sixth bill issued during the frozen period, 25% of the customer's delinquent account balance will be waived, and the customer will be issued an 18-month payment arrangement on the remaining account balance. Customers can agree to shorter payment arrangement terms.

Failure to pay the non-frozen portion in full by the due date of the sixth bill issued during the frozen period will result in the customer receiving an 18-month payment arrangement on the full delinquent balance. Customers can agree to shorter payment arrangement terms.

Enrollment into the CRP shall end on June 30, 2022.

Customers who are actively enrolled into the CRP are not eligible for any other rate discount.

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			—	$0.01	—	~~—(I)~~
100			—	$0.02	—	~~—(I)~~
150			—	$0.02	—	~~—(I)~~
250			—	$0.04	—	~~—(I)~~
400			—	$0.06	—	~~—(I)~~
Light-Emitting Diode (LED) — Cobra Head						
30			$0.00	$0.00	$0.00	(C) (C) (C)
45			~~—~~$0.00	$0.01	$0.01	(C)
60			$0.02	$0.01	$0.01	~~(I) (I) (I)~~
95			$0.03	$0.01	$0.01	~~(I) (I)~~
139			$0.04	$0.02	$0.02	~~(I) (I) (I)~~
219			$0.06	$0.03	$0.03	~~(I) (I) (I)~~
~~275~~			~~—~~	~~$0.04~~	~~$0.04~~	(C)
Light-Emitting Diode (LED) — Colonial						
~~48~~20			—	~~$0.01~~$0.00	~~$0.01~~$0.00	(C) (C)
~~83~~45			—	~~$0.01~~$0.00	~~$0.01~~ $0.00	(C) (C)
Light-Emitting Diode (LED) — Contemporary						
~~47~~40			—	~~$0.01~~$0.00	~~$0.01~~$0.00	(C) (C)
~~62~~55			—	~~$0.01~~$0.00	~~$0.01~~$0.00	(C) (C)

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 kW. 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

(C) – Indicates Change

Exhibit No. DBO-3

Duquesne Light Company

Digest of Proposed Changes
contained in
Tariff Electric – PA. P.U.C. No. 25
Supplement No. 25

Docket No. R-2021-3024750

April 16, 2021

Table of Contents

I. General

Duquesne Light Company's Supplement No. 25 to Tariff Electric – PA. P.U.C. No. 25 issued April 16, 2021, to become effective June 15, 2021, results in an overall average increase of 15.6% in distribution revenues and is expected to produce $85.8 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 — Original Pages No. 2H through 2L were added to Tariff No. 25 and to the Table of Contents.

Table of Contents — Original Page No. 3A has been added to Tariff No. 25 and to the Table of Contents

Rider Matrix — Original Page No. 87A has been added to Tariff No. 25 and to the Table of Contents.

Rider No. 4 – Federal Tax Adjustment Clause has been added to Tariff No. 25 and to the Table of Contents.

Rider No. 4 – Federal Tax Adjustment Clause — Original Pages No. 92A and 92B have been added to Tariff No. 25 and to the Table of Contents.

Rider No. 7 – Residential Subscription Service Pilot has been added to Tariff No. 25 and to the Table of Contents.

Rider No. 7 – Residential Subscription Service Pilot — Original Page No. 97A has been added to Tariff No. 25 and to the Table of Contents.

Rider No. 16 – Service to Non-Utility Generating Facilities — Original Page No. 124A has been added to Tariff No. 25 and to the Table of Contents.

Rider No. 19 – Community Development has been added to Tariff No. 25 and to the Table of Contents.

II. Proposed Changes to the Table of Contents – (Continued)

Rider No. 19 – Community Development — Original Page No. 128A has been added to Tariff No. 25 and to the Table of Contents.

Rider No. 21 – Net Metering Service — Original Page No. 136A has been added to the Table of Contents as an administerial update. Rider No. 21 - Net Metering Service now reflects the addition of Page No. 136A which was added and approved in the Company's DSP IX proceeding at Docket No. P-2020-3019522, Order entered January 14, 2021.

Rider No. 23 - Home Charging Pilot Program has been added to Tariff No. 25 and to the Table of Contents.

Rider No. 23 - Home Charging Pilot Program — Original Pages No. 141A – 141B have been added to Tariff No. 25 and to the Table of Contents.

Rider No. 24 – Fleet Charging Pilot Program has been added to Tariff No. 25 and to the Table of Contents.

Rider No. 24 – Fleet Charging Pilot Program — Original Pages No. 141C – 141E have been added to Tariff No. 25 and to the Table of Contents.

Rider No. 25 – New Business Stimulus has been added to Tariff No. 25 and to the Table of Contents.

Rider No. 25 – New Business Stimulus — Original Page No. 141F has been added to Tariff No. 25 and to the Table of Contents.

Rider No. 26 – Crisis Recovery Program has been added to Tariff No. 25 and to the Table of Contents.

Rider No. 26 – Crisis Recovery Program — Original Page No. 141G has been added to Tariff No. 25 and to the Table of Contents.

III. Proposed Changes to Tariff Rules

Rule No. 3.1 Definitions

(2) Applicant - Language has been added to clarify that the definition of "Applicant" includes non-residential applicants.

III. Proposed Changes to Tariff Rules – (Continued)

Rule No. 5 - Deposits and Advance Payments

Language has been modified to reflect that residential customers/applicants are permitted to pay their deposit in four (4) twenty-five percent (25%) installments.

Language has been modified to clarify security deposits for non-residential customers/applicants.

Rule No. 6.1 - Service Point

Language has been revised to accommodate the Company's proposed transportation electrification programs.

Rule No. 7 - Supply Line Extensions

Language has been modified to clarify that both customers and applicants for service are subject to tariff cost commitment requirements.

Language has been modified to allow applicants (e.g., developers) to pay Contribution in Aid of Construction ("CIAC") on behalf of the ultimate customer.

Rule No 10 - One Service of A Kind

Language has been modified to remove obsolete cross-reference.

Rule No. 16.1 - Interconnection, Safety and Reliability Requirements

New Rule No. 16.1 Interconnection, Safety and Reliability Requirements has been added to the tariff to clarify and memorialize the Company's existing process for customer generation interconnection (including facilities not eligible for net metering).

Measurement and Use of Service – Rule No. 18.1 – Electric Vehicle Charging and Rule No. 19 – Continuity and Safety

Rule No. 18.1 – Electric Vehicle Charging and Rule No. 19 – Continuity and Safety, previously found on First Revised Page No. 26, Cancelling Original Page No. 26 have been moved to Original Page No. 26A to accommodate the addition of Rule No. 16.1 – Interconnection, Safety and Reliability Requirements on Second Revised Page No. 26, Cancelling First Revised Page No. 26.

III. Proposed Changes to Tariff Rules – (Continued)

Measurement and Use of Service – Rule No. 18.1 – Electric Vehicle Charging and Rule No. 19 – Continuity and Safety

Rule No. 18.1 – Electric Vehicle Charging and Rule No. 19 – Continuity and Safety, previously found on First Revised Page No. 26, Cancelling Original Page No. 26 have been moved to Original Page No. 26A to accommodate the addition of Rule No. 16.1 – Interconnection, Safety and Reliability Requirements.

Rule No. 22.1 - Vegetation Management and Right-of-Way

Language has been added to clarify a customer's responsibility to manage vegetation around the Company's service facilities.

Rule No. 40 - Reconnection Charge

Language has been added to expand reconnection charge applicability to customers who apply for reconnection at the same premises more than thirty (30) days following disconnection (i.e., when then former customer now constitutes an "applicant").

Rule No. 41 - Prohibition of Residential Master Metering

Language has been modified to allow residential master metering for certain low-income supportive housing pursuant to Rule No. 41.1.

Rule No. 41.1 - Residential Master Metering for New Low-Income Supportive Housing

New Rule No. 41.1 Residential Master Metering for New Low-Income Supportive Housing has been added to the tariff to establish eligibility and conditions for master metering of certain low-income supportive housing.

General Provisions – Rule No. 42 – Meter Testing, Rule No. 43 – Other Services, Rule No. 44 – This Rule Intentionally Left Blank and Rule No. 45 – Supplier Switching

Rule No. 42 – Meter Testing, Rule No. 43 – Other Services, Rule No. 44 – This Rule Intentionally Left Blank and Rule No. 45 – Supplier Switching, previously found on Original Page No. 34, have been moved to Original Page No. 34A to accommodate the addition of Rule No. 41.1 – Residential Master Metering for New Low-Income Supportive Housing on First Revised Page No. 34, Cancelling Original Page No. 34.

III. Proposed Changes to Tariff Rules – (Continued)

General Provisions – Rule No. 42 – Meter Testing, Rule No. 43 – Other Services, Rule No. 44 – This Rule Intentionally Left Blank and Rule No. 45 – Supplier Switching

Rule No. 42 – Meter Testing, Rule No. 43 – Other Services, Rule No. 44 – This Rule Intentionally Left Blank and Rule No. 45 – Supplier Switching, previously found on Original Page No. 34, have been moved to Original Page No. 34A to accommodate the addition of Rule No. 41.1 – Residential Master Metering for New Low-Income Supportive Housing.

IV. Proposed Changes to Tariff Rate Schedules

Rate RS – Residential Service

Distribution		Current Rates with STAS	Proposed Rates with STAS
Customer Charge		$12.50	$16.25
All kWh	$/kWh	$0.060228	$0.070564

Administerial revision to add the word "cents" back to the Energy Charge line to indicate "cents per kilowatt hour."

Rate RH – Residential Service Heating

	Distribution		Current Rates with STAS	Proposed Rates with STAS
	Customer Charge		$12.50	$16.25
Summer:	All kWh	$/kWh	$0.060228	$0.070564
Winter:	All kWh	$/kWh	$0.045673	$0.063410

Rate RA – Residential Service Add-on Heat Pump

	Distribution		Current Rates with STAS	Proposed Rates with STAS
	Customer Charge		$12.50	$16.25
Summer:	All kWh	$/kWh	$0.060228	$0.070564
Winter:	All kWh	$/kWh	$0.016393	$0.027631

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		$12.50	$16.25
All kWh	$/kWh	$0.073307	$0.084241

Demand - Rate GM < 25

Distribution		Current Rates with STAS	Proposed Rates with STAS
Customer Charge		$54.50	$63.00
Demand over 5 kW	$/kW	$6.54	$7.89
All kWh	$/kWh	$0.013960	$0.018390

Demand - Rate GM ≥ 25

Distribution		Current Rates with STAS	Proposed Rates with STAS
Customer Charge		$65.64	$76.00
Demand over 5 kW	$/kW	$6.54	$7.89
All kWh	$/kWh	$0.009684	$0.012661

Language has been added under “Availability” to clarify eligibility.

Language has been modified under “Minimum Charge” to reflect current business practice.

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		$54.50	$63.00
Summer:				
	Demand over 5 kW	$/kW	$6.54	$7.89
	All kWh	$/kWh	$0.013960	$0.018390
Winter:				
	All kWh	$/kWh	$0.029607	$0.038382

Rate GL – General Service Large

Distribution	Current Rates with STAS	Proposed Rates with STAS
First 300 kW or less	$3,179.75	$3,675.00
Additional kW	$8.41	$10.66

Language has been added under “Availability” to clarify eligibility.

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		$66.99	$77.50
Summer:			
First 300 kW or less		$3,179.75	$3,675.00
Additional kW		$8.41	$10.66
Winter:			
All kWh	$/kWh	$0.023143	$0.030162

Language has been reorganized on the Rate Schedule to clarify that the Customer Distribution Charge is only applicable to the billing months of October through May.

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		$34,897.21	$41,800.00
Additional kW	$/kW	$13.12	$16.63

Language has been modified under “Minimum Charge” to reflect current business practice.

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	$2,050.15	$2,503.20
50,001 kW to 100,000 kW Billing Demand			
	$/kW	$3,202.46	$3,910.17
Greater than 100,000 kW Billing Demand			
	$/kW	$4,541.60	$5,545.24

Language has been added under “Availability” to clarify eligibility.

Language has been modified under “Minimum Charge” to reflect current business practice.

Rate AL – Architectural Lighting Service

Distribution		Current Rates with STAS	Proposed Rates with STAS
Customer Charge		$8.00	$8.00
Demand all kW	$/kW	$1.59	$1.83
All kWh	$/kWh	$0.002110	$0.002396

Language has been added to reflect that beginning January 15, 2022, Rate AL will no longer be available to new customers or applicants, or to new installations for existing customers.

Rate SE – Street Lighting Energy

Distribution	Current Rates with STAS	Proposed Rates with STAS
Customer Charge	$2.92	$3.23

Language has been modified to replace the word “men” with “workers.”

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	$12.69	$14.19
175 watt	per month	$12.95	$14.48
250 watt	per month	$13.20	$14.76
400 watt	per month	$13.73	$15.36
1000 watt	per month	$15.79	$17.66
Sodium Vapor:			
70 watt	per month	$13.11	$14.66
100 watt	per month	$13.21	$14.77
150 watt	per month	$13.40	$14.99
250 watt	per month	$13.75	$15.38
400 watt	per month	$14.30	$15.99
1000 watt	per month	$16.44	$18.39
Light-Emitting Diode (LED) – Cobra Head:			
30 watt	per month	$0.00	$12.91
45 watt	per month	$13.01	$12.91
60 watt	per month	$13.52	$13.33
95 watt	per month	$13.99	$14.71
139 watt	per month	$15.08	$15.37
219 watt	per month	$17.54	$15.65
Light-Emitting Diode (LED) – Colonial:			
20 watt	per month	$0.00	$16.89
45 watt	per month	$0.00	$17.23
Light-Emitting Diode (LED) – Contemporary:			
40 watt	per month	$0.00	$15.59
55 watt	per month	$0.00	$15.59
Poles	per month	$10.32	$11.54
Customer Owned and Maintained Equipment			
Distribution Charge per Unit		$2.71	$3.03

IV. Proposed Changes to Tariff Rate Schedules – (Continued)

Rate SM – Street Lighting Municipal – (Continued)

Language has been added to reflect that beginning January 15, 2022, only LED lighting options will be installed for customers being served under Rate SM.

Language has been added to reflect that beginning January 15, 2022, the Company may replace existing high pressure sodium lights with LED lights or that a customer may request to exchange functioning high pressure sodium lights with LEDs with advance payment to cover the costs of the Company's estimated removal costs of such replacement. Both will be at the Company's discretion.

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted under Cobra Head, Colonial and Contemporary fixtures.

Language has been modified to replace the word "his" with "its."

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	$12.54	$14.02
150 watt	per month	$12.71	$14.22
200 watt	per month	$12.89	$14.42
400 watt	per month	$13.57	$15.99
Light-Emitting Diode (LED) – Cobra Head:			
30 watt	per month	$0.00	$12.91
45 watt	per month	$0.00	$12.91
60 watt	per month	$13.52	$15.12
95 watt	per month	$13.99	$15.65
139 watt	per month	$15.08	$16.87
219 watt	per month	$17.54	$19.62
Customer Owned and Maintained Equipment			
Distribution Charge per Unit		$2.71	$3.03

Language has been added to reflect that beginning January 15, 2022, Rate SH will no longer be available to new customers or applicants, or to new installations for existing customers.

Language has been added to reflect that beginning January 15, 2022, replacement of high pressure sodium 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 LED lighting options.

Language has been added to reflect that due to the limited availability of high pressure sodium lighting, the Company will replace existing high pressure sodium lights with LED lights or a customer may request to exchange functioning high pressure sodium lights with LEDs with advance payment to cover the costs of the Company's estimated removal costs of such replacement. Both will be at the Company's discretion.

New LED lamp wattages have been inserted under Cobra Head fixtures.

IV. Proposed Changes to Tariff Rate Schedules – (Continued)

Rate UMS – Unmetered Service

Distribution		Current Rates with STAS	Proposed Rates with STAS
Customer Charge		$10.00	$11.50
All kWh	$/kWh	$0.018170	$0.027761

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	$13.11	$14.66
100 watt	per month	$13.21	$14.77
150 watt	per month	$13.40	$14.99
250 watt	per month	$13.75	$15.38
400 watt	per month	$14.30	$15.99
Flood Lighting:			
100 watt	per month	$13.11	$14.66
250 watt	per month	$13.72	$15.34
400 watt	per month	$14.34	$16.04
Light-Emitting Diode (LED) – Cobra Head:			
30 watt	per month	$0.00	$12.91
45 watt	per month	$13.01	$12.91
60 watt	per month	$13.52	$13.33
95 watt	per month	$13.99	$14.71
139 watt	per month	$15.08	$15.37
219 watt	per month	$17.54	$15.65
Light-Emitting Diode (LED) – Colonial:			
20 watt	per month	$0.00	$16.89
45 watt	per month	$0.00	$17.23

IV. Proposed Changes to Tariff Rate Schedules – (Continued)

Rate PAL – Private Area Lighting – (Continued)

Company Owned and Maintained Equipment

Distribution		Current Rates with STAS	Proposed Rates with STAS
Light-Emitting Diode (LED) – Contemporary:			
40 watt	per month	$0.00	$15.59
55 watt	per month	$0.00	$15.59
Poles	per month	$10.32	$11.54

Customer Owned and Maintained Equipment

Distribution Charge per Unit	$2.71	$3.03

Language has been added to reflect that beginning January 15, 2022, replacement of high pressure sodium 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 LED lighting options.

Language has been added to reflect that due to the limited availability of high pressure sodium lighting, the Company will replace existing high pressure sodium lights with LED lights or a customer may request to exchange functioning high pressure sodium lights with LEDs with advance payment to cover the costs of the Company's estimated removal costs of such replacement. Both will be at the Company's discretion.

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted under Cobra Head, Colonial and Contemporary fixtures.

Language has been modified to replace the word "his" with "its."

V. Proposed Changes to Tariff Riders

Rider Matrix

The Rider Matrix (Second Revised Page No. 87, Cancelling First Revised Page No. 87) has been updated to reflect the addition of the following Riders:

Rider No. 4 – Federal Tax Adjustment Clause
Rider No. 7 – Residential Subscription Service Pilot
Rider No. 19 – Community Development for New Load

"Continued on Original Page No. 87A" has been added to the bottom of Second Revised Page No. 87, Cancelling First Revised Page No. 87 to indicate that the Rider Matrix continues onto the next page.

Riders No. 20 through Appendix A, previously found in the Rider Matrix on First Revised Page No. 87, Cancelling Original Page No. 87, have been moved to Original Page No. 87A to accommodate the additional Riders placed into the Tariff.

The Rider Matrix (Original Page No. 187A) has been updated to reflect the addition of the following Riders:

Rider No. 23 – Home Charging Pilot Program
Rider No. 24 – Fleet Charging Pilot Program
Rider No. 25 – New Business Stimulus
Rider No. 26 – Crisis Recovery Program

Rider No. 4 – Federal Tax Adjustment Clause

Rider No. 4 – Federal Tax Adjustment Clause ("FTAC") is being added to Tariff No. 25 to provide for adjustments to base distribution revenue to reflect the effects of future increases or decreases in the federal corporate income tax rate.

Rider No. 5 – Universal Service Charge

The CAP participation level has been reset as per the provisions of Rider No. 5.

Rider No. 7 – Residential Subscription Service Pilot

Rider No. 7 – Residential Subscription Service Pilot is being added to Tariff No. 25 to offer eligible customers the option to select a specified level of grid access for a set monthly charge.

V. Proposed Changes to Tariff Riders – (Continued)

Rider No. 8 – Default Service Supply

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted under Cobra Head, Colonial and Contemporary fixtures.

In the "Calculation of Rates" section, the Docket No. has been updated in DSSa.

Rider No. 9 – Day-Ahead Hourly Price Service

Under the "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. 16 – Service to Non-Utility Generating Facilities

Rider No. 16 – Service to Non-Utility Generating Facilities has been modified to reflect changes in applicable terms, rules, and rates.

Rider No. 19 – Community Development for New Load

Rider No. 19 – Community Development for New Load is being added to Tariff No. 25 to provide incentives to eligible customers to move and/or expand their operations within the Company's service territory.

Rider No. 21 – Net Metering Service

Rider No. 21 – Net Metering Service has been revised to include Rate Schedule GLH and Rate Schedule L.

Language has been modified in regard to calculating the price-to-compare ("PTC") to reflect current business practice.

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.

V. Proposed Changes to Tariff Riders – (Continued)

Rider No. 23 – Home Charging Pilot Program

Rider No. 23 – Home Charging Pilot Program is being added to Tariff No. 25 to set forth the eligibility, terms, and conditions applicable to residential customers participating in the Company's voluntary Home Charging Pilot.

Rider No. 24 – Fleet Charging Pilot Program

Rider No. 24 – Fleet Charging Pilot Program is being added to Tariff No. 25 to set forth the eligibility, terms, and conditions applicable to non-residential customers participating in the Company's voluntary Fleet Charging Pilot.

Rider No. 25 – New Business Stimulus

Rider No. 25 – New Business Stimulus is being added to Tariff No. 25 to incent eligible new small or medium businesses by providing them with a reduced distribution rate for two (2) years.

Rider No. 26 – Crisis Recovery Program

Rider No. 26 – Crisis Recovery Program is being added to Tariff No. 25 to provide a relief program for eligible existing small or medium business customers who have accumulated a delinquent balance because of COVID-19 business restrictions.

VII. Appendix A – Transmission Service Charges

Appendix A – Transmission Service Charges

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted under Cobra Head, Colonial and Contemporary fixtures.

Exhibit DBO-4
Duquesne Light Company
LED Street Lighting Service
Rate Summary

		Cobrahead						Colonial LED		Contemporary LED	
Line No.	Description	30 Nominal Watts	45 Nominal Watts	60 Nominal Watts	95 Nominal Watts	139 Nominal Watts	219 Nominal Watts	20 Nominal Watts	45 Nominal Watts	40 Nominal Watts	55 Nominal Watts
1	Total Material Cost	$ 291.48	$ 291.48	$ 327.75	$ 448.39	$ 506.32	$ 530.80	$ 640.00	$ 670.00	$ 525.00	$ 525.00
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	$ 520.07	$ 520.07	$ 556.34	$ 676.98	$ 734.91	$ 759.39	$ 868.59	$ 898.59	$ 753.59	$ 753.59
4	Revenue Requirement NPV	$621.72	$621.72	$665.07	$809.29	$878.54	$907.81	$1,038.35	$1,074.21	$900.87	$900.87
5	Annualized Levelized Payment	$59.89	$59.89	$64.07	$77.97	$84.64	$87.46	$100.03	$103.49	$86.79	$86.79
6	Monthly Fixture Charge	$ 4.99	$ 4.99	$ 5.34	$ 6.50	$ 7.05	$ 7.29	$ 8.34	$ 8.62	$ 7.23	$ 7.23
7	Gross Receipts Tax	$ 0.31	$ 0.31	$ 0.33	$ 0.41	$ 0.44	$ 0.46	$ 0.52	$ 0.54	$ 0.45	$ 0.45
8	Monthly Fixture Charge	$ 5.30	$ 5.30	$ 5.67	$ 6.91	$ 7.49	$ 7.75	$ 8.86	$ 9.16	$ 7.68	$ 7.68
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)	$ 3.64	$ 3.64	$ 3.64	$ 3.64	$ 3.64	$ 3.64	$ 3.64	$ 3.64	$ 3.64	$ 3.64
12	2021 Distribution Increase	$1.26	$1.26	$1.31	$1.45	$1.53	$1.55	$1.68	$1.72	$1.56	$1.56
13	Total Monthly Charge	$ 12.91	$ 12.91	$ 13.33	$ 14.71	$ 15.37	$ 15.65	$ 16.89	$ 17.23	$ 15.59	$ 15.59

(1) As calculated in Howard Gorman Exhibit 6-11

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
30 W LED Installation

Financial Input	Input
Capital Investment - Material	$291.48
Capitalized Labor	$228.59
Total Capitalized Investment	$520.07

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	46.65%	4.29%	2.00%	1.42%
Preferred	0.00%	0.00%	0.00%	0.00%
Equity	53.35%	10.95%	5.84%	5.84%
	100.00%		7.84%	7.26%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$621.72
Levelized Annual Revenue Requirement	$59.89
Annual O&M / Maintenance Expense	$0.00
Annual Revenue Requirement	$59.89
Net Monthly Tariff Rate	$4.99
PA Gross Receipts Tax	$0.31
Total Monthly Distribution Rate	**$5.30**

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	520.07	10.40	0.00	30.38	40.78	26.00	26.00	0.00	0.00	12.34	12.34	79.13	73.77
2	494.07	9.88	0.00	28.86	38.74	26.00	26.00	0.00	0.00	11.73	11.73	76.48	140.24
3	468.07	9.36	0.00	27.34	36.70	26.00	26.00	0.00	0.00	11.11	11.11	73.82	200.06
4	442.06	8.84	0.00	25.82	34.67	26.00	26.00	0.00	0.00	10.49	10.49	71.16	253.81
5	416.06	8.32	0.00	24.31	32.63	26.00	26.00	0.00	0.00	9.88	9.88	68.51	302.06
6	390.06	7.80	0.00	22.79	30.59	26.00	26.00	0.00	0.00	9.26	9.26	65.85	345.29
7	364.05	7.28	0.00	21.27	28.55	26.00	26.00	0.00	0.00	8.64	8.64	63.19	383.97
8	338.05	6.76	0.00	19.75	26.51	26.00	26.00	0.00	0.00	8.02	8.02	60.54	418.52
9	312.04	6.24	0.00	18.23	24.47	26.00	26.00	0.00	0.00	7.41	7.41	57.88	449.31
10	286.04	5.72	0.00	16.71	22.43	26.00	26.00	0.00	0.00	6.79	6.79	55.22	476.70
11	260.04	5.20	0.00	15.19	20.39	26.00	26.00	0.00	0.00	6.17	6.17	52.57	501.01
12	234.03	4.68	0.00	13.67	18.35	26.00	26.00	0.00	0.00	5.56	5.56	49.91	522.52
13	208.03	4.16	0.00	12.15	16.31	26.00	26.00	0.00	0.00	4.94	4.94	47.25	541.51
14	182.03	3.64	0.00	10.63	14.27	26.00	26.00	0.00	0.00	4.32	4.32	44.60	558.22
15	156.02	3.12	0.00	9.11	12.23	26.00	26.00	0.00	0.00	3.70	3.70	41.94	572.87
16	130.02	2.60	0.00	7.60	10.20	26.00	26.00	0.00	0.00	3.09	3.09	39.29	585.67
17	104.01	2.08	0.00	6.08	8.16	26.00	26.00	0.00	0.00	2.47	2.47	36.63	596.79
18	78.01	1.56	0.00	4.56	6.12	26.00	26.00	0.00	0.00	1.85	1.85	33.97	606.40
19	52.01	1.04	0.00	3.04	4.08	26.00	26.00	0.00	0.00	1.23	1.23	31.32	614.66
20	26.00	0.52	0.00	1.52	2.04	26.00	26.00	0.00	0.00	0.62	0.62	28.66	621.72

PV Tax Shields	269.92
Tax on shields	77.99
Investment	520.07
After Tax Investment	442.09

Adjust for Tax Gross-Up 621.72 <----------------------------- = -----------------------------> PV Rev Req 621.72

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
45 W LED Installation

Financial Input	Input
Capital Investment - Material	$291.48
Capitalized Labor	$228.59
Total Capitalized Investment	$520.07

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	46.65%	4.29%	2.00%	1.42%
Preferred	0.00%	0.00%	0.00%	0.00%
Equity	53.35%	10.95%	5.84%	5.84%
	100.00%		7.84%	7.26%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$621.72
Levelized Annual Revenue Requirement	$59.89
Annual O&M / Maintenance Expense	$0.00
Annual Revenue Requirement	$59.89
Net Monthly Tariff Rate	$4.99
PA Gross Receipts Tax	$0.31
Total Monthly Distribution Rate	**$5.30**

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	520.07	10.40	0.00	30.38	40.78	26.00	26.00	0.00	0.00	12.34	12.34	79.13	73.77
2	494.07	9.88	0.00	28.86	38.74	26.00	26.00	0.00	0.00	11.73	11.73	76.48	140.24
3	468.07	9.36	0.00	27.34	36.70	26.00	26.00	0.00	0.00	11.11	11.11	73.82	200.06
4	442.06	8.84	0.00	25.82	34.67	26.00	26.00	0.00	0.00	10.49	10.49	71.16	253.81
5	416.06	8.32	0.00	24.31	32.63	26.00	26.00	0.00	0.00	9.88	9.88	68.51	302.06
6	390.06	7.80	0.00	22.79	30.59	26.00	26.00	0.00	0.00	9.26	9.26	65.85	345.29
7	364.05	7.28	0.00	21.27	28.55	26.00	26.00	0.00	0.00	8.64	8.64	63.19	383.97
8	338.05	6.76	0.00	19.75	26.51	26.00	26.00	0.00	0.00	8.02	8.02	60.54	418.52
9	312.04	6.24	0.00	18.23	24.47	26.00	26.00	0.00	0.00	7.41	7.41	57.88	449.31
10	286.04	5.72	0.00	16.71	22.43	26.00	26.00	0.00	0.00	6.79	6.79	55.22	476.70
11	260.04	5.20	0.00	15.19	20.39	26.00	26.00	0.00	0.00	6.17	6.17	52.57	501.01
12	234.03	4.68	0.00	13.67	18.35	26.00	26.00	0.00	0.00	5.56	5.56	49.91	522.52
13	208.03	4.16	0.00	12.15	16.31	26.00	26.00	0.00	0.00	4.94	4.94	47.25	541.51
14	182.03	3.64	0.00	10.63	14.27	26.00	26.00	0.00	0.00	4.32	4.32	44.60	558.22
15	156.02	3.12	0.00	9.11	12.23	26.00	26.00	0.00	0.00	3.70	3.70	41.94	572.87
16	130.02	2.60	0.00	7.60	10.20	26.00	26.00	0.00	0.00	3.09	3.09	39.29	585.67
17	104.01	2.08	0.00	6.08	8.16	26.00	26.00	0.00	0.00	2.47	2.47	36.63	596.79
18	78.01	1.56	0.00	4.56	6.12	26.00	26.00	0.00	0.00	1.85	1.85	33.97	606.40
19	52.01	1.04	0.00	3.04	4.08	26.00	26.00	0.00	0.00	1.23	1.23	31.32	614.66
20	26.00	0.52	0.00	1.52	2.04	26.00	26.00	0.00	0.00	0.62	0.62	28.66	621.72

PV Tax Shields	269.92
Tax on shields	77.99
Investment	520.07
After Tax Investment	442.09

Adjust for Tax Gross-Up 621.72 <----------------------------- = -----------------------------> PV Rev Req 621.72

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
60 W LED Installation

Financial Input	Input
Capital Investment - Material	$327.75
Capitalized Labor	$228.59
Total Capitalized Investment	$556.34

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	46.65%	4.29%	2.00%	1.42%
Preferred	0.00%	0.00%	0.00%	0.00%
Equity	53.35%	10.95%	5.84%	5.84%
	100.00%		7.84%	7.26%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$665.07
Levelized Annual Revenue Requirement	$64.07
Annual O&M / Maintenance Expense	$0.00
Annual Revenue Requirement	$64.07
Net Monthly Tariff Rate	$5.34
PA Gross Receipts Tax	$0.33
Total Monthly Distribution Rate	**$5.67**

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	556.34	11.13	0.00	32.50	43.63	27.82	27.82	0.00	0.00	13.21	13.21	84.65	78.92
2	528.53	10.57	0.00	30.88	41.45	27.82	27.82	0.00	0.00	12.55	12.55	81.81	150.02
3	500.71	10.01	0.00	29.25	39.26	27.82	27.82	0.00	0.00	11.88	11.88	78.97	214.01
4	472.89	9.46	0.00	27.63	37.08	27.82	27.82	0.00	0.00	11.22	11.22	76.13	271.51
5	445.08	8.90	0.00	26.00	34.90	27.82	27.82	0.00	0.00	10.56	10.56	73.28	323.12
6	417.26	8.35	0.00	24.38	32.72	27.82	27.82	0.00	0.00	9.90	9.90	70.44	369.37
7	389.44	7.79	0.00	22.75	30.54	27.82	27.82	0.00	0.00	9.24	9.24	67.60	410.75
8	361.62	7.23	0.00	21.13	28.36	27.82	27.82	0.00	0.00	8.58	8.58	64.76	447.71
9	333.81	6.68	0.00	19.50	26.18	27.82	27.82	0.00	0.00	7.92	7.92	61.92	480.65
10	305.99	6.12	0.00	17.88	24.00	27.82	27.82	0.00	0.00	7.26	7.26	59.08	509.95
11	278.17	5.56	0.00	16.25	21.81	27.82	27.82	0.00	0.00	6.60	6.60	56.23	535.95
12	250.35	5.01	0.00	14.63	19.63	27.82	27.82	0.00	0.00	5.94	5.94	53.39	558.96
13	222.54	4.45	0.00	13.00	17.45	27.82	27.82	0.00	0.00	5.28	5.28	50.55	579.28
14	194.72	3.89	0.00	11.38	15.27	27.82	27.82	0.00	0.00	4.62	4.62	47.71	597.15
15	166.90	3.34	0.00	9.75	13.09	27.82	27.82	0.00	0.00	3.96	3.96	44.87	612.83
16	139.09	2.78	0.00	8.13	10.91	27.82	27.82	0.00	0.00	3.30	3.30	42.03	626.51
17	111.27	2.23	0.00	6.50	8.73	27.82	27.82	0.00	0.00	2.64	2.64	39.18	638.41
18	83.45	1.67	0.00	4.88	6.54	27.82	27.82	0.00	0.00	1.98	1.98	36.34	648.69
19	55.63	1.11	0.00	3.25	4.36	27.82	27.82	0.00	0.00	1.32	1.32	33.50	657.53
20	27.82	0.56	0.00	1.63	2.18	27.82	27.82	0.00	0.00	0.66	0.66	30.66	665.07

PV Tax Shields	288.75
Tax on shields	83.42
Investment	556.34
After Tax Investment	472.92

Adjust for Tax Gross-Up 665.07 <----------------------------- = ----------------------------->PV Rev Req 665.07

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
95 W LED Installation

Financial Input	Input
Capital Investment - Material	$448.39
Capitalized Labor	$228.59
Total Capitalized Investment	$676.98

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	$809.29
Levelized Annual Revenue Requirement	$77.97
Annual O&M / Maintenance Expense	$0.00
Annual Revenue Requirement	$77.97
Net Monthly Tariff Rate	$6.50
PA Gross Receipts Tax	$0.41
Total Monthly Distribution Rate	**$6.90**

Weighted Cost of Capital

	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	46.65%	4.29%	2.00%	1.42%
Preferred	0.00%	0.00%	0.00%	0.00%
Equity	53.35%	10.95%	5.84%	5.84%
	100.00%		7.84%	7.26%

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	676.98	13.54	0.00	39.55	53.09	33.85	33.85	0.00	0.00	16.07	16.07	103.01	96.03
2	643.14	12.86	0.00	37.57	50.43	33.85	33.85	0.00	0.00	15.27	15.27	99.55	182.55
3	609.29	12.19	0.00	35.59	47.78	33.85	33.85	0.00	0.00	14.46	14.46	96.09	260.41
4	575.44	11.51	0.00	33.62	45.12	33.85	33.85	0.00	0.00	13.66	13.66	92.63	330.39
5	541.59	10.83	0.00	31.64	42.47	33.85	33.85	0.00	0.00	12.86	12.86	89.17	393.19
6	507.74	10.15	0.00	29.66	39.82	33.85	33.85	0.00	0.00	12.05	12.05	85.72	449.47
7	473.89	9.48	0.00	27.68	37.16	33.85	33.85	0.00	0.00	11.25	11.25	82.26	499.82
8	440.04	8.80	0.00	25.71	34.51	33.85	33.85	0.00	0.00	10.44	10.44	78.80	544.79
9	406.19	8.12	0.00	23.73	31.85	33.85	33.85	0.00	0.00	9.64	9.64	75.34	584.87
10	372.34	7.45	0.00	21.75	29.20	33.85	33.85	0.00	0.00	8.84	8.84	71.89	620.52
11	338.49	6.77	0.00	19.77	26.54	33.85	33.85	0.00	0.00	8.03	8.03	68.43	652.16
12	304.64	6.09	0.00	17.80	23.89	33.85	33.85	0.00	0.00	7.23	7.23	64.97	680.17
13	270.79	5.42	0.00	15.82	21.24	33.85	33.85	0.00	0.00	6.43	6.43	61.51	704.89
14	236.94	4.74	0.00	13.84	18.58	33.85	33.85	0.00	0.00	5.62	5.62	58.05	726.64
15	203.10	4.06	0.00	11.86	15.93	33.85	33.85	0.00	0.00	4.82	4.82	54.60	745.71
16	169.25	3.38	0.00	9.89	13.27	33.85	33.85	0.00	0.00	4.02	4.02	51.14	762.37
17	135.40	2.71	0.00	7.91	10.62	33.85	33.85	0.00	0.00	3.21	3.21	47.68	776.84
18	101.55	2.03	0.00	5.93	7.96	33.85	33.85	0.00	0.00	2.41	2.41	44.22	789.36
19	67.70	1.35	0.00	3.95	5.31	33.85	33.85	0.00	0.00	1.61	1.61	40.76	800.11
20	33.85	0.68	0.00	1.98	2.65	33.85	33.85	0.00	0.00	0.80	0.80	37.31	809.29

PV Tax Shields	351.36
Tax on shields	101.51
Investment	676.98
After Tax Investment	575.47

Adjust for Tax Gross-Up 809.29 <----------------------------- = ------------------------------>PV Rev Req 809.29

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
139 W LED Installation

Financial Input	Input
Capital Investment - Material	$506.32
Capitalized Labor	$228.59
Total Capitalized Investment	$734.91

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	46.65%	4.29%	2.00%	1.42%
Preferred	0.00%	0.00%	0.00%	0.00%
Equity	53.35%	10.95%	5.84%	5.84%
	100.00%		7.84%	7.26%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$878.54
Levelized Annual Revenue Requirement	$84.64
Annual O&M / Maintenance Expense	$0.00
Annual Revenue Requirement	$84.64
Net Monthly Tariff Rate	$7.05
PA Gross Receipts Tax	$0.44
Total Monthly Distribution Rate	**$7.50**

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	734.91	14.70	0.00	42.93	57.63	36.75	36.75	0.00	0.00	17.44	17.44	111.82	104.25
2	698.17	13.96	0.00	40.79	54.75	36.75	36.75	0.00	0.00	16.57	16.57	108.07	198.17
3	661.42	13.23	0.00	38.64	51.87	36.75	36.75	0.00	0.00	15.70	15.70	104.31	282.70
4	624.68	12.49	0.00	36.49	48.99	36.75	36.75	0.00	0.00	14.83	14.83	100.56	358.66
5	587.93	11.76	0.00	34.35	46.10	36.75	36.75	0.00	0.00	13.96	13.96	96.81	426.84
6	551.19	11.02	0.00	32.20	43.22	36.75	36.75	0.00	0.00	13.08	13.08	93.05	487.93
7	514.44	10.29	0.00	30.05	40.34	36.75	36.75	0.00	0.00	12.21	12.21	89.30	542.59
8	477.69	9.55	0.00	27.91	37.46	36.75	36.75	0.00	0.00	11.34	11.34	85.54	591.41
9	440.95	8.82	0.00	25.76	34.58	36.75	36.75	0.00	0.00	10.47	10.47	81.79	634.92
10	404.20	8.08	0.00	23.61	31.70	36.75	36.75	0.00	0.00	9.59	9.59	78.04	673.62
11	367.46	7.35	0.00	21.47	28.82	36.75	36.75	0.00	0.00	8.72	8.72	74.28	707.97
12	330.71	6.61	0.00	19.32	25.93	36.75	36.75	0.00	0.00	7.85	7.85	70.53	738.37
13	293.97	5.88	0.00	17.17	23.05	36.75	36.75	0.00	0.00	6.98	6.98	66.78	765.21
14	257.22	5.14	0.00	15.03	20.17	36.75	36.75	0.00	0.00	6.11	6.11	63.02	788.82
15	220.47	4.41	0.00	12.88	17.29	36.75	36.75	0.00	0.00	5.23	5.23	59.27	809.52
16	183.73	3.67	0.00	10.73	14.41	36.75	36.75	0.00	0.00	4.36	4.36	55.51	827.60
17	146.98	2.94	0.00	8.59	11.53	36.75	36.75	0.00	0.00	3.49	3.49	51.76	843.32
18	110.24	2.20	0.00	6.44	8.64	36.75	36.75	0.00	0.00	2.62	2.62	48.01	856.90
19	73.49	1.47	0.00	4.29	5.76	36.75	36.75	0.00	0.00	1.74	1.74	44.25	868.58
20	36.75	0.73	0.00	2.15	2.88	36.75	36.75	0.00	0.00	0.87	0.87	40.50	878.54

PV Tax Shields	381.42
Tax on shields	110.20
Investment	734.91
After Tax Investment	624.71
Adjust for Tax Gross-Up	878.54

<----------------------------- = ------------------------------>PV Rev Req 878.54

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
219 W LED Installation

Financial Input	Input
Capital Investment - Material	$530.80
Capitalized Labor	$228.59
Total Capitalized Investment	$759.39

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	46.65%	4.29%	2.00%	1.42%
Preferred	0.00%	0.00%	0.00%	0.00%
Equity	53.35%	10.95%	5.84%	5.84%
	100.00%		7.84%	7.26%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$907.81
Levelized Annual Revenue Requirement	$87.46
Annual O&M / Maintenance Expense	$0.00
Annual Revenue Requirement	$87.46
Net Monthly Tariff Rate	$7.29
PA Gross Receipts Tax	$0.46
Total Monthly Distribution Rate	**$7.75**

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	759.39	15.19	0.00	44.36	59.55	37.97	37.97	0.00	0.00	18.03	18.03	115.55	107.72
2	721.42	14.43	0.00	42.14	56.57	37.97	37.97	0.00	0.00	17.12	17.12	111.67	204.77
3	683.45	13.67	0.00	39.93	53.60	37.97	37.97	0.00	0.00	16.22	16.22	107.79	292.11
4	645.49	12.91	0.00	37.71	50.62	37.97	37.97	0.00	0.00	15.32	15.32	103.91	370.61
5	607.52	12.15	0.00	35.49	47.64	37.97	37.97	0.00	0.00	14.42	14.42	100.03	441.05
6	569.55	11.39	0.00	33.27	44.66	37.97	37.97	0.00	0.00	13.52	13.52	96.15	504.18
7	531.58	10.63	0.00	31.05	41.69	37.97	37.97	0.00	0.00	12.62	12.62	92.27	560.66
8	493.61	9.87	0.00	28.84	38.71	37.97	37.97	0.00	0.00	11.72	11.72	88.39	611.11
9	455.64	9.11	0.00	26.62	35.73	37.97	37.97	0.00	0.00	10.82	10.82	84.51	656.07
10	417.67	8.35	0.00	24.40	32.75	37.97	37.97	0.00	0.00	9.91	9.91	80.64	696.06
11	379.70	7.59	0.00	22.18	29.78	37.97	37.97	0.00	0.00	9.01	9.01	76.76	731.55
12	341.73	6.83	0.00	19.96	26.80	37.97	37.97	0.00	0.00	8.11	8.11	72.88	762.97
13	303.76	6.08	0.00	17.74	23.82	37.97	37.97	0.00	0.00	7.21	7.21	69.00	790.70
14	265.79	5.32	0.00	15.53	20.84	37.97	37.97	0.00	0.00	6.31	6.31	65.12	815.10
15	227.82	4.56	0.00	13.31	17.87	37.97	37.97	0.00	0.00	5.41	5.41	61.24	836.49
16	189.85	3.80	0.00	11.09	14.89	37.97	37.97	0.00	0.00	4.51	4.51	57.36	855.17
17	151.88	3.04	0.00	8.87	11.91	37.97	37.97	0.00	0.00	3.61	3.61	53.48	871.41
18	113.91	2.28	0.00	6.65	8.93	37.97	37.97	0.00	0.00	2.70	2.70	49.61	885.45
19	75.94	1.52	0.00	4.44	5.96	37.97	37.97	0.00	0.00	1.80	1.80	45.73	897.51
20	37.97	0.76	0.00	2.22	2.98	37.97	37.97	0.00	0.00	0.90	0.90	41.85	907.81

PV Tax Shields	394.13
Tax on shields	113.87
Investment	759.39
After Tax Investment	645.52

Adjust for Tax Gross-Up 907.81 <----------------------------- = ----------------------------->PV Rev Req 907.81

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
20 W LED Installation

Financial Input	Input
Capital Investment - Material	$640.00
Capitalized Labor	$228.59
Total Capitalized Investment	$868.59

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	46.65%	4.29%	2.00%	1.42%
Preferred	0.00%	0.00%	0.00%	0.00%
Equity	53.35%	10.95%	5.84%	5.84%
	100.00%		7.84%	7.26%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$1,038.35
Levelized Annual Revenue Requirement	$100.03
Annual O&M / Maintenance Expense	$0.00
Annual Revenue Requirement	$100.03
Net Monthly Tariff Rate	$8.34
PA Gross Receipts Tax	$0.52
Total Monthly Distribution Rate	**$8.86**

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	868.59	17.37	0.00	50.74	68.11	43.43	43.43	0.00	0.00	20.62	20.62	132.16	123.21
2	825.16	16.50	0.00	48.20	64.71	43.43	43.43	0.00	0.00	19.59	19.59	127.72	234.22
3	781.73	15.63	0.00	45.67	61.30	43.43	43.43	0.00	0.00	18.56	18.56	123.29	334.12
4	738.31	14.77	0.00	43.13	57.90	43.43	43.43	0.00	0.00	17.52	17.52	118.85	423.90
5	694.88	13.90	0.00	40.59	54.49	43.43	43.43	0.00	0.00	16.49	16.49	114.41	504.48
6	651.45	13.03	0.00	38.06	51.09	43.43	43.43	0.00	0.00	15.46	15.46	109.98	576.68
7	608.02	12.16	0.00	35.52	47.68	43.43	43.43	0.00	0.00	14.43	14.43	105.54	641.29
8	564.59	11.29	0.00	32.98	44.27	43.43	43.43	0.00	0.00	13.40	13.40	101.10	698.98
9	521.16	10.42	0.00	30.45	40.87	43.43	43.43	0.00	0.00	12.37	12.37	96.67	750.41
10	477.73	9.55	0.00	27.91	37.46	43.43	43.43	0.00	0.00	11.34	11.34	92.23	796.15
11	434.30	8.69	0.00	25.37	34.06	43.43	43.43	0.00	0.00	10.31	10.31	87.80	836.75
12	390.87	7.82	0.00	22.83	30.65	43.43	43.43	0.00	0.00	9.28	9.28	83.36	872.68
13	347.44	6.95	0.00	20.30	27.25	43.43	43.43	0.00	0.00	8.25	8.25	78.92	904.40
14	304.01	6.08	0.00	17.76	23.84	43.43	43.43	0.00	0.00	7.22	7.22	74.49	932.31
15	260.58	5.21	0.00	15.22	20.43	43.43	43.43	0.00	0.00	6.19	6.19	70.05	956.78
16	217.15	4.34	0.00	12.69	17.03	43.43	43.43	0.00	0.00	5.15	5.15	65.61	978.14
17	173.72	3.47	0.00	10.15	13.62	43.43	43.43	0.00	0.00	4.12	4.12	61.18	996.71
18	130.29	2.61	0.00	7.61	10.22	43.43	43.43	0.00	0.00	3.09	3.09	56.74	1,012.77
19	86.86	1.74	0.00	5.07	6.81	43.43	43.43	0.00	0.00	2.06	2.06	52.30	1,026.57
20	43.43	0.87	0.00	2.54	3.41	43.43	43.43	0.00	0.00	1.03	1.03	47.87	1,038.35

PV Tax Shields	450.80
Tax on shields	130.25
Investment	868.59
After Tax Investment	738.35

Adjust for Tax Gross-Up 1,038.35 <----------------------------- = ------------------------------>PV Rev Req 1,038.35

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
45 W LED Installation

Financial Input	Input
Capital Investment - Material	$670.00
Capitalized Labor	$228.59
Total Capitalized Investment	$898.59

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	46.65%	4.29%	2.00%	1.42%
Preferred	0.00%	0.00%	0.00%	0.00%
Equity	53.35%	10.95%	5.84%	5.84%
	100.00%		7.84%	7.26%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$1,074.21
Levelized Annual Revenue Requirement	$103.49
Annual O&M / Maintenance Expense	$0.00
Annual Revenue Requirement	$103.49
Net Monthly Tariff Rate	$8.62
PA Gross Receipts Tax	$0.54
Total Monthly Distribution Rate	**$9.16**

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	898.59	17.97	0.00	52.49	70.47	44.93	44.93	0.00	0.00	21.33	21.33	136.73	127.47
2	853.66	17.07	0.00	49.87	66.94	44.93	44.93	0.00	0.00	20.26	20.26	132.14	242.31
3	808.73	16.17	0.00	47.24	63.42	44.93	44.93	0.00	0.00	19.20	19.20	127.55	345.66
4	763.81	15.28	0.00	44.62	59.90	44.93	44.93	0.00	0.00	18.13	18.13	122.96	438.54
5	718.88	14.38	0.00	42.00	56.37	44.93	44.93	0.00	0.00	17.06	17.06	118.37	521.90
6	673.95	13.48	0.00	39.37	52.85	44.93	44.93	0.00	0.00	16.00	16.00	113.78	596.60
7	629.02	12.58	0.00	36.75	49.33	44.93	44.93	0.00	0.00	14.93	14.93	109.19	663.44
8	584.09	11.68	0.00	34.12	45.80	44.93	44.93	0.00	0.00	13.86	13.86	104.60	723.12
9	539.16	10.78	0.00	31.50	42.28	44.93	44.93	0.00	0.00	12.80	12.80	100.01	776.33
10	494.23	9.88	0.00	28.87	38.76	44.93	44.93	0.00	0.00	11.73	11.73	95.42	823.65
11	449.30	8.99	0.00	26.25	35.23	44.93	44.93	0.00	0.00	10.66	10.66	90.83	865.65
12	404.37	8.09	0.00	23.62	31.71	44.93	44.93	0.00	0.00	9.60	9.60	86.24	902.82
13	359.44	7.19	0.00	21.00	28.19	44.93	44.93	0.00	0.00	8.53	8.53	81.65	935.64
14	314.51	6.29	0.00	18.37	24.66	44.93	44.93	0.00	0.00	7.47	7.47	77.06	964.51
15	269.58	5.39	0.00	15.75	21.14	44.93	44.93	0.00	0.00	6.40	6.40	72.47	989.82
16	224.65	4.49	0.00	13.12	17.62	44.93	44.93	0.00	0.00	5.33	5.33	67.88	1,011.93
17	179.72	3.59	0.00	10.50	14.09	44.93	44.93	0.00	0.00	4.27	4.27	63.29	1,031.14
18	134.79	2.70	0.00	7.87	10.57	44.93	44.93	0.00	0.00	3.20	3.20	58.70	1,047.75
19	89.86	1.80	0.00	5.25	7.05	44.93	44.93	0.00	0.00	2.13	2.13	54.11	1,062.03
20	44.93	0.90	0.00	2.62	3.52	44.93	44.93	0.00	0.00	1.07	1.07	49.52	1,074.21

PV Tax Shields	466.37
Tax on shields	134.75
Investment	898.59
After Tax Investment	763.85

Adjust for Tax Gross-Up 1,074.21 <----------------------------- = ------------------------------>PV Rev Req 1,074.21

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
40 W LED Installation

Financial Input	Input
Capital Investment - Material	$525.00
Capitalized Labor	$228.59
Total Capitalized Investment	$753.59

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	46.65%	4.29%	2.00%	1.42%
Preferred	0.00%	0.00%	0.00%	0.00%
Equity	53.35%	10.95%	5.84%	5.84%
	100.00%		7.84%	7.26%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$900.87
Levelized Annual Revenue Requirement	$86.79
Annual O&M / Maintenance Expense	$0.00
Annual Revenue Requirement	$86.79
Net Monthly Tariff Rate	$7.23
PA Gross Receipts Tax	$0.45
Total Monthly Distribution Rate	**$7.69**

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	753.59	15.07	0.00	44.02	59.10	37.68	37.68	0.00	0.00	17.89	17.89	114.66	106.90
2	715.91	14.32	0.00	41.82	56.14	37.68	37.68	0.00	0.00	16.99	16.99	110.81	203.21
3	678.23	13.56	0.00	39.62	53.19	37.68	37.68	0.00	0.00	16.10	16.10	106.96	289.88
4	640.56	12.81	0.00	37.42	50.23	37.68	37.68	0.00	0.00	15.20	15.20	103.12	367.78
5	602.88	12.06	0.00	35.22	47.28	37.68	37.68	0.00	0.00	14.31	14.31	99.27	437.69
6	565.20	11.30	0.00	33.02	44.32	37.68	37.68	0.00	0.00	13.42	13.42	95.42	500.33
7	527.52	10.55	0.00	30.82	41.37	37.68	37.68	0.00	0.00	12.52	12.52	91.57	556.38
8	489.84	9.80	0.00	28.62	38.41	37.68	37.68	0.00	0.00	11.63	11.63	87.72	606.44
9	452.16	9.04	0.00	26.41	35.46	37.68	37.68	0.00	0.00	10.73	10.73	83.87	651.06
10	414.48	8.29	0.00	24.21	32.50	37.68	37.68	0.00	0.00	9.84	9.84	80.02	690.75
11	376.80	7.54	0.00	22.01	29.55	37.68	37.68	0.00	0.00	8.94	8.94	76.17	725.97
12	339.12	6.78	0.00	19.81	26.59	37.68	37.68	0.00	0.00	8.05	8.05	72.32	757.14
13	301.44	6.03	0.00	17.61	23.64	37.68	37.68	0.00	0.00	7.15	7.15	68.47	784.66
14	263.76	5.28	0.00	15.41	20.68	37.68	37.68	0.00	0.00	6.26	6.26	64.62	808.87
15	226.08	4.52	0.00	13.21	17.73	37.68	37.68	0.00	0.00	5.37	5.37	60.77	830.10
16	188.40	3.77	0.00	11.01	14.77	37.68	37.68	0.00	0.00	4.47	4.47	56.93	848.64
17	150.72	3.01	0.00	8.80	11.82	37.68	37.68	0.00	0.00	3.58	3.58	53.08	864.75
18	113.04	2.26	0.00	6.60	8.86	37.68	37.68	0.00	0.00	2.68	2.68	49.23	878.68
19	75.36	1.51	0.00	4.40	5.91	37.68	37.68	0.00	0.00	1.79	1.79	45.38	890.66
20	37.68	0.75	0.00	2.20	2.95	37.68	37.68	0.00	0.00	0.89	0.89	41.53	900.87

PV Tax Shields	391.12
Tax on shields	113.00
Investment	753.59
After Tax Investment	640.59

Adjust for Tax Gross-Up 900.87 <----------------------------- = ----------------------------->PV Rev Req 900.87

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
55 W LED Installation

Financial Input	Input
Capital Investment - Material	$525.00
Capitalized Labor	$228.59
Total Capitalized Investment	$753.59

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%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$900.87
Levelized Annual Revenue Requirement	$86.79
Annual O&M / Maintenance Expense	$0.00
Annual Revenue Requirement	$86.79
Net Monthly Tariff Rate	$7.23
PA Gross Receipts Tax	$0.45
Total Monthly Distribution Rate	**$7.69**

Weighted Cost of Capital

	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	46.65%	4.29%	2.00%	1.42%
Preferred	0.00%	0.00%	0.00%	0.00%
Equity	53.35%	10.95%	5.84%	5.84%
	100.00%		7.84%	7.26%

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	753.59	15.07	0.00	44.02	59.10	37.68	37.68	0.00	0.00	17.89	17.89	114.66	106.90
2	715.91	14.32	0.00	41.82	56.14	37.68	37.68	0.00	0.00	16.99	16.99	110.81	203.21
3	678.23	13.56	0.00	39.62	53.19	37.68	37.68	0.00	0.00	16.10	16.10	106.96	289.88
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5	602.88	12.06	0.00	35.22	47.28	37.68	37.68	0.00	0.00	14.31	14.31	99.27	437.69
6	565.20	11.30	0.00	33.02	44.32	37.68	37.68	0.00	0.00	13.42	13.42	95.42	500.33
7	527.52	10.55	0.00	30.82	41.37	37.68	37.68	0.00	0.00	12.52	12.52	91.57	556.38
8	489.84	9.80	0.00	28.62	38.41	37.68	37.68	0.00	0.00	11.63	11.63	87.72	606.44
9	452.16	9.04	0.00	26.41	35.46	37.68	37.68	0.00	0.00	10.73	10.73	83.87	651.06
10	414.48	8.29	0.00	24.21	32.50	37.68	37.68	0.00	0.00	9.84	9.84	80.02	690.75
11	376.80	7.54	0.00	22.01	29.55	37.68	37.68	0.00	0.00	8.94	8.94	76.17	725.97
12	339.12	6.78	0.00	19.81	26.59	37.68	37.68	0.00	0.00	8.05	8.05	72.32	757.14
13	301.44	6.03	0.00	17.61	23.64	37.68	37.68	0.00	0.00	7.15	7.15	68.47	784.66
14	263.76	5.28	0.00	15.41	20.68	37.68	37.68	0.00	0.00	6.26	6.26	64.62	808.87
15	226.08	4.52	0.00	13.21	17.73	37.68	37.68	0.00	0.00	5.37	5.37	60.77	830.10
16	188.40	3.77	0.00	11.01	14.77	37.68	37.68	0.00	0.00	4.47	4.47	56.93	848.64
17	150.72	3.01	0.00	8.80	11.82	37.68	37.68	0.00	0.00	3.58	3.58	53.08	864.75
18	113.04	2.26	0.00	6.60	8.86	37.68	37.68	0.00	0.00	2.68	2.68	49.23	878.68
19	75.36	1.51	0.00	4.40	5.91	37.68	37.68	0.00	0.00	1.79	1.79	45.38	890.66
20	37.68	0.75	0.00	2.20	2.95	37.68	37.68	0.00	0.00	0.89	0.89	41.53	900.87

PV Tax Shields	391.12
Tax on shields	113.00
Investment	753.59
After Tax Investment	640.59

Adjust for Tax Gross-Up 900.87 <----------------------------- = -----------------------------PV Rev Req 900.87

Exhibit DBO-5
Duquesne Light Company
Updated Unbundling Default Service Costs

Line	Item	Current Recovery Mechanism	Proposed Recovery Mechanism	Description	A = (B * 4) Total Estimated Costs	B = (C+D+E+F) Annualized Estimated Costs	C Forecasted Annual Default Service Costs by Customer Class: Residential & Lighting	D Small C&I	E Medium C&I <200	F Medium C&I >200 & Large C&I
1	Forecasted POLR Sales (MWh) - 6.1.2021 - 5.31.2024					4,048,700	2,722,000	480,600	542,600	303,500
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	$844,505	$211,126	$141,943	$25,062	$28,295	$15,827
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.	$5,638,282	$1,409,571	$947,675	$167,323	$188,908	$105,665
5	**Total (Line 3 + Line 4)**				**$6,482,787**	**$1,620,697**	**$1,089,618**	**$192,384**	**$217,203**	**$121,491**

1/ Assuming the Company's pre-tax weighted cost of capital of ~10.22%, the revenue requirement (annual expense) associated with DSS working capital is $1,409,571 [$13,796,655 multiplied by ~10.22% return]. The cash working capital cost of $13,796,655 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.

Duquesne Light Company

Schedule 1 - Computation of Proposed Federal Tax Adjustment Clause ("FTAC")

Illustrative Example - January 1, 2022 through December 31, 2022

Line No.		Total	
1	Federal Income Tax Adjustment	17,638,075	Exhibit 5, Statement No. 12, Exhibit MLS-3, Page 2, Line 10
2	Amount to be Recovered (w/o GRT)	27,216,228	Line 1 * Note 1
3	Amount to be Recovered (w/ GRT)	28,922,665	Line 2 * Note 2
4	PAR = Projected Annual Base Distribution Revenue	644,342,923	Exhibit 2, Schedule D-5D, page 3, Column C, line 19.
5	FTAC = Federal Tax Adjustment Clause Rate % of Base Distribution Revenues (w/ GRT)	4.49%	Line 3 / Line 4

Note 1:
(1/((1-SIT)*(1-FIT)))
SIT = 9.99% State Income Tax
FIT = 28% Federal Income Tax

Note 2:
1/(1-T) = (T = 5.9% Gross Receipts Tax)

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3024750

Duquesne Light Company

Statement No. 17

Direct Testimony of Margot Everett

Subjects: Rider No. 16, Community Development Rider, Residential Subscription Rate Pilot, and Electric Vehicle Program Rates

Dated: April 16, 2021

DIRECT TESTIMONY OF MARGOT EVERETT

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

A. My name is Margot Everett. My business address is 101 California Street, Suite 4100, San Francisco, California 94111. I am a Director for Guidehouse and will provide testimony on behalf of Duquesne Light Company ("DLC" or the "Company").

Q. BRIEFLY STATE YOUR EDUCATION, BACKGROUND AND EXPERIENCE.

A. I have a Master of Science and Bachelor of Arts in Applied Economics from University of California, Santa Cruz. With over thirty-five years in the energy industry, I have held many differing roles from evaluation and design of customer programs, wholesale power contract structuring, market, credit and enterprise risk management and cost of service and rate design. Recently I spent five years leading Pacific Gas and Electric's (PG&E's) electric and gas rates, load forecasting and cost of service departments. In that role I have led the development and design of alternative rate designs for distributed energy resources, such as a successor to the Net Energy Metering tariff.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION (THE "COMMISSION")?

A. No, however, I have testified numerous times in California and South Carolina, and on rate design policy and alternative rate designs. Further I supervised all testimony related to rates, cost of service and load forecasting for the five years I served as Senior Director of Rates and Regulatory Analytics at PG&E.

Q. HAVE YOU INCLUDED ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes, I have two Exhibits:

- Exhibit ME-1, which summarizes cost-shifting associated with the Company's current Rider No. 16; and
- Exhibit ME-2, which describes the methodologies and inputs for the benefit cost analyses of the Company's proposed Fleet and Home Charging EV programs.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present new rate options, the justification for those rate designs, and the proposed values for these rates. The rate options are as follows:

1. Revised Rider 16 for standby services;
2. New Rider for Community Development rates; and
3. New Residential Subscription Rate Pilot.

I am also providing testimony supporting rates included in the Fleet Pilot and Home Charging Pilot described in Witness Olexsak's testimony. Lastly, I am sponsoring testimony regarding the benefit and cost analysis (BCA) performed for the Fleet Pilot and Home Charging Pilot to support the adoption of these pilots.

REVISED RIDER No. 16

Q. PLEASE DESCRIBE THE EXISTING RIDER No. 16.

A. Rider No. 16 is an optional rate that applies to non-utility generating facilities[1]. Specifically, it applies to customers who self-generate through use of Combined Heat and Power (CHP) or other technologies and utilize supply and delivery capacity on Duquesne Light Company's distribution system. Rider No. 16 includes provisions for energy supply and delivery and is differentiated by levels of service to cover energy needs not being met by the customer's generator. Specifically, Rider No. 16 differentiates between Supplementary Power and Back-Up Power.

Rider No. 16 is an optional rate. Customers who elect to take service on Rider No. 16 agree to service for a "Base Period" defined as "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". The customer also agrees to the level of service that the Company would be required to provide. Specifically, the customer agrees to "Contract Demand" that is defined as "the maximum electrical capacity in kilowatts that the Company shall be required by the contract to deliver to the customer for Back-Up Power." Rider No. 16 also provides that a "Contract Demand may be established for Supplementary Power to the customer's facility."

Q. PLEASE DESCRIBE SUPPLEMENTARY POWER AND HOW IT APPLIES UNDER THE EXISTING RIDER No. 16.

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[1] Includes, but not limited to cogeneration and small power production facilities that are qualified in accordance with Part 292 of Chapter 1, Title 18, Code of Federal Regulations (qualifying facilities).

A. Supplementary Power refers to distribution services provided by the Company and regularly used by the customer to meet its energy needs that are in excess of the electricity that the customer's generation facility typically produces. Rider No. 16 specifically defines Supplementary Power as the "electric energy and capacity supplied 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." Also, Rider No. 16 notes that "The Company's regular and appropriate General Service Rates will be utilized for billing charges for Supplementary Power. Customers purchasing Supplementary Power from an EGS will be billed for charges according to their applicable rate and billing arrangement with their EGS." That is, the Company's tariffed General Service Rates (e.g., GM < 25, GM ≥ 25, GMH < 25, GMH ≥ 25, GL, GLH and L rates) are charged for Supplementary Power services and are based on the customer's actual monthly billing demand (kW) up to the contracted Supplementary Demand levels. If Supplementary Power supply is provided by the Company, the customer is charged for that supply by their Electric Generation Supplier ("EGS") or by the Company under either Rider No. 8 – Default Service Supply (if customer's demand is less than 200kW) or Rider No. 9 – Day-Ahead Hourly Price Service (if customer's demand is equal to or greater than 200kW).

Q. PLEASE DESCRIBE BACK-UP POWER AND HOW IT APPLIES UNDER THE EXISTING RIDER No. 16.

A. Back-Up Power refers to distribution services provided by the Company to enable a customer to replace electricity ordinarily generated by the customer's on-site equipment during any outage. Rider No. 16 currently defines Back-up Power as "electric energy and capacity supplied by the Company to a non-utility generating facility during any outage of the non-utility generating facility's electric generating equipment to replace electric energy ordinarily generated by the non-utility generating facility's generating equipment." By its nature, Back-Up Power is used infrequently but still requires the Company to maintain distribution capacity for that customer if the customer needs additional electricity delivered during those outages. To be eligible for Back-Up Power service, the number of hours the customer needs such services must be equal to or less than 15% of all hours in a year.

Back-up service requires the Company to ensure adequate distribution capacity for those times when the customer's generating facility is not producing adequate electricity for its needs. Examples of when such events occur include but are not limited to planned maintenance outages and forced outages that either reduce output or cause the plant to shut down entirely. When these events occur, the customer requires delivery of energy to meet the customer's electricity needs that are typically provided by their generation equipment. The additional delivery capacity can be required for several hours or for up to several weeks.

Q. PLEASE DESCRIBE ALL BACK-UP POWER CHARGES CURRENTLY APPLIED UNDER THE EXISTING RIDER No. 16.

A. As briefly noted above, a customer who selects Rider No. 16 contracts for Back-Up Power services for a "Base Period" and establishes a Contract Demand. Contract Demand represents the maximum electrical capacity in kilowatts (kW) that the Company shall be required to deliver to the customer for Back-Up Power. The customer then pays a monthly charge of $2.50 per kW of Contract Demand, regardless of whether the customer calls upon Back-Up Power services.

In any billing period during which the Company provides Back-Up Power, the customer is billed additional charges for energy supply. Like energy supplied by the Company under Supplement Power, the customer is charged for that supply by its Electric Generation Supplier ("EGS") or by the Company under either Rider No. 8 – Default Service Supply (if customer's demand is less than 200kW) or Rider No. 9 – Day-Ahead Hourly Price Service (if customer's demand is equal to or greater than 200kW).

Contract Demand is established in cooperation with the Company and set for the "Base Period." However, if a customer exceeds the Contract Demand by 5% or more in any billing period, the customer's actual maximum kW demand in that billing period becomes the customer's new Contract Demand for the remaining term of the Back-Up Power contract. Therefore, for the remaining term of the "Base Period," the customer's "ratcheted" Contract Demand applies to the $2.50/kW rate in the tariff.

Lastly, if the customer's actual demand during the time Back-Up Power is being provided exceeds Contract Demand by 10% or more, the customer is assessed an additional fee. This fee is equal to the difference between the actual demand and Contract Demand times the Contract Demand charge times two (i.e., $5.00 per kW).

Q. WHY ARE STAND-BY RATES NEEDED?

A. Stand-by rates are a common practice among utilities and are designed to recover distribution costs from those customers that infrequently or intermittently require distribution services over the course of the year. These customers rarely call upon the capacity of the grid for back-up service because they only require delivery during times when their generation is not operating as planned. However, their capacity needs can be dramatic during those occasions and the Company must have distribution services available to meet this unpredictable load at any time. A customer is only eligible for service under Rider No. 16 where the customer requires back-up service for less than 1,314[2] hours per year. However, the maximum capacity they require during those hours could be significant. Nevertheless, assets to deliver electricity to this customer must be available at all times for how long those assets will be needed by this customer. Put simply, stand-by rates are necessary to ensure that all other Duquesne Light customers do not pay for the costs the individual customer with a generator creates. Avoiding 'subsidization' of certain customers through 'cost shifts', or costs created by one customer or group of customers being 'shifted' and paid for by other customers or customer groups, is fundamental to cost-reflective rate design.

Q. WHY IS THE COMPANY PROPOSING TO CHANGE THE STRUCTURE OF RIDER 16?

A. As noted above, the key reason for creating standby rates is to eliminate or minimize the subsidy that other customers pay that should be paid by a customer with an operating generator behind the meter. The current rate structure is not cost-reflective. Therefore, the customers who select this rate (as noted above, Rider No. 16 is an optional rate) are able to avoid paying costs that are incurred to serve them and thus customers not on the rate are picking up the difference.

Q. PLEASE DESCRIBE HOW YOU CONCLUDED THAT THE CURRENT RIDER NO. 16 IS NOT COST REFLECTIVE AND THUS THERE IS A COST SHIFT.

[2] 1,310 hours is 15% of total hours in a non-leap year or 8,760.

A. A review of the bills that a typical customer would pay if they were on the GL General Services Rate, which is cost-reflective, versus the current Standby Rate shows that a typical customer on Rider No. 16 pays far less, up to 12% less, than if they were on their GL rate. This detail is provided in Exhibit No. ME-1. These differences in bills versus what the typical customer would pay otherwise represents the degree of cost-shifting. To rectify, Rider No. 16 should be redesigned to reflect costs to serve these customers.

Q. WHAT IS THE PROPOSED STRUCTURE FOR THE UPDATED RIDER 16?

A. The Company is proposing a new structure to Rider No. 16, hereafter referred to as Revised Rider No. 16, to better align this optional rate to other rates offered by the Company and to create a structure that is more reflective of costs and protects the Company's customers who do not have customer generation from cost shifts as more customer generators are installed in the Company's service territory.

Q. PLEASE DESCRIBE THE PROPOSED STRUCTURE OF THE REVISED RIDER NO. 16.

A The Company is proposing three modifications to Rider No. 16:

1. Creation of Maintenance Contract Demand with a related charge of $3.09 per kW of Maintenance Contract Demand.
2. Creation of As-Used Contract Demand with a related charge of $6.79 per kW of As-Used Contract Demand.
3. Adjustment of Overage Fees for periods during which Maintenance Contract Demand is exceeded by 10% or more to $9.88 per kW of actual demand in excess of Maintenance Contract Demand.

Q. PLEASE DESCRIBE YOUR APPROACH TO DESIGNING THE PROPOSED RIDER 16.

A. The basic approach was to create a rate that could be applied to all customer classes eligible for Back-Up service and have that rate represent cost of service. Specifically, the Company applied a Revenue Neutral Rate design approach across the following General Services Rate schedules: GM < 25, GMH < 25, GM ≥ 25, GMH ≥ 25, GL, GLH and L. This approach results in the development of an estimate of the bill that a typical customer would pay if they were on their applicable General Service rate.

The proposed rate design comprises a Maintenance Demand rate and an As-Used Demand rate. It also maintains both the Overage Fees for customers that significantly exceed their contracted Maintenance Demand and the mechanism for adjusting the contracted demands should the customer significantly exceed those agreed to service levels.

Q. WHAT IS THE PROPOSED COST REFLECTIVE MAINTENANCE DEMAND RATE AND HOW WAS IT COMPUTED?

A. The first step in this process is to estimate the service that would be provided under Back-Up Service, or specifically a level of Maintenance Contract Demand relative to a load shape of expected delivery services, by rate class. Because the Rider No. 16 structure charges customers the same amount for Back-Up or Maintenance Contract Demand every month, despite the actual level of services provided, the rate should reflect that the customer does not always consume the maximum demand every month and thus there is load diversity. That is, if every customer on Rider No. 16 were to pay based on maximum demand rather than the sum of their monthly demands, they would pay too much for their service relative to other customers. Further, because a customer may choose Supplementary Demand service in addition to Back-Up service, Supplementary Demand can be assumed to be set to the customer's minimum monthly demand and Back-Up services would provide for service above that minimum. Therefore, the Company calculated a Load Diversity factor (LD Factor) for each class based on the billing demands for each class. The LD Factor was calculated as the ratio of the average difference between minimum demand and actual demand and the maximum demand. Table 1 below shows the monthly billing demands by class and the calculation for the LD Factor by class.[3]

[3] Source of data are from the Proof of Revenues calculations, Attachment DFR IV-C-Proof.

Table 1: Average Monthly Maximum Demand by Rate

	GM<25	GM>25	GL	L	GMH <25	GMH >25	GLH
Jan	9.9	73.4	683.8	7,467.3			
Feb	9.4	68.9	644.8	7,376.0			
Mar	10.3	77.9	739.0	7,989.8			
Apr	9.8	73.3	709.8	7,849.6			
May	11.7	87.7	821.9	8,764.9			
Jun	11.9	89.3	807.1	8,729.8	9.5	58.8	704.0
Jul	12.4	92.9	844.0	9,137.0	9.0	62.1	755.4
Aug	11.5	90.1	849.9	9,093.9	8.6	60.9	754.0
Sep	10.6	82.5	761.9	8,234.6	8.4	52.7	622.9
Oct	11.0	80.2	768.0	8,295.8			
Nov	10.8	76.5	702.7	7,835.0			
Dec	10.3	73.8	691.2	7,592.0			
Total	129.6	966.5	9,024.1	98,365.6	35.4	234.4	2,836.3
Maximum	12.4	92.9	849.9	9,137.0	9.5	62.1	755.4
Minimum	9.4	68.9	644.8	7,376.0	8.4	52.7	622.9
Months	12.0	12.0	12.0	12.0	4	4	4
Average	10.8	80.5	752.0	8,197.1	8.9	58.6	709.1
Avg -Min	1.4	11.7	107.3	821.2	0.5	5.9	86.1
Max-Min	3.0	24.0	205.2	1,761.0	1.2	9.4	132.4
LD Factor	46%	49%	52%	47%	42%	63%	65%

The LD Factor is multiplied by the applicable demand charge for each rate schedule, representing the cost the customer would impose on the system if its demand could be smoothed out over time. This calculated rate then represents the cost-reflective value for the applicable Maintenance Contract Demand services provided by the Company. Table 2 shows the calculation of the diversified rate by rate schedule. Further, since customers from any of these rate schedules can select Rider No. 16, the rate must be revenue-neutral to the Company on an overall basis. Therefore, the final Back-Up Service rate is established using the load weighted average of each rate schedule, or $4.88/kW. This calculation is also shown in Table 2.

Table 2: Calculation of Proposed Back-Up Services Cost Reflective Rate

➔ Rate Schedule	GM<25	GM>25	GL	L	GMH<25	GMH>25	GLH
Total Billed Demand (MW)	2,621.0	6,547.2	6,657.6	1,972.2	89.2	150.6	251.3
Average Rate ($/kW)	7.89	7.89	10.66	16.63	7.89	7.89	10.66
Weighted Average Rate	9.88						
Diversification Factor	46%	49%	52%	47%	42%	63%	65%
Diversified Rate ($/kW)	3.64	4.05	5.08	8.88	4.55	2.91	3.74
[redacted]							
Weighted Rate ($/kW)	4.88						

Q. IS THE COMPANY PROPOSING TO IMPLEMENT THE FULL COST-REFLECTIVE MAINTENANCE DEMAND CHARGE AT THIS TIME?

A. No. While the value of $4.88/kW represents the revenue-neutral, cost-based rate for back-up service if customers smoothed out their demand, if the Company were to move to this rate level for Contract Demand, the change in the Rider No. 16 rate constitute a 95% increase over the present rate of $2.50 per kW for back-up service. To ensure a gradual change in rates toward a cost-reflective tariff, the Company proposes to increase the current Rider No. 16 rate of $2.50/kW to $3.09, which results in the rate moving closer to the cost reflective value of $4.88 without creating significant rate shock for these customers. This rate increase is particularly modest given that the current $2.50 per kW rate has not been adjusted since May 1, 2013, before which the corresponding rates were $6.45 per kW (for contract demand less than 5,000 kW) and $6.04 per kW (for contract demand of 5,000 kW or more) – or about double the rate proposed in this proceeding.

Q. WHAT IS THE PROPOSED AS-USED DEMAND RATE AND HOW WAS IT COMPUTED?

A. The As-Used Demand charge is design to ensure the Back-Up rate is fully cost reflective. The As-Used Demand charge only applies to load during a designated Peak Period, which represents the likely times when loads on the Company's system are highest.

Calculation of the As-Used Demand charge reflects the full costs of providing on-demand cost of service during peak demand periods, basically negating the LD Factor discount during times when demand is greatest across the Company's service territory. To best represent this additional cost, the As-Used Demand charge is applied to the customer maximum demand in that month that occurs during the Peak Period. This rate is computed based as the full General Service tariff demand charges less charges toward these costs already recovered under the Maintenance Demand rate. Again, since the proposed Rider No. 16 applies to all customers who choose this option, a weighted average of the demand costs per kW for all applicable rate schedules was calculated (see Table 2) as $9.88. Finally, care must be taken to not double count revenues from the Maintenance Contract Demand Charge. Therefore, the As-Used Demand Charge is set to the difference between the cost reflective rate of $9.88 and the Maintenance Contract Demand charge (or back-up rate) of $3.09, or $6.79 per kW. Going forward, as the Maintenance Contract Demand rate is increased in subsequent proceedings to closer to the full cost-recovery rate based on the LD factor, this difference will decline.

Q. WHAT IS THE "PEAK PERIOD" THAT APPLIES TO THE AS-USED DEMAND CHARGE AND HOW WAS IT DETERMINED?

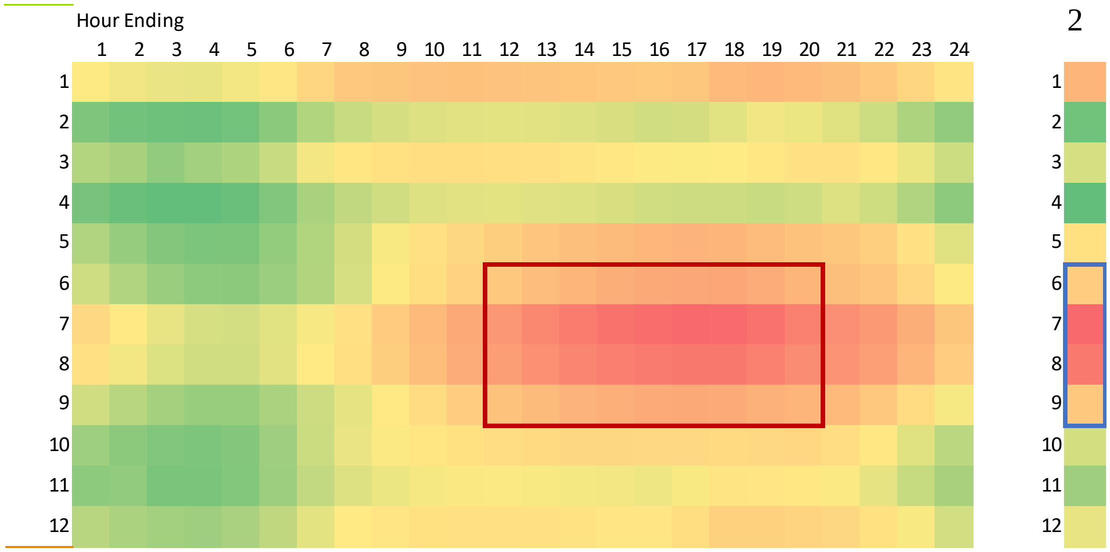
A. The Company reviewed hourly system loads to determine the season and times of day where load is most pronounced and potentially drives the Company's distribution costs. Figure 1 below shows a heat map that depicts total load by hour by month, with hours on the horizontal and months on the vertical axis. Figure 1 also shows the total load by month. Red indicates high load while green represents low load, relative to all hours. As this figure shows, the high load hours tend to happen in the afternoons between June through September (denoted in red or orange). Further, the red box included in Figure 1 shows that demand during these months are most pronounced from 11am to 8pm.[4]

Unexpected and potentially significant demands on the system during these high load hours could create additional costs and thus the As Used Demand charge, which is the full cost reflective rate for any customer who requires delivery services, should apply rather than a discounted Maintenance Demand Charge that reflects some load diversity benefits. Note that the As Used Demand Charge that applies during the Peak Period is net of the Maintenance Demand Charge to avoid double counting.

While including May as a 'peak month' was considered, the Company elected to be consistent with the current summer months used for established the heating rates for simplicity and ease of implementation.

[4] Figure 1 shows the range to be Hour Ending 12, which includes the hour from 11 am to 12 am, through Hour Ending 20, which includes the hour from 7pm to 8pm, thus ending the peak period at 8pm.

Figure 1: Heatmap of Average Weekday 2018 Hourly System Demand



Q. PLEASE DESCRIBE IN DETAIL THE 'OVERAGE FEE', HOW IT WAS DETERMINED AND HOW WILL OVER-COLLECTION BE ADDRESSED?

A. Under the current Rider No. 16, the overage fee applies to demand that exceeds the customer's Maintenance Contract Demand by 10% or more. Currently the overage fee is set to two times the Rider No. 16 rate for Back-Up Power (or $5.00/kW). This scaler is not closely linked to cost reflective principles.

The purpose of the overage fee is to incent setting the Maintenance Contract Demand to levels that represent the expected level of service to be provided under Back-Up Services. If a customer strategically chose a Back-Up service level that is lower than expected, the customer will not be paying their cost of service and those costs avoided by the customer are paid for by other customers. To ensure the overage fee is cost-reflective, the Company proposes to set an overage fee based on the average cost to serve the demand. As noted above, the computed average cost to serve is $9.88/kW and should be the overage rate, as compared to the Revised Rider No. 16 rate after the application of the Diversification factor of $4.88. This results in an Overage Charge Multiplier of 2.1 (simply

9.88/4.88). However, the Company is proposing to only increase the Revised Rider No. 16 rate to $3.09/kW. Since the overage charge should reflect full cost of service, the Company proposes increasing the overage charge to the full cost of service, or $9.88/kW. This results in a multiplier of 3.3, but only applies to the difference in the actual monthly demand (kW) and the Maintenance Demand.[5]

Q. PLEASE DESCRIBE IN DETAIL THE MECHANISM FOR ADJUSTING MAINTENANCE CONTRACT DEMAND?

A. The current Rider No. 16 calls for an increase in the Contract Demand if the customer's maximum demand exceeds 105% of its Contract Demand. Specifically, the tariff states, "If a customer's actual kW demand at the time back-up is being supplied exceeds the customer's back-up Contract Demand by 5% or more, the actual kW demand as established will become the customer's new back-up Contract Demand for the remaining term of the back-up contract." The Company proposes to keep this mechanism to ensure customers are incented to choose the correct level of Maintenance Demand relative to their expected demands on the system, therefore ensuring the customer pays their fair share of the costs of serving them. It is important to note that this mechanism only applies to Maintenance Contract Demand.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO RIDER No. 16 TARIFF LANGUAGE.

[5] Note that if a customer exceeds the Maintenance Demand by more than 5%, the Maintenance Demand is increased to the actual monthly demand for remainder of Base Period, but the overage fee applies in the month of the exceedance, prior to adjustment of Maintenance Demand, thus is based on the Maintenance Demand in effect during the billing month.

A. To address the current challenges of Rider No. 16 and move toward more cost-reflective rates, the Company proposed changes to Rider No. 16, with key changes described below:

1. Adjust definitions to clarify that Rider No. 16 is only for distribution services:
   - Replacement of the term "Supplemental Power" with "Supplemental Service" and change definition to refer only to providing distribution services energy provided under Supplemental Service;
   - Replacement of the term "Back-Up Power" with "Back-Up Service" and change definition to refer only to distribution services;
   - Adjust definition of Supplementary Service Billing Determinants to be based on the contracted kW specified for Supplementary Service;
   - Adjust definition of Back-Up Service Billing Determinants to be based on the contracted kW specified for Back-Up Service.
2. Elimination and introduction of terms to clarify the new rate design as follows:
   - Elimination of term "Contract Demand";
   - Introduction of the following terms:
     - "Contract" to refer to the agreement entered into by the customer and the Company and includes specification of the levels of service provided under Rider No. 16;
     - "Maintenance Contract Demand" to refer to the maximum electrical capacity in kilowatts (kW) that the Company shall be required to deliver to the customer for "Back-Up Delivery Service";

- “Supplementary Contract Demand” to refer to the threshold to which Supplementary Service is contracted and subsequently provided under applicable General Service Rates;
- “Peak Period” to refer to the period of time between 11am and 8pm EST, Mondays through Saturdays during the months of June through September; and
- “As Used Contract Demand” to refer to the maximum electrical capacity in kilowatts (kW) that the Company shall be required to deliver to the customer for “Back-Up Delivery Service” during the Peak Period.

3. Introduction of two distinct rate components for Back-Up Demand:
   - “Maintenance Rate” of $3.09 per kW of Maintenance Contract Demand, and
   - “As Used Premium Rate” of $9.88 per kW of As Used Contract Demand.
4. Introduction of three distinct billing determinants for Back-Up Demand service:
   - “Maintenance Demand Billing Determinant” refers to the contracted kW served under Back-Up Service and will be equal to Maintenance Contract Demand specified in the contract and applies to every month in the contract period;
   - “Supplementary Contract Demand Billing Determinant” refers to the contracted kW served under Supplementary Contract Demand and will be equal to the customer’s monthly maximum demand up to the level of demand contracted; and
   - “As Used Demand Billing Determinant” refers to the kW that applies if the customer called upon Back-Up Service during the Peak Period. Because the As Used Demand charge only applies to demand the customer calls upon during the Peak Period, the billing determinant for As Used Demand is zero if the

customer does not call upon Back-Up Service during the Peak Period. If the customer does call upon Back-Up service during the Peak Period, the billing determinant for As-Used Demand is equal to the customer's actual maximum demand, less the customer's Supplementary Contract Demand, during the Peak Period of that billing cycle.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE RIDER NO. 16 ELIGIBILITY CRITERIA?

A. No. Rider No. 16 will continue to be an optional rate that applies to customers who self-generate through use of Combined Heat and Power (CHP) or other technologies and also utilize supply delivery capacity on DLC's distribution system. Specifically, Rider No. 16 describes eligible customers as "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)". This proposal does not change these eligibility criteria.

Q. PLEASE DESCRIBE IN DETAIL THE PROCESS FOR DETERMINING MAINTENANCE CONTRACT DEMAND FOR BILLING PURPOSES.

A. The process currently used for developing Contract Demand under Rider No. 16 will continue to apply to the revised Rider No. 16. Specifically, the Maintenance Contract Demand is established during the contracting process and is mutually agreed to by the customer and the Company. Rider No. 16 will also continue to have provisions to mitigate any risk of gaming in the setting of the Contract Demand. Currently Rider No. 16 has the provision that, if the customer exceeds the Contract Demand by 5% or more during the billing period, the Company can unilaterally adjust the Contract Demand to the actual demand and this adjustment would remain until the end of the contract period. This same provision remains in Rider No. 16, with adjustments to reference Maintenance Contract Demand.

Q. PLEASE DESCRIBE IN DETAIL THE PROCESS FOR DETERMINING AS USED CONTRACT DEMAND FOR BILLING PURPOSES.

A. As Used Contract Demand will be a monthly demand that applies only if the customer calls upon Back-Up Services during the Peak Period. Specifically, if a customer consumes capacity in excess of the Supplementary Contract Demand (and equal to or less than Maintenance Contract Demand) during the Peak Period, proposed to be between 11am and 8pm EST during the months of June through September, then the As-Used Demand Billing Determinant is set to the customer's actual maximum demand, less the customer's Supplementary Contract Demand, during that the Peak period for that month. Otherwise, the value is set to zero.

Q. PLEASE PROVIDE EXAMPLES OF HOW THE NEW RATE RIDER WOULD APPLY IN COMPARISON TO THE CURRENT RATE.

A. This example assumes a customer with demand equal to 1MW and a generator with capacity of 600kW. The customer's contract under the current rider would specify that the Supplementary Contract Demand is 400kW and, for purposes of comparison to current rate, the Contract Demand is set to 600kW. Similarly, the customer's Maintenance Contract Demand under the revised Rider No. 16 would also be 600kW.

Focusing on the months September through November, the customer experiences a full outage (all hours) in the last week of September and first week of October. Further, in October, the customer's actual demand is 1,100kW. The monthly charges under the current and revised tariffs are shown in Table 3. Finally, because the customer's actual use resulted in overage of 100kW in October, the customer has exceeded both the 5% ratchet threshold (30kW) and the 10% overage fee threshold (60kW). Therefore the customer is charged the overage fee on the 10% and the customers Contract Demand (for the current rate) and Maintenance Demand (for the revised rate) is increased to the actual demand level in October.

Table 3: Hypothetical Bill Comparison

		September	October	November
	Current Rate			
A	Contract Demand (kW)	600	600	700
B	Rate ($/kW)	2.50	2.50	2.50
C=AxB	Monthly Charge ($/month)	1,500.00	1,500.00	1,750.00
D	Overage Demand (kW)	-	100	-
E=Bx2	Overage Rate ($/kW)	5.00	5.00	5.00
F=DxE	Overage Charge ($/Month)	-	500.00	-
G=C+D	Total Base Distribution Charges ($/Month)	1,500.00	2,000.00	1,750.00
	Revised Rate			
H	Maintenance Contract Demand	600	600	700
I	Maintenance Rate	3.09	3.09	3.09
J=HxI	Monthly Maintenance Charge	1,800.00	1,800.00	2,100.00
K	As-Used Contract Demand	600	-	-
L	As-Used Rate	6.79	-	-
M=KxL	Monthly As Used Charge	4,073.18	-	-
N	Overage Demand	-	100	-
P	Overage Rate	9.88	9.88	9.88
Q=N*P	Overage Charge	-	987.89	-
R=J+M+Q	Total Base Distribution Charges	5,873	2,788	2,100
S=R-G	Difference	4,373	788	350

As Table 3 shows, the customer's bill reflects the overage fees and the ratchet in demand starting in November triggered by the October load in excess of the contracted demands. Additionally, note that although the customer draws on Maintenance Contract Demand during both September and October, it does not incur a charge for As-Used Demand in October, as that month falls outside the Peak Period.

Q. HOW DOES THIS PROPOSED STRUCTURE ADDRESS THE CHALLENGES AND SHORTCOMINGS OF THE EXISTING RIDER 16?

A. This revised Standby rate structure and calculated rate of $4.88 is based on the cost of service, accounting for the fact that these customers pay a fixed amount monthly. Currently the billing determinants used in the Proof of Revenue calculation are 277,609 kW and thus revenues of $832,825.63. Although the proposed rate is not the actual cost reflective rate, it does move the rate towards the target by increasing the rate by 20% toward the cost-reflective rate of $4.88.

Further, from a policy perspective, the As-Used Demand Charge provides customers the opportunity to manage their demands on the Company's system to save money while ensuring those customers pay their full cost of service. Specifically, customers who are able to effectively manage their demand needs by scheduling outages during non-peak months or non-peak hours will be able to avoid these additional charges as they are also not contributing to the potential cost increase.

Lastly, the design of this rate was focused on eliminating the subsidization of customers with generation assets behind the meter but that still rely on the Company's system for serving all their delivery needs. It does this by allowing the Company to collect additional revenue towards cost of service for the customers that use the distribution system intermittently during peak times, and thus potentially increase the Company's operating costs.

NEW COMMUNITY DEVELOPMENT RIDER

Q. PLEASE DESCRIBE THE PROPOSED COMMUNITY DEVELOPMENT RIDER?

A. The proposed Community Development Rider is designed to provide incentives for customers to bring operations to the Company's service territory. The tariff provides a prescribed discount to distribution services demand charges for five years, with the structure providing the most savings in the first years of the offering. Specifically, the Community Development Rider is a prescribed percent discount to the demand charge of any General Services tariff during the months of January through May and October through December. The discount starts at 25% and decreases by 5 percentage points (20%) annually until the end of five years after which no discount is applied.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS RIDER AND WHY IT IS NEEDED NOW?

A. The Company is proposing this Community Development Rider to provide an incentive to attract non-residential customers with beneficial load profiles to the Company's service territory. This proposal offers benefits to many potential customers who can bring new operations to the Pittsburgh area, existing customers looking to substantially increase their operations within the Company's service territory, and former customers that shut down operations in the past year to reopen in the Company's service territory as the area recovers from the economic ramifications of Covid-19. Specifically, this rate would be open to new businesses, businesses considering a substantial expansion of existing operations, and businesses that shuttered during the pandemic and are considering re-opening.

Q. HOW DOES THIS PROPOSED STRUCTURE PROVIDE THE BENEFITS YOU DESCRIBED?

A. This discount will provide benefits to the participating customer by lowering their initial costs to reopen, invest in new technologies or establish the new operations while also benefiting the Company's existing customers by increasing sales, which results in downward pressure on rates. The rate discount is designed to only reduce rates for new customers in those months when system peak is unlikely: October through December, and January through May. The Company experiences the highest level of system load in the months of June through September. Figure 1 above shows a heat map that depicts the high load months and hours. The heat map shows hours on the horizontal and months on the vertical axis. As this figure shows, the high load hours tend to happen in the afternoons between June through September (denoted in red or orange). The community development rate discount does not apply during those months, thus selectively encouraging growth amongst customers with loads that are less likely to impact the Company's system peak. By offering the discount only in non-peak months, the rate structure will increase sales with relatively lower increases in costs. Therefore, these new customers may contribute significantly to the recovery of fixed costs without substantially increasing costs, thus mitigating rates for all customers.

Q. WHAT IS THE PROPOSED STRUCTURE FOR THE COMMUNITY DEVELOPMENT RATE?

A. The structure offers a percent discount to the volumetric demand charge for months of January through May and October through December. The discount would commence on the effective date of all rates, which is January 15, 2022, and decline by 20% every year over five years. To align the discount with the period covered by the Company's tariff, the discount will change every January from 2023 through 2026. The following table shows the discount schedule.

Table 4: Community Development Percent Discount

	January 2022	January 2023	January 2024	January 2025	January 2026
Discount	25%	20%	15%	10%	5%

Q. PLEASE DESCRIBE IN DETAIL THE COMMUNITY DEVELOPMENT RIDER ELIGIBILITY CRITERIA?

A. The rate discount applies to any customer eligible for service on a GM < 25, GM ≥ 25, GL and L rates who opens a new account related to the establishment of a new business operation or re-opening a business that was shut down after March 1, 2020 (to represent the start of the economic ramifications of Covid-19). Because the discount does not apply to demand during June through September, the heating customer rates (GMH < 25, GMH ≥ 25, GLH) would not receive a discount.

Q. BASED ON THE REVENUE TO BE COLLECTED AND BILLING DETERMINANTS, PLEASE SUMMARIZE THE ACTUAL COMMUNITY DEVELOPMENT RIDER FOR EACH CUSTOMER CLASS AND RATE COMPONENT.

A. Table 5 below shows the expected demand charges a customer on the Community Development Rider would pay during non-summer months. These values are computed using the proposed demand rates and the applicable rider percent discount for each year.

Table 5: Proposed Demand Charges for Eligible Tariffs

Rate Class	January 2022	January 2023	January 2024	January 2025	January 2026
GM<25	$5.92	$6.31	$6.71	$7.10	$7.50
GM>25	$5.92	$6.31	$6.71	$7.10	$7.50
GL	$8.00	$8.53	$9.06	$9.59	$10.13
L	$12.47	$13.30	$14.14	$14.97	$15.80

Q. DID YOU COMPUTE THE AVERAGE BILL SAVINGS FOR A CUSTOMER UNDER THE PROPOSED RIDER?

A. Yes. Table shows average bill savings by year for each rate class that qualifies using the average billing determinants for a customer in that class. In each case, the annual bill savings below were calculated by applying the percentage discount to the standard demand charge for each of the four rate classes, and applying this to the average number of Block 2 kilowatts (the billing determinant to which the demand charge applies) projected per customer during non-summer months by the Company.

Table 6: Average Customer Bill Savings

Rate Class	January 2022	January 2023	January 2024	January 2025	January 2026
GM<25	$93	$75	$56	$37	$19
GM>25	$1,128	$902	$677	$451	$226
GL	$8,985	$7,188	$5,391	$3,594	$1,797
L	$96,331	$77,065	$57,798	$38,532	$19,266

Q. DO THE RATES PROPOSED REPRESENT FULL COST OF SERVICE?

A. No, there is a discount to total cost of base distribution service. However, the benefits of increasing revenues that contribute to offsetting fixed costs for a specified period of time provide additional benefits as noted above.

Q. IS A CUSTOMER ELIGIBLE FOR ANY OTHER DISCOUNTS IF THEY ELECT THE COMMUNITY DEVELOPMENT RIDER OPTION?

A. No. Specifically, in this rate case the Company has included Covid-19 relief in this filing. Any customer electing that option would not be eligible for this discount, and vice a versa.

Q. THE COMMISSION'S POLICY STATEMENT ON ALTERNATIVE DISTRIBUTION RATEMAKING MECHANISMS, 52 PA. CODE §§ 69.3301 AND 69.3302, IDENTIFIES A NUMBER OF FACTORS THE COMMISSION MAY CONSIDER WHEN EVALUATING AN ALTERNATIVE DISTRIBUTION RATE MECHANISM. HAS THE COMPANY CONSIDERED THESE FACTORS WITH RESPECT TO THE COMMUNITY DEVELOPMENT RATE?

A. Yes. I address each of them below.

(1) How the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.

The rate design for the Community Development Rider is based on current rates for all customers on General Service Rates GM < 25, GM >25, GL and L, all of which are based on cost causation principles. The rate is simply a discount to these rates, reducing the customer's contribution to fixed costs for the designated period of time. While the customer receives this discount, the customer continues to make an incremental contribution to fixed costs while paying variable. That is, because a customer must bring additional load to qualify for this rate, the customer is covering variable costs of the new load and paying towards the fixed costs, lowering the burden of recovering fixed costs from all other customers. Further, the discount only applies for five years, and declines over time, minimizing the amount of the discount and avoiding any challenges of establishing discounts that prove to be inappropriate over time.

(2) How the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.

The discount only applies to months with lower demand. Referring back to Figure 1 above, the system load is highest during the months of June through September. By offering a discount only for months outside that peak load period, the Company is attracting load that would most benefit and thus likely to have significant loads in months other than June through September, potentially improving the utilization of the Company's delivery system and lowering rates for all customers.

Also, with no discount during the summer months, the Company will not experience additional growth during those months without the customer paying rates that are consistent with the cost to serve all other customers from the same class.

(3) Whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.

Because the discount is applied only to the demand charges, it is directly reflecting the level of demand associated with the customer's consumption levels.

(4) How the ratemaking mechanism and rate design limit or eliminate interclass and intraclass cost shifting.

The rate only applies to customers that bring additional load to the Company's service territory, and the customer pays variable costs. Further, because the customer's load is incremental and, even with the discount, the customer is making a contribution to fixed costs, and thus contributing to reducing costs paid for by other customers (e.g., more revenue to offset fixed costs from these customers reduces the amount of revenue needed to collect fixed costs from all other customers).

(5) How the ratemaking mechanism and rate design limit or eliminate disincentives for the promotion of efficiency programs.

While a discount to demand charges could arguably reduce the incentive for energy efficiency programs, the rate design structure mitigates this in two ways. First, the discount is only for five years and declines equally each year, thus a customer remains incented to invest in energy efficiency in the initial investment of operations for the new load (e.g., the customer is increasing operations and the long term incentive for installing energy efficient equipment remains). Second, the discount does not apply during the summer months. Therefore, the customer will still be equally encouraged to invest in energy efficient cooling systems.

(6) How the ratemaking mechanism and rate design impact customer incentives to employ efficiency measures and distributed energy resources.

As noted above, because the discount is applied to demand charges and is only for five years and declines equally each year, a customer is actually incented to invest in energy efficiency that reduces peak demand in the initial investment of operations for the new load (e.g., the customer is increasing operations and the long term incentive for installing energy efficient equipment remains). Further, because the discount does not apply during the summer months, the customer is be equally encouraged to invest in energy efficient cooling systems as they would under the current General Service rates.

(7) How the ratemaking mechanism and rate design impact low-income customers and support consumer assistance programs.

The program should assist low-income customers because the additional contribution to fixed costs from customers on the Community Development rider would reduce rates for all customers over time. Further, this rate will also support customers returning operations to the Company's service territory after many shuttered due to the pandemic. Therefore, this program is, in part, an assistance program as it makes it more affordable for customers to reopen and recover over the five-year discount period.

(8) How the ratemaking mechanism and rate design impact customer rate stability principles.

The rate design creates a discount to the customer's General Service Rate demand charge. Therefore, it is linked to current rates and thus the customer's rate stability remains the same as if the customer were on their General Service Rate. Further, the discount is explicit and the glidepath to reduce the level of discount over the five year period is predictable and transparent. Therefore, the rate structure is stable and transparent.

(9) How weather impacts utility revenue under the ratemaking mechanism and rate design.

This rate is linked to existing General Services rates and thus experiences similar impacts attributable to weather.

(10) How the ratemaking mechanism and rate design impact the frequency of rate case filings and affect regulatory lag.

This rate design will not impact the frequency of rate case filings or regulatory lag.

(11) If or how the ratemaking mechanism and rate design interact with other revenue sources, such as Section 1307 automatic adjustment surcharges, 66 Pa.C.S. § 1307 (relating to sliding scale of rates; adjustments), riders such as 66 Pa.C.S. § 2804(9) (relating to standards for restructuring of electric industry) or system improvement charges, 66 Pa.C.S. § 1353 (relating to distribution system improvement charge).

Not applicable.

(12) Whether the alternative ratemaking mechanism and rate design include appropriate consumer protections.

The rate is an optional rate and provides a discount to the current rates a customer would otherwise be charged, therefore the customer is better off under this rate design (and has the option to not choose the rate). This provides adequate protections as the customer's bill cannot be greater under this tariff than under the otherwise applicable General Services rate.

(13) Whether the alternative ratemaking mechanism and rate design are understandable to consumers.

By applying a simple discount that is transparent and predicable, it is very easy for a customer to understand the rider structure.

(14) How the ratemaking mechanism and rate design will support improvements in utility reliability.

This rate design is based on current General Services rates with a simple discount to the demand charge component to temporarily discount the participating customer's contribution to fixed costs. Further, the customer receives no discount during the summer months when the company experiences its highest loads and the discount is finite with steady decline over the five year period. Lastly, this rate only applies if the customer brings incremental load. All together these provide for full cost recovery of costs planned for by the company for reliability while potentially reducing rates for all customers over time.

(b) In any distribution rate filing by a fixed utility under 66 Pa.C.S. § 1308 (relating to voluntary changes in rates) that proposes an alternative ratemaking mechanism and rate design, the fixed utility shall explain how these factors impact the distribution rates for each customer class.

Table 6 demonstrates the rate impact expected for participating customers. Further, as noted above, these customers continue to pay variable costs and are contributing incrementally to fixed costs, thus other customers are not impacted and may, in fact, benefit from the additional contribution to fixed costs paid by the participating customers.

SUBSCRIPTION RATE PILOT FOR RESIDENTIAL CUSTOMERS

Q. PLEASE DESCRIBE THE PROPOSED SUBSCRIPTION RATE PILOT TARIFF?

A. The Company proposes to implement a pilot to test the feasibility and acceptance of a Residential Subscription tariff. This subscription rate would offer customers the option to select a specified level of grid access for a set monthly charge. This subscription applies to base distribution services, regardless of energy, or kWh use, up to a set level of demand, or kW. The level of subscription increases as the amount of demand subscribed to increases. The rate is structured based on incremental levels of demand, starting with a minimum Subscription Level of 1 kW and increasing in increments of 1 kW, based on a customers estimated maximum demand levels over the year.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS PILOT RATE AND WHY IT IS NEEDED NOW?

A. Recently subscription rates are gaining interest as possible innovative rate application that simplifies utility pricing for small general service and residential customers. This rate design substitutes the traditional volumetric rate structure, or price per kWh consumed, for a more stable rate structure that is easy to understand and predictable for customers. Analogous to data plans for cell phones or standard pricing for video streaming service, such as Amazon Prime and Netflix, the energy subscription rate is rate design option that may meet pricing needs of customers.

Subscription service rates, particularly for distribution service, is a better rate design than typical energy related volumetric rates to reflect the costs of these services to small general service and residential customers. That is, the cost of distribution delivery service is driven either by NCP demand or customers. The subscription rate would recover both customer costs and delivery charges included in rate RS, exclusive of Riders.[6] That is, any Rider as designed, and costs included in rates for RS, are collected via the subscription. This is because the utility must install distribution capacity to meet the customer's demands on their system regardless of the amount of energy the customer consumes. That is, regardless of whether a customer consumes 5 kW from the system for 1 hour or 8760 hours in a year, the distribution system must have the 5 kW of capacity to serve.

As customers start to use energy differently with technology innovation and behavior changes, a subscription rate may also prove to be a customer-centric solution to bill volatility while allowing them to embrace new technologies to help manage their peak demand.

Conducting a pilot before the Company files its next rate case will allow for the opportunity to study this new rate design with willing customers. The results of the pilot will provide both the Company and the Commission with valuable information regarding the potential benefits of such a rate design, the customer tools that are needed to make the design successful, and the acceptance of such a rate by customers. Also, it will serve as a means to understand if and how a subscription rate changes a customer's behavior.

Q. HOW DOES THIS PROPOSED STRUCTURE PROVIDE THE BENEFITS YOU DESCRIBED?

[6] Riders will be applied as designed and cost recovered from those riders will be based on the customer's relevant rider billing determinant.

A. First, this rate continues to follow cost-of-service principles and reflects the customers' costs. Further, providing customers with a meaningful price signal regarding their demand also creates the incentive for customers to manage their energy in such a way as to flatten their overall load profile. Specifically, with a subscription rate the Company can also inform the customer that the best way to reduce their bills is to reduce their peak use. This can be done with customer education focused on encouraging customers to use selected appliances during times when they are otherwise not using energy. Company witness Neiswonger discusses the Company's plans for customer outreach and education in her direct testimony, DLC St. No. 9. In effect, subscription rates can have the similar implications as TOU rates as both encourage customers to spread their usage across the day, improving utilization of the grid. However it also has the added benefit of smoothing a customer's bill over the year, similar to budget billing options offered by the Company.

Q. ONE CRITICISM OF SUBSCRIPTION RATES IS THAT IT DOES NOT CREATE AN INCENTIVE FOR CONSERVING AND COULD INCREASE CUSTOMER USAGE. PLEASE RESPOND.

A. As noted above, subscription rates can encourage peak shifting and thus provide many of the benefits of conservation programs that also incent this behavior. Also, subscription rate structures can include the introduction of energy efficiency technology as a requirement for participation. For example, a customer may be required to install a smart thermostat to qualify for the subscription rate.

While the Company's proposed pilot rate structure does not require these technologies, the pilot will allow the Company to understand how customers responded to the subscription rate and whether customers invested in these types of technologies to further manage their energy bill. The evaluation can also estimate the degree to which customers conserve or shift their energy usage under the subscription rate.

Q. WHAT IS THE PROPOSED STRUCTURE FOR THE PROPOSED SUBSCRIPTION RATE PILOT?

A. As noted above, the subscription rate starts with a minimum level of service of 1 kW, which includes customer charges plus delivery charges for up to 1kW of demand. This is akin to the minimum bills applicable to GL customers. The pilot then prescribes a "Subscription Unit" of 1 kW. Upon enrollment, each customer chooses a Subscription Level, which is the number of Subscription Units the customer needs to cover their annual peak demands plus 1 kW, which is covered with the minimum bill. The customer is then charged the Minimum Subscription plus Subscription Unit Charge times the Subscribed Units monthly. Table 7 below shows the subscription pricing proposed.

Table 7: Subscription Rate Pilot Pricing

Subscription Component	Subscription Fee
Minimum Subscription	$28.48
Subscription Unit Charge (per 1 kW)	$12.23

Additionally, to ensure that customers' subscription levels best represent their expected use, an overage fee will be applied if the customer's actual monthly demand exceeds the subscribed demand by 0.5 kW, hereafter referred to as "Overage Bandwidth." This threshold creates a fair bandwidth in which a customer may deviate. The Overage Fee is equal to two times the Subscription Unit Charge times the "Overage Amount," which is defined as the difference in actual monthly peak demand and the customer's "Subscription Level," less 0.5 kW (the Overage Bandwidth).

To provide clarity on the Subscription Pilot rate, assume the following example. A customer has a historically experienced maximum demand of 2.9 kW. To cover that level of demand, at enrollment the customer elects a Subscription Level of 3 kW. Each month the customer then pays the Minimum Subscription level of $28.48 plus two times the Subscription Unit Charge of $12.23 for a total monthly base distribution bill of $52.94 a month, regardless of the level of energy, or kWh they have delivered. Throughout the year, as long as the customer's monthly maximum demand remains below their Subscription Level plus 0.5 kW for Overage Bandwidth, the customer only pays the $52.94 in base distribution charges.

Assume then in a month the customer's demand is 3.3 kW. In this case the customer's monthly Subscription Charge remains $52.94 because the customer is within the 0.5 kW Overage Bandwidth. However, if the customer's demand is 3.8 kW, the customer has a positive Overage Amount of 0.3 kW, computed as the 3.8 kW less the 3 kW Subscription Level less the 0.5 kW Overage Bandwidth. In this case the customer pays an overage fee of $7.34, which is two times the Subscription Unit Charge of $12.23 times the positive Overage Amount of 0.3 kW.

However, if the customer exceeds their Subscription Level plus Overage Bandwidth more than three times in a year, the customer will be notified that they need to either increase their subscription level to accommodate the peak demands experienced in the past year or exit the pilot.

This approach would mimic a full implementation of a subscription rate where a mechanisms would have to be put in place to mitigate the risk that a customer would choose a subscription level that is habitually just under their expected use while not creating an overly punitive mechanism for a pilot. That is, the goal is to keep customers enrolled in the pilot to gain the most information regarding the potential issues of such rate options, which would also include the potential for customers to choose the wrong subscription level for their distribution needs.

Q. PLEASE DESCRIBE IN DETAIL THE PROPOSED SUBSCRIPTION RATE PILOT ELIGIBILITY CRITERIA?

A. The pilot will launch starting in 2022 and will be limited to 2,000 participants who can enroll through December 2022. Customers can remain on the subscription rate after December 2022; however, enrollment will stop such that the program can be thoroughly reviewed before the next rate case. The pilot will be limited to customers on General Services rate RS and excludes customers on the Company's Customer Assistance Program (CAP), as they are already on a payment assistance program that is linked to the customer's income. Any non-CAP customer on the Company's Rate RS will be eligible except for those customers selecting the Rider No. 21, Net Metering Services due to the administrative challenges of applying the NEM rider to the subscription rate (note it is highly unlikely that a customer installing rooftop solar would elect to join a subscription rate because much of the benefit of the NEM tariff is to allow a customer to export energy generated to be 'banked' and credited against future costs. With a subscription rate, the customer is no longer receiving a volumetric rate and thus this benefit would not be available to a NEM customer).

Q. PLEASE DESCRIBE IN DETAIL THE PROCESS FOR ENROLLING CUSTOMERS INTO THE PILOT?

A. The subscription rate is an optional rate that a customer can select. The offering will be publicized, and customers will be invited to request access to the pilot. Not all customers who request enrollment in the pilot will be selected. This is for two reasons. First, the pilot size will be limited to 2,000 customers. Second, in order to create an effective pilot design, certain customers who would elect this service should be used as the 'Control Group'. A 'Control Group' is the group of customers that are not enrolled in the program but represent the pool of customers that were enrolled in the program. The 'Control Group' is used to measure the expected participating customer's behavior had the participating customer not enrolled. This method provides a valid comparison group to ensure no bias in your sampling for comparison.

To create a valid 'Control Group,' the Company may employ a 'recruit and enroll or delay' approach such that a random subset of customers are delayed granted access to the pilot for one year and thus serve as a representative Control Group for the first year. The added benefit is that both the initial participant and the delayed participant groups can also be analyzed on a per customer pre-post basis to further augment the impact assessment. The Company will track whether a customer requests access to the tariff but is not enrolled, to facilitate the pilot evaluation process.

Q. WILL CUSTOMERS WHO ENROLLED RECEIVE BILL PROTECTION?

A. Yes, customers who enroll in this program will be allowed to terminate their subscription service for any reason at any time. Further, these customers will be eligible to receive a refund, upon request, for the actual difference in the customer's bill under the standard rate versus the subscription pilot rate. This calculation will be performed by the Company upon the request for the refund. Also, the refund would only apply to the shorter of the number of months since enrollment or the last three months of the customer's bill. For example, if a customer enrolls on February 1st and elects to depart May 1st and receive a rebate, the rebate will cover all the time that the customer has been in the pilot. However, if they chose to leave June 1st, they only receive a rebated for bills for March through May. This is to avoid a customer choosing to revert back at the end of the year, choosing the 'best annual' option versus addressing whether a customer can't respond to a subscription rate effectively.

To avoid unnecessary expense, the Company is not proposing to compute 'shadow bills' for all customers enrolled in the subscription pilot and will thus only perform these calculations upon request. If a customer exits the program, the Company will contact the customer to understand the reasons for their withdrawal and include this information in the pilot evaluation study. Also, any customer who exits will not be eligible to re-enroll in the subscription for the remainder of the pilot. This is to avoid customer gaming the rate options.

Q. PLEASE DESCRIBE YOUR APPROACH TO DESIGNING THE PROPOSED SUBSCRIPTION RATE PILOT?

A. The rate was designed to create a revenue neutral rate assuming an average customer would pay the same amount on the subscription as they would under their residential rate option.

To calculate the rate, the Company took hourly demand profiles from residential customers from February 2020 through January 2021. These data were screened for outliers and included only customers with 12 months of data. This resulted in a sample of 382,096 customers. The Company then calculated monthly the bills for each customer as if they were on their designated rate to compute the revenue collected from the sample, broken down between revenues from fixed customer charges and volumetric charges. This total revenue from volumetric charges was then divided by the sum of the monthly non-coincident demand for all of these customers. This resulted in a billing determinant much larger than the non-coincident demand of the collective group of customers in this analysis. The ratio of revenues to cumulative non-coincident monthly demands for each customer yields a rate per kW of subscription.

Similarly, the overage rate of two times the rate applied to the amount of $12.23 in excess of the bandwidth of 0.5 kW is roughly the amount the customer would have paid had they selected the correct level of subscription. That is, expanding on the example above, the customer would have paid for a Subscription Level of 4 kW versus 3 kW. By charging the overage on the 0.5 kW in excess of the bandwidth times two, the rate results in a payment very close to the amount the customer had chosen the correct subscription level. An amount in excess of the two times the bandwidth creates a monetary incentive for the customer to choose the right level, while the overage fee structure allows for the customer to deviate from their subscription by 0.5 kW without financial penalty.

Q. HOW DOES THE PROPOSED SUBSCRIPTION RATE PILOT COMPARE TO EXISTING RATES?

A.

Table 8 shows rates and expected monthly bills for both proposed RS rates and the proposed subscription pilot rate (RSS-P).

Table 8. Expected Monthly Bills – RS Rate and Proposed Subscription Rate

Rate	Proposed Energy Charge ($/kWh)	Customer Charge ($/month)	Average Energy per Customer (kWh/month)	Expected Average Bill ($/month)
RS	$0.070564	$16.25	575	$56.82
	Minimum Subscription ($-month)	**Subscription Unit Charge ($/Subscription Unit month)**	**Average Subscription Units (Units-month)**	**Expected Average Bill ($/month)**
RSS-P	28.48	12.23	2.3	$56.61

Q. HOW WILL CUSTOMER BILLS DIFFER WITH DIFFERENT LOAD PROFILES?

A. Using the sample of 382,096 customers noted above, each customer's bill under the subscription rate was also calculated then compared to their rate on the applicable tariff. Figure 2 below shows a series of bill impact heat maps. The first represents the change monthly bills by customer demand (kW), while the second shows the change monthly bills energy use (kWh). The third shows the percent change in bills by customer demand (kW) and the last shows the percent change in bills by customer energy use.

Figure 2: Expected Bill Impacts Heat Maps

Demand (kW)	< $-50	$-50 to $-40	$-40 to $-30	$-30 to $-20	$-20 to $-10	$-10 to $-5	$-5 to $5	$5 to $10	$10 to $20	$20 to $30	$30 to $40	> $50
1	0	1	35	1142	4053	12565	9677	862	18	0	0	0
2	19	186	1843	10906	13347	16364	12532	6221	1828	11	0	0
3	396	1860	7328	21226	16086	14867	11201	7580	6910	712	16	0
4	1059	2900	7971	14184	8019	7648	6972	6673	12330	5998	640	14
5	562	1226	3031	5714	3939	4853	5987	7017	15398	10409	2770	226
6	126	378	1182	3090	2727	3568	4614	5309	10675	7027	2599	449
7	17	122	485	1347	1228	1627	1920	2051	3972	2597	1188	352
8	1	16	100	363	317	451	517	611	1278	1000	468	262
9	0	0	17	76	75	114	159	220	461	390	241	182
>10	0	0	1	7	13	38	42	51	142	138	106	257

Energy (kWh)	< $-50	$-50 to $-40	$-40 to $-30	$-30 to $-20	$-20 to $-10	$-10 to $-5	$-5 to $5	$5 to $10	$10 to $20	$20 to $30	$30 to $40	> $50
200	0	0	0	1	1090	11905	13565	5141	3157	994	467	140
400	0	0	1	2802	11635	18768	14901	8940	11495	8857	3152	529
600	0	0	621	15295	18604	15490	9796	7770	17098	11020	2761	472
800	0	157	5535	22312	10161	7438	7080	8023	13977	5128	1074	303
1000	43	1895	9544	10734	4456	4941	5557	4830	5278	1595	392	187
1200	604	3110	4347	4480	2759	2680	2100	1388	1484	524	134	80
1400	994	1152	1414	1897	920	691	494	409	432	141	41	27
1600	442	315	456	455	145	147	107	87	83	20	6	4
1800	91	57	65	77	33	35	21	7	8	3	1	0
>2000	6	3	10	2	1	0	0	0	0	0	0	0

Demand (kW)	< -50%	-50% to -40%	-40% to -30%	-30% to -20%	-20% to -10%	-10% to -5%	-5% to 5%	5% to 10%	10% to 20%	20% to 30%	30% to 40%	> 50%
1	23	289	1677	4434	6846	4527	4669	3516	1482	570	207	113
2	211	2137	7435	12960	14050	5872	4874	6809	4105	2421	1299	1084
3	467	3961	12236	19695	18591	6813	5492	7549	4882	3273	2187	3036
4	328	3007	9312	13072	11480	4582	3970	6682	5421	4666	3566	8322
5	38	716	2811	5307	6756	3697	3961	8055	7659	6486	5026	10620
6	0	73	628	2314	4871	3185	3556	7216	6266	4886	3188	5561
7	0	2	112	830	2263	1619	1728	3262	2576	1764	1092	1658
8	0	0	4	140	618	486	531	1137	917	622	383	546
9	0	0	0	14	130	138	190	441	383	246	151	242
>10	0	0	0	0	14	45	56	148	125	101	77	229

Energy (kWh)	< -50%	-50% to -40%	-40% to -30%	-30% to -20%	-20% to -10%	-10% to -5%	-5% to 5%	5% to 10%	10% to 20%	20% to 30%	30% to 40%	> 50%
200	0	0	170	1974	5907	4945	5515	5763	3909	2669	1741	3867
400	2	231	2915	9112	13927	7019	6429	9696	6693	5146	4464	15446
600	41	1114	6666	16194	19016	6979	5466	8675	8340	8925	7524	9987
800	112	2200	9852	16617	12211	4611	4581	10198	9850	6437	2812	1707
1000	231	2877	8806	8649	7087	3963	4397	7338	3819	1451	513	321
1200	298	2384	4099	3863	4847	2489	1955	2310	938	343	95	69
1400	259	1041	1279	1722	2036	731	529	682	239	56	25	13
1600	94	298	362	542	487	177	131	141	25	7	2	1
1800	29	37	63	84	96	49	24	12	3	1	0	0
>2000	1	3	3	9	5	1	0	0	0	0	0	0

Q. DO THE RATES PROPOSED REPRESENT FULL COST OF SERVICE?

A. Yes, as noted above, a customer's maximum delivery demand is the primary driver of delivery capacity. By structuring a rate that is based on the customer's delivered capacity, the rate is more cost reflective. Further the rate is designed to cover the full cost of service, as represented by the existing residential customer rate, of an average residential customer. As described, the rate is designed to collect the same amount of revenue from an average residential customer on General Service rate RS, thus cost reflective and revenue neutral.

Q. DO EXISTING AND FUTURE SURCHARGES STILL APPLY TO CUSTOMERS WHO ELECT THE SUBSCRIPTION RATE PILOT?

A. Yes. The subscription only applies to the customers' delivery services covered in the RS rate. All other applicable Riders (for example, Rider No. 5 – Universal Service Charge; Rider No. 15A – Energy Efficiency Surcharge; etc.) will be applied as designed and added to the customer's monthly bill.

Q. ARE CUSTOMERS ENROLLED IN THE SUBSCRIPTION RATE PILOT ELIGIBLE TO SHOP FOR SUPPLY?

A. Yes. Since the subscription only applies to the customers' delivery services covered in the RS rate, the customer would still need to elect a supply option that would be met through an EGS or by the Company through its default service program.

Q. PLEASE DESCRIBE THE TOOLS THAT WILL BE DEVELOPED TO ASSIST SUBSCRIPTION CUSTOMERS IN MANAGING THEIR BILLS?

A. There are several aspects of the subscription pilot that are included to protect the participating customer and glean the best information for the pilot. First, customers will be contacted by the Company in the event that the customer exceeds their subscription level to inform the customer of options for adjusting their subscription level. Second, the customer is able to cancel their subscription at any time without penalty. Lastly, the customer can request a refund of the difference between what their bill would have been had they remained on the standard Rate RS and the subscription rate (as noted above, for up to three months and customer must leave pilot if they receive the refund). This refund will be computed upon request such that the Company does not need to build shadow billing capabilities for this small pilot.

In summary, the pilot focuses on a high touch approach of reaching out to customers to help them adjust to the subscription rate. This will then inform the Company on the customer tools that would have to be developed for a larger roll-out of such a program. This approach saves administrative costs of building tools that prove un-helpful to customers and also allows for more expeditious implementation of the pilot, which results in more information to be gathered during the pilot prior to the next rate case.

Q. HOW WILL THE COMPANY ASSESS THE SUCCESS OF THE PILOT?

A. The Company will collect data for the pilot over the course of the pilot, to include the tracking of customers who requested enrollment but were not able to enroll for various reasons, thus identifying those likeminded customers for the control group. That is, a control group is used to evaluate what a customer would have done without the program. It is best to select customers who would have enrolled in the program to avoid systematic and unintended bias in the evaluation results.

After two full years of enrollment, to ensure at least one year of customer usage data for late-enrolling customers, the Company will conduct an evaluation. The general approach will be to review how the customers' usage patterns may have changed due to being on the subscription, to include identification of any estimated change in the time or magnitude of the aggregate monthly peak demands of the participant group that may be the result of individual peak shifting to minimize the subscription levels, as well as potential increases in overall energy use. Although the goal of the rate is to induce shifts in individual customer monthly NCP demands, individual customer hour data typically has too much apparently random variation ("noise") to allow for the robust estimation of statistically significant changes in an *individual's* demand. Since residential customers tend to have relatively homogenous patterns of use, an evaluation of the average collective impact at times (for example) in which the control group's demand is peaking, will accurately identify the degree to which participants have responded to the price signal. The Company will also conduct customer surveys to gain an understanding of the participating customers' level of satisfaction with, and understanding of, the Pilot Rate, any potential challenges or improvements that could be employed and a review of the customer journey of enrolling and participating. Best practice is to conduct compulsory entrance and exit surveys that are designed to test the participants' understanding of how the rate works as well as perhaps a few additional questions around customer characteristics (e.g., size of home, number of inhabitants and special technologies such as EVs). A full evaluation plan will be developed in parallel to the administrative set up of the program such that the evaluation plan is set prior to implementation, eliminating any perceived conflict in the evaluation of program performance.

Q. HOW WILL THE SUBSCRIPTION RATE BE SHOWN ON THE CUSTOMER'S BILL?

A. To minimize pilot costs the Subscription Rate will be a rate Rider that:

- Credits the $/kWh charge for base delivery services, set to the level of the customer's applicable rate.

- Credits the base customer charge, set to the level of the customer's applicable rate.
- Adds a fixed monthly charge for the subscription.
- Adds any overage fees as described above.

Q. THE COMMISSION'S POLICY STATEMENT ON ALTERNATIVE DISTRIBUTION RATEMAKING MECHANISMS, 52 PA. CODE §§ 69.3301 AND 69.3302, IDENTIFIES A NUMBER OF FACTORS THE COMMISSION MAY CONSIDER WHEN EVALUATING AN ALTERNATIVE DISTRIBUTION RATE MECHANISM. HAS THE COMPANY CONSIDERED THESE FACTORS WITH RESPECT TO THE RESIDENTIAL SUBSCRIPTION RATE PILOT?

A. Yes. I address each of them below.

(1) How the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.

The rate design is based off of the customer's demand, rather than traditionally volume or kWhs of customer use. This change moves the customer closer to cost of service principles as delivery services are more driven by demand than volume. This is demonstrated by the fact that the company's rates for larger customers all have demand charges. Demand charges for residential customers are, historically, uncommon because of the complexity and potential bill volatility that can result. This rate design addresses this issue by providing for the linkage to demand by customers but also creating bill smoothing.

Also, the rate was designed as 'revenue neutral' to the current rates, which represent the cost to service this customer class. Therefore, the rate recovers the fixed and variable costs allocated to this customer class.

(2) How the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.

Subscription rates are a new rate design that has not been widely tested. For this reason, the Company proposes to first pursue a pilot that would allow for the Company to understand the changes in customer behavior, if any, that may result from this rate design. To that end, the pilot will provide information regarding the impact on the capacity utilization and allow both the Company and the Commission understand the potential benefits of a Subscription rate before providing access to such a rate for all residential customers.

(3) Whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.

The subscription rate is designed for a customer to choose a level of demand to which they manage their load, creating a direct link between the rate design and level of demand associated with the customer's consumption levels.

(4) How the ratemaking mechanism and rate design limit or eliminate interclass and intraclass cost shifting.

The rate design is a revenue neutral rate design, meaning that the rate is designed to collect all the revenues allocated to the class as if all customers were on the alternative rate. This ensures that, on average, the rate does not produce interclass or intraclass cost-shifting.

(5) How the ratemaking mechanism and rate design limit or eliminate disincentives for the promotion of efficiency programs.

As noted above, the Subscription rate is a new rate that has not been widely tested, therefore the impact on energy efficiency cannot be directly estimated. However, because the subscription is also based on the customer's demand level, the customer will be incented to reduce their peak usage to lower their bill directly without necessarily reducing their total energy consumption. This can be done through peak shifting or investment in energy efficient equipment used during peak times (e.g., air conditioning). The evaluation of the pilot will provide for the assessment of the impact on energy efficiency and allow both the Company and the Commission understand the potential benefits of a Subscription rate before providing access to such a rate for all residential customers.

(6) How the ratemaking mechanism and rate design impact customer incentives to employ efficiency measures and distributed energy resources.

As noted above, the Subscription rate is a new rate that has not been widely tested, therefore the impact on energy efficiency it cannot be directly estimated. However, because the subscription is also based on the customer's demand level, the customer is now incented to reduce their peak usage to lower their bill directly without necessarily reducing their total energy consumption. Again, the evaluation of the pilot will provide for the assessment of the impact on energy efficiency and allow both the Company and the Commission understand the potential benefits of a Subscription rate before providing access to such a rate for all residential customers

(7) How the ratemaking mechanism and rate design impact low-income customers and support consumer assistance programs.

All residential customers on rate RS not enrolled in Rider No. 21 or the Company's Customer Assistance Program (CAP) are eligible; and thus the rate is available to low-income customers who choose not to enroll in CAP. The subscription rate offers many of the same benefits of budget billing, which provides steady and predictable rates. However, this rate has two additional benefits. First, there is no true-up with the subscription (e.g., under budget billing a customer's 'average bill' is based on past usage, so is highly subject to impact of the past on current rates; while the Subscription bill provides for bills that reflect the customer's current behavior.) Lastly, unlike budget billing, the customer can choose to manage to a lower level of usage than in the past.

Additionally, with the pilot, customer will be allowed to leave the program and are offered bill protection during the billing. This further protects low-income customers from bill shocks and allows for testing if this rate option is preferable for low-income customers.

(8) How the ratemaking mechanism and rate design impact customer rate stability principles.

The Subscription Rate offers bill stability, particularly if the customer is able to manage their load to the subscription levels.

(9) How weather impacts utility revenue under the ratemaking mechanism and rate design.

With the Subscription Rate, the customer pays the same amount each month unless the customer exceeds the subscription level. As a result, it may mitigate weather impacts on utility revenue. With a pilot, the Company can research the potential impact on utility revenue under subscription pricing.

(10) How the ratemaking mechanism and rate design impact the frequency of rate case filings and affect regulatory lag.

This rate design will not impact the frequency of rate case filings or regulatory lag.

(11) If or how the ratemaking mechanism and rate design interact with other revenue sources, such as Section 1307 automatic adjustment surcharges, 66 Pa.C.S. § 1307 (relating to sliding scale of rates; adjustments), riders such as 66 Pa.C.S. § 2804(9) (relating to standards for restructuring of electric industry) or system improvement charges, 66 Pa.C.S. § 1353 (relating to distribution system improvement charge).

Not applicable.

(12) Whether the alternative ratemaking mechanism and rate design include appropriate consumer protections.

The Subscription Pilot offers appropriate consumer protections in three ways. First, enrollment is optional for the customer and the customer chooses to enroll (e.g., opt-in enrollment). Second, the customer may elect to exit the pilot at any time with no penalty. Third, a customer can request bill protection and thus end up with the same bill payments as if under the customer's default rate. This protection, necessarily, only applies for up to a three month period to ensure customers don't game the rate design.

(13) Whether the alternative ratemaking mechanism and rate design are understandable to consumers.

Many consumer offerings rely on subscriptions, to include but not limited to Netflix, Amazon, and cell phone plans. Customers are generally familiar with these pricing options; a subscription may even be easier to understand than a customer's current energy bill. Nevertheless, the pilot is designed to solicit this information from customers. That is, the pilot study will include gaining insights from the customer on the understanding of the rate and any implications of an alternative rate design.

(14) How the ratemaking mechanism and rate design will support improvements in utility reliability.

The rate design is revenue neutral therefore is expected to the same support for improvements in utility reliability as the current rate options for these customers.

(b) In any distribution rate filing by a fixed utility under 66 Pa.C.S. § 1308 (relating to voluntary changes in rates) that proposes an alternative ratemaking mechanism and rate design, the fixed utility shall explain how these factors impact the distribution rates for each customer class.

I address how the Subscription Rate Pilot rate design impacts participating customers' distribution rates in my testimony above. As discussed, it will only impact rates for up to 2,000 participating customers in Rate RS.

EV PILOT RATES

Q. PLEASE BRIEFLY DESCRIBE THE BASIS FOR THE FLEET PILOT AND HOME CHARGING PILOTS?

A. Both the Home Charging Pilot and Fleet Pilot include rates charged to participating customers to recover the costs of the chargers, and some of the costs incurred to establish charging solutions, for Duquesne Light customers who are using electric vehicles (EVs). Specifically and as described in the direct testimony of Company Witness Olexsak, DLC Statement No. 8, the pilots offer Duquesne Light customers EV charging solutions. Pilot program costs include administration, equipment, marketing and outreach, and infrastructure costs. These costs establish the pilots for customers, provide customers with the necessary equipment and installation, and provide ongoing support to administer the pilots.

Q. PLEASE DESCRIBE THE COSTS FOR THE FLEET PILOT, INCLUDING THE TIMING OF THESE COSTS.

A. As Witness Olexsak describes in her testimony, costs include labor to plan and construct charging equipment, administer IT systems, and manage the administration of the pilots. Costs also relate to the make-ready, charging stations, networking, station commissioning, maintenance and warranties, equipment shipping, and marketing materials. These costs are both expenses and capital investments, with the latter being converted to revenue requirement by taking the sum of the depreciation expense, associated taxes, and the return on capital determined for each year of a given asset's life.

Q. PLEASE DESCRIBE THE COSTS FOR THE HOME CHARGING PILOT, INCLUDING THE TIMING OF THESE COSTS.

A. As Witness Olexsak describes in her testimony, costs for the Home Charging Pilot relate to the charging system equipment, installation, and ongoing maintenance of charging equipment. The pilot also includes costs for IT systems, marketing, advertising, education, and rebates for low-income participants. Costs also relate to labor for program management, data management, billing, and operations. As with the Fleet Pilot, these costs are both expenses and capital investments, with the latter being converted to revenue requirement by taking the sum of the depreciation expense, associated taxes, and the return on capital determined for each year of a given asset's life.

Q. HOW IS THE COMPANY PROPOSING TO RECOVER THESE COSTS?

A. The Company proposes to recover charger and charger installation costs, as applicable, from participants through rates specified in each Pilot design. The Company will then recover program implementation and administrative costs, as well as the costs of make-ready infrastructure, from all customers, similar to cost treatment for other customer programs. In other words, the revenue requirement associated with these costs is included in the Company's proposal, but revenues will be collected from both participants through the pilot program and through general rates, consistent with how costs from other customer programs are collected.

Q. WHAT ARE THE TOTAL COSTS TO BE RECOVERED FROM PARTICIPANTS FOR EACH PILOT?

A. Table 9 shows the revenue requirement to be collected by pilot, by cost type and by year.

Table 9: Revenue Requirement Collected Through Participant Charge

	2022	2023	2024	Total
Fleet Pilot				
Capital				
Charging Station	$139,044	$211,293	$250,825	$601,162
Network	$54,625	$83,008	$98,538	$236,171
Commissioning	$7,449	$11,319	$13,437	$32,205
Capital Revenue Requirement	**$201,118**	**$305,620**	**$362,801**	**$869,538**
Expense				
Maintenance/Warranty	$109,140	$165,850	$165,850	$440,840
Shipping	$4,911	$7,463	$8,860	$21,234
Expense Revenue Requirement	**$114,051**	**$173,313**	**$174,710**	**$462,074**
Total Fleet Revenue Requirement	**$315,169**	**$478,933**	**$537,510**	**$1,331,613**
Home Charging Pilot				
Capital				
Charging Station	$74,780	$74,780	$74,780	**$224,340**
Charging Station Installation	$62,317	$62,317	$62,317	**$186,950**
Capital Revenue Requirement	**$137,097**	**$137,097**	**$137,097**	**$411,291**
Expense				
Charging Station Maintenance/Replacement/Non-Payment	$4,125	$4,125	$4,125	**$12,375**
Expense Revenue Requirement	**$4,125**	**$4,125**	**$4,125**	**$12,375**
Total Home Charging Revenue Requirement	**$141,222**	**$141,222**	**$141,222**	**$423,666**

Q. HOW WAS THE MONTHLY CHARGE FOR EACH PILOT CALCULATED?

A. Calculation of the revenues to collect from participants required several steps. First, all capital investments needed to be converted to annual costs. This was done by taking a straight-line depreciation estimate based on the estimated equipment lifetimes to determine annual depreciation expenses. Generally, annual depreciation expenses are the capital expenditure divided by the equipment lifetime, measured in years. The capital expenditures resulting in additional revenue requirement are incurred over 3 to 10 years for the Fleet Pilot, depending on the expected asset life, and over 5 years for the Home Charging Pilot assets. These lifetimes fall within the bounds of each pilot's contract terms; therefore, all costs can be recovered over the intended contract term and capital assets related to these pilots will be fully depreciated at the end of the pilot periods.

Second, the annual return on the capital investment was calculated consistently with how return on rate base is calculated by the Company for all rate base. Specifically, a rate of return of 7.84% was applied to the remaining balance of capital, or total capital less depreciation, in each year.

With the results of the first two steps as well as the annual expense estimates, a present value of program costs was calculated using a 7.84% cost of capital. To then develop a per customer charge, these present value costs are then divided by the expected level of participation in the given pilot with enrollment occurring from 2022 through 2024.

Q. PLEASE DESCRIBE HOW THESE COSTS WILL BE COLLECTED FROM PARTICIPATING FLEET PILOT CUSTOMERS.

A. Customers enrolling in the Fleet Pilot Bundled Option will pay the Company a monthly charge designed to recover all the costs shown in Table 10 over a ten year period. This rate will be set from 2022 through 2024 regardless of enrollment year for the participant. For the Fleet Pilot, 221 customers are expected to enroll during the program pilot from 2022 through 2024. A monthly payment was calculated by taking the previously described total estimated per customer costs and calculating a levelized payment over the contract term, which is expected to be 10 years. This ensures the full costs are collected over the contract term. Table 10 shows the calculation of the Fleet Pilot Monthly Charge of $63.24 for a 10 year contract term. Table 11 shows additional details for the cost drivers of those charges.

Table 10: Fleet Pilot Costs

	Present value of Fleet Pilot costs	**Total Monthly costs**	**Monthly costs per billing determinant**	**Billing determinant**
Col Row	B	C	D	E
1	$1,157,426	$13,945	$63.24	221

Table 11: Fleet Pilot Summary Component Cost Drivers and Related Charges

		Nominal costs per port	**Net present value per-port, levelized over 10 year contract term**	**Monthly per-port payments levelized over 120 payments**
Col Row	A	B	C	D
1	Charging Station	$2,726.36	$2,018.95	$24.33
2	Network	$1,071.07	$793.16	$9.56
3	Commissioning	$146.06	$108.16	$1.30
4	**Total equipment and installation (1+2+3)**	**$3,943.49**	**$2,920.27**	**$35.18**
5	Return on capital	N/A	$836.71	$10.08
6	Maintenance/Warranty	$2,140.00	$1,427.86	$17.20
7	Shipping	$96.30	$64.25	$0.77
8	**Total costs (4+5+6+7)**	**$6,179.79**	**$5,249.10**	**$63.24**

Q. PLEASE DESCRIBE HOW COSTS WILL BE COLLECTED FROM PARTICIPATING HOME CHARGING PILOT CUSTOMERS.

A. The monthly charge for Home Charging was computed using a method similar to the one described above for the Fleet Pilot. Customers enrolling in the Home Charging Pilot will pay the Company a monthly charge designed to recover all the costs shown in

Table 12 over a five year period. This rate will be set from 2022 through 2024 regardless of enrollment year for the participant. The only differences are the total costs to be collected, the expected number of enrolled customers and the term over which those costs are collected. Specifically, the Company expects approximately 375 customers will enroll through 2024. Further, the expected contract term is set to five years for the Home Charging Pilot. Table 12 shows the calculation of the Home Charging Pilot Monthly Charge of $21.17 for a 5 year contract term. Table 13 shows additional details for the cost drivers of those charges.

Table 12: Home Charging Pilot Costs

	Present value of Home Charging Pilot costs	**Total Monthly costs**	**Monthly costs per billing determinant**	**Billing determinant**
Col Row	B	C	D	E
1	$392,920	$7,937	$21.17	375

Table 13: Home Charging Pilot Summary Component Cost Drivers and Related Charges

		Nominal costs per participant	**Net present value per-participant, levelized over 5 year contract term**	**Monthly per-participant payments levelized over 60 payments**
Col Row	A	B	C	D
1	Charging Station	$598.24	$472.60	$9.55
2	Installation	$498.53	$393.83	$7.96
3	**Total equipment and installation (1+2)**	**$1,096.78**	**$866.43**	**$17.50**
4	Return on capital (related to rows 1, 2)	N/A	$152.93	$3.09
5	Charging station maintenance	$33.00	$28.43	$0.57
6	**Total costs (3+4+5)**	**$1,129.78**	**$1,047.79**	**$21.17**

II. FLEET PILOT AND HOME CHARGING PILOT BENEFIT COST ANALYSES

Q. DID YOU ANALYZE THE BENEFITS AND COSTS OF DLC'S FLEET AND HOME CHARGING PILOTS?

A. Yes, we conducted several benefit and cost tests to review the cost-effectiveness of the Company's pilots. The Benefit Cost Analysis (BCA) is performed from the perspective of several stakeholders: Company's customers who do not participate in the program (Non-participating utility customers), the Company's customers who do enroll (Participating customers who enroll in the pilots and install EV charging equipment through the Company's pilots), the Company and all Pennsylvanians.

Q. WHAT DID THE BCA CONCLUDE FOR THE FLEET AND HOME CHARGING PILOTS?

A. Both pilots prove to be highly cost-effective from many perspectives. The individual tests, as described below, result in a benefit to cost ratio. All tests for both pilots exceeded a benefit cost ratio of 0.85 and were as high as 1.83. As a result, these pilots are not only supporting the growth of EVs in the Company's service territory as described by Witness Olexsak, but all stakeholders also benefit to some degree from the programs.

Q. PLEASE DESCRIBE WHAT BENEFIT COST ANALYSES ARE AND HOW THEY ARE USED IN THIS CONTEXT.

A. Benefit cost analyses are used to evaluate the relationship between costs and benefits of investments made by utilities or customers to manage electricity use behind the customer's meter. The methodologies within the benefit cost analyses generate a series of discounted cash flows related to different components of benefits or costs. Whether any of these discounted cashflows are considered benefits or costs is determined by the perspective of the test. For example, if the test is from the perspective of the participating customer, the benefits are the reductions in gasoline fuel costs while costs are any expenditures the customer must make as part of the program as well as increased energy bills resulting from EV charging. Conversely, this same discounted cash flow for increased energy bills is a benefit to non-participating customers and the utility.

The results of a benefit cost analysis are a series of metrics that show the net benefits of an investment, in net present value terms, as well as a ratio of absolute value of benefits to absolute value of costs. The former metric indicates the magnitude net benefits, which are benefits less costs. If the value is positive, the investment is yielding a positive "return" relative to similar investments. The latter metric provides an indication of the level of benefits relative to costs. Specifically, a ratio close to 1 indicates the value of costs and benefits are nearly equal, while a number far greater than 1 provides insights that the costs are much lower than benefits (and conversely a value far less than 1 indicates the costs are much larger than benefits).

Q. DID YOU USE A STANDARDIZED METHODOLOGY FOR THE BENEFIT COST ANALYSIS?

A. Yes. Our methodology was based on the "California Standard Practice Manual Economic Analysis of Demand-Side Programs and Projects," October 2001 (Standard Practice Manual or "Manual"). The methodology established in that manual is widely used to evaluate customer programs. Additionally, we used the Total Resource Cost

(TRC) Test guidance from the PA PUC for Act 129 Energy Efficiency and Demand Response programs to align with current practices in Pennsylvania. The Commission's guidance was initially established in 2009 and the most recent updates were made in December 2019. (2021 TRC Test Final Order[7]). That guidance also refers to and builds on the "California Standard Practice Manual" for Pennsylvania's Act 129 energy efficiency programs.

Q. WHY IS THIS METHODOLOGY ACCEPTABLE FOR USE IN EVALUATING THE COMPANY'S ELECTRIC VEHICLE PILOTS?

A. The California Standard Practice Manual establishes, on page 2, the definition of DSM Categories and Programs as follows:

> This manual employs the use of general program categories that distinguish between different types of demand-side management programs, conservation, load management, fuel substitution, load building and self-generation. Conservation programs reduce electricity and/or natural gas consumption during all or significant portions of the year. 'Conservation" in this context includes all 'energy efficiency improvements'. An energy efficiency improvement can be defined as reduced energy use for a comparable level of service, resulting from the installation of an energy efficiency measure or the adoption of an energy efficiency practice. Level of service may be expressed in such ways as the volume of a refrigerator, temperature levels, production output of a manufacturing facility, or lighting level per square foot. Load management programs may either reduce electricity peak demand or shift demand from on peak to non-peak periods.
>
> Fuel substitution and load building programs share the common feature of increasing annual consumption of either electricity or natural gas relative to what would have happened in the absence of the program. This effect is accomplished in significantly different ways, by inducing the choice of one fuel over another (fuel substitution), or by increasing sales of electricity, gas, or electricity and gas (load building).

[7] Pennsylvania Public Utility Commission. Total Resource Cost Test. 2021 TRC Test Final Order. https://www.puc.pa.gov/pcdocs/1648126.docx.

As noted above, the California Standard Practice Manual contemplated the use of the evaluation methodologies and resulting cost benefit tests for assessment of load building programs such as EV charging. In other words, the methodology we are using is consistent with the methodologies outlined in this manual.

Q. PLEASE DESCRIBE, AT A HIGH LEVEL, THE BENEFIT COST ANALYSIS PERFORMED.

A. As noted above, the Company used the methodology for BCA outlined in the California Standard Practice Manual. This approach involves the review of benefits and costs from the perspective of key stakeholders, also noted above. This was done for each of the Benefit Cost tests as defined in Table 14 below. A detailed explanation of these tests, the quantification of benefits and costs to be included in each test and the application of each benefit or cost to each test is included in Exhibit ME-2.

Table 14: Description of Benefit Cost Tests

Test	Abbreviation	Description
Participant Cost Test	**PCT**	The Participant Cost Test (PCT) is the measure of the quantifiable benefits and costs to the participating customer due to their participation in a program or pilot.
Ratepayer Impact Measure Test	**RIM**	The Ratepayer Impact Measure (RIM) test measures implications on customer bills or rates due to changes in utility revenues and operating costs caused by the program.
Total Resource Cost Test	**TRC**	The Total Resource Cost (TRC) test measures the net costs of a program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.
Societal Cost Test	**SCT**	The Societal Cost Test (SCT) is an expanded view of the TRC that includes additional societal costs and benefits, or externalities, such as monetized emissions increases or decreases.
Utility Cost Test	**UCT**	The Utility Cost Test (UCT) measures the net costs of a customer program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant.

Q. WHY ARE THE TESTS INCLUDED IN THE STANDARD PRACTICE MANUAL APPROPRIATE FOR A BENEFIT COST ANALYSIS FOR THE COMPANY'S FLEET CHARGING AND HOME CHARGING PILOTS?

A. The tests outlined in the Standard Practice Manual are widely used in evaluation of other customer programs such as Energy Efficiency and Demand Response programs, which have similar characteristics to EV programs, particularly since customers install behind the meter technologies to change their energy bills. Although Energy Efficiency and Demand Response programs aim to reduce energy bills and EV programs generally increase energy bills, the economic implications and evaluation methodologies are consistent. For example, EV program energy bill increases can be viewed as negative energy savings.

Secondly, as noted above, Pennsylvania Act 129 Energy Efficiency and Demand Response programs use the TRC test to determine cost effectiveness of customer programs that impact energy bills.

Q. PLEASE SUMMARIZE THE IMPLICATIONS OF THE FLEET PILOT BENEFIT COST ANALYSIS.

A. Table 15 shows the results of the BCA for the Fleet Pilot.

Table 15: Fleet Pilot BCA Results

	PCT	RIM	SCT	TRC	UCT
Total Benefits	$32,262	$14,656	$37,072	$32,262	$4,994
Total Costs	$38,179	$9,430	$29,420	$28,076	$3,149
Net Benefits (Benefits – Costs)	($5,917)	$5,226	$7,652	$4,186	$1,844
Ratio (Benefits/Costs)	0.85	1.55	1.26	1.15	1.59

The results for the Fleet Pilot analysis show that the PCT is not cost effective for participants who engage in the pilot given that the cost benefit ratio is below 1. Each EV enrolled in the pilot (i.e., as a proxy for each installed charging port) incurs a $5,917 net cost to the participant over the life of the EV. This is primarily driven by the increase in electricity sales and the EV incremental vehicle cost that are categorized as costs in the PCT. Note that the BCA is based on one vehicle per charge port. If customers are able to optimize and charge more vehicles per port, the economics improve.

Next, the RIM test is cost effective with a cost benefit ratio of 1.55. Each EV participant enrolled in the pilot results in a $5,226 net benefit for Duquesne Light customers. The increase in electricity sales from EV charging exceeds the additional capacity costs the Company incurs, which results in a net benefit for pilot non-participant Duquesne Light customers.

The TRC test is also cost effective with a cost benefit ratio of 1.15. Benefits are greater than costs by $4,186 per EV. Benefits are similar to the PCT and primarily relate to the benefits of EV ownership that avoid gasoline fuel costs and higher O&M of a gas vehicle over the vehicle's lifetime. Costs are slightly greater than these benefits and driven by the additional capacity costs, program administration costs, and incremental vehicle purchase costs.

The SCT is cost effective as it is similar to the TRC with the addition of cashflows related to emissions. The benefits from avoided ICEV emissions outweigh the costs of increased emissions from increased generation supply to meet EV charging demands. The SCT cost benefit ratio is 1.26 and each EV results in a net societal benefit of $7,652.

Finally, the UCT is cost effective with a cost benefit ratio of 1.59 and a benefit to the Company of $1,844 per EV. This is primarily driven by the electricity sales that are greater than the additional capacity costs.

Q. PLEASE SUMMARIZE THE IMPLICATIONS OF THE HOME CHARGING PILOT BENEFIT COST ANALYSIS.

A. Table 16 shows the results of the BCA for the Home Charging Pilot.

Table 16: Home Charging Pilot BCA Results

	PCT	RIM	SCT	TRC	UCT
Total Benefits	$13,777	$2,482	$15,825	$13,777	$2,042
Total Costs	$8,739	$2,653	$8,637	$8,198	$1,580
Net Benefits (Benefits – Costs)	$5,037	($171)	$7,187	$5,579	$462
Ratio (Benefits/Costs)	1.58	0.94	1.83	1.68	1.29

The results for the Home Charging Pilot analysis show that the PCT is cost effective for participants who engage in the pilot given that the cost benefit ratio is above 1 at a value of 1.58. Each EV enrolled in the pilot results in a $5,037 net benefit to the participant over the life of the EV. This is primarily driven by avoiding the costs associated with ICEV ownership, gasoline fuel and higher O&M costs.

Next, the RIM test is not cost effective with a cost benefit ratio of 0.94, below 1. Each EV enrolled in the pilot incurs a net cost of $171 for Duquesne Light customers. This is driven by the increased capacity costs related to EV charging and pilot administrative costs socialized to the RS rate class (instead of all pilot costs going to pilot participants). These costs are nearly offset by the increase in electric sales resulting from EV charging that are a benefit to rate paying customers.

The TRC test is cost effective with a cost benefit ratio of 1.68. Each EV enrolled in the program results in a net benefit of $5,579. Benefits are similar to the PCT and primarily relate to the benefits of EV ownership that avoid gasoline fuel costs and higher O&M over the vehicle’s lifetime. Costs, which are lower in magnitude than the benefits, are driven by the additional capacity costs, program administration costs, and incremental vehicle purchase costs.

The SCT is cost effective as it is similar to the TRC with the addition of cashflows related to emissions. The benefits from avoided ICEV emissions outweigh the costs of increased emissions from increased generation supply to meet EV charging demands. The SCT cost benefit ratio is 1.83 and each EV results in a net societal benefit of $7,187.

Finally, the UCT is cost effective with a cost benefit ratio of 1.29 and a net benefit to the Company of $462 per EV. This is primarily driven by the electricity sales that are greater than the additional capacity costs.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does. I reserve the right to supplement my testimony as may be necessary through the course of this proceeding.

EXHIBIT ME-1

SUMMARY OF REVIEW OF COST SHIFTING FOR TYPICAL GL CUSTOMER ON RIDER NO. 16

In assessing Rider No. 16, a review of the cost to serve customer with generation was performed. To do this, the Company reviewed what a customer that has generation offsetting behind-the-meter load would pay if on General Service rate GL. This is because the proposed (and current) GL rate is cost reflective and thus a bill of an average customer on that tariff also represents the Company's cost to serve that customer. This first step in this review was to develop the 'typical customer' profile by taking the total billing demand from GL class divided by the number of customers. This profile is shown below in Table 1. Table 1 also shows the calculation of a typical customer's bill, and thus total cost of service, as if that customer were served completely by the Company.

Table 1: Bill Calculations for 'Typical' GL Customer

Month	Delivered kW (kW)	Min Load (kW)	Contract Demand (kW)	Billed Demand (kW)	Min Bill ($/Month)	Rate ($/kW)	Incremental Bill ($/Month)	Total Bill ($/Month)
Jan	684	300	852	384	3,675	10.66	4,091	7,766
Feb	645	300	852	345	3,675	10.66	3,678	7,353
Mar	739	300	852	439	3,675	10.66	4,683	8,358
Apr	710	300	852	410	3,675	10.66	4,375	8,050
May	823	300	852	523	3,675	10.66	5,575	9,250
Jun	808	300	852	508	3,675	10.66	5,420	9,095
Jul	846	300	852	546	3,675	10.66	5,817	9,492
Aug	852	300	852	552	3,675	10.66	5,884	9,559
Sep	764	300	852	464	3,675	10.66	4,945	8,620
Oct	770	300	852	470	3,675	10.66	5,014	8,689
Nov	705	300	852	405	3,675	10.66	4,319	7,994
Dec	694	300	852	394	3,675	10.66	4,198	7,873
Total	9,041				44,100		57,999	102,099

As Table 1 shows, the customer's peak demand is 852 kW, and thus, per the GL rate structure, the customer's GL Contract Demand would be set at 50% of that peak, or 426kW. For this rate case, the GL rate proposed is a fixed charge of $3,675.00 and a demand charge of $10.66/kW for each additional kilowatt of demand over 300 kilowatts. Using these proposed rates, the customer's bill would total $102,099 a year. Further, since the total demand for each month never dips below the minimum (i.e. 50% of the contract demand), the customer pays the minimum bill plus the demand charge on volumes greater than 300kW.

To estimate the bill a customer would pay if it installed generation, the Company first assumed the level of generation installed equaled the customer's maximum or 852kW. This was to create the most direct example to understand the differences in bills between Rider No. 16 and Rate GL. The calculation of a customer's bill on Rate GL with generation of 852 kW is shown in Table 2.

Table 2: Bill Calculations for 'Typical' GL Customer with On-site Generation

Month	Generation (kW)	Delivered kW (kW)	Min Load (kW)	Contract Demand (kW)	Billed Demand (kW)	Min Bill ($/Mont)	Rate ($/kW)	Incremental Bill ($/Mont)	Total Bill ($/Month)
Jan	852	0	300	852	126	3,675	10.66	1,343	5,018
Feb	852	0	300	852	126	3,675	10.66	1,343	5,018
Mar	852	0	300	852	126	3,675	10.66	1,343	5,018
Apr	852	0	300	852	126	3,675	10.66	1,343	5,018
May	852	0	300	852	126	3,675	10.66	1,343	5,018
Jun	852	0	300	852	126	3,675	10.66	1,343	5,018
Jul	0	846	300	852	546	3,675	10.66	5,817	9,492
Aug	0	852	300	852	552	3,675	10.66	5,884	9,559
Sep	852	0	300	852	126	3,675	10.66	1,343	5,018
Oct	852	0	300	852	126	3,675	10.66	1,343	5,018
Nov	852	0	300	852	126	3,675	10.66	1,343	5,018
Dec	852	0	300	852	126	3,675	10.66	1,343	5,018
Total		1,698				44,100		25,129	69,229

Table 2 shows the calculation of the customer's bill assuming the customer experiences a maintenance outage in the two highest load months (July and August).

Under the proposed GL rate, the customer would pay $69,229 per year. This is driven by the requirement to pay the minimum bill of $3,675 per month plus paying additional minimum charges of the difference in 50% of the GL Contract Demand charges and minimum load of 300kW times the demand rate of $10.66, or $1,343 per month. The customer also pays $10.66/kW for the actual delivered kW in June and July. Together this results in additional per kW costs of $25,129 for those two months.

By comparison, assume this customer selected Rider No. 16. In this case, if a customer takes Supplementary Service under GL rate, they pay a minimum of charge for the first 300kW. To minimize their bill under Rider No. 16, the customer is unlikely to build a generation facility equal to maximum use but rather target generator size that is equal to the customer's maximum annual demand and the minimum amount to of 300 kW. Therefore, the customer's generation unit would be 552 kW, as would their Contract Demand under Rider No. 16. In this scenario the customer pays minimum bill for Supplementary Services of $44,100 and Rider No. 16 charges of $16,560 for a total of $60,660, or 12% less than their alternative on GL Rate.

It should be noted that a customer with behind the meter generation can reduce their 'Supplementary Demand' requirements to less than 300 kW. In this case it would install a 645 kW generator and request Supplementary Demand service up to 207 kW under General Service Rate GM > 25. As a result, the customer would avoid the minimum payment while paying a nominal ($76/month) customer charge, volumetric charges on energy delivery services ($0.012661/kWh) as well as a demand charge of $7.89 kW. In this case the customer would then pay a slightly more annually, or

$19,350, for Rider No. 16 service at a contract demand of 645 kW while most likely experiencing a lower bill than receiving 300 kW of Supplementary Service under GL).

Another scenario was run where the customer experiences an outage during the lowest demand months, or February and March. In this example, the customer would pay $59,887 a year on Rate GL, the cost reduction coming from paying less for the delivered demand (difference between July and August demand versus February and March) of $3,339. In this case the customer pays about the same under Rider No. 16 charges of $16,560 for a total of $60,660, about the same as if they were on GL rate.

The above examples show that no matter how much the customer on Rider 16 uses the Company's delivery services, they pay the same amount, regardless of whether the customer demands Back-Up service during the higher volume months of June and July or the actual level of demand used (e.g., max of 852 kW in July versus 739 kW in March).

These examples also demonstrate that customers with behind the meter generation have several opportunities to avoid costs to serve. Specifically, in all scenarios the *typical* customer pays either the same amount or less depending on the operations of their generator and choice of Supplementary Service. The Company acknowledges that there are scenarios where a customer would be better off on the GL rate rather than Rider No. 16. In those cases, the customer would choose GL service rather than Rider No. 16. However, this review presented above does shed light on the fact that these customers can 'select' a rate option that allows them to avoid paying their full cost of service because that optional rate is not reflective of cost of service. That is, because Rider No. 16 does not follow cost causation principles, the offering enables some customers the opportunity to arbitrage rates and thus avoid costs, shifting those costs to other customers.

EXHIBIT ME-2

ELECTRIC VEHICLE BENEFIT COST ASSESSMENT SUMMARY

This exhibit describes, in detail, each benefit cost test, the designation of costs and benefits to each test and the quantification of each benefit and cost.

BENEFIT COST TEST DESCRIPTIONS

As noted in Witness Everett's testimony, there are five benefit costs test included in this study:

- The Participant Cost Test (PCT) is the measure of the quantifiable benefits and costs to the customer due to participation in a program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.
- The Ratepayer Impact Measure (RIM) test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills would go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.
- The Total Resource Cost (TRC) test measures the net benefits or costs of the customer resource option (i.e., EV charging). Using the identified cashflows as the basis for benefits and costs, the benefits calculated in the TRC test are the avoided generation supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction. The costs in this test are the program costs paid by both the utility and the participants plus the increase in supply costs for the periods in which load is increased. Thus, all equipment costs,

installation, operation and maintenance (or, changes in O&M), and administration costs, no matter who pays for them, are included in this test. Any tax credits are considered a reduction to costs in this test, if applicable.

- The Societal Cost Test (SCT). The SCT differs from the TRC test in that it includes the effects of externalities (e.g., environmental, emissions, etc.) and excludes tax credit benefits.
- The Utility Cost Test, also known as the Program Administrator Cost Test, measures the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator, the utility, (including incentive costs) and excluding any net costs incurred by the participant. Note that the UCT provides a detailed perspective of the costs the utility incurs for the program, and thus customers, to include administrative costs and incentives, that typically pass through to customers. A positive UCT indicates that the benefits exceed costs thus have no impact on customers, while a negative indicates that there are incremental costs, thus revenue requirement, resulting from the test.

Because of the interplay among all these tests, it is most important to review the results as a whole rather than focus on any one test.

BENEFIT AND COST COMPONENTS

As noted above, the Company used industry best practices and the "California Standard Practice Manual Economic Analysis of Demand-Side Programs and Projects,"[1] Additionally, the Company referred to Total Resource Cost (TRC) Test guidance from the PA PUC for Act

[1] California Public Utilities Commission. Cost-effectiveness. Standard Practice Manual. https://www.cpuc.ca.gov/general.aspx?id=5267.

129 Energy Efficiency and Demand Response programs.[2] These two sources, in addition to expert judgment, guided the cost benefit analysis approaches. Specifically, these guidance sources identify the perspectives and cashflows that inform the various tests which may include direct or indirect economic benefits.

The first step of the analysis methodology involves developing a framework that outlines each benefit and cost and then quantifying each of these benefits and costs. The second step is determining the impacts on different groups of customers (e.g., pilot participants and non-participants), the utility, and the Commonwealth. The last step is then quantifying each of the components of costs and benefits and then quantifying the net benefits (benefits less costs) and benefit to cost ratio (benefits divided by costs) for each stakeholder group noted above.

The Company looked at costs in five key categories. Depending on the test, these categories are considered costs or benefits. Categories may also be excluded from some tests.

- Additional capacity costs
- Electricity sales costs
- Incremental Revenues
- Pilot administrative costs
- Participant vehicle costs
- Externalities

Additional Capacity Costs

The Company used the capacity costs that the utility also uses to determine cost effectiveness for Act 129 Energy Efficiency programs. In the Act 129 context, these are

[2] Pennsylvania Public Utility Commission. Total Resource Cost Test. https://www.puc.pa.gov/filing-resources/issues-laws-regulations/act-129/total-resource-cost-test/

avoided costs. This analysis uses the recently-developed capacity costs that the PA PUC recently approved within the Company's Phase IV Energy Efficiency and Conservation (EE&C) plan, Docket No. M-2020-3020818. Additional capacity costs are discussed in detail below.

Generation Capacity Costs

These are costs to create or procure a kW of capacity to generate energy. Generation related costs include:

- Costs of building capacity to generate the kWh;
- Cost related to maintaining system reliability and voltage control (e.g., Ancillary Services);
- Cost associated with plant operations, such as Criteria Pollutants, CO2, and other emissions costs; and
- Fuel costs and any related hedging costs.

Transmission Costs

These are costs to deliver a kWh from a generator to the customer's meter within transmission infrastructure. Transmission related costs include:

- Costs of building transmission capacity; and
- Cost related to transmission line losses resulting from moving electricity across generation to the customer.

Distribution costs

These are costs to deliver a kWh from a generator to the customer's meter within distribution infrastructure. Distribution related costs include:

- Costs of building distribution capacity; and

- Cost related to distribution line losses resulting from moving electricity across generation to the customer.

Energy Supply Costs

Energy Supply costs are the costs of the delivered energy supply to the customer's meter. Following Act 129 methodologies, costs are distinguished for six periods during the year: summer peak, summer off-peak, winter peak, winter off-peak, shoulder peak, and shoulder off-peak.

Incremental Revenues

Because adoption of EVs increases electricity use, customers receiving service from the Company increases sales and thus both pay towards variable costs and fixed costs, much like a Community Development rate. These create a benefit equal to the increase in revenues. The Fleet Pilot analysis uses the GM>25, GMH>25, and GL tariffs and the Home Charging Pilot analysis uses the RS tariff.

Pilot Administrative Costs

As previously detailed in the revenue requirement recovery discussion. These are costs associated with administering the pilots and include both capital and expense items. Therefore the costs included in the BCA are include both these costs as well as the costs associated with financing capital. These costs are recovered by both the Company's non-participating customers and the participating customers.

Participant vehicle cost

The costs associated with switching from an internal combustion engine vehicle (ICEV) to an EV. These are separate from pilot monthly charges to participants that are captured under the pilot administrative costs. These include:

- Vehicle costs: The incremental cost of an EV compared to an ICEV.
- O&M costs: The difference in O&M cost over the life of an EV compared to an ICEV.
- Fuel costs: The avoided gasoline costs to fuel an ICEV (note electricity costs paid for are included in participant program costs).

Externalities

The costs associated with changes in vehicle emissions and grid-side generation emissions resulting from changes in consumption. These include:

- Reduced Fuel GHG Emissions: CO_2e avoided emissions related to avoided ICEV gasoline fuel consumption.
- Reduced Fuel Air Pollutants: Non-methane organic gases (NMOG) and NOx avoided emissions related to avoided ICEV gasoline fuel consumption.
- Increased Electricity GHG Emissions: Incremental CO_2e emissions related to increased utility energy generation to supply EV charging.
- Increased Electricity Air Pollutants: Incremental NOx emissions related to increased utility energy generation to supply EV charging.

Externalities also include direct impacts from these pilots refer to the creation of economic growth, as measured in conventional economic growth metrics such as an increase in Pennsylvania's Gross Domestic Product ("GDP") and increases in job levels within the Commonwealth. Direct impacts from the pilots implies that the program would be measurably responsible for creating GDP growth or new jobs while Indirect would be the secondary or tertiary impacts of these pilots on these metrics.

The challenge with including these types of components is that they are extremely difficult to specifically measure and thus must be inferred through economic forecasting methodologies. That is, to measure, one has to be able to determine a "Base Case" what job levels and GDP would have been without the program and then compare that to what the actual job creation and GDP growth. This is not possible for the obvious reason that there is no direct way to compute these metrics for the "Base Case." Second, even if anecdotal evidence points to job growth or GDP growth, such as the increase in "electric vehicle related" jobs, it is not clear that increase is directly attributed to the Company's pilots or program versus other efforts encouraged by the Commonwealth or other stakeholders. Lastly, it is important to remember that there may also be negative direct or indirect economic impacts from these pilots that result in higher rates for customers.

Given these challenges in measuring these impacts it is not possible to develop a credible, defensible, and transparent methodology for estimating these impacts.

BENEFIT COST ANALYSIS METHODOLOGY

The benefit cost analysis methodology includes defining 25 value components and specifying the methodology for calculating each. Table 1 below shows each of these components, grouped by the five categories noted above. The costs represent the present value per EV for estimated cashflows.

Benefits and costs are derived on a per-electric vehicle basis where the analysis conservatively assumes one EV per installed charging port. Particularly for the Fleet Pilot, the number of EVs may often exceed the number of charging ports installed, which would amplify the benefits of that program beyond the conservative projections shown below.

Table 1: Benefit cost components

	Component	Fleet Pilot Levelized cost ($/EV)	Home Charging Pilot Levelized cost ($/EV)
Col Row	A	B	C
1	Additional Capacity Costs (Generation)	$726	$385
2	Transmission Capacity Costs	$557	$295
3	Distribution Capacity Costs	$290	$154
4	Energy Supply Costs	$2,254	$750
5	Increased Electricity Sales Revenue Base Distribution	$2,508	$1,719
6	Increased Electricity Sales Revenue Ancillary Riders	$11,364	$290
7	Increased Electricity Sales Revenue Supply	$4,088	$1,358
8	Increased Electricity Sales Revenue Transmission	$784	$473
9	Increased Electricity Sales Revenue Other	$0	$0
10	Total - Rev Req - Capital – Socialized	$5,272	$842
11	Total - Rev Req - Return on Capital – Socialized	$1,649	$170
12	Total - Rev Req - Gross up for Taxes - Socialized	$852	$88
13	Total - Rev Req - Expense – Socialized	$811	$1,103
14	Total - Rev Req – Capital	$2,488	$787
15	Total - Rev Req - Return on Capital	$837	$153
16	Total - Rev Req - Gross up for Taxes	$432	$79
17	Total - Rev Req – Expense	$1,492	$28
18	Avoided Fuel Costs	$28,776	$11,625
19	Customer O&M Savings	$3,486	$2,152
20	Reduced Fuel GHG Emissions	$4,733	$1,996
21	Reduced Fuel Air Pollutants	$78	$52
22	Increased Electricity GHG Emissions	$1,282	$419
23	Increased Electricity Air Pollutants	$63	$20
24	Vehicle Costs	$14,186	$3,852
25	Upfront Program Costs[3]	$0	$0

The component values in Table 1 relied on several sources of information in addition to the previously discussed California Standard Practice Manual, Total Resource Cost (TRC) Test guidance from the Commission for Act 129 Energy Efficiency and Demand Response programs, and the capacity costs sourced from the Company's Act 129 Energy Efficiency program efforts. Additional sources include but are not limited to the following:

[3] Upfront Program Costs reflect an option where enrolled customers can pay for charging equipment at the outset of participation and reduce their monthly participant charges. The analysis assumes no upfront participant costs are incurred; all costs are bundled in the monthly participant charge.

- Company-developed budget assumptions for the pilots. Given that these are pilots, the Company is proposing to cap participant levels, thereby adding more certainty to the overall budget estimations for administrative costs.
- Company-developed throughput assumptions. These include estimated annual energy consumption totals for participating EV charging.
- National Renewable Energy Laboratory (NREL) EV charging profiles.[4] These profiles are used to distribute the Company's energy consumption estimates to determine peak charging (kW/EV) and what portion of charging occurs during the six previously identified peak periods where energy supply costs vary (summer peak, summer off-peak, winter peak, winter off-peak, shoulder peak, and shoulder off-peak).
- ICEV fuel costs,[5] fuel efficiency, and estimated year-over-year changes in fuel costs.[6]

For the Fleet sales estimates the Company assumed a blend of GM>25, GMH>25, and GL program participants. Additionally, the Company assumed a blend of vehicle types including light duty trucks, light duty fleet vehicles, medium duty fleet vehicles, and school buses.

The Company developed the cost benefit analysis with 13 years of cashflows for both the Fleet Pilot and Home Charging Pilot analyses. This duration determination is primarily informed by the pilot contract terms and conservative vehicle lifetime assumptions. The duration is the same for both pilots to offer a comparison. This thirteen-year time horizon provides a more conservative measure of program benefits than the fifteen-year maximum time

[4] US Department of Energy. Energy Efficiency and Renewable Energy. Alternative Fuels Data Center. Landing page for loadshapes and related data (Electric Vehicle Infrastructure Projection Tool). https://afdc.energy.gov/evi-pro-lite/load-profile.
[5] AAA. Gas prices. https://gasprices.aaa.com/state-gas-price-averages/.
[6] EPA. 2020. "The 2020 EPA Automotive Trends Report." https://nepis.epa.gov/Exe/ZyPDF.cgi/P1010U68.PDF?Dockey=P1010U68.PDF.

period allowed in the Total Resource Cost Test analysis for Act 129 Energy Efficiency Programs.

The Company also characterized the different customer groups and vehicle types within the pilot. Specifically, the Company's benefit cost analysis developed results that reflect the benefits and costs for a typical EV serviced by the pilot for a typical pilot participant. The Company developed a typical or average participating customer and a typical or average EV for the Fleet Pilot analysis. Additionally, the Company conservatively assumes one EV is serviced by one charger port installed through the pilot.

For the Fleet pilot, an average participating customer represents an assumed weighted average mix of GM>25, GMH>25, and GL customers. This assumed weighted average informs the creation of blended inputs for certain analysis cashflows. Primarily, for example, cashflows characterizing the increased electricity sales resulting from EV charging are dependent on rate class-specific tariffs. Therefore, the Company created increased electricity sales for a typical pilot participant that represents the weighted average mix of those tariffs.

Similarly for the Fleet pilot, an average vehicle type represents an assumed weighted average mix of light duty trucks, light duty fleet vehicles, medium duty fleet vehicles, and school buses. This assumed weighted average informs the creation of blended inputs for certain analysis cashflows. For example, cashflows representing avoided vehicle fuel costs, avoided vehicle O&M costs, and increased electricity sales related to differing charging requirements for the different vehicle types. Therefore, the Company created impacts for the given cashflow using weighted average values for the inputs needed to calculate a result. As a final example, the incremental vehicle cost, which is a cost in the PCT, TRC, and SCT, represents the weighted average incremental vehicle cost for the four vehicle types previously mentioned.

It is important to note that the Home Charging Pilot analysis assumes all participating customers are from the RS customer class. Additionally, all EVs are assumed light duty vehicles for personal use.

ASSIGNMENT OF BENEFITS AND COSTS TO EACH TEST

Benefits and costs are assigned in each BCA test as identified in the chart below. These assignments are consistent and apply to both the Fleet and Home Charging analyses.

	Component	**PCT**	**RIM**	**SCT**	**TRC**	**UCT**
Col Row	A	B	C	D	E	F
1	Additional Capacity Costs	N/A	N/A	Cost	Cost	N/A
2	Transmission Capacity Costs	N/A	Cost	Cost	Cost	Cost
3	Distribution Capacity Costs	N/A	Cost	Cost	Cost	Cost
4	Energy Supply Costs	N/A	N/A	Cost	Cost	N/A
5	Increased Electricity Sales Revenue Base Distribution	Cost	Benefit	N/A	N/A	Benefit
6	Increased Electricity Sales Revenue Ancillary Riders	Cost	Benefit	N/A	N/A	N/A
7	Increased Electricity Sales Revenue Supply	Cost	N/A	N/A	N/A	N/A
8	Increased Electricity Sales Revenue Transmission	Cost	Benefit	N/A	N/A	N/A
9	Increased Electricity Sales Revenue Other	Cost	Benefit	N/A	N/A	N/A
10	Total - Rev Req - Capital – Socialized	N/A	Cost	Cost	Cost	N/A
11	Total - Rev Req - Return on Capital – Socialized	N/A	Cost	N/A	N/A	Benefit
12	Total - Rev Req - Gross up for Taxes - Socialized	N/A	Cost	N/A	N/A	N/A
13	Total - Rev Req - Expense – Socialized	N/A	Cost	Cost	Cost	Cost
14	Total - Rev Req – Capital	Cost	N/A	Cost	Cost	N/A
15	Total - Rev Req - Return on Capital	Cost	N/A	N/A	N/A	Benefit
16	Total - Rev Req - Gross up for Taxes	Cost	N/A	N/A	N/A	N/A
17	Total - Rev Req – Expense	Cost	N/A	Cost	Cost	Cost
18	Avoided Fuel Costs	Benefit	N/A	Benefit	Benefit	N/A

19	Customer O&M Savings	Benefit	N/A	Benefit	Benefit	N/A
20	Reduced Fuel GHG Emissions	N/A	N/A	Benefit	N/A	N/A
21	Reduced Fuel Air Pollutants	N/A	N/A	Benefit	N/A	N/A
22	Increased Electricity GHG Emissions	N/A	N/A	Cost	N/A	N/A
23	Increased Electricity Air Pollutants	N/A	N/A	Cost	N/A	N/A
24	Vehicle Costs	Cost	N/A	Cost	Cost	N/A
25	Upfront Program Costs[7]	Cost	N/A	Cost	Cost	N/A

The final step is to sum up the present value benefits and costs separately for each test and compute two metrics for each. First is the net benefit, which is the difference between benefits and costs. The second is the benefit cost ratio, which divides costs into benefits. In this case, a program is assumed to pass a test if it has a benefit to cost ratio of close to or greater than 1. The final results are contained in the direct testimony of witness Everett, DLC St. No. 17.

[7] Upfront Program Costs reflect an option where enrolled customers can pay for charging equipment at the outset of participation and reduce their monthly participant charges. The analysis assumes no upfront participant costs are incurred; all costs are bundled in the monthly participant charge.