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August 31, 2021

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission
v.
PECO Energy Company – Electric Division
Docket No. R-2021-3024601

Dear Secretary Chiavetta:

Consistent with 52 Pa. Code Section 5.412(a) of the Commission's regulations, which requires the electronic submission of pre-served testimony, and the Briefing Order issued on August 18, 2021, enclosed for electronic filing please find the following Pre-Served Testimony and Exhibits on behalf of the Office of Consumer Advocate ("OCA") in the above-referenced proceeding. Please note that the documents listed below were admitted into the record at the evidentiary hearing conducted on August 11, 2021.

Office of Consumer Advocate's Direct Testimony

OCA Statement 1 – (Public Version) Direct Testimony of Dante Mugrace -- Schedules DM-1 through DM-21, Exhibits DM-1 through DM-2, and Appendix A

OCA Statement 2 -- Direct Testimony of David J. Garrett – Appendix A, Appendix B, and Exhibits DJG-1 through DJG-18

OCA Statement 3 -- Direct Testimony of Clarence L. Johnson -- Schedules CJ-1 through CJ-4 and Appendix A

OCA Statement 4 -- Direct Testimony of Roger D. Colton and Appendix A

OCA Statement 5 -- Direct Testimony of Noah D. Eastman -- Exhibit NDE-1 and Appendix A

OCA Statement 6 -- Direct Testimony of Ron Nelson and curricula vitae

Office of Consumer Advocate's Rebuttal Testimony

OCA Statement 3-R -- Rebuttal Testimony of Clarence L. Johnson

OCA Statement 4-R -- Rebuttal Testimony of Roger D. Colton

Office of Consumer Advocate's Surrebuttal Testimony

OCA Statement 1-SR -- Surrebuttal Testimony of Dante Mugrace and Schedules SR DM-1 through SR DM-21

OCA Statement 2-SR -- Surrebuttal Testimony of David J. Garrett

OCA Statement 3-SR -- Surrebuttal Testimony of Clarence L. Johnson and Schedules CJ-SR-1 through CJ-SR-3

OCA Statement 4-SR -- Surrebuttal Testimony of Roger D. Colton

OCA Statement 5-SR -- Surrebuttal Testimony of Noah D. Eastman and Schedule NDE-1S

OCA Statement 6-SR -- Surrebuttal Testimony of Ron Nelson

The following Confidential Testimony and Exhibits will be e-mailed directly to Secretary Rosemary Chiavetta:

OCA Statement 1 – (**CONFIDENTIAL** Version) Direct Testimony of Dante Mugrace -- Schedules DM-1 through DM-21, Exhibits DM-1 through DM-2, and Appendix A

All testimony is accompanied by a witness verification. The OCA's submission also addresses the requirements of the Commission's January 10, 2013 Implementation Order at Docket M-2012-2331973, which requires electronic access to pre-served testimony.

All parties and the presiding officer have been served previously with the testimony and exhibits and copies have been served per the attached Certificate of Service.

Respectfully submitted,

/s/ Laura J. Antinucci
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Enclosures:
cc: The Honorable Marta Guhl **(letter only, served by email)**
Certificate of Service
*316703

CERTIFICATE OF SERVICE

Re: Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024601
	:	
PECO Energy Company – Electric Division	:	

I hereby certify that I have this day served a true copy of the following document, the Office of Consumer Advocate's Letter Re: Pre-Served Testimony and Exhibits, upon parties of record in this proceeding in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant), in the manner and upon the persons listed below:

Dated this 31st day of August 2021.

SERVICE BY E-MAIL ONLY

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Dated: August 31, 2021
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OCA Statement No. 1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
v.	**)**	**Docket No. R-2021-3024601**
PECO Energy Company – Electric	**)**	
Division	**)**	

DIRECT TESTIMONY OF

DANTE MUGRACE

ON BEHALF OF THE

COMMONWEALTH OF PENNSYLVANIA

OFFICE OF CONSUMER ADVOCATE

June 28, 2021

<u>PUBLIC VERSION</u>

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I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dante Mugrace. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am a Senior Consultant with the Economic and Management Consulting Firm of PCMG and Associates, LLC. (PCMG). In my capacity as a Senior Consultant, I am responsible for evaluating and examining rate and rate related proceedings before various governmental entities, preparing expert testimony recommending revenue requirement, as well as, offering opinions on economic policy and policy issues and methodologies used to set a value on a utility's rate base and cost of service components of revenue requirement.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. PCMG is an association of experts in utility regulation and policy, economics, accounting and finance. PCMG's members have over 75 years collective experience providing assistance to counsel and expert testimony regarding the regulation of electric, gas, water and wastewater utilities that operate under local, state and federal jurisdictions. PCMG focuses on areas regarding revenue requirement, cost of service, rate design, cost of capital and rate of return. Prior to my association with PCMG, I was employed as a Senior Consultant with the consulting firm of Snavely King Majoros and Associates (SKM) from 2013 to 2015, in the same capacity as PCMG. Prior to SKM I was employed by the New Jersey Board of Public Utilities (NJBPU) from 1983 to my retirement in 2011. During my tenure at the NJBPU, I held various Accounting, Rate Analyst, Supervisory and Management Positions. My last position was Bureau Chief of Rates in the Agency's Water Division (Bureau Chief of Rates). I held this position for nearly 10 years. My resume is attached as Appendix A.

Q. WHAT EXPERIENCE DO YOU HAVE IN THE AREA OF UTILITY RATE SETTING PROCEEDINGS AND OTHER UTILITY MATTERS?

A. In my capacity as Bureau Chief of Rates at NJBPU, I was responsible for overseeing the rate process regarding administrative, financial, and managerial functions of the Rates Bureau. My primary duties were to ensure that the jurisdictional utilities had sufficient revenues to cover their operating expenses, the ability to earn a reasonable rate of return on plant investments, and to ensure that the provision of safe, adequate and proper service at reasonable rates was met. During my time at the NJBPU, I was involved in hundreds of rate and rate related proceedings. In my capacity as a Senior Consultant previously with SKM and now with PCMG, I have been and am currently involved in rate and rate related proceedings before the Commissions in the Commonwealth of Massachusetts and Pennsylvania, and the States of Maine, Maryland, New Jersey, New York, North Dakota, and Ohio. I was involved in the Generic Proceedings to Establish Parameters for the Next Generation Performance Based Rate Plans before the Alberta Utilities Commission. I was involved in transmission formula rate plans before the Federal Energy Regulatory Commission (FERC) regarding the PECO Energy Company on behalf of the Pennsylvania OCA and the Rockland Electric Company on behalf of the NJ Division of Rate Counsel.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Master of Business Administration (MBA) degree with a concentration in Strategic Management from Pace University-Lubin School of Business in New York, New York. I hold a Master of Public Administration (MPA) degree from Kean University in Union, New Jersey. I hold a Bachelor of Science (BS) degree in Accounting from Saint Peter’s University in Jersey City, New Jersey.

II. PURPOSE OF TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Pennsylvania Office of the Consumer Advocate (OCA).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to calculate and to make a recommendation regarding the PECO Energy Company – Electric Division. (PECO or Company) base rate case proceeding. My recommendation includes the setting of the Company's Rate Base Valuation, and Pro Forma Operating Income at Present Rates for the Fully Projected Future Test Year Period Ending December 31, 2022. On March 30, 2021, PECO filed a base rate case with the Pennsylvania Public Utility Commission (PAPUC or Commission) requesting an overall increase in rates for its electric distribution service of approximately $246 million or 7.00% above current jurisdictional operating revenue. Included in my recommended position on Rate Base Valuation and Operating Income, I am also incorporating the recommendations of OCA witness Mr. David Garrett with respect to the overall rate of return, OCA witness Mr. Clarence Johnson on any rate design adjustments, OCA witness Mr. Roger Colton on Universal Service adjustments, and Mr. Noah Eastman on COVID-19 Impacts.

III. REVENUE REQUIREMENT ISSUES

A. SUMMARY

Q. WHAT REVENUE DEFICIENCIES OR ADJUSTMENTS ARE YOU RECOMMENDING?

A. Based upon the use of the Company's proposed fully projected future test year ending December 31, 2022, I have the following recommendations:

- My recommended Rate Base balance is $6,052,270,989 which is $333,626,011 lower than the Company's proposed Rate Base balance of $6,385,897,000.
- My overall Rate of Return based upon OCA witness Garrett's recommendation is 6.22%, which includes a Common Equity component of 8.50%.
- My recommended Operating Revenue at Present Rates is computed at $2,334,400,791, which is $721,816 higher than the Company's Present Rate Revenue of $2,333,680,000.[1]
- My recommended total Operating Expenses is $1,494,869,974 which is $63,410,026 lower than the Company's proposed Operating Expenses of $1,558,280,000.
- My recommended Federal Income Tax is $24,574,577, which is $31,485,423 lower than the Company's proposed Federal Income Taxes of $56,060,000.
- My recommended State Income Tax is $6,116,806, which is $23,788,194 lower than the Company's Proposed State Income Tax of $29,905,000.
- Overall, I recommend a revenue requirement decrease or stated another way, a revenue requirement sufficiency of $13,236,633, which is $260,145,138 lower than the Company's proposed revenue requirement increase of $246,908,000.

Q. WHAT RATE BASE COMPONENTS ARE YOU ACCEPTING IN THIS PROCEEDING?

A. I am accepting the Company's balances related to Customer Deposits, Customer Advances for Construction and Materials and Supplies, which are shown on my Schedule DM-3.

[1] Any differences between Company Operating Revenues at Present Rates in its filing and my Schedules are due to rounding.

B. RATE BASE (Measures of Value)

1. Electric Plant in Service (EPIS)

Q. WHAT HAS THE COMPANY PROPOSED REGARDING ITS ELECTRIC PLANT IN SERVICE?

A. The Company has proposed an EPIS balance of $8,915,180,000[2] for the fully projected future test year for the twelve months ending December 31, 2022. (Company Exhibit MJT-1 Schedule C-1 and Schedule C-2). This balance represents the electrical jurisdictional allocation to the Pennsylvania operations. (Trzaska Statement No. 3 at 13) (Exhibit MJT-1 Schedule C-2). Included in that balance are plant additions that the Company expects to place in service during the future test year period ending December 31, 2021, in the amount of $799,494,000 (Exhibit MJT-2 Schedule C-1 and C-2), and an additional $843,227,000 for the Fully Projected Future Test period ending December 31, 2022. The total proposed plant additions sum up to $1,642,721,000. Company witness Stefani (PECO Statement No. 2 at 2-3) has stated that since January 1, 2019, it has invested approximately $1.5 billion in new and replacement electric distribution plant through December 31, 2020.

Q. HOW DID THE COMPANY DEVELOP ITS CAPITAL INVESTMENT TO PRODUCE THE TOTAL PROPOSED PLANT ADDITIONS OF $1,642,721,000 AS OF DECEMBER 31, 2022?

A. Company witness McDonald (PECO Statement No. 1 at 8) stated that the capital investments are developed through a detailed budget and long–range plan development process. The Company aligns capital investments with PECO's strategic operational goals and regulatory and financial plans. The mix of capital investment needs can change from year to year and is the product of a variety of factors including trends in the housing market, emergent operational constraints, local municipal workloads and the conditions of the facilities. (PECO Statement No. 1 at 8-9). The Company categorizes capital investment requirements based

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[2] Differences between the Company's balance and my balance are due to rounding.

upon (1) corrective maintenance; (2) system performance; (3) capacity improvement; (4) facility relocation and; (5) new business. These capital projects are ranked based upon certain criteria such as age, failure rate, customer complaints, cost to replace versus cost to repair, condition, and environmental factors. (Statement No. 1 at 9).

Q. HAS THE COMPANY INCLUDED ANY TRANSMISSION RELATED PLANT OR OTHER NON-JURISDICTIONAL PLANT IN ITS EPIS BALANCE?

A. No. Company witness Trzaska (PECO Statement No. 3 at 13) stated that transmission related plant has been removed from the Company's EPIS balance. Company Exhibit MJT-1 Schedule C-2 shows the adjustments necessary to remove all transmission related intangible, general and transmission plant recorded in transmission accounts under FERC jurisdiction from the account balances. (PECO Statement No. 3 at 15).

Q. WHAT TYPES OF PLANT INVESTMENTS ARE INCLUDED IN THE COMPANY'S $799,494,000 PLANNED ADDITIONS IN 2021 AND IN THE $843,227,000 PLANNED ADDITIONS IN 2022?

A. The majority of these plant investments are related to new distribution facilities and new transmission facilities. (PECO Statement No. 1 at 10). The Company has claimed that these plant investments will be in service and used by the Company to provide safe and reliable service to customers by the end of the FPFTY period. (Statement No. 1 at 11). Also included in the Company's plant investment balance are costs related to the Company's deployment of its Advanced Metering Infrastructure (AMI), and has installed nearly 1.8 million of the electric AMI at customer premises. (PECO Statement No. 1 at 24).

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S PROPOSED EPIS BALANCE OF $8,915,180,000?

A. I reviewed the response to OCA-VI-6 where I asked the Company to provide and identify all project additions in the FTY and in the FPFTY periods that have been abandoned or delayed and the reasons for such. The Company provided a schedule showing all projects no longer having forecasted capital additions in the

FTY and in the FPFTY periods. The Company provided and identified capital projects that have been delayed and the reason for the delay or changes in forecasts. For the specific projects, the Company has provided 7 projects that have been delayed beyond the FPFTY period. OCA-VI-6 shows these projects and the costs associated with these projects are shown in response to IE-RB-8-D which amount to $11,629,965. I have removed these projects from the Company's EPIS balance.

Q. WHAT IS YOUR NEXT ADJUSTMENT TO THE COMPANY'S EPIS BALANCE?

A. I reviewed the projects as shown on Attachment OCA-VI-6 (a) and identified capital additions that have either been delayed to December 2022 or are expected to be completed in December 2022. Most of these capital projects have been pushed back or delayed by up to one year. It is uncertain whether the Company will be able to meet the deadline for placing these capital projects in service. The balance of the capital projects amount to $69,784,261. I am not confident or assured of the Company's timeline in completing these projects. According to the Company some of these projects may be finished on time, some dates have not been secured to meet the in-service dates, some delays relate to engineering and construction issues, some projects need to be aligned with the LTIIP, and some are due to constructability issues and additional scope of work to be performed. Given these uncertainties, I am recommending removal of these projects from the Company's EPIS balance. I have highlighted these projects in blue in Attachment OCA-VI-6 (a).

Q. WHAT IS YOUR NEXT ADJUSTMENT?

A. The next list of projects shown in response to OCA-VI-6 –(a) attachment were delayed due to demolition issues, coordination issues, construction obstructions, engineering issues, permitting requirements, reprioritizing issues. Most of these set of projects were expected to be completed in 2021 but were pushed into 2022 due to the delay issues indicated above. These projects amount to a balance of $22,502,364. It is unclear whether the Company will be able to have these set of projects placed in service in 2022. I have highlighted these projects in green in Attachment OCA-VI-6 (a).

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE COMPANY'S PROJECTED TIMELINE OF THESE IN-SERVICE DATES?

A. Yes. Beginning on page 2 of 7 of Attachment OCA-VI-6 (a), the Company identified and delayed some the capital projects forward to a later date in 2021. Although I am not recommending an adjustment of these capital projects, the Company should provide an update as to whether these capital projects have been placed in service and provide a firm in-service date if these capital projects are expected to be in-service in 2021.

Q. WHAT IS YOUR FINAL ADJUSTMENT RELATED TO THE COMPANY'S CAPITAL PROJECTS?

A. I reviewed the Company's response to OCA-III-12 which referred me to the response to IE-RB-8-D. The Company provided a schedule of capital projects related to baseline additions. The Company proposed to add $501,241,012 of baseline additions in 2021 and an additional $720,507,158 in 2022. The Company has not provided any specific timelines of these baseline additions but have indicated that the in-service dates vary.

Q. WHAT ARE YOUR ADJUSTMENTS TO THE COMPANY'S PROPOSED BASELINE CAPITAL ADDITIONS?

A. I am recommending normalizing these baseline additions between the balances in the FTY and the balances in the FPFTY period. This adjustment results in a reduction of $99,633,073. According to the Company, baseline work is short duration and is capitalized on a monthly or quarterly basis. Once detailed baseline and program work is identified, costs are assigned to a specific project. (IE-RB-8-D). The Company has indicated that all costs in the schedule have in-service dates within the FTY and the FPFTY. This does not provide a sufficient comfort level that all of these baseline additions will be completed through 2022. The various in-service dates does not provide sufficient information and are not known and measurable. Therefore, I am recommending that normalizing these capital projects provide for better certainty.

Q. WHAT IS YOUR TOTAL ADJUSTMENT TO THE COMPANY'S EPIS BALANCE?

A. My total adjustment is a reduction of $203,549,663 million as shown on my Schedule DM-5.

2. Accumulated Depreciation

Q. WHAT HAS THE COMPANY CALCULATED WITH RESPECT TO ITS ACCUMULATED DEPRECIATION?

A. The Company computed accumulated depreciation in the amount of $2,251,728,000 as shown on Company Exhibit MJT-1 Schedule C-3. This balance removes transmission related plant and other non-jurisdictional costs from the accumulated depreciation balance. The Accumulated Depreciation balance is calculated based upon the Pennsylvania jurisdiction for electric operations. (PECO Statement No. 3 at 16). The Company has included the cost of removal net of salvage value in the amount of $54,724,000 in the Company's FPFTY accumulated depreciation calculations. (Statement No. 3 at 16).

Q. WHAT IS YOUR RECOMMENDATION?

A. I am accepting the Company's calculation with respect to the development of the Accumulated Depreciation balance. My adjustment is related to my recommended removal of certain projects and baseline additions as I identified in my EPIS section of my testimony. As I removed certain projects and baseline additions, I am making the associated adjustment to the Accumulated Depreciation balance. The Company utilized a composite rate of 2.90% (OCA-III-22 (a) attachment) related to distribution plant. This results in an adjustment of $5,902,940 ($203,549,663 times 2.90%). My recommendation is shown on my Schedule DM-6.

3. Common Plant

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO COMMON PLANT?

A. The Company has included $424,369,000 (net of accumulated depreciation and net of the allocation factor of 69.697%) as shown on Company Exhibit MJT-1 Schedule C-8. The Company has included allocated costs related to Land, Organization, Software, General Plant and Other Plant for a total of $1,132,095,000. The Company adjusted this balance by $523,218,000 related to accumulated depreciation to arrive at a net Common Plant balance of $608,877,000. The Company then allocated 69.697% to the Electric Division to arrive at the $424,369,000 balance.

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S COMMON PLANT BALANCE OF $424,369,000?

A. I reviewed the Company's development of the Common Plant balance, and I have no changes to the balance.

4. Working Capital

Q. WHAT DID THE COMPANY PROPOSED RELATED TO ITS CASH WORKING CAPITAL (CWC)?

A. The Company has proposed a CWC balance of $155,548,000 as shown on Company Exhibit MJT-1 Schedule C-1 and C-4.

Q. DO YOU HAVE ANY ADJUSTMENTS OR CHANGES IN THE METHODOLOGY USED BY THE COMPANY TO CALCULATE ITS CWC?

A. No. I am accepting the Company's CWC methodology. My adjustments relate to my adjustments with respect to O&M Expenses, and other adjustments used to develop the CWC balance.

Q. WHAT ARE YOUR ADJUSTMENTS WITH RESPECT TO THE COMPANY'S CWC BALANCE?

A. I adjusted the Company's Cash Working Capital to incorporate my adjustments to my recommended O&M Expenses which flow through to the Cash Working Capital document. My recommended balance is $154,041,438 and is shown on my Schedule DM-7.

5. <u>Pension Asset</u>

Q. WHAT HAS THE COMPANY PROPOSED REGARDING THE PENSION ASSET BALANCE?

A. The Company has proposed to recover in Rate Base a Pension Asset balance of $128,977,000 as shown on Company Exhibit MJT-1 Schedule C-1 and in detail on Schedule C-5.

Q. WHAT ARE THE REASONS STATED BY THE COMPANY IN INCLUDING THE PENSION ASSET FOR RECOVERY IN RATE BASE?

A. The Company stated that this Pension Asset balance represents the portion of the Company's net aggregate total of pension costs incurred to date, calculated in the manner required for ratemaking purposes, that was not recovered in operating expenses and was also not capitalized to its plant accounts. (PECO Statement No. 3 at 26). Company witness Trzaska stated that this asset represents the difference between the manner in which pension expense is calculated for ratemaking purposes and the manner in which pension costs are determined for purposes of calculating the labor loading rate used to capitalize a portion of pension costs under applicable Generally Accepted Accounting Principles (GAAP). (PECO Statement No. 3 at 26). Mr. Trzaska stated that specifically for ratemaking purposes, and consistent with Commission policy and practice, PECO has historically claimed for recovery its actual cash contributions to its pension fund. Also consistent with Commission policy and practice, the amount of the total cash contribution included in operating and maintenance expenses was determined by reducing the total cash contribution by the capitalization rate used for ratemaking purposes to separate labor-related costs between the amounts that are expensed, and amounts assigned, on a pro-forma basis to capital. (PECO Statement No. 3 at 26).

Q. WHAT OTHER ASSUMPTIONS DID THE COMPANY STATED AS THE REASONS TO CAPITALIZE PENSION COSTS?

A. The Company stated that a gap of $3.9 million of pension costs would be realized on the basis of ASC 715, as GAAP and applicable financial reporting mandates require and as a consequence this gap has occurred. (PECO Statement No. 3 at 26-27).

Q. WHAT ARE YOUR ADJUSTMENTS WITH RESPECT TO THE COMPANY'S BALANCE OF $128,977,000 OF PENSION ASSET?

A. I am recommending removal of the Company's Pension Asset of $128,977,000 from Rate Base. The Company has not specifically provided a reason for including the capitalized portion of its Pension in Rate Base. Company witness Mr. Trzaska stated that this capitalized amount represented the portion of the Company's net of total pension costs incurred to date that was not recovered in operating expenses and was also not capitalized to its plant accounts. (PECO Statement No. 3 at 26). In response to OCA Set III- 30 the Company was asked how it developed its Pension Asset and for how long the Company has capitalized its Pension Asset as part of its Rate Base development. The Company responded that since 2015, the Pension Asset was part of its Rate Base development. However, the attachment OCA-Set III-30 (a), the Company could not provide prior years capitalized costs by transmission, distribution and gas line products because it was unavailable. It is unclear how the $128,977,000 balance was developed or calculated. Further, I asked how many years the Company is proposing to amortize these costs. The Company referred to Mr. Trzaska's direct testimony for the explanation. I could not find it.

Q. DO YOU BELIEVE THAT THESE PENSION ASSETS SHOULD BE CAPITALIZED?

A. No. In PECO Energy Company – Gas Division's (PECO Gas) most recent base rate proceeding at Docket No. R-2020-3018929, a similar claim for a pension asset was made. The Commission recently issued its Order on June 22, 2021, denying rate base recognition of the Pension Asset in that case. The Commission held as follows:

> "[W]e are not persuaded that inclusion of the Company's Pension Asset in rate base is a reasonable and necessary means of recovery of PECO's pension expense."[3]

In that Order, the Commission correctly concluded that the Pension Asset is a financial accounting mismatch that arises from the unique nature of the applicable accounting requirements for pension expenses in addition to the employer's obligation to comply with specific pension funding requirements.

Accordingly, in this instance, PECO's claimed Pension Asset is merely a financial accounting mismatch that, if allowed in rate base, will overstate rate base indefinitely. It should also be noted that the Company has not proposed to amortize this balance over time, which allow the Company to over earn on these amounts. Moreover, such treatment would inappropriately allow the Company to earn a return on past pension expense, which violates fundamental principles of ratemaking. Furthermore, while there is currently an accounting mismatch due to fluctuations in the general funding requirements, those funding requirements are intended to equal employer's contributions over the life of the pension. For these reasons, the Pension Asset should not be included in rate base as proposed by the Company, consistent with the Commission's recent decision at Docket No. R-2020-3018929.

6. <u>Accumulated Deferred Income Taxes (ADIT)</u>

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO ITS ACCUMULATED DEFERRED INCOME TAXES (ADIT)?

A. The Company proposed a balance in its ADIT in the amount of $658,825,000 as shown on Company Exhibit MJT-1 Schedule C-1 and C-6. This balance represents the federal income taxes that must be deferred in compliance with the

[3] Docket No. R-2020-3018929, Opinion and Order at 67 (June 22, 2021)

normalization provisions pertaining to the use of accelerated tax depreciation for federal income tax purposes on the test year plant balances and other tax/book timing differences that have been normalized. (PECO Statement No. 3 at 27). This balance incorporates all necessary adjustments as required for its Contribution in Aid of Construction (CIAC).

Q. WHAT ADJUSTMENTS DO YOU HAVE RELATED TO THE COMPANY'S ADIT BALANCE?

A. I do not have any adjustments with respect to the methodology the Company used to calculate the ADIT balance. My adjustments reflects my recommended removal of certain projects that I addressed in my EPIS testimony section.

Q. WHAT IS YOUR TOTAL ADJUSTMENT RELATED TO THE COMPANY'S ADIT BALANCE?

A. I utilized my recommended balance of the Accumulated Depreciation adjustment of $5,902,940 and multiplied that amount by the Company's composite rate of 28.89%. This produces an adjustment of $1,705,359 ($5,902,940 x 28.89%). This is shown on my schedule DM-9.

7. Accumulated Deferred Income Taxes – Excess (ADIT) Regulatory Liability

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS ADIT BALANCE?

A. The Company has proposed an Excess ADIT balance of $296,665,000 as shown on Company Exhibit MJT-1 Schedule C-1 and C-12. This represents the Excess Accumulated Deferred Income Tax that has been removed from the ADIT account and recorded as a regulatory liability. (PECO Statement No. 3 at 30).

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S PROPOSED ADIT – REGULATORY LIABILITY BALANCE?

A. After a review of the data responses provided by the Company in OCA Set III-33, I am accepting the Company's balance of $296,665,000. My balance is shown on my Schedule DM-10.

C. OPERATING INCOME

1. <u>Operating Revenues</u>

Q. WHAT HAS THE COMPANY PROPOSED AS ITS OPERATING REVENUE AT PRESENT RATES AND PROPOSED RATES?

A. As shown on Company Exhibit MJT-1 Schedule D-1 the Company proposed total Operating Revenues at Present Rates of $2,333,680,000, and total Operating Revenues at Proposed Rates of $2,580,588,000. The difference represents the revenue increase of $246,908,000. (PECO Statement No. 3 at 31).

Q. WHAT ADJUSTMENTS DID THE COMPANY MAKE TO DERIVE ITS $2,333,680,000 BALANCE AT PRESENT RATE REVENUE?

A. As shown on Company Schedule MJT-1 Schedule D-5, the Company made various adjustments to: (1) to annualize revenues for the projected number of customers at the end of the FPFTY period of $4,060,000 (Schedule D-5 Column 2); (2) to remove Customer Assistance program (CAP) revenue credits and adjustments reflecting the number of CAP customer at the end of the FPFTY period of $778,000 (Schedule D-5B); (3) to account for lost revenue due to load reduction through the FPFTY period of $13,207,000[4] (Schedule D-5C); (4) to remove budgeted revenues associated with the recovery of costs to develop and implement PECO's energy efficiency and conservation programs of $95,856,000 (Schedule D-5D); and (5) to account for the normalized revenues related to a Leap Year adjustment of $845,000 (Schedule D-5F).

[4] This is related to the energy efficiency and conservation provision of Act 129 of 2008, which requires the Company to assist customers in saving energy and reduce demand.

Q. DID THE COMPANY UPDATE ITS OPERATING REVENUE SUBSEQUENT TO THE INITIAL FILING?

A. No, the Company did not update its Operating Revenue subsequent to the initial filing.

Q. HAS THE COMPANY ACCOUNTED FOR THE IMPACT OF COVID-19 WITH RESPECT TO ITS ELECTRIC SALES FORECAST?

A. Yes. Company witness Mr. Stefani (PECO Statement No. 2) page 19 indicated that the impact of COVID-19 sales has been noticeable. 2020 weather normalized electric sales were approximately 3% lower than budget forecast primarily due to COVID-19 impacts. Residential Sales were higher due to stay-at-home orders while commercial and industrial sales were 7% lower than expected due to business closure mandates. A full recovery is not expected until the economy is able to fully re-open and recover from lingering recessionary impacts. (Statement No. 2 at 20). Mr. Stefani stated that the COVID-19 impact to sales will taper off almost completely by the FPFTY.

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S PRESENT RATE REVENUE?

A. With respect to the Company's Forfeited Discount adjustment of $924,000 (Exhibit MJT-1 Schedules A-1 and D-1) I am adjusting this balance based upon my recommended revenue requirement decrease of $13,236,633. This reduces the Forfeited Discount adjustment by $973,518 or a balance of ($49,518). With respect to the Company's Miscellaneous Service Revenues, Rent for Electric Property and Other Electric Revenues, I am normalizing these revenues for the 2020-2022 periods. The Company, in response to OCA Set III-35, indicated that these costs do fluctuate from year to year, and it is appropriate to average out these costs. My adjustments are shown on my Schedule DM-4.

2. OPERATION AND MAINTENANCE EXPENSES

Q. HOW DID THE COMPANY DEVELOP ITS OPERATING EXPENSES PRESENTED FOR RECOVERY IN THIS RATE PROCEEDING?

A. According to witness Trzaska the Company budgets its operating expenses by cost element or business activity such as payroll, employee benefits, rent, etc. (PECO Statement No. 3 at 36). Company witness Trzaska stated that the Company does not budget its operating expenses by FERC account, but were analyzed to develop a chart showing charges for each cost element within each FERC account in the transmission, distribution, administrative and general functions. Mr. Trzaska distributed the forecasted FPFTY charges by cost elements in those categories to the corresponding FERC accounts based upon the ratios experienced in the HTY. (PECO Statement No. 3 at 37). This process was used for each cost category to transform the FPFTY expense forecast by cost element to a FERC-based forecast and brought forward to Company Schedule B-4. (PECO Statement No. 3 at 37). These transformations were needed because the Company's annual reports to the Commission were presented on a FERC-account basis and having the FPFTY forecast presented in the same format facilitates a comparison to prior years' experience. The transformation was also need for use by Company witness Ms. Jamison in the cost of service study. (PECO Statement No. 3 at 37-38).

Q. WHAT LEVEL OF OPERATING EXPENSES HAS THE COMPANY PROPOSED TO RECOVER IN THIS PROCEEDING UNDER ITS FPFTY TEST PERIOD?

A. As shown on Company Exhibit MJT-1 Schedule D-1 and further broken down on Schedule D-4 the Company has proposed to recover $1,558,280,000 of Operating Expenses.

Q. WHAT LEVEL OF OPERATING EXPENSES HAS THE COMPANY PROJECTED IN ITS FTY PERIOD?

A. As shown on Company Exhibit MJT-2 Schedule D-1 and further broken down on Schedule D-4, the Company has proposed to recover $1,520,100,000 of Operating Expenses, a difference of $38,180,000. (2.51% increase).

Q. WHAT LEVEL OF OPERATING EXPENSES HAS THE COMPANY RECOVERED UNDER ITS HTY PERIOD?

A. As shown on Company Exhibit MJT-3 Schedule D-1 and further broken down on Schedule D-4, the Company booked $1,500,579,000 of Operating Expenses, a difference of $19,521,000 compared to FTY period. (1.28% increase).

a. <u>Power Supply Expenses</u>

Q. WHAT DID THE COMPANY PROPOSE REGARDING ITS POWER SUPPLY EXPENSES?

A. The Company proposed a Power Expense balance of $689,927,000 as shown on Company Exhibit MJT-1 Schedule D-1 and Schedule D-4.

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S POWER SUPPLY EXPENSE?

A. No. I am accepting the Company's balance of $689,927,000. My balance is shown on my Schedule DM-12.

b. <u>Transmission Expense</u>

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO ITS TRANSMISSION EXPENSE?

A. As shown on Company Exhibit MJT-1 Schedule D-1 and Schedule D-4 the Company proposed a Transmission Expense balance of $161,192,000. $78,643,000 was related to Transmission Operations and $82,548,000 was related to Transmission Maintenance.

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S PROPOSED TRANSMISSION EXPENSE BALANCE?

A. In response to OCA Set VI-4, the Company stated that the Transmission costs for the FPFTY are offset by the Transmission revenues shown on Exhibit MJT-1 Schedule B-3. The Company stated that it is not seeking recovery of costs for Transmission expenses related to Miscellaneous and Maintenance expenses. In that same response the Company identified Stock Compensation expense totaling $457,000 (Column 25). I am removing these for ratemaking purposes, as I believe these costs represent a form of incentive compensation. The Company has not identified who are the recipients of the Stock Compensation costs, nor provided how these Stock Compensation costs were developed. I don't believe ratepayers should be bearing these costs nor do I believe the ratepayers benefit from Stock Compensation.

Q. WHAT ARE YOUR ADJUSTMENTS RELATED TO THE COMPANY'S TRANSMISSTION EXPENSE?

A. I am removing $457,000 from the Company's balance. My balance is shown on my Schedule DM-13.

c-1. <u>Company Overall Salary & Wages (S&W) Increase</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS SALARY AND WAGES INCREASE?

A. As shown on Company Exhibit MJT-1 Schedule 6, the Company proposed an overall Salary & Wages increase of $11,982,000 or 7.50% over adjusted S&W for employees in the FPFTY period which included increase to its Union and Non-Union Employees. The Company's jurisdiction payroll before the proposed rate increase was computed at $159,643,000. To that amount, the Company's added the $11,982,000 increase, to arrive at a total S&W balance of $171,625,000 as shown on Schedule D-6 pages 69 and 71.

Q. HOW DID THE COMPANY DEVELOP ITS PROPOSED S&W INCREASE OF $11,982,000?

A. The Company performed a few calculations and analyses to develop its proposed $11,982,000 S&W increase. First, the Company annualized its number of employees at the end of the FPFTY period. The Company projected 960 Union employees and 1,054 Non-Union employees for a total of 2,104 employees (Company Exhibit MJT-1 Schedule D-6 page 68). The Company then allocated a portion of the total S&W to the Distribution operations of the Company; 47.67% for Union and 52.33% for Non-Union. The Company then calculated a 2.50% increase for its Non-Union employees effective March 1, 2022, for two month (January – February 2022); and a 2.50% increase for both its Union and Non-Union employees effective January 1, 2023, and March 1, 2023, respectively. (PECO Statement No. 3 at 39).

Q. WHAT WERE THE COMPANY'S NEXT ADJUSTMENTS?

A. After the Company annualized its S&W adjustments, the Company included a One-Time Contract payment for Union employees (currently being negotiated between the Company and the Union) in the amount of $1,127,000 allocated 76.26% to the Company and amortized over 6 years to reflect the six-year term of the new contract or $143,000 (PECO Statement No. 3 at 39) (Exhibit MJT-1 Schedule D-6 page 69). The Company then included a one-time payment of $3,800,000 for certain union employees for the FPFTY as part of the new union contract. The Company will update the one-time union contract ratification payment once the contract is finalized. (PECO Statement No. 3 at 40).

Q. WHAT WAS THE LAST ADJUSTMENT THE COMPANY MADE TO ITS S&W ADJUSTMENT?

A. The Company annualized the increase in the number of employees during the FPFTY period. The Company projected that the number of employees at the end of the FPFTY is 2,227. The average number of employees during the FPFTY period is 2,179, a difference of 48. (PECO Statement No. 3 at 40) (Exhibit MJT-1 Schedule D-8). The Company multiplied this amount by the average annual S&W per employee of $77,100 as shown on Schedule D-6 page 69 to compute the total annualization adjustment of $3,691,000. (PECO Statement No. 3 at 41) (Exhibit MJT-1 Schedule 6 page 69).

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S PROPOSED S&W INCREASE OF $11,982,000?

A. My first adjustment is to the Company's annualized wage increase to become effective as of January 1, 2023, in the amount of $1,902,000 for Union employees and effective as of March 1, 2023, in the amount of $2,097,000 for Non-Union employees, a total of $3,999,000. These adjustment increases are beyond the Company's test year period ending December 31, 2022 and should not be included in the revenue requirement proposal. These are considered out of period adjustments and should not be included in the development of the Company's salary and wages expense.

Q. WHAT ARE YOUR NEXT ADJUSTMENTS TO THE COMPANY'S S&W INCREASE?

A. My next adjustments are to the Company's proposed one-time Contract Payment of $143,000 and the labor cost increase of $3,800,000 as shown on Exhibit MJT-1, Schedule D-6. I am removing these adjusted costs because I consider these to be bonus payments which are not related to any type of performance goals or targets. As stated in OCA-III-42 the $143,000 was a one-type ratification bonus based upon a Memorandum of Understanding. In response to IE-RE-25-D, the Company stated that performance for pay must be earned and not automatic or guaranteed. However, the Company has not provided any information as to whether employees have actually achieved the goals and targets required to receive these one-time bonuses. In response to OCA-III-43, the Company stated that the $3,800,000 was an estimate under the new contract and the Company will update the incremental labor related costs in its rebuttal testimony (IE-RE-33-D). In addition, given that the Company will update these costs, currently they are not known and measurable.

Q. WHAT ARE YOUR NEXT ADJUSTMENTS TO THE COMPANY'S S&W INCREASE?

A. My next adjustments are to the Company's proposed Incentive Compensation included in the development of the S&W increase. In response to OCA-III-39, which refers to IE-RE-33-D and IE-RE-27-D, which refers to SDR-OM-28, the Company has included incentive / bonus expenses of $18,028,000 in 2021 and $19,008,000 in 2022. In response to OCA-III-36 (a), the portion allocated to PECO Electric was $13,545,000. In IE-RE-27-D, (Attachment IR-RE-27-D (a)) the Company provide the Annual Incentive Plan by Performance Criteria.

Q. DID THE COMPANY IDENTIFY THE LEVEL OF INCENTIVE COMPENSATION INCLUDED IN THE S&W WAGE CATEGORY?

A. In response to IE-RE-27-D the Company identified the level of incentive compensation in the S&W wage category. The Company stated that it calculates incentive expense in the aggregate based on the total payout and not by individual performance criteria. In response to OCA SET III-36, the Company provided a breakdown of its expense adjustment category (Attachment OCA SET III-36 (a) FPFTY 2022), which shows incentive compensation that has been included in the expenses in the amount of $13,545,000. (Column 5). In response to IE-RE-27D the Company provided the incentive / bonus expense by performance criteria under various incentive plans for 2018-2020 and for the FTY and FPFTY periods.

Q. IN REVIEWING THIS DOCUMENT WHAT IS YOUR RECOMMENDATION REGARDING INCENTIVE COMPENSATION?

A. According to the Attachment IE-RE-27-D (a) the Company provided a matrix of performance criteria based upon key performance indicators (KPI). However the Company has not provided whether these KPIs were met or achieved by employees. In response to OCA-III-39, the Company stated that the PECO systems currently do not have the capability to provide the Salary and Wages costs broken down into the respective employee groupings (i.e. Incentive Compensation). In reviewing the Confidential Documents (SDR-OM-28 (aa), (ab), (v), (w), (x), (y) and (z), **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)** Absent such information, I am recommending removing these costs from the revenue requirement calculations. The Company should provide a detailed breakdown as to the level of AIP it has provided to its collective bargaining employees, regular employees and to its Management employees. My adjustment is shown on my Schedule DM-14A.

Q. WHAT IS YOUR NEXT ADJUSTMENT TO THE COMPANY'S S&W INCREASE?

A. My next adjustment to the Company's S&W increase is to the annualization of new employees and the development of the annual S&W per employee of $77,069 as shown on Exhibit MJT-1 Schedule D-6 line 20. The Company developed this number by using the proposed S&W balance of $167,933,080 and dividing that number by the average number of employees of 2,179. The Company then multiplied this number by 48 to reflect the average number of employees expected to be hired in the FPFTY period, which resulted in an annualized adjustment of $3,691,000. My adjustments reflects my proposed adjusted S&W balance of $146,445,086 and dividing this balance by the average number of employees of 2,179, which results in an average annual S&W per employee of $67,207. I then multiplied this amount by the additional 48 employees expected to be hired through the FPFTY period to arrive at an average per employee of $3,225,959, an adjustment of $465,041.

Q. WHAT IS YOUR FINAL ADJUSTMENT TO THE COMPANY'S S&W INCREASE?

A. My final adjustment is the use of a vacancy ratio. In response to OCA-III-38, the Company provided a three year vacancy ratio (2018-2020). Normalizing this ratio over three years equals 1.83%. Given that the Company hasn't provided any further updates as to the anticipated number of employee to be hired in 2021 and 2022, it is appropriate to use a vacancy ratio to normalize the level of employees going forward. The Company should update its response to OCA-III-38 showing the actual dates of employee hires through 2021 and what employees the Company expects or has projected to hire in 2022. This results in an adjustment of $2,679,945 (recommended S&W balance of $146,445,086 times 1.83%). This adjustment is shown on my Schedule DM-4.

Q. WHAT IS THE IMPACT OF YOUR ADJUSTMENTS TO THE COMPANY'S PROPOSED S&W INCREASE OF $11,982,000?

A. My adjustments reduce the Company's S&W increase by $8,408,044 and my recommended balance is $3,574,048 shown on my Schedule DM-14A.

Q. HAVE YOU ALLOCATED YOUR ADJUSTMENTS TO THE COMPANY'S S&W INCREASE BY ACCOUNT CATEGORIES?

A. Yes. My Schedule DM-14A shows the allocation by account categories that I performed to adjust the Company's S&W adjustment. I've also addressed this allocation to my adjustments for each of the Company's Operating Expenses below:

c. <u>Distribution Operations and Maintenance Expense</u>

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO ITS DISTRIBUTION EXPENSES – OPERATIONS AND MAINTENANCE?

A. The Company has proposed a Distribution Expense of $379,691,000; $117,072,000 is related to Distribution Operations and $262,619,000 is related to Distribution Maintenance. These balances are shown on Company Exhibit MJT-1 Schedule D-4 with the total carrying over to Schedule D-1.

Q. DID THE COMPANY INCLUDE SPECIFIC ADJUSTMENTS IN ITS DISTRIBUTION EXPENSE BALANCE?

A. Yes. Included in the balance are adjustments related to Salary and Wages of $5,905,000; and Storm Cost of $2,807,000. These will be addressed below in Section 1 and Section 2.

Q. ARE THERE ANY OTHER SPECIFIC ADJUSTMENTS YOU MADE TO THE COMPANY'S DISTRIBUTION OPERATION AND MAINTENANCE EXPENSE?

A. Yes. I am addressing the Company's Vegetation Management costs concerning vegetation control / tree trimming costs that are included in the Company's Distribution Maintenance category. I address these adjustments in Section 3 below. I am also addressing the Company's costs related to the Exelon Business Service Company (EBSC) specifically the incentive compensation included in the total charges. I address these adjustments in Section 4 below.

1. Salary and Wages (Schedule D-6)

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS SALARY AND WAGES FOR ITS DISTRIBUTION EXPENSE?

A. The Company has proposed $1,392,000 of additional S&W expense for its Distribution Operations and $4,513,000 for its Distribution Maintenance Expense for a total S&W increase of $5,905,000. (Exhibit MJT-1 Schedule D-4 page 56). The breakdown and description of these adjustments are outlined in my section c-1 of my testimony and shown on my Schedule DM-14A.

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S S&W EXPENSE?

A. As I testified to and outlined my reasoning in Section c-1 above, I am recommending a total adjustment (reduction) of $977,014 for S&W related to Distribution Operations and a reduction of $3,167,307 related to Maintenance expenses. I carried over these adjustments from my Schedule DM-14A to my Schedule DM-14. My recommended balance for Distribution – Operations S&W is $415,304 and for Distribution - Maintenance is $1,346,343.

2. Stock Compensation

Q. HAS THE COMPANY INCLUDED OR PROVIDED COSTS RELATED TO STOCK COMPENSATION?

A. Yes. In response to OCA Set VI-4 (a) Attachment, the Company included total Stock Compensation of $440,000 under Distribution Operations and $1,132,000 under Distribution Maintenance. I am removing these for ratemaking purposes, as I believe these costs represent a form of incentive compensation. The Company has not identified who are the recipients of the Stock Compensation costs, nor provided how these Stock Compensation costs were developed. I don't believe ratepayers should be bearing these costs nor do I believe the ratepayers benefit from Stock Compensation.

Q. WHAT IS YOUR ADJUSTMENT?

A. My adjustment is a total reduction of $1,572,000 ($440,000 + $1,132,000). This is shown on my Schedule DM-14.

3. <u>Storm Expenses (Schedule D-13)</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO STORM EXPENSE?

A. As shown on Company Exhibit MJT-1 Schedule D-13 and Schedule D-4, the Company has proposed an increase of $2,807,000 related to the recovery of storm damage restoration expenses. Mr. Trzaska has stated that the Company has proposed, for ratemaking purposes, a normalization of storm damage expense based upon a five-year historical storm damage expense. Mr. Trzaska stated that the five-year period is long enough to reflect appropriate levels of expense associated with normal storm events, major storms and extraordinary storms. (PECO Statement No. 3 at 46). The Company has calculated an average storm restoration expense at 2022 levels of $51,145,000. ($255,725,000/5 years) The Company has calculated its FPFTY budget balance of $48,338,000 to arrive at the $2,807,000 increase. (Include responses to OCA Set VI #1 regarding Heat Wave Storm

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S PROPOSED STORM EXPENSE INCREASE OF $2,807,000?

A. As shown on Company Exhibit MJT-1 Schedule D-13, the Company has included an inflation factor in the years 2016 through 2020 to adjust its storm expense. The five-year balance before the Company's inclusion of the inflation factors is $239,948,000. This is a difference of $15,777,000 ($255,725,000 - $239,948,000). By removing the inflation factors in each of the years 2016 through 2020 a five-year balance results in an average storm restoration expense of $47,989,600.

Using the Company's FPFTY budget of $48,338,000, an adjustment of ($348,400) is calculated. This reduces the Company's adjustment by $3,155,400. ($2,807,000 + $348,400).

Q. WHY ARE YOU REMOVING THE INFLATION FACTORS TO COMPUTE THE COMPANY'S STORM EXPENSE NORMALIZATION?

A. I believe that inflation factors should be removed from the Company's adjustments because these cost adjustments are not known and measurable, as they do not reflect the true cost of the expense. Inflation adjustments are typically blanket adjustments or increases/decreases which do not directly relate to actual costs expected to be incurred by the Company in the period in which new rates are to be set. Cost should be based upon evidence or documentation that supports the Company's adjustments. The Company has not provided or supported any information to show that approximately $15,777,000 of additional storm expense was realized in the past and will be realized in the FPFTY period. My adjustment is shown on my Schedule DM-14.

4. <u>Vegetation Management</u>

Q. HAS THE COMPANY IDENTIFIED THE LEVEL OF VEGETATION-RELATED PREVENTIVE MANAGEMENT COSTS INCLUDED IN THIS PROCEEDING?

A. No. In response to OCA-III-14 I asked for a cost breakdown of the Company's O&M expenses related to vegetation – related preventive maintenance work. The Company referred me to the attachment which showed the distribution Preventive Maintenance Program – O&M Expenses from 2016 through 2020. In response to OCA-Set III-13 the Company provided the Vegetation Management Reports filed with the Commission. These reports included the costs related to preventive maintenance and corrective/emergent maintenance. The Company also referred me to the response to I&E-RE-32-D (f) through (j). (Confidential Attachments). This response appears to include all vegetation control/tree trimming costs and other programs.

Q. DOES THE COMPANY MAINTAIN A SINGLE VEGETATIVE MANAGEMENT PLAN?

A. No. The Company have a five year distribution preventive maintenance routine pruning program in which all circuits on the PECO system are trimmed to specification.

Q. WHAT COSTS DID THE COMPANY PROVIDE REGARDING ITS FIVE-YEAR PLAN?

A. The Company provided the following costs for under a five-year period:

2017	$42,857,376	(actual) IE-RE-32-D
2018	$44,285,656	(actual) IE-RE-32-D
2019	$44,167,571	(actual) IE-RE-32-D
2020	$52,200,000	(actual) OCA III-13 (a)
2021	$48,689,796	FTY – 2021 (IE-RE-32-D)

The Company proposed a FPFTY vegetation management program cost of $49,994,521.

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S COSTS RELATED TO ITS VEGETATION MANAGEMENT PROGRAM COSTS?

A. I relied on the response to IE-RE-32-D which appeared to include all of the Company's vegetation management costs including the preventive maintenance, tree trimming, vegetation control and other related costs. Using a five-year normalization (2017-2021) of actual and proposed costs I arrive at a total average of ($231,628,3993/5) $46,325,680. This reduces the Company's FPFTY balance by $3,668,841 ($49,994,521 - $46,325,680).

Q. WHY IS A FIVE-YEAR NORMALIZATION APPROPRIATE?

A. In response to IE-RE-32-D, the Company provided a budget vs. actual costs of vegetation costs for 2017-2019, and these variances range from -4% to +7%. In 2020 (Attachment OCA-III-13 (a) the variance was +1.35%. In 2021 and 2022 these budgeted amounts increased 10.23% in 2021 and an additional 2.68% in 2022. These fluctuations and changes from year to year justify the need to normalize these expenses going forward, in the same manner as storm management costs. In addition, I am unsure whether there are inflation factors or CPI increases included in these costs as the Company has not provided a detailed cost breakdown to warrant these added costs in each year. If there are inflation factors or CPI increases, I would need to make an additional adjustment to remove the additional expense related to the inflation factor or CPI increases.

5. Exelon Business Service Company (EBSC)

Q. WHAT HAS THE COMPANY PROVIDED WITH RESPECT TO ITS COSTS RELATED TO ITS EBSC CHARGES?

A. The Company has proposed total EBSC charges of $114.1 million as shown on PECO Exhibit RJS-3. In response to OCA Set III-21, I asked for a cost breakdown for the periods 2016-2020, projected 2021 and for fully projected 2022 test year periods. I also asked the level of incentive compensation included in the FPFTY 2022 period, which the Company stated was $8.3 million. A further breakdown of this amount was not available. The incentive compensation costs were booked in accounts 923000 (A&G – Outside Services), 588000 (Distribution – Miscellaneous Expenses) and 903000 (Customer Accounts – Customer Records and Collections).

Q. HAS THE COMPANY INDICATED WHAT THESE INCENTIVE COSTS REPRESENT OR WHETHER THESE COSTS ARE BENEFICIAL TO CUSTOMERS?

A. Not that I am aware. The Company has not provided any further information as to whether these incentive compensation costs benefit ratepayers. A further breakdown of these costs are not available. Given the absence of information it is unclear what these costs represent.

Q. WHAT IS YOUR RECOMMENDATION?

A. I am recommending removing these costs from the Company's ESBC expense level.

Q. HOW DID YOU ALLOCATE THESE COSTS FROM THE COMPANY'S A&G, DISTRIBUTION AND CUSTOMER ACCOUNTS EXPENSES?

A. I used a ratio of total costs for each of the above categories and multiplied the ratio amounts by the total incentive compensation balance of $8.30 million My schedules reflect the adjustments in each account as follows:

923000 – A&G – Outside Services	31.14% -	$2,584,620	DM-18
588000 – Distribution – Misc. Expense	31.77% -	$2,636,910	DM-14
903000 – Customer Accounts – Cust. Rec.	37.09% -	<u>$3,078,470</u>	DM-15
Total		$8,300,000	

Q. WHAT ARE YOUR TOTAL DISTRIBUTION EXPENSE ADJUSTMENTS?

A. My total Distribution Expense adjustments result in a reduction of $15,177,715 and is shown on my Schedule DM-14.

d. <u>Customer Accounts Expense</u>

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS CUSTOMER ACCOUNTS EXPENSE?

A. As shown on Company Exhibit MJT-1 Schedule D-4 page 57 and 59, the Company proposed a balance of $119,238,000 before adjustments and a balance of $127,032,000 after adjustments. These adjustment were related to Salary and Wages of $2,718,000, Uncollectible Accounts of ($12,649,000), COVID-19 Related Bad Debt Regulatory Asset of $16,083,000 and; Customer Deposit Interest of $1,643,000. Also included in this account category are costs associated with EBSC charges of $3,078,470. I will address each below:

1. <u>Salary and Wages (Schedule D-6)</u>

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS SALARY AND WAGES?

A. The Company proposed total adjustments to its Salary and Wages of $2,718,000; $2,619,000 for Customer Records and Collections, and $98,000 for Miscellaneous Customer Accounts Expense. The breakdown of these adjustments are shown on my Schedule DM-14A and in my testimony Section c-1.

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S SALARY AND WAGE EXPENSE ADJUSTMENT?

A. As I indicated previously in my testimony and as further discussed under Section c-1 my adjustments are related to the Company's incentive compensation, one time contract payments, the labor cost increase of $3.8 million, the March 2023 rate increase, and the annualization of new employees. These flow through the adjustments shown on DM-14A to DM-15. My adjustment is a $1,906,942 reduction ($1,837,669 for Customer Accounts and $68,738 for Miscellaneous Customer Accounts).

2. <u>Uncollectible Accounts (Schedule D-10)</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS UNCOLLECTIBLE ACCOUNTS?

A. As shown on Schedule D-10, the Company proposed a reduction to its Uncollectible Accounts of $12,649,000. Mr. Trzaska utilized a three-year average of charge – offs (excluding CAP-in program arrearages write-offs) as a percentage of total tariff revenue for the 2018-2020 period, which resulted in an uncollectible accounts expense ratio of 0.05622%. (PECO Statement No. 3 at 42-43). Using the Company's tariff revenue of $3,302,647,000 and multiplying it by 0.05622% the Company calculated a pro-forma uncollectible account expense of $18,566,000. Mr. Trzaska then added the average of Pre-program arrearages (PPA) associated with the CAP program of $4,336,000 to arrive at a present rate uncollectible accounts expense of $22,902,000. The Company then subtracted this amount from the Company's uncollectible accounts expense of $35,551,000 to arrive at a balance of ($12,649,000).

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S UNCOLLECTIBLE ACCOUNTS?

A. I reviewed the Company's Uncollectible Accounts proposal and am accepting the Company's methodology. The Uncollectible Accounts balance is derived from the prior three-years of uncollectible expenses, and the prior three-years of Net PPA Uncollectible Accounts. My only adjustment is to additional revenue requirement multiplied by the Company's three-year average of uncollectible ratio of 0.05622%, which I address below.

3. <u>COVID-19 Related Bad Debt Regulatory Asset (Schedule D-11)</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO COVID-19 RELATED INCREMENTAL BAD DEBT EXPENSE?

A. As shown on Company Exhibit MJT-1 Schedule D-11, the Company has proposed to recover total incremental bad debt expense of $48,250,000 amortized over a three-year period or $16,083,000 annually. This incremental uncollectible expense was incurred as a result of the COVID-19 pandemic. (PECO Statement No. 3 at 44). Mr. Trzaska stated that the Commission authorized the Company to create a regulatory asset, or any incremental uncollectible expenses incurred since the issuance of the Emergency Order above the amount embedded in rates. The Company established a regulatory asset in the third quarter of 2020 and the Company booked a regulatory asset for the HTY period of $37,918,000. The Company then computed an estimated incremental bad debt expense in 2021 of $10,332,000 for a total incremental bad debt expense of $48,250,000. The Company then amortized this amount over a three-year period to arrive at an annual recovery of $16,083,000.

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S PROPOSED INCREMENTAL BAD DEBT EXPENSE RELATED TO THE COVID-19 PANDEMIC?

A. After a review of the documents, I am accepting the Company's Incremental Bad Debt Expense balance of $48,250,00, but I am extending the amortization period to five-years instead of the Company's proposed three-year recovery. This reduces the Company's COVID-19 Bad Debt Expense from $16,083,000 to $9,650,000, a reduction of $6,433,000. I believe a five-year amortization is a more appropriate time period that properly balances sharing between ratepayers and shareholders. This is shown on my Schedule DM-15.

4. Customer Deposit Interest (Schedule D-12)

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS CUSTOMER DEPOSIT INTEREST?

A. The Company has calculated interest on its Customer Deposits of $1,643,000 as shown on Company Exhibit MJT-1 Schedule D-12. This adjustment is included in the Company's Miscellaneous Customer Accounts Expense. The Company utilized an annual interest rate of 5.0% and a monthly interest rate of 0.417% for its residential customer deposits, and an annual interest rate of 1.66% (0.138% monthly) for commercial and industrial customers.

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S CUSTOMER DEPOSIT INTEREST?

A. After a review of the documents and discovery responses I am accepting the Company's adjustment of $1,643,000. This is shown on my Schedule DM-15.

5. Exelon Business Service Company – (EBSC)

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S EXELON BUSINESS SERVICE COMPANY?

A. As I testified to above under the Distribution Expense section, I am removing $3,078,470 of EBSC costs that represent incentive compensation. My reasons are addressed in the Distribution Expense section on page 26. This is shown on my Schedule DM-15.

6. Stock Compensation

Q. WHAT HAS THE COMPANY INCLUDED WITH RESPECT TO STOCK COMPENSATION EXPENSE?

A. As shown in the response to OCA Set VI-4 (a) Attachment, the Company has included Stock Compensation costs in the amount of $923,000.

Q. WHAT IS YOUR ADJUSTMENT?

A. As I removed the Stock Compensation in my prior adjustments to the Company's expense categories, I am removing the Stock Compensation costs of $923,000. My arguments are the same as I testified to under my Transmission and Distribution section above.

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S ADDITIONAL UNCOLLECTIBLE ACCOUNTS EXPENSE BALANCE?

A. Utilizing the Company's Uncollectible Account ratio of 0.05622% and multiplying that amount by my recommended revenue requirement decrease of $13,187,116, I arrive at an additional uncollectible account expense of ($74,138)

Q. WHAT ARE YOUR TOTAL ADJUSTMENTS TO THE COMPANY'S CUSTOMER ACCOUNTS EXPENSE?

A. My total adjustments to the Company's Customer Accounts Expense is a reduction of $12,340,877, plus the additional uncollectible accounts expense reduction of $74,138 and is shown on my Schedule DM-15.

e. <u>Customer Service & Information Expense</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS CUSTOMER SERVICE & INFORMATION EXPENSE?

A. The Company proposed a pre-adjustment balance of $102,673,000 and an adjusted balance of $11,740,000.[5] These adjustments related to a $91,055,000 reduction for Energy Efficiency Program Cost Recovery and $123,000 related to Salary and Wage adjustments. I will address each below.

[5] Any differences due to rounding

1. Energy Efficiency Programs Expense (Schedule D-5D)

Q. WHAT ADJUSTMENTS HAS THE COMPANY PROPOSED REGARDING ITS ENERGY EFFICIENCY PROGRAM EXPENSE?

A. The Company has removed the budgeted revenues associated with the recovery of costs associated with developing and implementing PECO's energy efficiency and conservation programs (EE&C) of $91,055,000. Act 129 allows the Company to recover such costs though a separate Section 1307 reconciliation adjustment clause. The Company will continue to utilize its EE&C surcharge mechanism for the recovery of these costs in the future. (PECO Statement No. 3 at 35).

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S EE&C PROGRAM EXPENSE?

A. After a review of the documents and discovery, I am accepting the Company's adjustments related to the EEP expense adjustment of $91,055,000. This adjustment is shown on my Schedule DM-16

2. Salary and Wages (Schedule D-6)

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS SALARY AND WAGES?

A. As shown on Company Exhibit MJT-1 Schedule D-4, the Company has included increases to its Salary & Wages of $123,000. The breakdown and development of these adjustments are shown on my Schedule DM-14A and in my testimony Section c-1.

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S PROPOSED $123,000 SALARY & WAGE INCREASE?

A. As I indicated previously in my testimony and as further discussed under Section c-1 my adjustments are related to the Company's incentive compensation, one time contract payments, the labor cost increase of $3.8 million, the March 2023 rate increase, and the annualization of new employees. These flow through the adjustments shown on DM-14A to DM-16. My adjustment is an $86,330 reduction, and my balance is $36,670.

3. Economic Development – Labor and Benefits

Q. HAS THE COMPANY SPECIFICALLY IDENTIFIED ADJUSTMENTS TO ITS REVENUE REQUIREMENT REQUEST RELATED TO ECONOMIC DEVELOPMENT COSTS AND RELATED WORKFORCE DEVELOPMENT, COMMUNITY SERVICES/INVOLVEMENT AND OTHER VOLUNTEER ACTIVITIES?

A. In response to OCA Set III-18, the Company provided a cost breakdown of the above expenses. The Company allocated these costs to Account Nos. 908000 (Customer Service), 912000 (Sales Expense) and 926000 (A&G Employee Benefits). The total costs were $961,000. For Workforce Development the Company provided a cost breakdown of $557,000. These costs were allocated to Account Nos. 920000 and 926000 (A&G Expenses). For Community Involvement the Company provided a cost breakdown of $234,000 and allocated them to Account No. 921000 (A&G). For Employee Volunteer Events the Company provided a cost breakdown of $54,000 and allocated them to Account No. 921000 (A&G).

Q. WHAT IS YOUR RECOMMENDATION?

A. I made adjustments to the Company's Economic Development costs in the amount of $961,000. I also made adjustments to Employee Volunteer Events of $54,000 which I will address in my A&G Expense section. Regarding the $961,000 costs for Economic Development, I believe these costs should be removed from the Company's revenue requirement proposal as these types of costs should not be borne by ratepayers. These costs should be borne by local, municipal and state organizations. These types of costs appear to be related to regional and various local communities that may or may not be customers of the Company. I do not see the nexus between these costs and the provision of safe and reliable service to customers. If the Company wants to be good corporate citizens, then the shareholders should pay for these types of costs and should not require ratepayers to pay for them. I removed $727,000 from the Company's Customer Service & Information Account, $179,000 from the Company's Sales Expense Account, and $54,000 from the Company's A&G Expense Account. My adjustment is shown on my Schedule DM-16.

4. Stock Compensation

Q. WHAT HAS THE COMPANY INCLUDED WITH RESPECT TO STOCK COMPENSATION EXPENSE?

A. As shown on OCA Set VI-4 (a) Attachment, the Company has included $42,000 of Stock Compensation allocated to the Customer Service and Information account category.

Q. WHAT IS YOUR ADJUSTMENT?

A. As I previously stated in my testimony, I am removing these costs for ratemaking purposes. This reduces the Customer Service & Information account by $42,000.

Q. WHAT IS YOUR TOTAL ADJUSTMENT TO THE COMPANY'S CUSTOMER SERVICE AND INFORMATION?

A. As shown on my Schedule DM-16, my total adjustment is a reduction of $855,330.

f. Sales Expense

Q. WHAT DID THE COMPANY PROPOSE RELATED TO ITS SALES EXPENSE?

A. The Company proposed a pre-adjusted balance of $1,676,000 and an adjusted balance of $1,740,000, a difference of $64,000. (Company Exhibit MJT-1 Schedule D-4). This difference is due to the Company's adjustments for Salary & Wages. I will address this below.

1. **Salary and Wages (Schedule D-6)**

Q. HOW DID THE COMPANY DEVELOP ITS ADJUSTMENT OF $64,000 RELATED TO SALES EXPENSE?

A. As more fully explained in Section c-1 of my testimony, the Company proposed an increase to its Sales Expense Salary and Wages of $64,000. The overall adjustments are shown on Company Exhibit MJT-1 Schedules D-6 and D-8.

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S $64,000 ADJUSTMENT TO SALARY & WAGES?

A. As I indicated previously in my testimony and as further discussed under Section c-1, my adjustments are related to the Company's incentive compensation, one time contract payments, the labor cost increase of $3.8 million, the March 2023 rate increase, and the annualization of new employees. These flow through the adjustments shown on DM-14A to DM-17. My adjustment is a $44,911 reduction, and my balance is $19,089.

2. **Stock Compensation**

Q. WHAT HAS THE COMPANY INCLUDED REGARDING STOCK COMPENSATION?

A. As shown on OCA Set VI-4 (a) Attachment, the Company has included $20,000 of Stock Compensation allocated to the Customer Service and Information account category.

Q. WHAT IS YOUR ADJUSTMENT?

A. I am removing these costs from the Company's Sales Expense balance. As more fully explained previously, I believe these costs do not benefit ratepayers and ratepayers should not be burden by these types of costs.

3. **Economic Development**

Q. WHAT HAS THE COMPANY PROPOSED OR PROVIDED RELATED TO ECONOMIC DEVELOPMENT?

A. As indicated previously, the Company proposed an Economic Development expense of $916,000, of which $179,000 is accounted for in the Company's Sales Expense. My arguments for removing these costs are explained under my Customer Service and Information expense section.

Q. WHAT IS YOUR OVERALL ADJUSTMENTS RELATED TO SALES EXPENSE?

A. My overall adjustment is a reduction of $243,911 and is shown on my Schedule DM-17.

g. Administrative & General (A&G) Operations and Maintenance Expense

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS ADMINISTRATIVE & GENERAL EXPENSES?

A. The Company proposed a pre-adjustment expense balance of $160,384,000 and an adjusted balance of $184,723,000, a difference of $24,339,000 as shown on Company Exhibit MJT-1 Schedule D-4. The Company proposed several adjustments to its Administrative & General Expenses: (1) Salary and Wages of $3,172,000; (2) Rate Case Expenses of $800,000; (3) Employee Benefits Expense of $462,000; (4) Pension Expense of $11,699,000; (5) COVID-19 Related CWC Recovery of $5,778,000 and; (6) Emergency Relief & Grant/Other Programs of $2,427,000. I will address each of these adjustments below:

1. Salary and Wages (Schedule D-6)

Q. HOW DID THE COMPANY DEVELOP ITS ADJUSTMENT TO ITS SALARY & WAGES OF $3,172,000?

A. As more fully explained and described on Schedules D-6 and D-8, the breakdown and development of these adjustments are shown on my Schedule DM-14A and in my testimony Section c-1. The $3,172,000 balance is comprised of several accounts that include Salary & Wage components.

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S BALANCE OF $3,172,000?

A. As I indicated previously in my testimony and as further discussed under Section c-1, my adjustments are related to the Company's incentive compensation, one time contract payments, the labor cost increase of $3.8 million, the March 2023 rate increase, and the annualization of new employees. These flow through the adjustments shown on DM-14A to DM-18. My adjustment is a $2,225,607 reduction, and my balance is $946,050.

2. Stock Compensation

Q. WHAT HAS THE COMPANY INCLUDED REGARDING STOCK COMPENSATION?

A. The Company has included $1,413,000 of Stock Compensation as shown in response to OCA VI-4 (a) Attachment.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I am removing these costs from the Company's Sales Expense balance. As more fully explained previously, I believe these costs do not benefit ratepayers and ratepayers should not be burdened by these types of costs.

3. Rate Case Expenses (Schedule D-7) (Set III #44)

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO RATE CASE EXPENSES?

A. The Company has proposed a total rate case expense of $2,400,000 amortized over a three-year period or $800,000 annually. This is shown on Company Exhibit MJT-1 Schedule D-7.

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S $800,000 RATE CASE EXPENSE RECOVERY?

A. The first adjustment is that I am adjusting the Company's rate case expense of $2,400,000. I believe that these costs should not be amortized, instead they should be normalized, and they should be based upon the Company's actual prior rate case expense filings. As shown in response to OCA SET III - 44 the Company has filed the following base rate case proceedings along with the associated actual rate case expenses incurred in those proceedings:

R-2018-3000164	$1,477,000
R-2015-2468981	$1,329,000
R-2010-2161575	<u>$1,433,000</u>
Total	$4,239,000/3 = $1,413,000

Using the above data, normalizing these rate case costs based upon prior filings calculates to a level of $1,413,000. This reduces the Company's proposed rate case expense from $2,400,000 to $1,413,000 or a $987,000 reduction.

Q. WHAT ARE YOUR OTHER ADJUSTMENTS TO THE COMPANY'S RATE CASE EXPENSES?

A. The second adjustment is to the period over which the costs are to be normalized. First, the Commission routinely normalizes, not amortizes rate case expense. It then looks to the historical filing frequency to determine the proper normalization period. I am extending the rate case normalization period to a 3.5 year normalization period, based upon the Company's historical rate case filings. Historical rate case filings calculate to an average time span of 3.5 years. (11 years between 2010 and 2021) A 3.5 year normalization period would result in an annual recovery balance of $403,714, ($1,413,000 / 3.5 years) a reduction of $396,286 from the Company proposed balance of $800,000 ($2,400,000/3 years). My adjustment is shown on my Schedule DM-18. Line 17.

4. <u>Employee Benefits Expense (Schedule D-8)</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS EMPLOYEE EXPENSES?

A. As shown on Company Exhibit MJT-1 Schedule D-8, the Company has computed an increase to its Employee Expenses of $462,000. The Company began with a total Benefits expense of $21,009,000 and divided that amount by the average number of employees in the FPFTY period of 2,179 to arrive at a budget expense of $10,000 per employee. The Company then multiplied that amount by the budgeted additional employees of 48 to arrive at an annual increase of $462,000. (Statement No. 3 at 41).

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S $462,000 EXPENSE ADJUSTMENT TO EMPLOYEE BENEFITS EXPENSES?

A. I have several. In order to determine the appropriate amount of the incremental expense per employee, there needs to be adjustments related to all Employee Pensions and Benefits. I made the following adjustments to determine the appropriate balance of the Company's Employee Benefits Expense:

Company Proposed	$20,334,000	
Remove 3% Medicare Adv. Cost of Living	(466,230)	– OCA Set III-20
Remove Employee Activities	(757,031)	– OCA Set III-10
Remove Economic Development	(54,000)	– OCA Set III-18
Normalized OPEB Costs	(1,348,000)	– OCA Set III-19
Normalized Pension Costs	(5,802,000)	– OCA Set III-19
Adjusted Employee Benefits	$11,906,739/	
Average number of Employees	2,179	
Budget Expenses per Employee	$ 5,464	
Additional Employees	48	
Total Benefit Pro-Forma Amount	**$ 262,287**	

My adjustment is therefore, $262,287 a difference of $199,713 from the Company's proposed amount of $462,000. My adjustment is shown on my Schedule DM-18 Line 12.

The remaining above adjustments will be discussed below.

5. Medicare Advantage

Q. WHY ARE YOU ADJUSTING MEDICARE ADVANTAGE AND PRESCRIPTION DRUG PLAN?

A. In response to OCA Set III-20, the Company stated that the 3% annual increase was applied to the Medicare Advantage and Prescription Drug Plan and was a discretionary cost of living increase. The Company stated that it took into account the inflation information current at the time of the adoption of the plan modification. I am removing the 3% cost of living increase because I do not believe these types of cost increases are known and measurable. As I stated previously under my adjustments for Storm Expense, inflationary adjustments do not reflect the true cost of the expense. Inflation adjustments are typically blanket adjustments or increases/decreases which do not directly relate to actual costs expected to be incurred by the Company in the period in which new rates are to be set. Cost should be based upon evidence or documentation that supports the Company's adjustments.

Q. WHAT ARE YOU RECOMMENDING?

A. I am recommending removing the 3% inflationary increase from the Company's Medical, Disability and Other Benefits Plan. The total balance for 2022 is $15,541,000 (OCA Set III-19 Attachment SDR-OM-11 (a). I then removed the 3% inflation costs which equated to $466,230. This is shown on my Schedule DM-18 Line 11.

6. Employee Activities

Q. WHAT ARE YOUR ADJUSTING WITH RESPECT TO EMPLOYEE ACTIVITIES?

A. I am removing approximately $757,031 of Employee Activities from the Company's A&G expense balance. As shown on Attachment SDR-OM-14 (b) the Company booked costs associated with recognition awards, service awards, picnics, and celebration and networking groups. I am recommending removing these costs from the Company's revenue requirement proposal. These costs do not directly benefit ratepayers in the provision of utility service, but rather a spirit of friendship and community between and among the employees. I do not see a nexus between these costs and the provision of providing safe and reliable service to customers. The shareholders of the Company should be providing for these types of expenses if the Company believes it provides benefits to the employees. My adjustment is shown on my Schedule DM-18 Line 16.

7. Economic Development

Q. WHAT ARE YOU ADJUSTING WITH RESPECT TO ECONOMIC DEVELOPMENT?

A. In response to OCA Set III-18, the Company provided a cost breakdown of the above expenses. The Company allocated these costs to Account Nos. 908000 (Customer Service), 912000 (Sales Expense) and 926000 (A&G Employee Benefits). The total costs were $961,000. For Employee Volunteer Events the Company provided a cost breakdown of $54,000 and allocated them to Account No. 921000 (A&G). I am removing these costs because I do not believe these costs should be borne by ratepayers. These costs should be borne by local, municipal and state organizations or the Company itself through shareholder money. It appears that these types of costs are related to regional and various local communities that may or may not be customers of the Company. I do not see the nexus between these costs and the provision of safe and reliable service to customers. If the Company wants to be good corporate citizens, then the shareholders should pay for these types of costs and should not require ratepayers to pay for them. My adjustment is shown on my Schedule DM-18 Line 15.

8. Other Post-Employment Benefits (OPEB)

Q. WHAT ARE YOUR ADJUSTING WITH RESPECT TO OPEB?

A. I am adjusting the Company's OPEB costs by normalizing these costs based upon a five-year period from 2018 through 2022). The Company indicated that approximately $1.6 million was adjusted to reflect costs associated with OPEB costs. The Company did not provide a breakdown of this adjustment but stated that the method for developing OPEB was based upon a series of actuarial assumptions and was not development by separate components. (OCA Set III-19). Normalizing these costs results in a balance of $1,022,000/5 years or $204,400. I then adjusted $1.6 million down to $204,400 to arrive at a reduction of $1,395,600. Given that the Company could not provide any further detail on this expense, it is appropriate to normalize these costs over the most recent 5-year period. If the Company can supplement additional information related to the adjustment, I will make any further necessary adjustments. My adjustment is shown on my Schedule DM-18 Line 14.

9. <u>Pension (Schedule D-9)</u> (Set III #46)

Q. WHAT HAS THE COMPANY PROPOSED WITH REGARD TO ITS PENSION EXPENSE?

A. The Company has included an increase to its Pension Expense of $11,699,000 as shown on Company Exhibit MJT-1 Schedule D-9. Mr. Trzaska has stated that the calculation is based upon a five-year average of actual and projected contributions to its pension plan of $20,031,000. The Company allocated 76.26% to its electric distribution operating expense to arrive at a balance of $15,275,000; and then capitalized 41.71% to arrive at a balance of $6,371,000. The expense portion is computed as $15,275,000 less $6,371,000 or $8,904,000. The Company then added its FPFTY pension expense balance of $2,795,000 to arrive at a pro-forma expense of $11,699,000.

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S PRO-FORMA BALANCE OF $11,699,000?

A. In response to OCA-Set III-46 which refers to the response to IE-RE-10-D, the Company's adjustments are based upon a five-year average of the expense portion of pension contributions, and many factors are considered when making pension funding decisions, including actuarially determining minimum contribution requirements under ERISA[6] and contributions required to avoid benefit restrictions and at-risk status defined under the Pension Protection Act of 2006. In response to OCA-Set III-19 the Company provided five-years of Pension expense (2018 through the FPFTY). In the same manner as I normalized OPEB costs, I am normalizing the Pension expense. These costs are attributable to PECO Energy Company – Electric Distribution. The net balances are 2018- $8.811 million; 2019 - $4.468 million; 2020 - $3.050 million; 2021 - $1.502 million and 2022 – ($2.795 million). The five-year normalization equates to $15,036,000/five-years or $3,007,000. I then reduced the Company's proposed $8,904,000 (Exhibit MJT-1 Schedule D-9) by $3,007,000 to arrive at a balance of $5,897,000 for the FPFTY period. This reduces the Pension expense from the Company's proposed balance of $11,699,000 by $5,802,000 or $5,897,000. My adjustment is shown on my Schedule DM-18 Line 13.

10. <u>COVID-19 Related CWC Recovery (Schedule D-14)</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT ITS COVID-19 RELATED CWC RECOVERY?

A. The Company proposed an expense adjustment of $5,778,000 shown on Company Exhibit MJT-1 Schedule D-14. Mr. Trzaska stated that this adjustment is related to COVID-19 -incremental return on CWC, due to the extended termination moratorium in effect since mid-March 2020. The Company's accounts receivable balance in 2020 has increased significantly above the normal level and are not expected to return to normal levels after the FPFTY period. (Statement No.3 at 46). The HTY accounts receivable balances do not reflect normal levels, thus the Company's utilized accounts receivable balances and total billed revenues from 2019 to estimate its CWC claim. (Statement No. 3 at 47). The

[6] Employee Retirement Income Security Act of 1974 or ERISA.

Company estimated its total incremental CWC for those years at $17,335,000 and is proposing to amortize this balance over a three-year period or $5,778,000.

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S CLAIM OF ITS CWC RECOVERY OF $5,778,000?

A. I am recommending that the Company not recover this claim of $5,778,000 as a CWC recovery component. The Company has proposed incremental bad debt expense of $48,250,000 to be recovered over a three-year period that is related to COVID-19. [7] To request additional recovery related to CWC components appears to be unreasonable without additional support showing the cost breakdown. CWC is typically needed to bridge the gap between the time that expenditures are required to provide service and the time collections are received for that service. CWC focuses on actual cash expenses going forward or prospectively and should not be used to recover past costs. Further the Company has not provided a detailed breakdown of these costs, although in response to OCA-Set III-51, I asked for a detailed breakdown of these costs the results of which were shown on IE-RE-41-D. This response does not show a detailed breakdown of costs used to develop the proposed annual recovery of $5,788,000. In response to IE-RE-41-D (b) the Commission required the utilities to maintain detailed accounting records of such expenses related to extraordinary, nonrecurring incremental COVID-19 related expenses. To be eligible for inclusion in a utility's COVID-19 designated regulatory asset, the utility must maintain detailed records of the incremental, extraordinary, nonrecurring expenses incurred as a result of compliance with the Commission's March 13 Emergency Order, the October 13 Order and this Order (March 11, 2021). My adjustment is shown on my Schedule DM-18 Line 19.

11. <u>Experimental / General and Corporate Dues</u>

Q. WHAT HAS THE COMPANY PROPOSED OR INCLUDED RELATED TO EXPERIMENTAL / GENERAL AND CORPORATE DUES?

[7] OCA recommends a five-year average.

A. As shown in the response to OCA VI-2 the Company has included costs of $48,089 for Experimental and General Research costs and $171,680 for Corporate Dues, as of the historical test year ending 2020. For the FPFTY period the Company has included $47,000 related to Experimental and General Expenses and, $169,000 for Corporate Dues (Attachment II-D-7 (a)).

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I am removing these costs from the Company's A&G expense category. I am using the balances shown on Attachment II-D-7 that reflects the cost balances under the 2022 period. I believe these costs do not benefit ratepayers. These costs, by their nature reflect experimental and research costs that may or may not come to be realized or achieved. The Company has not provided any further detail on these costs. With respect to Corporate Dues, these expenses relate primarily for chambers of commerce, business alliances, societal, economic, and civic issues, which I believe do not benefit ratepayers in the provision of utility services. If the Company wants to provide this support, the Company's shareholders should pay for these costs, and not expect ratepayers to fund these choices. In 66 Pa. C.S. Section 1316.1, regarding the recovery of such dues its states that "no public utility may charge to its customers as a permissible operating expense for ratemaking purposes membership fees, dues or charges to fraternal, social or sports clubs or organizations." As such, ratepayers cannot be charged for costs associated with these types of expenses.

12. <u>Emergency Relief & Grant/Other Programs (Schedule D-15)</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS EMERGENCY RELIEF & GRANT / OTHER PROGRAMS?

A. As shown on Company Exhibit MJT-1 Schedule D-15, the Company has proposed to recover $5,525,000 related to certain programs as part of additional needed relief to customers during the pandemic as well as the acceleration of the adoption of transportation electrification in its service territory. (PECO Statement No. 3 at 47). The Company is proposing to recover these costs over a three-year period or

$1,842,000 annually. To that balance the Company has included $586,000 related to an annual convenience fee that the Company has waived and proposing to recover these costs under this Program. The breakdown and explanation of these costs are as follows:

i.	Non-CAP Residential Relief	$3,000,000
ii.	Small Business Recovery Program	$ 900,000
iii.	Public Transportation Electrification	$1,000,000
iv.	Level 2 Charger Incentive	$ 525,000
v.	EV Education / Outreach	$ 50,000
	Total	**$5,525,000**
	Amortization Period	3 years
	Annual Recovery	$1,842,000
vi.	Residential Convenience Fee	$ 586,000
	Total Emergency Relief/Grant/Other	**$2,427,000**

i. Non-Cap Residential Relief - $3,000,000

Q. WHAT IS THE NON-CAP RESIDENTIAL RELIEF PROGRAM?

A. As described in Ms. Feldhake's testimony (PECO Statement No. 10 at 6) the Non-Cap Residential Relief Program provides a bill credit to each qualifying customer that is equal to 25% of a customer arrearage with a maximum bill credit of $400. The Company has assumed that 6,750 customers will be eligible for assistance. ($400 times 6,750 = $2,700,000). Any remaining arrearages would be entered into a payment credit agreement of up to five-year. The total program budget is $3 million with 90% dedicated to customer bill credits and the remaining 10% will be used for administrative fees to operate the Program and for customer outreach and communications. The Company is seeking recovery of Program costs over a three-year period (PECO Statement No. 10 at 6).

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I am accepting the Company's program budget of $2,700,000, consistent with the recommendation of OCA witness Colton, along with the proposed administrative costs of $300,000 (10% of program budget). in which the Company stated that the $300,000 was an estimate related to the administrative fees to operate the Program. I am recommending that these costs be amortized over a ten-year period, without interest, which effectuates a sharing between PECO ratepayers and the Company.

ii. Small Business Recovery Program - $900,000

Q. WHAT IS THE SMALL BUSINESS RECOVERY PROGRAM?

A. As described by Ms. Golden's testimony (PECO Statement No. 9 at 12) the Small Business Recovery Program will provide small businesses that were affected by the COVID-19 Pandemic a one-time grant of $3,000 to be applied as a credit on the customer's existing electric account and can be applied to either existing arrearages or future electric bills. The projected costs of the Program is $1,000,000 which includes $950,000 for grants and $50,000 for administrative costs. (PECO Statement No. 9 at 13). The Company has planned to initiate the Program in 2021 with a budget of $100,000 and will allow application and implementation process to be developed and piloted in 2021. If the Company receives approval of the Program in this proceeding, the Company will spend an additional $900,000 in 2021. (PECO Statement No 9 at 13). The Company is proposing to recover these costs from Rate GS customers over a three-year period (2022-2024). The Company is not seeking recovery of program expenditures in 2021. (Statement No. 9 at 14).

Q. WHAT IS YOUR RECOMMENDATION?

A. I am accepting the Company's budget of $900,000, along with the estimated $50,000 related to the administrative costs. I am also recommending that these costs be amortized over a 10-year period, consistent with my recommendation related to the Non-Cap Residential Relief Program, as stated above. The

Company, however, should explain the cost breakdown in more detail related to this program.

iii. Public Transportation Electrification - $1,000,000

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO PUBLIC TRANSPORTATION ELECTRIFICATION?

A. The Company is proposing to offer several transportation electrification initiatives to help deliver public benefits through the elimination of ground level emissions in Clean Air Act non-attainment counties and reduce greenhouse gas emissions. (PECO Statement No. 3 at 47). The Company is proposing an EV Charging Pilot that is designed to incentivize customers to construct and deploy EV chargers, generate data regarding public and fleet charging and expand the Company's effect to educate customers about transportation electrification (TE). (PECO Statement No. 9 at 5). The Company is proposing a program budget of $1,000,000 to be recovered over a three-year period as the customer meets charging station development milestones. (PECO Statement No. 9 at 7).

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. I am adopting the recommendation of OCA witness Ron Nelson and accepting the Company's proposed budget.

iv. Level 2 Charging Incentive - $575,000

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS LEVEL 2 CHARGING INCENTIVE?

A. The Company is proposing to recover $575,000 designed to address the upfront costs of developing charging sites and help the Company understand the load profile and other implications of commercial and industrial L2 EV charging. (PECO Statement No. 9 at 8). $500,000 of the Program costs is related to incentives available to all applicable classes of commercial and industrial customers for applications including but not limited to public charging, fleet charging, bus charging, multi-dwelling charging and workplace charging (PECO Statement No.

9 at 9). $75,000 of the Program costs is related to administrative costs related to incentive processing and ongoing data collection. (PECO Statement No. 9 at 9).

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S L2 CHARGING INCENTIVE?

A. I am adopting the recommendation of OCA witness Ron Nelson and accepting the Company's proposed budget.

<u>v. EV Education and Outreach - $50,000</u>

Q. WHAT HAS THE COMPANY PROPOSED REGARDING EV EDUCATION AND CUSTOMER OUTREACH?

A. The Company is proposing to conduct proactive EV education and outreach to increase customer knowledge of the Company's EV offerings. The awareness campaign will utilize a variety of communication channels including, but not limited to, bill inserts, email, social media, website updates, and printed materials. (PECO Statement No. 9 at 11). The proposed budget for the EV Education and Outreach plan is $50,000 per year.

Q. WHAT ARE YOUR ADJUSTMENTS?

A. I am adopting the recommendation of OCA witness Ron Nelson and accepting the Company's proposed budget.

<u>vi. Annual Residential Convenience Fee - $586,000</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS ANNUAL RESIDENTIAL CONVENIENCE FEE?

A. The Company is proposing to waive transaction fees associated with making payments at authorizing payment locations in the PECO service territory. The Company's customer solution center has remained closed during the pandemic and its reopening date has not been determined. The Company will have absorbed the 2021 expense associated with this transaction fee waiver as a shareholder contribution. The Company is proposing to continue these transactions fees at authorized payment locations in perpetuity and seek cost recovery as a general operating and maintenance expense with an estimated cost of $586,000. (PECO Statement No. 10 at 4). The Company calculated this balance by taking a three-year average of customers (minus 60,000) or 390,000 customers and multiplying this balance by $1.50 per transaction fee to arrive at a balance of $585,000.

Q. WHAT ARE YOUR ADJUSTMENTS?

A. I am recommending removing these convenience fees from rates. Given that the Company's offices have remained closed, and a reopening date has not been determined, the Company should absorb these convenience fees. The ratepayers should not be burdened with additional fees because of the Company's decision to keep offices closed. Customers need a location to pay their utility bills. I am therefore, removing the convenience fee cost of $586,000.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF ALL THESE A&G EXPENSE i through vi ADJUSTMENST?

A. The revenue requirement impact is a total reduction of $1,507,000 from the Company's proposed balance of $2,427,000 as shown below:

Non-Cap Residential Relief	$3,000,000	
Small Business Recovery Program	$ 950,000	
Sub-Total	$3,950,000/10 =	$395,000
Public Transportation	$1,000,000	
Level 2 Charging	$525,000	
EV Education/Outreach	$50,000	
Total	$1,575,000/3 =	$525,000
Residential Convenience Fee	$	$ 0
Recommended Balance	**$**	**920,000**

My balance is shown on my Schedule DM-18. Line 21.

Q. ARE THERE ANY OTHER ADJUSTMENTS INCLUDED IN THE COMPANY'S A&G EXPENSES?

A. Yes. The Company has included an additional $851,000 related to additional PUC/OCA/SBA Assessments on its proposed revenue requirement increase of $245,985,000. The Company has used an assessment rate of 0.3459% to calculate the additional assessment balance of $851,000.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. My adjustment is related to my recommended revenue requirement decrease of $13,187,116 multiplied by the assessment rate of 0.3459% equals ($45,614).

Q. WHAT IS YOUR OVERALL ADJUSTMENT TO THE COMPANY'S A&G EXPENSE?

A. My overall adjustment is a reduction of $29,300,495 plus the adjustment for the additional PUC/OCA/SBA Assessment of ($45,637).

3. <u>DEPRECIATION EXPENSE</u>

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO ITS DEPRECIATION EXPENSE?

A. The Company proposed a Depreciation Expense of $271,916,000 as shown on Company Exhibit MJT-1 Schedule D-4 and Schedule D-17. The Company began with the annual depreciation for electric distribution and common plant and allocating a portion of the common plant to the electric division. The Company annualized the depreciation expense related to the FPFTY additions, to reflect a full year's deprecation for that plant. (PECO Statement No. 3 at 49). The Company's total adjustments to its depreciation expense was $12.1 million (from $259,834,000 to $271,916,000).

Q. DID THE COMPANY HAVE DEPRECIATION STUDIES PERFORMED FOR USE IN THIS RATE PROCEEDING?

A. Yes. According to Company witness Ms. Fulginiti (PECO Statement No. 4 at 6), the company performed a service-life study based upon PECO's plant balances as of December 31, 2018. The Company relied upon the service lives and depreciation rates that were developed in the Company's 2018 service life study. (Statement No. 4 at 7).

Q. WHAT ARE YOUR RECOMMENDATIONS RELATED TO THE COMPANY'S DEPRECIATION EXPENSE?

A. I am accepting the Company's service lives and depreciation rates. My adjustments relate to my disallowance of certain plant that was included in the Company's EPIS balance.

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S NEGATIVE NET SALVAGE VALUE BALANCE?

A. No.

Q. WHAT ARE YOUR ADJUSTMENTS TO THE COMPANY'S DEPRECIATION EXPENSE?

A. Since I removed certain capital additions from the Company's EPIS balance in the amount of $203,549,663, I am removing the Depreciation Expenses associated with this adjustment. I am also averaging out the Company's base capital spending additions. This removes capital additions of about $99,633,073. Using the Company's composite depreciation rate of 2.90% I compute a depreciation expense adjustment of $5,902,940.

Q. DO YOU HAVE ANY OTHER ADJUSTMENTS TO THE COMPANY'S DEPRECIATION EXPENSE?

A. No.

4. <u>TAXES OTHER THAN INCOME</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO TAXES OTHER THAN INCOME TAXES?

A. The Company proposed total Taxes Other than Income in the amount of $173,068,883 as shown on Company Exhibit MJT-1 Schedule D-16. These Taxes other than Income are related to Public Utility Real Tax of $6,273,000; Use Tax

Accrued of $460,000; Real Estate Tax Accrued of $5,200,000; Payroll Tax Accrued to $13,341,001 and Gross Receipts Tax of $133,281,767. To that balance, the Company added additional Gross Receipts Tax of $14,513,115 based upon its recommended revenue requirement increase of $245,908,000 times the Gross Receipt tax rate of 5.90%.

Q. WHAT ARE YOUR ADJUSTMENTS AND YOUR RECOMMENDED LEVEL OF TAXES OTHER THAN INCOME TAXES?

A. I am accepting the Company's methodology in the calculation of its Taxes Other Than Income. I am making adjustments to the Company's Payroll Taxes that reflect my recommended S&W balance, which includes my adjustments to the Company's vacancy positions and my adjustments to the Company's Incentive Compensation. I removed costs associated with certain Incentive Compensation, which are reflective in the Company's payroll rates accordingly. My adjustment is a $653,298 reduction from the Company's proposed balance of $13,341,001 or $12,687,704.

Q. WHAT IS YOUR OTHER ADJUSTMENT TO TAXES OTHER THAN INCOME?

A. I adjusted the Real Estate Taxes to reflect the changes in my recommended EPIS balance. I used the Company's Real Estate tax level of $5,200,000 to the Company's proposed GPIS balance of $8,915,180,000 to calculate a composite Property tax rate of 0.0005832%. In using my recommended average EPIS balance of $6,052,270,989 times the composite tax rate of 0.0005832%, I computed a Property Tax expense of $6,129,764, a reduction of $143,236. With respect to the additional Gross Receipts Tax of $14,513,115, I utilized my recommended overall revenue requirement decrease of $13,187,116 to compute the additional tax adjustment, multiplied by the 5.90% rate to arrive at a balance of ($778,040). My adjustments are shown on my Schedule DM-20.

Q. WHAT IS YOUR TOTAL ADJUSTMENT?

A. My total adjustment is a reduction of $16,087,688 and a balance of $156,981,195.[8] This is shown on my Schedule DM-20.

5. INCOME TAXES

Q. WHAT DID THE COMPANY CALCULATE WITH RESPECT TO ITS INCOME TAXES?

A. The Company proposed total Income Taxes of $85,965,000 as shown on Exhibit MJT-1 Schedule D-18. This is comprised of Federal Income Taxes of $56,060,000, (Line 60) and State Income Taxes of $29,905,000, (Line 61).

Q. WHAT OTHER ADJUSTMENTS DID THE COMPANY MAKE TO COMPUTE ITS INCOME TAX EXPENSE?

A. According to Mr. Trzaska, the Company included synchronized interest expense based upon Company witness Mr. Moul's weighted cost of debt. (PECO Statement No. 3 at 50). The Company incorporated the effects of accelerated depreciation for both the calculation of State and Federal Income Taxes (PECO Statement No. 3 at 50). The Company utilized a State Tax Rate of 9.99% and a Federal Tax Rate of 21.00%. The effect of the TCJA are included in the flow-back of the Excess Accumulated Deferred Income Taxes (EADIT) are included in the calculation of the proposed Income Tax balance. (Statement No. 3 at 51).

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S METHODOLOGY WITH RESPECT TO THE CALCULATION OF THE COMPANY'S INCOME TAXES?

A. No I am accepting the Company's methodology. My adjustments reflect the recommended changes of Rate Base and Operating Income.

[8] Differences due to rounding

Q. WHAT IS YOUR RECOMMENDED FEDERAL INCOME TAXES AND RECOMMENDED STATE INCOME TAXES?

A. My recommended Federal Income Taxes is $24,574,577. My recommended State Income Taxes is $6,116,806.[9]

Q. WHAT IS YOUR ADJUSTMENT RELATED TO THE COMPANY'S INTEREST EXPENSE CALCULATION?

A. Using my recommended Rate Base Balance of $6,052,270,989 and using OCA Garrett's recommended cost of debt of 1.97%, my recommended Interest Expense is $118,927,125.

Q. WHAT IS YOUR TOTAL INCOME TAX EXPENSE?

A. My total Income Tax Expense is $30,691,475 which is $55,273,617 lower than the Company's Income Tax Expense of $85,964,840 which is shown on my Schedule DM-21.

D. Act 40 Requirements (Act 40 of 2016)

Q. WHAT ARE THE ACT 40 REQUIREMENTS?

A. Act 40 took effect on August 11, 2016, which among other things, eliminated the consolidated tax savings adjustment. Prior to Act 40, the Company would have been required to adjust its revenue increase request downward to reflect tax savings associated with filing taxes as part of a parent or holding company. This practice recognized that the Company's ratepayers only paid through rates those taxes that the Company actually paid. Act 40 requires the Company to continue its performance of the consolidated tax savings calculation and provide that consolidated tax savings differential as part of its rate case filing. In part, Act 40 states:

> If an expense or investment is allowed to be included in a public utility's rates for ratemaking purposes, the related income tax

[9] Differences due to rounding

> deductions and credits shall also be included in the computation of current or deferred income tax expense to reduce rates. If an expense or investment is not allowed to be included in a public utility's rates, the related income tax deductions and credits, including tax losses of the public utility's parent or affiliated companies, shall not be included in the computation of income tax expense to reduce rates. The deferred income taxes used to determine the rate base of a public utility for ratemaking purposes shall be based solely on the tax deductions and credits received by the public utility and shall not include any deductions or credits generated by the expenses or investments of a public utility's parent or any affiliated entity. The income tax expense shall be computed using the statutory income tax rates.

Act 40 further states:

> REVENUE USE- If a differential accrues to a public utility resulting from applying the ratemaking methods employed by the commission prior to the effective date of subsection (a) for ratemaking purposes, the differential shall be used as follows:
>
> (1) Fifty percent to support reliability or infrastructure related to the rate-base eligible capital investment as determined by the commission; and
> (2) Fifty percent for general corporate purposes.

As a result, ratepayers now pay taxes in excess of those taxes that the Company actually pays, and the revenue use requirement specifies how those additional revenues are to be applied. Section 1301.1 (b) requires the Company to use 50% of that differential for reliability or infrastructure related capital investment and the remaining 50% for general corporate purposes.

Q. HAS THE COMPANY CALCULATED A CONSOLIDATED TAX EXPENSE ADJUSTMENT (CTA)?

A. According to Mr. Trzaska, the Company has not calculated a CTA, because such an adjustment is no longer authorized under Section 1301.1 (a). Act 40 provides that the current and deferred income taxes of a Pennsylvania utility are to be calculated for ratemaking purposes based only on the income, deductions and credits of the utility itself, (Stand-Alone computation) without regard to taxable income, deductions or credits of other companies in the same consolidated group. (Statement No. 3 at 53).

Q. HAS THE COMPANY SATISFIED THE FIRST REQUIREMENT UNDER ACT 40 – 50% OF THE DIFFERENTIAL SPENT ON INFRASTRUCTURE REPLACEMENT?

A. Yes. As explained in the response to OCA-III-56 the Company calculated a combined CTA of $14.4 million, of which 50% of the differential is $7.2 million. The Company stated that the capital additions for reliability and infrastructure are well in excess of 50% of the $14.4 million that would represent a CTA prior to the enactment of Section 1301.1 (a) and (b) and, therefore the remaining 50% of $14.4 million is available for use by the Company for general corporate purposes, including paying the Company's operating and maintenance expenses that, as shown on Schedule B-2, pages 6-7, also substantially exceed 50% of the $14.4 million.

Q. WHAT IS PECO'S PROPOSAL FOR THE OTHER 50% OF THE DIFFERENTIAL, WHICH SECTION 1301.1(b)(2) STATES MUST BE USED FOR "GENERAL CORPORATE PURPOSES"?

A. PECO does not appear to propose a specific treatment for the other 50% of the differential, which Section 1301.1(b)(2) states must be used for "general corporate purposes." In response to OCA-VI-5 the Company stated that "general corporate purposes" is the term that appears in Section 1301.1 (b) (2), which encompasses any lawful purpose authorized by the Company's articles of incorporation, certificate(s) of public convenience and other applicable regulatory authority. 50% of the CTA monies will become part of the Company's general funds and will be used for all of the corporate purposes for which its total electric distribution utility operating revenues are deployed subject to the ratemaking requirements imposed by Section 1301.1 (a).

Q. WHAT DO YOU CONCLUDE FROM PECO'S FAILURE TO SPECIFY A USE FOR THE 50% OF THE DIFFERENTIAL THAT ACT 40 REQUIRES TO BE USED FOR "GENERAL CORPORATE PURPOSES"?

A. PECO has identified no specific ways in which that 50% of the differential would be used in any way to benefit Pennsylvania ratepayers. One might conclude from this that PECO therefore basically intends to use that money for the benefit of its stockholders, and not apply it in any manner to provide a quantifiable ratepayer benefit or in a manner that directly benefits service to Pennsylvania customers.

Q. WHAT DOES "GENERAL CORPORATE PURPOSES" AS USED IN ACT 40 MEAN?

A. Because PECO is a regulated utility in Pennsylvania, its "general corporate purpose" is to provide regulated utility service in the Commonwealth of Pennsylvania. While the term "general corporate purposes" is rather vague, consistent with that general corporate purpose of regulated utilities, general corporate purposes would include uses for such "differential" revenues as supporting capital expenditures necessary to execute utility business plans, paying off debt, funding construction projects, paying dividends, paying for maintenance and operating expenses, investing in utility plant in Pennsylvania, and providing a source of working capital. Many of these uses for "general corporate purposes" would have a quantifiable benefit to Pennsylvania ratepayers. As I read the entirety of Act 40, the "revenue use differential" addressed in the Act for "general corporate purposes" should mean public utility purposes and uses that result in having some identifiable and quantifiable benefit to Pennsylvania and PECO ratepayers, rather than just resulting in a windfall of $7.202 million annually to PECO's shareholders or affiliates.

Q. WHAT SPECIFIC RECOMMENDATION DO YOU HAVE IN THE CURRENT PECO RATE CASE FOR APPLYING THE 50% OF THE "REVENUE USE" DIFFERENTIAL THAT ACT 40 REQUIRES TO BE FOR "GENERAL CORPORATE PURPOSES"?

A. I have reflected the 50% differential for general corporate purposes as a source of non-investor-supplied funding for utility working capital. I have reduced the Company's Rate Base balance by $7.202 million as shown on my Schedule DM-3.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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SCHEDULES

	REVENUE REQUIREMENT SUMMARY	(1) Company Proposed	Adjustment	OCA	References
1	Rate Base	$ 6,385,897,000	$ (333,626,011)	$ 6,052,270,989	
2	Rate of Return	7.68%		6.22%	
3	Operating Income	$ 490,436,890	$ (114,288,248)	$ 376,148,642	
4	Operating Income - Present Rates	$ 326,774,000	$ 58,148,534	$ 384,922,534	
5	Additional Income Requirement	$ 163,662,890	$ (172,436,782)	$ (8,773,892)	
6	Gross Revenue Conversion Factor	1.502995		1.502995	
7	Base Revenue Requirement Increase	$ 245,984,505	$ (259,171,621)	$ (13,187,116)	
8	Other Operating Revenue	$ 924,000	$ (973,518)	$ (49,518)	
9	Total Revenue Requirement Increase	$ 246,908,505	$ (260,145,138)	$ (13,236,633)	
10	Present Rate Revenues	$ 2,333,680,000		$ 2,334,623,531	
11	% Increase	10.580%		-0.567%	

(1) Company Exhibit MJT-1
Schedule A-1
Differences due to rounding

RATE OF RETURN

		Capitalization Ratio	Embedded Cost	Return %
(1)	Company Proposed			
1	Long - Term Debt	46.590%	3.930%	1.83%
2	Common Equity	53.410%	10.950%	5.85%
3	**Total**	100.000%		7.68%
	OCA (2)			
4	Long - Term Debt	50.000%	3.930%	1.965%
5	Common Equity	50.000%	8.500%	4.250%
6	**Total**	100.000%		6.215%

(1) Company Exhibit MJT-1
Schedule B-7
(2) Testimony of David Garrett

	MEASURE OF VALUE - RATE BASE (Jurisdictional)	(1) Company Proposed	Adjustments	OCA	References
1	Utility Plant in Service	$ 8,915,180,000	$ (203,549,663)	$ 8,711,630,337	
2	Accumulated Depreciation	$ (2,251,728,000)	$ (5,902,940)	$ (2,245,826,060)	DM-6
3	Common Plant	$ 424,369,000	$ -	$ 424,369,003	DM-5
4	**Net Plant In Service**	$ 7,087,821,000	$ (197,647,720)	$ 6,890,173,280	
5	Working Capital	$ 155,548,000	$ (1,506,562)	$ 154,041,438	DM-7
6	Pension Assets / (Liabilities)	$ 128,977,000	$ (128,977,000)	$ -	DM-8
7	Accumulated Deferred Income Taxes	$ (658,825,000)	$ 1,706,272	$ (657,118,728)	DM-9
8	Customer Deposits	$ (49,195,000)	$ -	$ (49,195,000)	
9	Customer Advances	$ (1,707,000)	$ -	$ (1,707,000)	
10	Materials and Supplies	$ 19,944,000	$ -	$ 19,944,000	
11	Accumulated Deferred Income Taxes - Regulatory Liabilities	$ (296,666,000)	$ -	$ (296,665,000)	DM-10
	CTA	$ -	$ (7,202,000)	$ (7,202,000)	OCA VI-5
12	**Total Measure of Value - Rate Base**	$ 6,385,897,000	$ (333,626,011)	$ 6,052,270,989	

(1) Company Exhibit MJT-1
Schedule C-1

	INCOME STATEMENT	(1) Company Present Rates	Company Rate Increase	Company Proposed Rates	Adjustments	OCA Present Rates	References
	Operating Revenues						
1	Residential / Residential House Heating	$ 1,515,162,000	$ -	$ 1,515,162,000	$ -	$ 1,515,162,000	
2	C& I Small / Large	$ 567,253,000	$ -	$ 567,253,000	$ -	$ 567,253,000	
3	Railroads & Railways	$ 8,118,000	$ -	$ 8,118,000	$ -	$ 8,118,000	
4	Street Lighting	$ 21,305,000	$ -	$ 21,305,000	$ -	$ 21,305,000	
5	InterCompany	$ 1,283,000	$ -	$ 1,283,000	$ -	$ 1,283,000	
6	Transmission - All Classes	$ 172,082,000	$ -	$ 172,082,000	$ -	$ 172,082,000	
7	Forfeited Discounts	$ 12,795,000	$ 924,000	$ 13,719,000	$ (49,518)	$ 13,669,482	
8	Miscellaneous Service Revenue	$ 3,829,000	$ -	$ 3,829,000	$ (389,000)	$ 3,440,000	OCA-III-35
9	Rent for Electric Property	$ 19,219,000	$ -	$ 19,219,000	$ (353,333)	$ 18,865,667	OCA-III-35
10	Other Electric Revenues	$ 12,633,000	$ -	$ 12,633,000	$ 589,667	$ 13,222,667	OCA-III-35
11	Revenue Increase	$ -	$ 245,985,000	$ 245,985,000			
12	Total Operating Revenues	$ 2,333,679,000	$ 246,909,000	$ 2,580,588,000	$ 721,816	$ 2,334,400,816	
	Operating Expenses						
13	Power Supply	$ 689,927,000	$ -	$ 689,927,000	$ -	$ 689,927,000	DM-12
14	Transmission Expense	$ 161,192,000	$ -	$ 161,192,000	$ (458,000)	$ 160,734,000	DM-13
15	Distribution Expense	$ 379,691,000	$ -	$ 379,691,000	$ (15,177,715)	$ 364,513,285	DM-14
16	Customer Accounts Expense	$ 127,033,000	$ 1,383,000	$ 128,416,000	$ (13,799,015)	$ 114,616,985	DM-15
17	Customer Service & Info. Expense	$ 11,740,000	$ -	$ 11,740,000	$ (854,330)	$ 10,885,670	DM-16
18	Sales Expense	$ 1,740,000	$ -	$ 1,740,000	$ (243,911)	$ 1,496,089	DM-17
19	Administrative & General Expense	$ 184,723,000	$ 851,000	$ 185,574,000	$ (30,197,110)	$ 155,376,890	DM-18
20	Vacancy Rate	$ -	$ -	$ -	$ (2,679,945)	$ (2,679,945)	OCA-III-38
21	Sub-Total	$ 1,556,046,000	$ 2,234,000	$ 1,558,280,000	$ (63,410,026)	$ 1,494,869,974	
22	Depreciation & Amortization Expense	$ 271,915,000	$ -	$ 271,915,000	$ (5,901,940)	$ 266,013,060	DM-19
23	Amortization of Regulatory Expense	$ 923,000	$ -	$ 923,000	$ -	$ 923,000	DM-19
24	Taxes Other Than Income	$ 158,556,000	$ 14,513,000	$ 173,069,000	$ (16,087,805)	$ 156,981,195	DM-20
25	Total Operating Expenses	$ 1,987,440,000	$ 16,747,000	$ 2,004,187,000	$ (85,399,771)	$ 1,918,787,229	
26	Net Operating Income Before Income Taxes	$ 346,239,000	$ 230,162,000	$ 576,401,000	$ (160,787,414)	$ 415,613,586	
27	State Income Taxes	$ 6,912,000	$ 22,993,000	$ 29,905,000	$ (23,788,194)	$ 6,116,806	DM-21
28	Federal Income Taxes	$ 12,554,000	$ 43,506,000	$ 56,060,000	$ (31,485,423)	$ 24,574,577	DM-21
28	Net Operating Income	$ 326,773,000	$ 163,663,000	$ 490,436,000	$ (105,513,797)	$ 384,922,203	
	Net Operating Income Present Rates					$ 376,148,642	
	Rate Base			$ 6,385,897,000		$ 6,052,270,989	
	Rate of Return			7.680%		6.215%	

(1) Company Exhibit MJT-1 Schedule A-1
Schedule D-18

ELECTRIC PLANT IN SERVICE COMMON PLANT IN SERVICE

		(1) Company Proposed	Adjustments	OCA	References
1	Intangible Plant	$ 232,753,000	$ -	$ 232,753,000	
2	Transmission Plant	$ -	$ -	$ -	
3	Distribution Plant	$ 8,405,217,000	$ (203,549,663)	$ 8,201,667,337	OCA VI-6
4	General Plant	$ 277,210,000		$ 277,210,000	
5	**Total Electric Plant In Service Balance**	$ 8,915,180,000	$ (203,549,663)	$ 8,711,630,337	
6	Land	$ 6,783,000	$ -	$ 6,783,000	
7	Organization	$ 677,000	$ -	$ 677,000	
8	Software	$ 373,618,000	$ -	$ 373,618,000	
9	General Plant	$ 751,017,000	$ -	$ 751,017,000	
10	Other	$ -	$ -	$ -	
11	**Total Common Plant In Service Balance**	$ 1,132,095,000	$ -	$ 1,132,095,000	OCA-III-12 OCA-III-24
	<u>Accumulated Depreciation</u>				
12	Land	$ -	$ -	$ -	
13	Organization	$ -	$ -	$ -	
14	Software	$ 295,102,000		$ 295,102,000	
15	General Plant	$ 228,116,000		$ 228,116,000	
16	Other	$ -	$ -	$ -	
17	**Total Accumulated Depreciation**	$ 523,218,000	$ -	$ 523,218,000	
18	Net Common Plant in Service	$ 608,877,000	$ -	$ 608,877,000	
19	Allocation Factor	69.697%		69.697%	OCA-III-24
20	**Net Common Plant to Utility**	$ 424,369,003	$ -	$ 424,369,003	

(1) Company Exhibit MJT-1 Schedule C-2
Schedule C-8
See Set VI 6

	ACCUMULATED DEPRECIATION	(1) Company Proposed	Adjustments	OCA	References
1	Intangible Plant	$ 165,969,000	$ -	$ 165,969,000	
2	Transmission Plant	$ -	$ -	$ -	
3	Distribution Plant	$ 1,977,526,000	$ (5,902,940)	$ 1,971,623,060	OCA-VI-6
4	General Plant	$ 108,234,000	$ -	$ 108,234,000	
5	Total Accumulated Depreciation	$ 2,251,729,000	$ (5,902,940)	$ 2,245,826,060	OCA-III-27

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(1) Company Exhibit MJT-1 Schedule C-3

WORKING CAPITAL ALLOWANCE

		(1) Expenses	Company Proposed Lead/Lag Days	Dollar Days	Adjustments	OCA	References
1	Revenue Lag Days		48.3000				
	Expense Lag Days						
2	Payroll (Distribution Only)	$ 171,625,000	13.4375	$ 2,306,210,938		$ 2,011,204,665	
3	Pension Expense	$ 8,904,000	-167.0044	$ (1,487,007,178)		$ (984,824,947)	
4	Commodity Purchased	$ 689,927,000	35.4411	$ 24,451,785,000		$ 24,451,785,000	
5	PJM Transmission Purchased	$ 161,192,000	12.5000	$ 2,014,895,000		$ 2,009,170,014	
6	Other Expenses	$ 501,496,000	40.0439	$ 20,081,861,000		$ 19,594,495,374	OCA-III-28
7	Sub-Total	$ 1,533,144,000		$ 47,367,744,760		$ 47,081,830,106	
8	Payment to Suppliers	$ 1,017,444,000	38.1645	$ 38,830,239,000		$ 38,830,239,000	OCA-III-28
9	Total O&M and POR Payments	$ 2,550,588,000		$ 86,197,983,760		$ 85,912,069,106	
10	O&M Expense/POR Payment Expense Lag Days		33.8000				
11	Net Lead/Lag Days		14.5000				
12	Days in Current Year		365.0000				
13	Operating Expenses Per Day	$ 6,987,912				$ 6,884,927	
14	Working Capital for O&M Expenses	$ 101,337,992				$ 99,831,438	
15	Average Prepayments	$ 5,442,000				$ 5,442,000	
16	Accrued Taxes	$ 62,517,000				$ 62,517,000	
17	Interest Payments	$ (13,749,000)				$ (13,749,000)	
18	Total Working Capital Requirements	$ 155,547,992				$ 154,041,438	
19	Proforma O&M Expenses	$ 1,556,046,000				$ 1,494,869,974	
20	Uncollectible Expense	$ 22,902,000				$ 22,902,000	
21	Proforma Cash O&M Expense	$ 1,533,144,000				$ 1,517,771,974	

	PENSION ASSET	(1) Company Proposed	Adjustments	OCA	References
1	Balance at end of HTY - 2020	$ 375,428,000			
2	Activities in FTY - 2021	$ 11,656,000			
3	Activities in FPFTY - 2022	$ 18,428,000			
4	**Balance at end of FPFTY - 2022**	$ 405,512,000	$ (405,512,000)	$ -	
5	Allocation Factor to Utility	76.26%			
6	Utility Amount	$ 309,240,000	$ 309,240,000	$ -	
7	Allocation Factor to Distribution Capital	41.71%			
8	**Balance at end of FPFTY - Distribution Capital**	$ 128,977,000	$ (128,977,000)	$ -	OCA III-29/30/31

(1) Company Exhibit MJT-1 Schedule C-5

ACCUMULATED DEFERRED INCOME TAXES

		(1) Company Proposed	Adjustments	OCA	References
	HTY				
1	ADIT - CIAC - 100.00%	$ (26,543,000)	$ -	$ (26,543,000)	
2	ADIT - Common Plant - 62.34%	$ 17,815,525	$ -	$ 17,815,525	
3	ADIT - Electric Common Plant - 80.99%	$ 3,056,563	$ -	$ 3,056,563	
4	ADIT - Electric Distribution - 100%	$ 631,703,000	$ -	$ 631,703,000	
5	Sub-Total	$ 626,032,088	$ -	$ 626,032,088	
	FTY				
6	DIT - CIAC - 100%	$ (4,407,000)	$ -	$ (4,407,000)	
7	DIT - Common Plant - 62.34%	$ -	$ -	$ -	
8	DIT - Electric Common Plant - 80.99%	$ -	$ -	$ -	
9	DIT - Electric Distribution - 100.00%	$ 26,066,000	$ -	$ 26,066,000	
10	Sub-Total	$ 21,659,000	$ -	$ 21,659,000	
	FPFTY				
11	DIT - CIAC - 100.00%	$ (4,566,000)	$ -	$ (4,566,000)	
12	DIT - Common Plant - 62.34%	$ -	$ -	$ -	
13	DIT - Electric Common Plant - 80.99%	$ -			
14	DIT Electric Distribution - 100.00%	$ 15,699,000	$ (1,705,359)	$ 13,993,641	OCA-III-23/VI-6
15	Sub-Total	$ 11,133,000	$ (1,705,359)	$ 9,427,641	
16	Total	$ 658,824,088	$ (1,705,359)	$ 657,118,728	OCA-III-32

(1) Company Exhibit MJT-1 Schedule C-6

	ACCUMULATED DEFERRED INCOME TAXES - REGULATORY LIABILITY	(1) Company Proposed	Adjustments	OCA	References
	HTY				
1	ADIT - Distribution	$ 330,796,000	$ -	$ 330,796,000	
2	ADIT - CIAC	$ (6,753,000)	$ -	$ (6,753,000)	
3	**Sub-Total**	$ 324,043,000	$ -	$ 324,043,000	
	FTY				
4	DIT - Distribution	$ (11,804,000)	$ -	$ (11,804,000)	
5	DIT - CIAC	$ (2,251,000)	$ -	$ (2,251,000)	
6	**Sub-Total**	$ (14,055,000)	$ -	$ (14,055,000)	
	FPFTY				
7	DIT - Distribution	$ (11,072,000)	$ -	$ (11,072,000)	
8	DIT - CIAC	$ (2,251,000)	$ -	$ (2,251,000)	
9	**Sub-Total**	$ (13,323,000)	$ -	$ (13,323,000)	
10	**Total**	$ 296,665,000	$ -	$ 296,665,000	OCA III-33

(1) Company Exhibit MJT-1 Schedule C-12

	POWER SUPPLY EXPENSE	(1) Company Proposed	Adjustments	OCA	References
1	Purchased Power	$ 689,927,000	$ -	$ 689,927,000	OCA-III-36

(1) Company Exhibit MJT-1 Schedule 4

	TRANSMISSION EXPENSE	(1) Company Proposed	Adjustments	OCA	References
1	Scheduling, System Control & Dispatch	$ 78,643,000	$ (236,000)	$ 78,407,000	OCA-VI-4
2	Reliability, Planning & Standard Develop.	$ 82,548,000	$ (221,000)	$ 82,327,000	
3	**Total**	$ 161,191,000	$ (457,000)	$ 160,734,000	OCA-III-36

(1) Company Exhibit MJT-1 Schedule 4

SALARY AND WAGES (1)

	Company Proposed				Adjustments	OCA	References
	Union	Non-Union	Union	Non-Union			
	Number of Employees		Salary Allocation				
	960	1,054	$ 76,096,000	$ 83,547,000			
Total		2,014		$ 159,643,000		$ 159,643,000	
Distribution - OP	112	122	$ 8,843,262	$ 9,707,738	$ (1,519,000)		OCA-III-36
Distribution - MN	362	397	$ 28,661,588	$ 31,463,413	$ (4,087,000)		
Customer Accounts	218	239	$ 17,261,784	$ 18,949,216	$ (3,493,000)		
Customer Service	10	11	$ 781,788	$ 858,212	$ (159,000)		
Sales	5	6	$ 405,672	$ 445,328	$ (84,000)		
Admin & General	254	279	$ 20,147,249	$ 22,116,751	$ (4,203,000)		
	960	1054	$ 76,101,341	$ 83,540,659	$ (13,545,000)		
Total		2014		$ 159,642,000	$ (13,545,000)	$ 146,097,000	
Annualize 3/1/2022 Wage Increase 2.5%			$ -	$ 348,086	$ -	$ 348,086	
Annualize 1/1-3/1/2023 2.5%			$ 1,902,534	$ 2,097,219	$ (3,999,752)	$ -	
Annualized Salary and Wages	960	1054	$ 78,003,875	$ 85,985,963			
		2014		$ 163,989,838	$ (17,544,752)	$ 146,445,086	OCA-III-7
One Time Contract Payment				$ 143,242	$ (143,242)	$ -	OCA-III-42
Labor Cost Increase				$ 3,800,000	$ (3,800,000)	$ -	OCA-III-43
Adjusted Salary & Wages				$ 167,933,080	$ (21,487,994)	$ 146,445,086	
Additional Employees				48		48	OCA-III-39
Annual Salary & Wages per Employee				$ 77,069	$ (9,861)	$ 67,207	
Annualization of New Employees				$ 3,691,000	$ (465,041)	$ 3,225,959	
Total Proforma Salary & Wages				$ 171,624,080	$ (21,953,035)	$ 149,671,045	
Total Proposed Increase				$ 11,982,080	$ (8,408,035)	$ 3,574,045	
Distribution - OP				$ 1,392,318	$ (977,014)	$ 415,304	
Distribution - MN				$ 4,513,650	$ (3,167,307)	$ 1,346,343	
Customer Accounts				$ 2,717,536	$ (1,906,942)	$ 810,593	
Customer Service				$ 122,936	$ (86,266)	$ 36,670	
Sales				$ 63,996	$ (44,907)	$ 19,089	
Admin & General				$ 3,171,657	$ (2,225,607)	$ 946,050	
				$ 11,982,092	$ (8,408,044)	$ 3,574,048	OCA-III-39 OCA-III-36

	DISTRIBUTION EXPENSE	(1) Company Present Rates	Adjustments	Company Proposed Rates	Adjustments	OCA	References
1	Proposed Balance at 12/31/2022	$ 370,979,000	$ 8,712,000	$ 379,691,000	$ (15,177,715)	$ 364,513,285	
	Distribution Operations						
2	Operation & Supervision - salaries	$ 1,056,000	$ 64,000	$ 1,120,000	$ (44,938)	$ 1,075,062	
3	Load Dispatching	$ -	$ -	$ -			
4	Station Expense	$ 640,000	$ -	$ 640,000	$ -	$ 640,000	
5	Overhead Line Expense - salaries	$ 17,030,000	$ 174,000	$ 17,204,000	$ (122,087)	$ 17,081,913	
6	Underground Line Expense - salaries	$ 11,313,000	$ 173,000	$ 11,486,000	$ (121,378)	$ 11,364,622	
7	Meter Expense - salaries	$ 5,199,000	$ 155,000	$ 5,354,000	$ (108,860)	$ 5,245,140	
8	Customer Installation Expense - salaries	$ 9,499,000	$ 358,000	$ 9,857,000	$ (251,184)	$ 9,605,816	
9	Miscellaneous Expense - salaries	$ 67,803,000	$ 469,000	$ 68,272,000	$ (329,084)	$ 67,942,916	
	Incentive Compensation - EBSC charges				$ (2,636,910)	$ (2,636,910)	OCA-III-9/21
	Total Distribution Operations - Salaries				$ -	$ -	DM-14A
	Stock Compensation				$ (440,000)	$ (440,000)	OCA VI-4
10	Rents	$ 3,139,000	$ -	$ 3,139,000	$ -	$ 3,139,000	
11	Total	$ 115,679,000	$ 1,393,000	$ 117,072,000	$ (4,054,440)	$ 113,017,560	
	Distribution Maintenance						
12	Maint. of Structures - salaries	$ 1,891,000	$ 82,000	$ 1,973,000	$ (57,631)	$ 1,915,369	
13	Maint. of Station Equipment - salaries	$ 15,973,000	$ 557,000	$ 16,530,000	$ (390,861)	$ 16,139,139	
14	Maint. of Overhead Lines - salaries	$ 192,828,000	$ 2,640,000	$ 195,468,000	$ (1,852,524)	$ 193,615,476	
	Vegetative Management		$ -	$ -	$ (3,668,841)	$ (3,668,841)	OCA-III-14/VI-7
	Storm Expense Normalization	$ -	$ 2,807,000	$ 2,807,000	$ (3,155,400)	$ (348,400)	OCA-III-7/50
15	Maint. of Underground Lines - salaries	$ 28,017,000	$ 996,000	$ 29,013,000	$ (698,997)	$ 28,314,003	
16	Maint. of Line Transformers - salaries	$ 1,476,000	$ 24,000	$ 1,500,000	$ (16,851)	$ 1,483,149	
17	Maint. of Street Lighting & Signal Systems - salaries	$ 1,014,000	$ 10,000	$ 1,024,000	$ (7,025)	$ 1,016,975	
18	Maint. of Misc. Distribution - salaries	$ 14,100,000	$ 204,000	$ 14,304,000	$ (143,145)	$ 14,160,855	
	Stock Compensation				$ (1,132,000)	$ (1,132,000)	OCA VI-4
	Total Distribution Maintenance Salaries				$ -	$ -	DM-14A
19	Total	$ 255,299,000	$ 7,320,000	$ 262,619,000	$ (11,123,275)	$ 251,495,725	
20	Total Distribution Expense	$ 370,978,000	$ 8,713,000	$ 379,691,000	$ (15,177,715)	$ 364,513,285	OCA-III-36

(1) Company Exhibit MJT-1 Schedule D-4
Pages 56-59
Differences due to rounding
Storm - MJT-1 D-13

	CUSTOMER ACCOUNTS EXPENSE	(1) Company Present Rates	Adjustments	Company Proposed Rates	Adjustments	OCA	References
1	Proposed Balance at 12/31/2022	$ 119,238,000	$ 7,795,000	$ 127,033,000	$ (12,341,877)	$ 114,691,123	
2	Supervision	$ -	$ -	$ -			
3	Meter Reading	$ 338,000	$ -	$ 338,000	$ -	$ 338,000	OCA-III-36
4	Customer Records & Collection	$ 79,174,000		$ 81,793,000			
	Customer Accounts Salaries		$ 2,619,000		$ (1,837,669)	$ 79,955,331	DM-14A
	Incentive Compensation - EBSC charges	$ -		$ -	$ (3,078,470)	$ (3,078,470)	OCA-III-21
5	Uncollectible Accounts	$ 35,551,000	$ (12,649,000)	$ 22,902,000	$ -	$ 22,902,000	
	COVID-19 Bad Debt Reg. Asset	$ -	$ 16,083,000	$ 16,083,000	$ (6,433,000)	$ 9,650,000	OCA-III-49
6	Misc. Customer Accounts Expense - Int Dep.	$ 4,175,000	$ 1,643,000	$ 5,818,000	$ -	$ 5,818,000	
	Stock Compensation			$ -	$ (923,000)	$ (923,000)	OCA VI-4
	Customer Accounts Salaries		$ 98,000	$ 98,000	$ (68,738)	$ 29,262	DM-14A
7	Total	$ 119,238,000	$ 7,794,000	$ 127,032,000	$ (12,340,877)	$ 114,691,123	OCA-III-36 OCA-III-47/48
(2)	Additional Uncollectible Accounts			$ 1,382,928	$ (1,457,066)	$ (74,138)	

(2) Revenue Requirement increase times 3 year average of Uncollectible Accounts of .5622%

(1) Company Exhibit MJT-1 Schedule D-4 D-11
Pages 56-59
Differences due to rounding

	CUSTOMER SERVICE & INFORMATION	(1) Company Present Rates	Adjustments	Company Proposed Rates	Adjustments	OCA	References
1	Proposed Balance at 12/31/2022	$ 102,672,000	$ (90,932,000)	$ 11,740,000	$ (854,330)	$ 10,885,670	
2	Customer Assistance - EEP	$ 101,187,000	$ (91,055,000)	$ 10,132,000	$ -	$ 10,132,000	
	Salaries & Wages		$ 123,000	$ 123,000	$ (86,330)	$ 36,670	
	Stock Compensation			$ -	$ (42,000)	$ (42,000)	OCA VI-4
	Economic Development - Labor/Ben.			$ -	$ (727,000)	$ (727,000)	OCA-III-18
3	Informational & Instructional	$ 1,351,000	$ -	$ 1,351,000	$ -	$ 1,351,000	
4	Miscellaneous Customer & Informational	$ 135,000	$ -	$ 135,000	$ -	$ 135,000	
5	Total	$ 102,673,000	$ (90,932,000)	$ 11,741,000	$ (855,330)	$ 10,885,670	OCA-III-36

(1) Company Exhibit MJT-1 Schedule D-4
Pages 56-59
Differences due to rounding

	SALES EXPENSE	(1) Company Present Rates	Adjustments	Company Proposed Rates	Adjustments	OCA	References
1	Proposed Balance at 12/31/2022	$ 1,676,000	$ 64,000	$ 1,740,000	$ (243,911)	$ 1,496,089	
2	Demonstrating and Selling	$ 1,676,000		$ 1,676,000	$ -	$ 1,676,000	
	Demonstrating and Selling Salaries		$ 64,000	$ 64,000	$ (44,911)	$ 19,089	DM-14A
	Stock Compensation			$ -	$ (20,000)	$ (20,000)	OCA VI-4
	Economic Development			$ -	$ (179,000)	$ (179,000)	OCA-III-18
3	Miscellaneous Sales	$ -	$ -	$ -			
4	Total	$ 1,676,000	$ 64,000	$ 1,740,000	$ (243,911)	$ 1,496,089	OCA-III-36

(1) Company Exhibit MJT-1 Schedule D-4
Pages 56-59
Differences due to rounding

	ADMINISTRATIVE & GENERAL EXPENSE	(1) Company Present Rates	Adjustments	Company Proposed Rates	Adjustments	OCA	References
1	Proposed Balance at 12/31/2022	$ 160,384,000	$ 24,339,000	$ 184,723,000	$ (29,300,495)	$ 155,422,505	
2	Administrative & General Salaries	$ 40,954,000	$ 2,972,000	$ 43,926,000	$ (2,085,930)	$ 41,840,070	DM-14A
3	Office Supplies & Expenses (salaries)	$ 6,998,000	$ 7,000	$ 7,005,000	$ (4,913)	$ 7,000,087	
4	Employee Volunteer Events - off. Supp.				$ (54,000)	$ (54,000)	OCA-III-18
5	Administrative Expenses - Trans/Credit	$ -	$ -	$ -	$ -	$ -	
6	Outside Services Employed - (salaries)	$ 66,466,000	$ (5,000)	$ 66,461,000	$ 3,510	$ 66,464,510	DM-14A
7	Incentive Compensation - EBSC charges			$ -	$ (2,584,620)	$ (2,584,620)	OCA-III-21
	Stock Compensation			$ -	$ (1,413,000)	$ (1,413,000)	OCA VI-4
8	Property Insurance	$ 499,000	$ -	$ 499,000	$ -	$ 499,000	
9	Injuries and Damages - (salaries)	$ 9,851,000	$ 112,000	$ 9,963,000	$ (78,614)	$ 9,884,386	DM-14A
10	Employee Pension & Benefits - (salaries)	$ 20,334,000	$ 8,000	$ 20,342,000	$ (5,616)	$ 20,336,384	DM-14A
11	Medicare Advantage 3% cost of living			$ -	$ (466,230)	$ (466,230)	OCA-III-45/20/46
12	Employee Benefits - add'l employees		$ 462,000	$ 462,000	$ (199,713)	$ 262,287	OCA-III-45
13	Pension		$ 11,699,000	$ 11,699,000	$ (5,802,000)	$ 5,897,000	OCA-III-19/29
14	OPEB		$ -	$ -	$ (1,395,600)	$ (1,395,600)	OCA-III-19
15	Economic Development - M&S			$ -	$ (54,000)	$ (54,000)	OCA-III-18
16	Employee Activities			$ -	$ (757,031)	$ (757,031)	OCA-III-10
17	Regulatory Commission Expense	$ 7,576,000	$ 800,000	$ 8,376,000	$ (396,286)	$ 7,979,714	OCA-III-44
18	Duplicate Charges - Credit	$ (675,000)	$ -	$ (675,000)	$ -	$ (675,000)	
19	Miscellaneous General Expenses-COVID	$ 1,931,000	$ 5,778,000	$ 7,709,000	$ (5,778,000)	$ 1,931,000	OCA-III-51
20	Experimental / General			$ -	$ (47,000)	$ (47,000)	OCA-III-8
	Corporate Dues			$ -	$ (169,000)	$ (169,000)	OCA-VI-2
21	Emergency Relief /Grant/Other	$ -	$ 2,427,000	$ 2,427,000	$ (1,507,000)	$ 920,000	OCA-III-57/58/59/60/61/62
22	A&G Maintenance of General Expenses	$ 6,450,000	$ 79,000	$ 6,529,000	$ (55,453)	$ 23,547	DM-14A
23	Total	$ 160,384,000	$ 24,339,000	$ 184,723,000	$ (29,300,495)	$ 155,422,505	OCA-III-36
24	Additional PUC/OCA/SBA Assessment Revenue Requirement Increase times the Assessment Rate of .03459%			$ 850,862	$ (896,476)	$ (45,614)	OCA-III-34

(1) Company Exhibit MJT-1 Schedule D-4
Pages 56-59
Differences due to rounding
Company Schedule D-19

	DEPRECIATION & AMORTIZATION	(1) Company Present Rates	Adjustments	Company Proposed Rates	Adjustments	OCA	References
1	Proposed Balance at 12/31/2022	$ 258,833,333					
2	Distribution Plant	$ 179,462,000	$ 8,450,000	$ 187,912,000	$ (5,902,940)	$ 182,009,060	OCA VI-6
3	Common Plant	$ 16,763,000	$ 1,021,000	$ 17,784,000	$ -	$ 17,784,000	
4	General Plant	$ 19,569,000	$ 358,000	$ 19,927,000	$ -	$ 19,927,000	
5	Transmission Plant	$ -	$ -	$ -	$ -	$ -	
6	Sub-Total	$ 215,794,000	$ 9,829,000	$ 225,623,000	$ (5,902,940)	$ 219,720,060	
7	Intangible Plant	$ 44,040,000	$ 2,253,000	$ 46,293,000	$ -	$ 46,293,000	OCA-III-54
8	Total	$ 259,834,000	$ 12,082,000	$ 271,916,000	$ (5,902,940)	$ 266,013,060	OCA-III-22
9	Amortization of Regulatory Expense	$ 923,000		$ 923,000	$ -	$ 923,000	OCA-III-34/VI-3

(1) Company Exhibit MJT-1 Schedule D-17
Company Exhibit MJT-1 Schedule D-4
Page 57 and 59
Differences due to rounding

	TAXES OTHER THAN INCOME	(1) Company Proposed	Adjustments	OCA	References
1	Public Utility Real Tax (PURTA)	$ 6,273,000	$ (143,236)	$ 6,129,764	
2	Use Tax Accrued	$ 460,000	$ -	$ 460,000	
3	Real Estate Tax Accrued	$ 5,200,000	$ -	$ 5,200,000	
4	Miscellaneous TOTI	$ -			
5	Payroll Tax Accrued	$ 13,341,001	$ (653,298)	$ 12,687,704	
6	**Sub-Total**	$ 25,274,001	$ (796,533)	$ 24,477,468	
7	Gross Receipts Tax	$ 133,281,767	$ -	$ 133,281,767	OCA-III-52
8	**Total**	$ 158,555,768	$ (796,533)	$ 157,759,235	
9	Additional Gross Receipts Tax	$ 14,513,115	$ (15,291,155)	$ (778,040)	
10	Revenue Requirement Increase times 5.90%				
11	**Total Taxes Other Than Income**	$ 173,068,883	$ (16,087,688)	$ 156,981,195	

(1) Company Exhibit MJT-1 Schedule D-16
Differences due to rounding

INCOME TAXES	(1) Company Proposed	Adjustments	OCA	References
Revenues	$ 2,580,588,000		$ 2,334,400,816	
Operating Expenses	$ 2,004,187,000		$ 1,918,787,229	
Operating Income Before Taxes	$ 576,401,000		$ 415,613,586	
Rate Base	$ 6,385,897,000		$ 6,052,270,989	
Weighted Cost of Debt	1.830970%		1.97%	
Synchronized Interest Expense	$ 116,860,858		$ 118,927,125	
Base Taxable Income	$ 459,540,142		$ 296,686,462	
State Accelerated Tax Depreciation	$ 272,228,000		$ 272,228,000	OCA-III-55
Pro-Forma Book Depreciation	$ 271,916,000		$ 271,916,000	
State Tax Depreciation (Over) Under Book	$ (313,000)		$ (313,000)	
Regulatory Asset Programs M-1 Pension / PBOP	$ (17,696,000)		$ (17,696,000)	
Other Property Basis Adjustments (CIAC/ICM)	$ (24,716,000)		$ (24,716,000)	
Removal Costs/Software	$ (20,433,000)		$ (20,433,000)	
AFUDC Equity	$ (15,645,000)		$ (15,645,000)	
Permanent Adjustments	$ 4,203,000		$ 4,203,000	
Repair Deductions	$ (128,000,000)		$ (128,000,000)	
State Taxable Income	$ 256,940,142		$ 94,086,462	
State Income Tax Rate	9.99%		9.990%	
State Income Tax Benefit / (Expense) before NOL	$ (25,668,320)	$ 16,269,083	$ (9,399,238)	
NOL Utilization %	40.00%		40.00%	
NOL Utilization	$ 10,267,328	$ (6,507,633)	$ 3,759,695	
State Income Tax Benefit (Expense)	$ (15,400,992)	$ 9,761,450	$ (5,639,543)	
Federal Accelerated Tax Depreciation	$ 247,075,000		$ 247,075,000	
Proforma Book Depreciation	$ 271,916,000		$ 271,916,000	
Federal Tax Deduct (Over) Under Book	$ 24,841,000		$ 24,841,000	
Regulatory Asset Program M-1	$ (17,696,000)		$ (17,696,000)	
Other Property Basis Adjustment (CIAC/ICM)	$ (24,716,000)		$ (24,716,000)	
Removal Costs/Software	$ (20,433,000)		$ (20,433,000)	
AFUDC Equity	$ (15,645,000)		$ (15,645,000)	
Permanent Adjustments	$ 4,203,000		$ 4,203,000	
Repair Deductions	$ (128,000,000)		$ (128,000,000)	
Federal NOL	$ -		$ -	
Federal Taxable Income	$ 266,693,150	$ (153,092,231)	$ 113,600,919	
Federal Income Tax Rate	21.00%		21.00%	
Federal Income Tax Benefit / Expense before Deferred and Adjustments	$ (56,005,561)	$ 32,149,368	$ (23,856,193)	
Total Tax Benefit (Expense) before DIT	$ (71,406,554)	$ 41,910,818	$ (29,495,735)	
DIT on Timing - Federal	$ (4,935,000)	$ (664,384)	$ (5,599,384)	
DIT on Timing - State	$ (4,236,959)	$ -	$ (4,236,959)	
Deferred State Tax on NOL	$ (10,267,328)	$ 14,027,023	$ 3,759,695	
Excess Deferred Amortization	$ 9,742,000	$ -	$ 9,742,000	
Federal Income Tax on Flow-Through Adjust.	$ (4,881,000)	$ -	$ (4,881,000)	
Deferred Income Tax Benefit (Expense)	$ (14,578,287)		$ (1,215,648)	
Net Income Tax Benefit (Expense)	$ (85,984,840)		$ (30,711,383)	
Amortization of ITC	$ 20,000		$ 20,000	
Combined Income Tax Benefit (Expense)	$ (85,964,840)	$ 55,273,457	$ (30,691,383)	
Federal Income Tax Benefit (Expense)	$ (56,059,561)		$ (24,574,577)	
State Income Tax Benefit (Expense)	$ (29,905,279)		$ (6,116,806)	

(1) Company Exhibit MJT-1 Schedule D-18

EXHIBITS

Project Type	Project Description	Comment
Specific Projects	LTIIP Overbrook Building Substation Retirement	Delayed beyond FPFTY due to developing detailed breakdowns
	220-60 Line Relay Replacement	Delayed beyond FPFTY due to scheduling
	Baltimore Pike Travel Lanes	Delayed beyond FPFTY due to PennDot schedule change
	FEP North Philly Substation	Delay until 1/2024, scheduling
	OHT Rebuild Aerial Lights on River Xing Twrs	Delay until 12/2023, scheduling
	Ucomm Tier-2 WiMax Conversion to Fiber	Delayed beyond FPFTY due to scheduling
	Newlinville-343 Express Main - LTIIP	Went in-service 11/2019 and further charging is no longer forecasted

Responsible Witness: Robert J. Stefani

Project Description	Additions to Capital - YTD April 2021	Additions to Capital for FTY	Additions to Capital for FPFTY	In-Service	Prior In-Service (IE-RB-8-D)	Status	Commentary
Kennett Square TSO Properties Renovation and Purchase	-	-	37,558,003	September 2022	September 2022		
Upper Darby Building Substation Retirement (LTIIP)	-	-	30,130,321	December 2022	December 2022		
Plymouth Control House	-	-	13,911,434	December 2022	December 2022		
Oregon 4kV to 13kV Conversion	-	-	11,462,353	April 2022	April 2022		
b2752 Furnace Run Substation	-	-	11,145,077	June 2022	June 2022		
BIDA – SES 4 Enhancements	-	-	8,219,236	October 2022	October 2022		
Penrose 20 MVA to The Navy Yard	-	-	6,738,085	August 2022	September 2022		
Tulip and Holmesburg Unit Substation Retirement (LTIIP)	-	-	5,249,945	December 2022	December 2022		
FEP Waneeta Substation	-	-	5,017,641	July 2022	September 2021	Delayed	Due to the delay on the parallel building demolition project.
ADMS RTU Telemetry interface	-	-	4,564,508	March 2022	March 2022		
FEP Chichester Substation	-	-	4,555,939	July 2022	June 2022	Delayed	Due to short delay on coordination with new AIMs product to IFC drawings.
FEP Westmoreland Substation	-	-	4,337,336	June 2022	June 2022		
EU IT Load Profile Settlement (LPS) Development	-	-	4,145,460	February 2022	February 2022		
130-36 Line Partial Rebuild	-	-	3,907,549	July 2022	July 2022		
SR 202-61S - Relocate poles from Johnson Hwy to Swede St.	-	-	3,685,063	December 2022	December 2022		
FEP Schuylkill N/C Substation	-	-	3,437,162	March 2022	July 2021	Delayed	Due to underground obstructions found at that start of construction therefore re-engineering IFC for fence line and type.
FEP - Southwark Sub	-	-	2,676,331	February 2022	July 2021	Delayed	Due to site conditions found during site investigations which delayed engineering and construction.
LPFF- Bryn Mawr #19 and #20	-	-	2,456,284	December 2022	December 2021	Delayed	Outage Date could not be secured to meet the in-service Date for #20 LPFF. However, #19 LPFF will meet the listed in-service date
Replace UGT Pumping Plant Station at Westmoreland Sub	-	-	2,211,680	March 2022	March 2021	Delayed	In Service Date was pushed out due to Permitting Requirements with City of Philadelphia & with coordination w/Westmoreland Switchgear project
LTIIP II CEMI Targeted Circuits Crusher-000 Tree Wire	-	3,640,467	2,144,187	December 2021	December 2021		
FEP Master Sub	-	-	2,008,834	November 2022	October 2022	Delayed	Due to finalizing IFC, but may still finish with earlier date.
Ridge Pike Section B Belvoir to Chemical Rd Facilities Relocation	-	-	1,986,531	December 2022	December 2022		
SR 95 Sec AF-2 Delaware, Castor, and Alleghany Ave Facilities Relocation	-	-	1,975,931	December 2022	December 2022		
FR - SR 0001-RC2 Relocation	-	-	1,954,479	January 2022	December 2021	Delayed	PennDOT Schedule
FEP Tredyffrin Substation	-	-	1,895,495	September 2022	September 2022		
Storm Critical Systems - IT Hardening and Remediation	7,092	7,092	1,714,296	November 2022	November 2022		
1104 Hancock St	-	-	1,542,491	December 2022	December 2022		
FR - SR 2025-001 Relocation	-	-	1,329,350	December 2022	March 2022	Delayed	PennDOT Schedule
b2985 Linwood 225 CB Add Second CB	-	-	1,137,419	June 2022	June 2022		
b3041 Peach Bottom 5007 Line Upgrades	-	-	1,135,188	December 2022	January 2021	Delayed	Scheduling delays
I-95 GR6	-	-	1,045,044	September 2022	September 2022		
Peach Bottom North/South 2 Bus Tie	-	-	1,034,667	January 2022	January 2022		
Kulps 001 Unit Substation Retirement (LTIIP)	-	-	961,055	December 2022	December 2022		
CIVIC SUB 6637 LINE RECNDCTRNG	-	22,623,521	952,702	December 2021	December 2021		
Buckingham 240 CB	-	-	813,811	October 2022	October 2022		
TRIP Mainstem – Callowhill 138	-	-	766,177	December 2022	December 2021	Delayed	Project in service delayed to 2022 to align LTIIP II PUC Mainstem Cable 2021/2022 scope commitments and reprioritize other critical/emergent Mainstem projects.
Penn Civic Center Switchyard – Land Acquisition	-	-	764,504	June 2022	June 2022		
1 Red Lion Rd HT	-	-	736,186	March 2022	#N/A	New	
G&L Building	-	-	696,292	December 2022	December 2022		
Eddystone U3-4 Separation	-	13,485,950	690,312	December 2021	December 2021		

Project Description	Additions to Capital - YTD April 2021	Additions to Capital for FTY	Additions to Capital for FPFTY	In-Service	Prior In-Service (IE-RB-8-D)	Status	Commentary
Grays Ferry Circuit Breaker 375	-	-	683,233	December 2022	April 2021	Delayed	TSO scheduling
Transmission & Substation (T&S) Document Management System Upgrade	-	-	651,856	February 2022	February 2022		
1 Dock Drive	-	-	640,298	March 2022	September 2021	Delayed	New Business job delayed by Customer timing
TRIP Mainstem – Eddystone 130	-	-	551,467	December 2022	December 2021	Delayed	Project in service delayed to 2022 to align LTIIP II PUC Mainstem Cable 2021/2022 scope commitments and reprioritize other critical/emergent Mainstem projects.
TRIP Mainstem – Harmony 001	-	-	505,087	December 2022	December 2021	Delayed	Project in service delayed to 2022 to align LTIIP II PUC Mainstem Cable 2021/2022 scope commitments and reprioritize other critical/emergent Mainstem projects.
PA Turnpike & NE Extension	-	562,062	486,532	January 2021	January 2021		
TRIP URD Mainstem – Byberry 184	-	-	441,237	December 2022	December 2021	Delayed	Project in service delayed to 2022 to align LTIIP II PUC Mainstem Cable 2021/2022 scope commitments and reprioritize other critical/emergent Mainstem projects.
LTIIP URD Mainstem – Byberry 131	-	-	339,628	December 2022	December 2021	Delayed	Project in service delayed to 2022 to align LTIIP II PUC Mainstem Cable 2021/2022 scope commitments and reprioritize other critical/emergent Mainstem projects.
LPFF- Byberry #17, #18 and #19	-	-	258,344	December 2022	December 2022		
Buckingham - New 34kV circuit to relieve Buck. 351	13,671,495	14,692,815	253,317	June 2021	June 2021		
Line-1300CR Horseshoe Trail Hendrix	-	-	248,684	December 2022	#N/A	New	
Buckingham-351 RM1	-	-	246,105	December 2022	#N/A	New	
TRIP Mainstem – Line 7700	-	-	208,836	December 2022	December 2021	Delayed	Project in service delayed to 2022 to align LTIIP II PUC Mainstem Cable 2021/2022 scope commitments and reprioritize other critical/emergent Mainstem projects.
Line-1300CR Howell Rd Tree Wire	-	-	186,590	December 2022	#N/A	New	
PECO DA Automation Control	-	-	178,391	October 2022	October 2022		
Replace Emilie #8 Transformer	-	6,043,236	165,345	December 2021	December 2021		
220-52 Whitpain (525 BF)/Jarret (565 BF)	-	1,177,974	152,582	December 2021	December 2021		
FEP Conowingo (230kV) Substation	15,386	15,386	151,611	January 2022	November 2022		
Bucknell Unit Substation Retirement (LTIIP)	-	-	147,676	#N/A	#N/A	New	
York MP11 (LTIIP)	-	-	140,356	December 2022	December 2022		
220-51 Heaton/Jarret P&C Obsolence	-	1,167,158	135,268	December 2021	December 2021		
Sadsbury Stottsville MP8 (LTIIP)	-	-	95,387	December 2022	December 2022		
WHITEMARSH-142 URD Replacement at Summit Ave	-	-	91,912	#N/A	#N/A	New	
LTIIP II -CEMI- Newlinville 353 Rock Raymond Rd	-	-	83,645	March 2022	#N/A	New	
FR - Rte 202 - Section 61N	-	-	75,753	May 2022	May 2022		
CAP Shopping	-	1,566,412	59,564	January 2021	January 2021		
Pencoyd 134 Mainstem Cable Replacement	-	-	53,445	December 2022	#N/A	New	
Spruce Substation Retirement	-	39,993,841	-	December 2021	December 2021		
EU Analytics - Advanced Metering Infrastructure (AMI)	-	9,920,817	-	December 2021	December 2021		
New T&S Building	8,572,723	8,955,576	-	January 2021	December 2021		
Howell 001 & 002 Retirements (LTIIP)	-	7,532,880	-	December 2021	December 2021		
FEP Grays Ferry Substation	-	6,567,384	-	November 2021	June 2021	Delayed	Due to engineering/constructability issue on the wall adjacent to the railroad. Delayed engineering and construction.
FIN_002 Conversion (LTIIP)	-	6,473,956	-	October 2021	June 2021	Delayed	There was additional scope on the project, which also triggered the need for additional vegetation work. The vegetation work was held up by obtaining customer approvals, all of which resulted in four additional months being required.

Project Description	Additions to Capital - YTD April 2021	Additions to Capital for FTY	Additions to Capital for FPFTY	In-Service	Prior In-Service (IE-RB-8-D)	Status	Commentary
Castle, Willis,&Leopard-001-Leopard-002 Unit Sub Retirement (LTIIP)	2,299,411	6,473,420	-	June 2021	April 2021	Delayed	ITN includes multiple Project IDs associated with 4 individual interconnected units. Load was removed from 2 of the units in 2020, placing those Project IDs in service. The 2 remaining Project IDs will go into service in 2021. Delays in 2021 in servicing due to slow Verizon pole sets.
Berwyn SEC Infrastructure Upgrade	-	6,108,100	-	December 2021	December 2021		
SR 202 Markley Street Project Section 510	5,933,592	6,082,119	-	April 2021	March 2021	Delayed	Outage delays caused by DSO
Lincoln 005 & 006 Retirement (LTIIP)	-	5,916,107	-	December 2021	December 2021		
LTIIP II Mainstem Harmony 004	-	5,751,408	-	December 2021	December 2021		
PECO DSP5 Gen-Only TOU (Res/SCI)	-	5,575,171	-	September 2021	September 2021		
Nice and Venango Unit Substation Retirement (LTIIP)	70,193	5,117,575	-	December 2021	December 2021		
Bellevue 001 Conversion	-	4,860,208	-	December 2021	July 2021	Delayed	Challenges with crews being deployed for storm work, weather, and ability to get customer outages to complete pre-conversion work; final conversion must be coordinated with SEPTA
Non LTIIP II CEMI Tgtd Circuits Middletown 349 and Concord-351 Extension	4,044,207	4,769,490	-	February 2021	December 2021		
Master 133 new circuit to relieve N Phila. circuits & substation	-	4,073,472	-	July 2021	June 2021	Delayed	Weather and a blocked duct requiring an unexpected civil permit caused project delays
LTIIP II Mainstem Line 2445	-	4,038,568	-	December 2021	December 2021		
LTIIP Mainstem Bryn Mawr 144	-	4,009,222	-	December 2021	December 2021		
Lawrence 002 Mainstem Cable Replacement Project (LTIIP)	-	3,865,872	-	October 2021	June 2021	Delayed	Delays due to breakdown circuit Lawrence-003 out-of-configuration, which will need to be coordinated and repairs prior to cutover and in service of Lawrence-002.
Leopard-002 URD Cable Replacement (LTIIP)	-	3,765,714	-	September 2021	June 2021	Delayed	Delays due to coordination with 56141: Castle, Willis,&Leopard-001-Leopard-002 Unit Sub Retirement (LTIIP)
Non LTIIP AIR Wentz 000	-	3,551,488	-	December 2021	December 2021		
Linton-341 Walker URD (LTIIP)	-	3,463,805	-	December 2021	December 2021		
FEP Planebrook Sub	-	3,215,019	-	November 2021	November 2021		
FEP Schuylkill East Substation	-	3,198,139	-	October 2021	July 2021	Delayed	Due to engineering delays with final design of the new entrance.
LTIIP CEMI Line 132-00 ROW Relocation (LTIIP)	-	3,160,157	-	December 2021	December 2021		
Master 162 - new 13 kV circuit to relieve Tuna Substation	2,719,720	2,740,486	-	April 2021	January 2021	Delayed	Project was delayed due to customer equipment issues, circuits out of configuration, and OCC resources being focused on manhole fires and unable to accommodate switching for this project.
LTIIP II Mainstem Line 2288	-	2,421,580	-	December 2021	December 2021		
Securing EMS/SCADA Systems	-	2,283,969	-	December 2021	December 2021		
Llanerch (4kv) Substation	134,333	2,255,391	-	May 2021	January 2021	Delayed	Delayed due to bus outages getting rescheduled due to conflicts. Consists of multiple projects. Latest project in-service date is May 2021.
TRIP Mainstem Line 2680	2,184,393	2,176,657	-	February 2021	January 2021	Delayed	In service delay due to outage coordination with large customers in Philadelphia.
CEMI Concord 351 Tie Relocation (LTIIP)	-	1,961,666	-	December 2021	December 2021		
229 W Upsal St	-	1,919,260	-	December 2021	December 2021		
900 - 958 N 9th St	-	1,839,108	-	July 2021	March 2021	Delayed	The station leg portion of this Project that places it in-service was pushed out by the OCC. The Project team is working in-prog to determine a new date

Project Description	Additions to Capital - YTD April 2021	Additions to Capital for FTY	Additions to Capital for FPFTY	In-Service	Prior In-Service (IE-RB-8-D)	Status	Commentary
Buckingham-351 R3 Point Pleasant Pk Express Main Non LTIIP II CEMI Tgtd	-	1,746,946	-	December 2021	December 2021		
TRIP URD – Line 2710	-	1,723,365	-	December 2021	December 2021		
130-34 Line (Covanta Plymouth)	1,160,814	1,694,263	-	April 2021	April 2021		
Buckingham 351 Assessment Area	1,649,008	1,658,899	-	March 2021	December 2021		
Whitpain Circuit Breaker 385	-	1,648,054	-	November 2021	November 2021		
Whitpain Circuit Breaker 575	-	1,636,221	-	May 2021	May 2021		
TRIP Mainstem Keystone 041	-	1,602,237	-	May 2021	January 2021	Delayed	In service delay due to outage coordination with large customers and breakdown circuits out-of-configuration
Island Road-136 Chalets URD Cable Replacement (LTIIP)	-	1,448,710	-	October 2021	June 2021	Delayed	Delays due to negative customer response to padmount transformers proposed to be installed in small front yards in Philadelphia County (replacing submersibles) requiring redesign.
TRIP Mainstem – Keystone 039	-	1,448,248	-	May 2021	January 2021	Delayed	In service delay due to outage coordination with large customers and breakdown circuits out-of-configuration
LTIIP II AIR Jenkintown 137	-	1,444,979	-	December 2021	December 2021		
SR 202-65S - Relocate poles from Morris Rd. to Swedesford Rd.	-	1,428,438	-	September 2021	June 2021	Delayed	PennDOT Schedule
220-69 Plymouth Meeting & Upper Merion P&C Obsolence	-	1,401,597	-	October 2021	October 2021		
Conowingo 220-98 Static Wire Repair	-	1,390,035	-	December 2021	#N/A	New	
Non LTIIP II CEMI Targeted Circuits Newtown Square 131 Relocation	-	1,361,158	-	December 2021	December 2021		
FR - SR 2308-M04 Relocation	-	1,335,439	-	October 2021	October 2021		
Mall & Lombard-Retire 2.4kV Substations	1,305,859	1,305,859	-	December 2023	#N/A		
36th St	-	1,256,195	-	October 2021	August 2021	Delayed	New Business job delayed by Customer timing
TRIP ASP – Planebrook 341 new Reclosers	-	1,213,895	-	May 2021	March 2021	Delayed	Construction Delay due to COC Rework Required.
LTIIP II AIR Tabor 139	-	1,181,533	-	December 2021	December 2021		
Non LTIIP AIR Jenkintown 143	-	1,174,963	-	December 2021	December 2021		
New Upper Merion 146 Circuit (EBCUM145C)	1,198,281	1,174,647	-	February 2021	February 2021		
PECO AMI OMS (AMOS) Outage 2021 Enhancements	-	1,169,254	-	December 2021	October 2021	Delayed	Increased scope
Bryn Mawr-Wynnewood 500 Line Upgrades	-	1,116,516	-	December 2021	December 2021		
Line 2295 Mainstem Cable Replacement Project (LTIIP)	286,938	1,094,778	-	December 2021	December 2021		
Byberry-163 Audubon URD Cable Replacement (LTIIP)	-	1,070,647	-	June 2021	June 2021		
LTIIP II AIR Line 2214	-	1,070,012	-	December 2021	December 2021		
OHT replace wood poles on 130-54 line (Newlinville to Mittal Stel)	-	1,032,100	-	December 2021	#N/A	New	
Byberry-160 URD Cable Replacement (LTIIP)	-	961,516	-	December 2021	December 2021		
Whitpain Bus 2/2-3 Tie	-	946,984	-	July 2021	July 2021		
EU Ratings Database Convergence Initiative Implementation	-	923,141	-	October 2021	October 2021		
220-22 structure 21-17 to 21-20 relocation	-	875,445	-	December 2021	#N/A	New	
Line 2405 Mainstem Cable Replacement Project (LTIIP)	-	863,193	-	December 2021	December 2021		
Island Road-136 Delphi URD Cable Replacement (LTIIP)	-	863,069	-	June 2021	June 2021		
Buckingham 220 Breakers	-	854,607	-	October 2021	October 2021		
Whitpain 220-10 Line Relays	-	849,256	-	September 2021	September 2021		
PECO ADMS Field (RTU) Communication	-	837,138	-	December 2021	December 2021		
Buckingham 230 CB	-	824,424	-	October 2021	March 2021	Delayed	TSO scheduling
Blueball Retirement	414,848	818,323	-	January 2021	January 2021		
LTIIP II AIR Line 534	-	817,821	-	December 2021	December 2021		
Passyunk 235 CB	827,897	812,930	-	February 2021	December 2021		
Lenape-343 Pleasant Grove URD Cable Replacement	-	794,846	-	December 2021	December 2021		
Lock Substation - Const new 34kV sub&ccts (T/D)	-	788,148	-	May 2021	February 2021	Delayed	Caused by Material delays
Byberry-134 Riverside URD Cable Replacement (LTIIP)	-	782,850	-	December 2021	December 2021		
Waverly 144 Mainstem Cable Replacement Project (LTIIP)	-	775,820	-	December 2021	December 2021		
LTIIP II Mainstem – Civic 010	786,218	763,667	-	January 2021	January 2021		
Buckingham-344 Westwyck URD Cable Replacement	-	763,637	-	December 2021	December 2021		

Project Description	Additions to Capital - YTD April 2021	Additions to Capital for FTY	Additions to Capital for FPFTY	In-Service	Prior In-Service (IE-RB-8-D)	Status	Commentary
1911 Walnut St	-	735,377	-	October 2021	October 2021		
Waneeta Circuit Breaker 285	396,261	726,370	-	April 2021	April 2021		
Tabor 905 Breaker Replacement	417,164	723,298	-	April 2021	April 2021		
Circuit Rebuild Enabling Unit Retirement (LTIIP)	-	700,000	-	January 2021	January 2021		
LTIIP II AIR Ambler 004	-	678,687	-	December 2021	December 2021		
TRIP Mainstem Jenkintown 143	-	663,062	-	December 2021	December 2021		
CEMI Landenberg-000 Penn Green Hendrix Cable (LTIIP)	-	661,916	-	December 2021	December 2021		
Parrish 905 Circuit Breaker	-	655,854	-	November 2021	November 2021		
Concord-347 W Forge Rd Express Main LTIIP II CEMI Targeted Circuits	-	616,195	-	December 2021	December 2021		
Bala Cynwyd Mainstem Cable Replacement Project (LTIIP)	-	607,153	-	December 2021	December 2021		
Buckingham 342 URD Replacement at Rittenhouse Cir	-	603,202	-	December 2021	#N/A	New	
Eddystone 255 Circuit Breaker	588,157	587,862	-	February 2021	February 2021		
LTIIP II CEMI Targeted Circuits Llanerch-163 Tree Wire	-	576,168	-	December 2021	December 2021		
Richmond 140 CB	511,427	563,412	-	January 2021	January 2021		
Upper Darby Circuit Breaker 65	-	555,545	-	December 2021	December 2021		
OHT replace wood structure 0-5 on 130-35 line	-	543,745	-	December 2021	#N/A	New	
OHT Rebuild 6681 Line	144,634	540,272	-	January 2021	January 2021		
Newtown Square-134 Hendrix	-	534,711	-	December 2021	December 2021		
Heaton 144 Mainstem Cable Replacement Project (LTIIP)	-	519,102	-	December 2021	December 2021		
EU Digital System Hardening	401,989	518,311	-	December 2021	December 2021		
SM MV 90 - Capital	140,484	496,827	-	December 2021	December 2021		
Heaton 142 URD Replacement at Hidden Meadows	-	492,281	-	December 2021	December 2021		
Byberry-144 Levy URD Cable Replacement (LTIIP)	-	484,629	-	December 2021	December 2021		
3500 Civic Center Blvd	-	483,038	-	June 2021	March 2021	Delayed	New Business job delayed by Customer timing
TRIP URD Mainstem – Jenkintown 134	-	462,111	-	December 2021	December 2021		
1101 Checstnut St	-	451,494	-	December 2021	May 2021	Delayed	New Business job delayed by Customer timing
2116-38 Market St	-	440,231	-	July 2021	July 2021		
4101 Market St	-	433,557	-	October 2021	September 2021	Delayed	New Business job delayed by Customer timing
1341 S. Columbus Ave.	-	425,000	-	July 2021	July 2021		
Falls 341URD Replacement at Village of Pennbrook	-	394,221	-	December 2021	December 2021		
Peach Bottom North/South 1 Bus Tie	-	392,267	-	December 2021	December 2021		
Upper Merion 351 Mainstem Cable Replacement (LTIIP)	145,935	389,252	-	January 2021	January 2021		
Lenape 341 URD Replacement at Beversrede Trail	-	384,386	-	December 2021	#N/A	New	
Middletown-352 Gordon URD Cable Replacement	-	354,277	-	December 2021	December 2021		
CEMI Clay 343 Express Main (LTIIP)	378,646	342,726	-	February 2021	December 2021		
Church-Jordan Unit Substation Retirements (LTIIP)	-	336,330	-	January 2021	January 2021		
Blue Grass 143 URD Replacement at Chalfont Dr	-	331,117	-	December 2021	#N/A	New	
Island Rd 136 Mainstem Cable Replacement Project (LTIIP)	-	321,668	-	December 2021	December 2021		
New Eagle-353 Circuit (LTIIP CEMI)	66,524	295,091	-	January 2021	January 2021		
Bala Plaza Mainstem Cable Replacement Project (LTIIP)	561,377	292,198	-	January 2021	January 2021		
6657 LPFF Line Replacement	-	290,854	-	June 2021	June 2021		
Line 2470 Navy Yard Mainstem Cable Replacement Project (LTIIP)	36,313	287,071	-	January 2021	January 2021		
Newlinville 344 Tree Wire LTIIP CEMI	391,290	277,096	-	March 2021	December 2021		
Woodbourne-351 Knolls URD Cable Replacement	-	251,179	-	December 2021	#N/A	New	
Howell-002 Conversion (LTIIP)	246,206	248,590	-	January 2021	January 2021		
Blue Grass 140 URD Replacement at Keswick Rd - Part 1	-	248,236	-	December 2021	#N/A	New	
1700 Line Extension to Replace the 9900 Line to Wayne	-	237,477	-	January 2021	January 2021		
ROCI Bala 132	-	233,706	-	January 2021	January 2021		
TRIP ASP Buckingham 342 new Reclosers	-	232,226	-	October 2021	#N/A	New	
Non LTIIP AIR North Wales 351	-	225,106	-	December 2021	December 2021		
CEMI Llanerch 161 Rear Property Reconfig (LTIIP)	221,319	220,821	-	February 2021	December 2021		
Byberry 141 URD Replacement	-	217,240	-	December 2021	#N/A	New	
CEMI Wayne 131 St. David’s Ave and Glen Mary Rd Hendrix (LTIIP)	-	215,517	-	December 2021	December 2021		
Chronic TPC - Lenape 351 Conversion	39,906	210,343	-	January 2021	January 2021		
EU IT Energy Management System(EMS) Implementation	-	210,191	-	January 2021	January 2021		

Project Description	Additions to Capital - YTD April 2021	Additions to Capital for FTY	Additions to Capital for FPFTY	In-Service	Prior In-Service (IE-RB-8-D)	Status	Commentary
Middletown-133 St. Andrews URD Cable Replacement	-	209,893	-	December 2021	December 2021		
Eddington 142 URD Replacement at Berkley Trace Apts	-	204,031	-	December 2021	December 2021		
Line 3340 Hilltop URD Cable Replacement (LTIIP)	261,291	195,129	-	January 2021	January 2021		
LTIIP Mainstem – Line 326	300,462	191,633	-	March 2021	January 2021	Delayed	In service delay due to outage coordination with large customers in Philadelphia.
CEMI Pencoyd 133 Transformer Relocation (LTIIP)	-	187,133	-	December 2021	December 2021		
Line 2276 Mainstem Cable Replacement (LTIIP)	(69,955)	182,644	-	January 2021	January 2021		
Line 132-00 Woodlyn Crossing (LTIIP)	25,838	176,962	-	January 2021	January 2021		
City Hall Emergent Mainstem Cable Replacement Project (LTIIP)	64,883	170,848	-	January 2021	January 2021		
Warrington-362 Cornell Estates URD Cable Replacement (LTIIP)	-	164,894	-	December 2021	#N/A	New	
SR 202-61N - Rt 202 from Swede St to Morris Rd	-	161,580	-	December 2021	June 2021	Delayed	PennDOT Schedule
Line 550 Mainstem Cable Replacement Project (LTIIP)	5,618	160,900	-	January 2021	May 2021		
FEP Byberry Substation	84,527	160,891	-	January 2021	January 2021		
Line 6659 Chester/Paper Tap	-	159,991	-	November 2021	#N/A	New	
Elkins 004 Mainstem Cable Replacement Project	-	152,440	-	December 2021	December 2021		
TRIP Mainstem – Paoli 004	39,971	151,450	-	January 2021	January 2021		
Plymouth - Mobile Transformer Storage Facilities	150,996	150,996	-	March 2021	December 2022		
Newlinville-342 Express Main - LTIIP	1,284	143,359	-	January 2021	January 2021		
Pencoyd-134 URD Cable Replacement (LTIIP)	284,660	141,281	-	January 2021	January 2021		
Byberry-163 Rennard URD Cable Replacement (LTIIP)	121,587	141,215	-	January 2021	January 2021		
Warrington 363 URD Replacement at Warrington MEWs	-	139,970	-	December 2021	#N/A	New	
Lenape 351 Station Leg Extension (LTIIP)	221	138,331	-	January 2021	January 2021		
ROCI Saville 132	3,077	138,304	-	January 2021	January 2021		
Replace UGT Pumping Plant Stations-Eddystone Substation	(64,278)	131,285	-	January 2021	January 2021		
Open Span Secondary Wire Replacement Project	522,785	128,119	-	January 2021	#N/A	New	
Newtown Square Bus Relay	-	127,981	-	January 2021	January 2021		
FEP - Linwood Substation	23,280	127,588	-	January 2021	September 2021		
ROCI Jenkintown 131	7,814	126,725	-	January 2021	January 2021		
FEP Cooper Substation	(178,555)	125,388	-	December 2021	December 2021		
Regent-000 Goshen Terrace URD Cable Replacement	(147,725)	124,389	-	December 2021	December 2021		
LTIIP-CEMI- Newtown_Square_133 Sugartown Rd Hendrix Cable Installation	-	117,193	-	December 2021	#N/A	New	
CEMI Buckingham Stump Rd Reclosers (LTIIP)	39,537	115,649	-	January 2021	January 2021		
Health - EU Microstation Upgrade	-	115,485	-	October 2021	October 2021		
ROCI - Overbrook 131	-	113,189	-	January 2021	January 2021		
TRIP Mainstem – Whitemarsh 132	-	108,651	-	December 2021	December 2021		
Limerick 225 (500kV) CB – Circuit Breaker Replacement	-	105,418	-	January 2021	January 2021		
LTIIP CEMI Areas - Flint_147 Spring Mill Rd Tree Wire	-	105,249	-	December 2021	December 2021		
Chronic TPC - Bethayres 002 Partial Conversion	23,390	100,592	-	January 2021	January 2021		
EU Gas AS8 Assets Data Alignment (OneMDS)	-	100,040	-	October 2021	October 2021		
Big Oak-3 Part 2 URD Cable Replacement (LTIIP)	-	99,304	-	January 2021	January 2021		
Vegetation Management IT NorthStar- Inspections and Work Mgmt Systems	-	98,109	-	October 2021	October 2021		
Emilie 1-2 Bus Tie Upgrade	7,089	97,494	-	January 2021	January 2021		
Salmon-012 and Orthodox Unit Substation Retirement (LTIIP)	86,279	96,547	-	January 2021	January 2021		
Neshaminy-141 Washington URD Cable Replacement (LTIIP)	26,672	94,557	-	January 2021	#N/A	New	
ROCI Bala 131	94,218	94,246	-	January 2021	January 2021		
Blue Grass 140 URD Replacement at Keswick Rd - Part 2	-	93,005	-	December 2021	#N/A	New	
Byberry 133 Nandina St Part 1 URD Cable Replacement	-	91,049	-	December 2021	#N/A	New	
URD Neshaminy-145 Bensalem Village (LTIIP)	19,187	90,784	-	January 2021	#N/A	New	
Waverly 142 Mainstem Cable Replacement Project	-	85,236	-	December 2021	#N/A	New	
Byberry 137 Somerton Ct URD Cable Replacement	-	84,018	-	December 2021	#N/A	New	
ROCI Line 2235	-	81,958	-	January 2021	January 2021		
Alternate CIMS Batch Schedule for 2020/2021	80,558	80,558	-	April 2021	#N/A	New	
Emilie 15 CB Replacement	940	80,172	-	January 2021	January 2021		
Upper Merion 351 URD replacement at Springdell Village	-	78,843	-	December 2021	December 2021		
Parish 825 CB Replacement	12,506	76,787	-	January 2021	January 2021		

Project Description	Additions to Capital - YTD April 2021	Additions to Capital for FTY	Additions to Capital for FPFTY	In-Service	Prior In-Service (IE-RB-8-D)	Status	Commentary
AB Chance 13kV Cutout Replacement	175,884	75,903	-	January 2021	#N/A	New	
130-18 Line Relay Replacement	2,272	75,803	-	January 2021	January 2021		
China Tap 15 CB Replacement	75,682	75,682	-	January 2021	January 2021		
Neshaminy 134 URD Replacement at County Downe	-	75,657	-	December 2021	#N/A	New	
Byberry 133 Nandina St Part 2 URD Cable Replacement	-	72,825	-	December 2021	#N/A	New	
Plymouth 133 Mainstem Cable Replacement Project (LTIIP)	47,344	70,735	-	January 2021	January 2021		
Island Road-136 URD Cable Replacement (LTIIP)	-	65,207	-	June 2021	June 2021		
Whitpain Bus 1 Relays	-	64,258	-	March 2021	January 2021	Delayed	TSO scheduling
CEMI Newlinville 342 Telegraph Rd Express Main (LTIIP)	-	63,418	-	December 2021	December 2021		
220-11 Passyunk (435 BF) Line Relay Replacement	63,238	63,238	-	January 2021	January 2021		
Jarrett 133 URD Replacement at Wynmere Downs	-	62,650	-	December 2021	#N/A	New	
Cedarbrook 131 Carlisle Rd URD Replacement	-	62,329	-	December 2021	#N/A	New	
TRIP URD – Blue Grass 144	1,215	61,497	-	January 2021	January 2021		
Howell-002 URD Cable Replacement (LTIIP)	(67,604)	60,090	-	January 2021	January 2021		
AMTRAK Zoo to Paoli Transmission Line Upgrade	43,027	59,276	-	July 2021	#N/A	New	
Emilie 25 CB Replacement	59,261	59,261	-	January 2021	January 2021		
Bradford 342 URD Replacement at Glen Dr	-	56,243	-	December 2021	#N/A	New	
TRIP Mainstem Phoenixville 002	-	54,912	-	December 2021	#N/A	New	
Neshaminy-163 Country Village URD Cable Replacement (LTIIP)	-	53,813	-	January 2021	January 2021		
TRIP Mainstem Neshaminy 134	-	51,444	-	January 2021	January 2021		
Other Projects under $50,000	77,950	1,398,201	283,746				
	54,276,469	**335,286,020**	**200,210,257**				

Project Type	Project Description	Additions to Capital for FTY	Additions to Capital for FPFTY	In-Service
Baseline/Program	Back Office Allocation	11,385,813	3,229,425	Various
	Battery Replacements	360,136	385,525	Various
	BIDA - PECO	313,722	-	Various
	Breaker Replacement	108,942	9,412,988	Various
	Capacity Expansion - Distribution	49,241,926	34,853,056	Various
	Capacity Expansion - Transmission	904,490	880,436	Various
	Corrective Maintenance - Distribution	104,403,402	112,185,357	Various
	Corrective Maintenance - Smart Meter	1,824,161	1,869,767	Various
	Corrective Maintenance - Storms	25,879,258	26,542,913	Various
	Corrective Maintenance - Subs	7,648,113	8,097,830	Various
	Corrective Maintenance - Trans	3,494,662	11,000,138	Various
	Customer Operations	695,695	699,238	Various
	Customer Smart Grid Operations	2,302,870	4,473,839	Various
	Customer Strategy & Governance	1,413,150	2,930,400	Various
	Customer Target Program	4,201,454	3,763,490	Various
	Distribution Substation Fencing	1,262,289	-	Various
	Facility Enhancement Program	1,292,621	7,338,535	Various
	IT Projects	3,043,530	2,164,658	Various
	LTIIP CEMI	794,357	801,648	Various
	LTIIP II Aerial Infrastructure Resiliency Areas	633,879	3,532,041	Various
	LTIIP II Aerial Infrastructure Resiliency Targeted	36,217,051	80,326,305	Various
	LTIIP II Building Sub Retirement	219,675	7,791,826	Various
	LTIIP II CEMI Areas	13,194,157	15,929,953	Various
	LTIIP II CEMI Targeted Circuits	2,011,701	5,165,245	Various
	LTIIP II Mainstem Cable	15,042,179	43,327,597	Various
	LTIIP II Switchgear Replacement	575,219	6,906,723	Various
	LTIIP II Underground Res Development	28,658,429	71,200,945	Various
	LTIIP II Unit Sub Retirement	239,083	23,411,747	Various
	New Business - Smart Meter	1,372,779	1,407,098	Various
	New Business	62,494,563	63,125,783	Various
	Non- LTIIP II Accelerated Sectionalizing	122,931	19,103,081	Various
	Non- LTIIP II Aerial Infrastructure Resiliency Areas	537,910	5,587,038	Various
	Non- LTIIP II CEMI "Targeted Circuits"	4,040,131	7,452,287	Various
	Non- LTIIP II Mainstem Cable	-	2,037,049	Various
	Non- LTIIP II Underground Res Development	2,654,732	7,090,608	Various
	Other	4,273	4,669	Various
	P&C Obsolence	2,421,223	10,470,589	Various
	Priority One	627,547	646,567	Various
	Public Relocation	11,065,094	7,506,893	Various
	Pumping Plant Replacements	-	2,529,218	Various
	Real Estate and Facilities	1,512,206	303,681	Various
	Replace Distribution Poor performing URD	2,806,354	2,896,325	Various
	RTEP	596,811	2,036,975	Various
	Smart Meter - 1307 Rec only	993,674	908,130	Various
	Switchgear Replacement	32,882,736	21,045,479	Various
	System Performance	45,221,906	64,488,743	Various
	Top Priority Circuits	8,473,631	8,016,685	Various
	Transmission Wood Pole Replacements	3,241,301	1,065,446	Various
	UG Oil Switch Program	-	2,286,204	Various
	Unit Tie breaker repair / replace	1,252,351	721,280	Various
	URD Manhole Lid Replacement	1,556,894	1,555,706	Various
Baseline/Program Total		**501,241,012**	**720,507,158**	
Specific Projects	Kennett Square TSO Properties Renovation and Purchase	-	29,945,342	September 2022
	Upper Darby Building Substation Retirement (LTIIP)	-	29,740,647	December 2022
	Plymouth Control House	-	13,894,802	December 2022
	b2752 Furnace Run Substation	-	11,529,440	June 2022
	Oregon 4kV to 13kV Conversion	-	11,161,469	April 2022
	BIDA – SES 4 Enhancements	-	8,219,236	October 2022
	LTIIP Overbrook Building Substation Retirement	-	7,281,539	December 2022
	Tulip and Holmesburg Unit Substation Retirement (LTIIP)	-	6,103,417	December 2022
	130-36 Line Partial Rebuild	-	6,048,990	July 2022
	FEP Chichester Substation	-	4,546,737	June 2022
	FEP Westmoreland Substation	-	4,284,189	June 2022
	ADMS RTU Telemetry interface	-	4,081,750	March 2022
	EU IT Load Profile Settlement (LPS) Development	-	3,741,629	February 2022
	SR 202-61S - Relocate poles from Johnson Hwy to Swede St.	-	3,711,314	December 2022
	Penrose 20 MVA to The Navy Yard	-	3,655,265	September 2022
	SR 95 Sec AF-2 Delaware, Castor, and Alleghany Ave Facilities Relocation	-	2,216,251	December 2022

Project Type	Project Description	Additions to Capital for FTY	Additions to Capital for FPFTY	In-Service
	LTIIP II CEMI Targeted Circuits Crusher-000 Tree Wire	3,647,628	2,144,187	December 2021
	Ridge Pike Section B Belvoir to Chemical Rd Facilities Relocation	-	2,000,408	December 2022
	FEP Master Sub	-	1,999,301	October 2022
	FEP Tredyffrin Substation	-	1,829,457	September 2022
	FEP Waneeta Substation	3,156,974	1,775,435	September 2021
	Storm Critical Systems - IT Hardening and Remediation	-	1,603,547	November 2022
	FR - SR 2025-001 Relocation	-	1,555,345	March 2022
	220-60 Line Relay Replacement	-	1,337,584	May 2022
	Baltimore Pike Travel Lanes	-	1,322,689	April 2022
	1104 Hancock St	-	1,210,250	December 2022
	b2985 Linwood 225 CB Add Second CB	-	1,192,191	June 2022
	I-95 GR6	-	1,044,751	September 2022
	Peach Bottom North/South 2 Bus Tie	-	1,039,437	January 2022
	CIVIC SUB 6637 LINE RECNDCTRNG	27,668,769	952,702	December 2021
	Buckingham 240 CB	-	809,720	October 2022
	Penn Civic Center Switchyard – Land Acquisition	-	764,504	June 2022
	Eddystone U3-4 Separation	13,556,924	690,312	December 2021
	Transmission & Substation (T&S) Document Management System Upgrade	-	582,644	February 2022
	PA Turnpike & NE Extension	562,235	486,532	January 2021
	PECO DA Automation Control	-	348,105	October 2022
	G&L Building	-	344,460	December 2022
	FEP North Philly Substation	-	318,218	December 2022
	LPFF- Byberry #17, #18 and #19	-	314,524	December 2022
	Buckingham - New 34kV circuit to relieve Buck. 351	14,902,049	253,317	June 2021
	FEP Conowingo (230kV) Substation	-	192,622	November 2022
	Replace Emilie #8 Transformer	5,843,750	165,345	December 2021
	Plymouth - Mobile Transformer Storage Facilities	-	153,719	December 2022
	220-52 Whitpain (525 BF)/Jarret (565 BF)	1,235,559	152,582	December 2021
	220-51 Heaton/Jarret P&C Obsolence	1,225,895	135,268	December 2021
	York MP11 (LTIIP)	-	124,252	December 2022
	Sadsbury Stottsville MP8 (LTIIP)	-	91,124	December 2022
	Kulps 001 Unit Substation Retirement (LTIIP)	-	81,811	December 2022
	FR - Rte 202 - Section 61N	-	75,753	May 2022
	CAP Shopping	1,605,070	59,564	January 2021
	Spruce Substation Retirement	38,620,335	-	December 2021
	EU Analytics - Advanced Metering Infrastructure (AMI)	9,836,286	-	December 2021
	New T&S Building	9,157,249	-	December 2021
	Howell 001 & 002 Retirements (LTIIP)	8,375,731	-	December 2021
	Castle, Willis,&Leopard-001-Leopard-002 Unit Sub Retirement (LTIIP)	7,263,792	-	April 2021
	Berwyn SEC Infrastructure Upgrade	6,341,289	-	December 2021
	SR 202 Markley Street Project Section 510	6,197,155	-	March 2021
	Lincoln 005 & 006 Retirement (LTIIP)	6,138,442	-	December 2021
	FIN_002 Conversion (LTIIP)	6,116,037	-	June 2021
	FEP Grays Ferry Substation	6,075,096	-	June 2021
	Nice and Venango Unit Substation Retirement (LTIIP)	5,891,401	-	December 2021
	LTIIP II Mainstem Harmony 004	5,764,366	-	December 2021
	LPFF- Bryn Mawr #19 and #20	5,240,201	-	December 2021
	Non LTIIP II CEMI Tgtd Circuits Middletown 349 and Concord-351 Extension	4,878,858	-	December 2021
	PECO DSP5 Gen-Only TOU (Res/SCI)	4,738,518	-	September 2021
	Bellevue 001 Conversion	4,534,505	-	July 2021
	Master 133 new circuit to relieve N Phila. circuits & substation	3,989,375	-	June 2021
	Non LTIIP AIR Wentz 000	3,765,410	-	December 2021
	Lawrence 002 Mainstem Cable Replacement Project (LTIIP)	3,745,171	-	June 2021
	LTIIP Mainstem Bryn Mawr 144	3,710,872	-	December 2021
	Leopard-002 URD Cable Replacement (LTIIP)	3,688,419	-	June 2021
	Linton-341 Walker URD (LTIIP)	3,635,255	-	December 2021
	LTIIP II Mainstem Line 2445	3,628,491	-	December 2021
	FEP Schuylkill N/C Substation	3,392,058	-	July 2021
	FEP Schuylkill East Substation	3,179,117	-	July 2021
	FEP Planebrook Sub	3,140,419	-	November 2021
	LTIIP CEMI Line 132-00 ROW Relocation (LTIIP)	2,900,681	-	December 2021
	FEP - Southwark Sub	2,701,646	-	July 2021
	Master 162 - new 13 kV circuit to relieve Tuna Substation	2,681,816	-	January 2021
	LTIIP II Mainstem Line 2288	2,388,709	-	December 2021
	Replace UGT Pumping Plant Station at Westmoreland Sub	2,247,196	-	March 2021
	Llanerch (4kv) Substation	2,225,672	-	January 2021
	TRIP Mainstem Line 2680	2,129,041	-	January 2021
	Securing EMS/SCADA Systems	2,075,329	-	December 2021

Project Type	Project Description	Additions to Capital for FTY	Additions to Capital for FPFTY	In-Service
	FR - SR 0001-RC2 Relocation	1,986,240	-	December 2021
	Buckingham-351 R3 Point Pleasant Pk Express Main Non LTIIP II CEMI Tgtd	1,886,330	-	December 2021
	CEMI Concord 351 Tie Relocation (LTIIP)	1,846,050	-	December 2021
	36th St	1,746,372	-	August 2021
	900 - 958 N 9th St	1,690,214	-	March 2021
	229 W Upsal St	1,681,833	-	December 2021
	130-34 Line (Covanta Plymouth)	1,634,274	-	April 2021
	Buckingham 351 Assessment Area	1,616,683	-	December 2021
	Whitpain Circuit Breaker 385	1,589,572	-	November 2021
	Whitpain Circuit Breaker 575	1,575,357	-	May 2021
	TRIP Mainstem Keystone 041	1,568,391	-	January 2021
	b3041 Peach Bottom 5007 Line Upgrades	1,445,208	-	January 2021
	TRIP URD – Line 2710	1,439,988	-	December 2021
	Non LTIIP II CEMI Targeted Circuits Newtown Square 131 Relocation	1,414,613	-	December 2021
	FR - SR 2308-M04 Relocation	1,413,312	-	October 2021
	TRIP Mainstem – Keystone 039	1,407,062	-	January 2021
	SR 202-65S - Relocate poles from Morris Rd. to Swedesford Rd.	1,392,212	-	June 2021
	Island Road-136 Chalets URD Cable Replacement (LTIIP)	1,389,058	-	June 2021
	220-69 Plymouth Meeting & Upper Merion P&C Obsolence	1,348,546	-	October 2021
	LTIIP II AIR Jenkintown 137	1,245,176	-	December 2021
	OHT Rebuild Aerial Lights on River Xing Twrs	1,216,840	-	December 2021
	Bryn Mawr-Wynnewood 500 Line Upgrades	1,158,584	-	December 2021
	New Upper Merion 146 Circuit (EBCUM145C)	1,151,254	-	February 2021
	LTIIP II AIR Tabor 139	1,149,455	-	December 2021
	Non LTIIP AIR Jenkintown 143	1,126,168	-	December 2021
	Byberry-163 Audubon URD Cable Replacement (LTIIP)	1,060,737	-	June 2021
	TRIP ASP – Planebrook 341 new Reclosers	1,043,573	-	March 2021
	Byberry-160 URD Cable Replacement (LTIIP)	1,005,605	-	December 2021
	Whitpain Bus 2/2-3 Tie	950,765	-	July 2021
	LTIIP II AIR Line 2214	907,221	-	December 2021
	PECO AMI OMS (AMOS) Outage 2021 Enhancements	904,085	-	October 2021
	Whitpain 220-10 Line Relays	877,084	-	September 2021
	1911 Walnut St	864,944	-	October 2021
	Buckingham 220 Breakers	853,902	-	October 2021
	Line 2295 Mainstem Cable Replacement Project (LTIIP)	833,301	-	December 2021
	LTIIP II Mainstem – Civic 010	833,281	-	January 2021
	Buckingham 230 CB	823,278	-	March 2021
	Blueball Retirement	821,888	-	January 2021
	Island Road-136 Delphi URD Cable Replacement (LTIIP)	818,140	-	June 2021
	LTIIP II AIR Line 534	809,541	-	December 2021
	EU Ratings Database Convergence Initiative Implementation	806,097	-	October 2021
	Passyunk 235 CB	802,961	-	December 2021
	Byberry-134 Riverside URD Cable Replacement (LTIIP)	789,734	-	December 2021
	Lenape-343 Pleasant Grove URD Cable Replacement	759,207	-	December 2021
	Buckingham-344 Westwyck URD Cable Replacement	744,214	-	December 2021
	Waneeta Circuit Breaker 285	742,983	-	April 2021
	Tabor 905 Breaker Replacement	734,760	-	April 2021
	TRIP Mainstem – Callowhill 138	731,257	-	December 2021
	Line 2405 Mainstem Cable Replacement Project (LTIIP)	716,394	-	December 2021
	Circuit Rebuild Enabling Unit Retirement (LTIIP)	714,749	-	January 2021
	Grays Ferry Circuit Breaker 375	698,406	-	April 2021
	PECO ADMS Field (RTU) Communication	694,320	-	December 2021
	Concord-347 W Forge Rd Express Main LTIIP II CEMI Targeted Circuits	666,553	-	December 2021
	LTIIP II CEMI Targeted Circuits Llanerch-163 Tree Wire	646,349	-	December 2021
	Parrish 905 Circuit Breaker	645,929	-	November 2021
	4101 Market St	639,461	-	September 2021
	1101 Checstnut St	634,670	-	May 2021
	1 Dock Drive	624,558	-	September 2021
	2116-38 Market St	620,329	-	July 2021
	3500 Civic Center Blvd	619,020	-	March 2021
	1341 S. Columbus Ave.	611,579	-	July 2021
	Waverly 144 Mainstem Cable Replacement Project (LTIIP)	610,321	-	December 2021
	LTIIP II AIR Ambler 004	608,980	-	December 2021
	Eddystone 255 Circuit Breaker	588,903	-	February 2021
	TRIP Mainstem Jenkintown 143	580,044	-	December 2021
	Lock Substation - Const new 34kV sub&ccts (T/D)	564,803	-	February 2021
	OHT Rebuild 6681 Line	547,539	-	January 2021
	Richmond 140 CB	530,422	-	January 2021

Project Type	Project Description	Additions to Capital for FTY	Additions to Capital for FPFTY	In-Service
	Ucomm Tier-2 WiMax Conversion to Fiber	517,712	-	January 2021
	Upper Darby Circuit Breaker 65	512,624	-	December 2021
	TRIP Mainstem – Eddystone 130	509,481	-	December 2021
	SM MV 90 - Capital	500,004	-	December 2021
	TRIP Mainstem – Harmony 001	470,249	-	December 2021
	CEMI Landenberg-000 Penn Green Hendrix Cable (LTIIP)	464,150	-	December 2021
	Byberry-144 Levy URD Cable Replacement (LTIIP)	422,162	-	December 2021
	Newtown Square-134 Hendrix	420,621	-	December 2021
	TRIP URD Mainstem – Byberry 184	410,674	-	December 2021
	Heaton 142 URD Replacement at Hidden Meadows	403,645	-	December 2021
	Bala Cynwyd Mainstem Cable Replacement Project (LTIIP)	399,657	-	December 2021
	Heaton 144 Mainstem Cable Replacement Project (LTIIP)	350,896	-	December 2021
	FEP - Newlinville Substation	347,739	-	January 2021
	Church-Jordan Unit Substation Retirements (LTIIP)	336,330	-	January 2021
	TRIP URD Mainstem – Jenkintown 134	332,562	-	December 2021
	6657 LPFF Line Replacement	326,844	-	June 2021
	LTIIP URD Mainstem – Byberry 131	315,795	-	December 2021
	Upper Merion 351 Mainstem Cable Replacement (LTIIP)	304,221	-	January 2021
	CEMI Clay 343 Express Main (LTIIP)	296,692	-	December 2021
	Peach Bottom North/South 1 Bus Tie	290,431	-	December 2021
	Island Rd 136 Mainstem Cable Replacement Project (LTIIP)	286,348	-	December 2021
	Line 2470 Navy Yard Mainstem Cable Replacement Project (LTIIP)	282,632	-	January 2021
	New Eagle-353 Circuit (LTIIP CEMI)	275,272	-	January 2021
	Bala Plaza Mainstem Cable Replacement Project (LTIIP)	273,999	-	January 2021
	Middletown-352 Gordon URD Cable Replacement	263,649	-	December 2021
	Howell-002 Conversion (LTIIP)	248,590	-	January 2021
	EU IT Energy Management System(EMS) Implementation	242,547	-	January 2021
	1700 Line Extension to Replace the 9900 Line to Wayne	237,317	-	January 2021
	Pottstown Streetlights Cable Replacement Project (LTIIP)	230,198	-	January 2021
	ROCI Bala 132	229,796	-	January 2021
	Newlinville 344 Tree Wire LTIIP CEMI	225,314	-	December 2021
	Chronic TPC - Lenape 351 Conversion	212,744	-	January 2021
	CEMI Llanerch 161 Rear Property Reconfig (LTIIP)	209,076	-	December 2021
	Line 2276 Mainstem Cable Replacement (LTIIP)	198,504	-	January 2021
	TRIP Mainstem – Line 7700	195,265	-	December 2021
	FEP Cooper Substation	194,577	-	December 2021
	FEP - Linwood Substation	187,901	-	September 2021
	LTIIP Mainstem – Line 326	186,268	-	January 2021
	Line 132-00 Woodlyn Crossing (LTIIP)	171,477	-	January 2021
	Falls 341URD Replacement at Village of Pennbrook	170,163	-	December 2021
	City Hall Emergent Mainstem Cable Replacement Project (LTIIP)	166,463	-	January 2021
	FEP Byberry Substation	159,639	-	January 2021
	EU Digital System Hardening	158,805	-	December 2021
	Line 550 Mainstem Cable Replacement Project (LTIIP)	157,028	-	May 2021
	EU Transmission Outage Application (TOA) Implementation	154,747	-	January 2021
	TRIP Mainstem – Paoli 004	151,416	-	January 2021
	Replace UGT Pumping Plant Stations-Eddystone Substation	147,463	-	January 2021
	Newlinville-342 Express Main - LTIIP	143,095	-	January 2021
	Byberry-163 Rennard URD Cable Replacement (LTIIP)	139,032	-	January 2021
	Lenape 351 Station Leg Extension (LTIIP)	138,285	-	January 2021
	ROCI Saville 132	138,204	-	January 2021
	Eddington 142 URD Replacement at Berkley Trace Apts	135,224	-	December 2021
	Newlinville-343 Express Main - LTIIP	132,092	-	January 2021
	Middletown-133 St. Andrews URD Cable Replacement	129,969	-	December 2021
	Island Road-136 URD Cable Replacement (LTIIP)	128,024	-	June 2021
	Newtown Square Bus Relay	127,981	-	January 2021
	SR 202-61N - Rt 202 from Swede St to Morris Rd	127,513	-	June 2021
	ROCI Jenkintown 131	124,979	-	January 2021
	Pencoyd-134 URD Cable Replacement (LTIIP)	122,042	-	January 2021
	CEMI Pencoyd 133 Transformer Relocation (LTIIP)	117,555	-	December 2021
	Health - EU Microstation Upgrade	117,125	-	October 2021
	CEMI Buckingham Stump Rd Reclosers (LTIIP)	114,120	-	January 2021
	Line 3340 Hilltop URD Cable Replacement (LTIIP)	112,675	-	January 2021
	ROCI - Overbrook 131	109,843	-	January 2021
	Limerick 225 (500kV) CB – Circuit Breaker Replacement	105,418	-	January 2021
	EU Gas AS8 Assets Data Alignment (OneMDS)	101,479	-	October 2021
	Big Oak-3 Part 2 URD Cable Replacement (LTIIP)	99,435	-	January 2021
	Vegetation Management IT NorthStar- Inspections and Work Mgmt Systems	99,042	-	October 2021

Project Type	Project Description	Additions to Capital for FTY	Additions to Capital for FPFTY	In-Service
	TRIP Mainstem – Whitemarsh 132	98,931	-	December 2021
	Chronic TPC - Bethayres 002 Partial Conversion	96,382	-	January 2021
	Non LTIIP AIR North Wales 351	95,814	-	December 2021
	Emilie 1-2 Bus Tie Upgrade	95,065	-	January 2021
	ROCI Bala 131	94,254	-	January 2021
	Parish 935 CB Replacement	91,691	-	January 2021
	CEMI Wayne 131 St. David's Ave and Glen Mary Rd Hendrix (LTIIP)	90,114	-	December 2021
	Elkins 004 Mainstem Cable Replacement Project	84,309	-	December 2021
	CEMI Newlinville 342 Telegraph Rd Express Main (LTIIP)	82,855	-	December 2021
	Emilie 15 CB Replacement	80,172	-	January 2021
	Salmon-012 and Orthodox Unit Substation Retirement (LTIIP)	78,839	-	January 2021
	ROCI Line 2235	78,567	-	January 2021
	Parish 825 CB Replacement	76,787	-	January 2021
	China Tap 15 CB Replacement	75,682	-	January 2021
	130-18 Line Relay Replacement	75,278	-	January 2021
	Regent-000 Goshen Terrace URD Cable Replacement	74,685	-	December 2021
	Upper Merion 351 URD replacement at Springdell Village	66,095	-	December 2021
	Whitpain Bus 1 Relays	64,294	-	January 2021
	Plymouth 133 Mainstem Cable Replacement Project (LTIIP)	63,789	-	January 2021
	220-11 Passyunk (435 BF) Line Relay Replacement	63,238	-	January 2021
	Line-7500 Hershey Mills Estates URD Cable Replacement (LTIIP)	62,733	-	January 2021
	Wayne-146 Hendrix Install	61,758	-	January 2021
	TRIP URD – Blue Grass 144	61,131	-	January 2021
	LTIIP CEMI Areas - Flint_147 Spring Mill Rd Tree Wire	60,731	-	December 2021
	Howell-002 URD Cable Replacement (LTIIP)	60,343	-	January 2021
	ROCI - Solebury 001	59,959	-	January 2021
	Emilie 25 CB Replacement	59,261	-	January 2021
	Jenkintown Circuit Breaker 240	57,581	-	May 2021
	Woodbourne 905 Circuit Breaker	55,485	-	January 2021
	220-11 Graysferry (115 BF) Line Relay Replacement	54,625	-	January 2021
	FEP Cochranville Substation	54,232	-	April 2021
	Neshaminy-163 Country Village URD Cable Replacement (LTIIP)	53,813	-	January 2021
	TRIP Mainstem Neshaminy 134	52,062	-	January 2021
	Other Projects under $50,000	1,483,599	129,730	Various
Specific Project Total		**352,976,437**	**177,443,405**	
	Gross Plant Additions	**854,217,449**	**897,950,563**	
	Calculated Cost of Removal	**(54,723,531)**	**(54,723,531)**	
	Plant Additions	**799,493,918**	**843,227,032**	

Reconciliation to Exhibit CF-2 and CF-3:

	FTY	FPFTY
Plant Additions per Exhibits MJT-2 and MJT-1, Schedule C-2, Page 19, Row 34	**799,493,918**	**843,227,032**
Adjustments		
Intangible Plant (Transmission portion)	(2,196,161)	(810,074)
Transmission Plant	(128,233,102)	(175,898,666)
General Plant (Transmission portion)	(823,649)	(687,707)
Total Transmission Related Plant Additions	**(131,252,912)**	**(177,396,447)**
Common Plant Additions Allocated to Distribution	**72,418,597**	**69,574,769**
Total Adjustments	**(58,834,315)**	**(107,821,678)**
Plant Additions per Exhibits CF-2 and CF-3, Column 6, Row 21	**740,659,603**	**735,405,354**

APPENDIX A

DANTE MUGRACE

Education

Master Business Administration, MBA Strategic Management, Pace University, Lubin School of Business, New York, NY, 2010

Master Public Administration, MPA, Kean University, Union, NJ, 2001

Bachelor of Science, BS. Accounting, St. Peter's University, Jersey City, NJ, 1983

Position

Senior Consultant – PCMG and Associates	2014 – present
Senior Consultant – Snavely King Majoros and Associates	2013 – 2014
Independent Consultant	2012 – 2013
Bureau Chief/Administrative Analyst/Accountant – New Jersey Board of Public Utilities	1983 – 2011

Professional Experience

Mr. Mugrace has 35 years' experience in all aspects of regulatory accounting and policy including processing, analyzing and evaluating utility rate case petitions before Public Service Commissions. Mr. Mugrace examines and evaluates rate filings, contracts, agreements and rate matters regarding utility operations and provides recommendations as to best course of action. Additionally, Mr. Mugrace analyzes and reviews utility regulatory matters and sets forth recommendations for resolution of issues, calculates total revenue requirement needed to cover operating expenses and rate of return; researches and evaluates regulatory utility matters to assess impact on various classes of customers, regarding rates, service, compliance and cost of service provisions, as well as annual true-up and tracking mechanisms.

Prior to undertaking consulting assignments, Mr. Mugrace was the Bureau Chief Utility Rate Manager for the New Jersey Board of Public Utilities, in which role he managed and assigned tasks to a staff of 12 professionals and supervisory personal in the daily administrative, financial and managerial functions of the Division. Mr. Mugrace's primary duties were to determine whether the utility had sufficient revenues to cover its operating expenses and earn a return on its plant investment and to ensure that the utility provided safe, reliable and continuing utility service to its customers. Mr. Mugrace set rates and charges for utility companies, which had revenues of up to $500 million, and ensured that the revenue requirement provided for recovery of all operating expenses, return on investment and depreciation. Mr. Mugrace was also responsible for reviewing and verifying that the companies' property, plant and equipment (up to $2.5 billion) were used and useful in providing service to its customers. Mr. Mugrace coordinated and met with the New Jersey State Department of Environmental Protection to determine whether water and wastewater utilities were complying with state regulations and were adhering to any regulatory agency directives or orders. Mr. Mugrace developed ways to minimize the rising costs of water utility services by investigating alternative rate structures, analyzing engineering mechanisms and techniques, looking into the feasibility of mergers and acquisitions within the water industry and reviewing financing, and rate alternatives to minimize the impact on ratepayers. Mr. Mugrace was responsible for ensuring that the rate-case process adhered the statutory timeframe for preparing, reviewing and recommending findings to the Board Commissioners on financial operations, costs, revenues and operating expenses, prior to the litigation proceedings. Mr. Mugrace also examined alternative rate recovery mechanisms and clauses, phase-ins of revenue requirements, deferral mechanisms and pass-through of rate charges. Mr. Mugrace assumed the role of Director during transition periods and Administrative changes. Finally, Mr. Mugrace conducted the recruitment and hiring of employees for placement within the Division and the Board.

Professional and Business Affiliations

- Institute of Public Utilities (IPU) Michigan State University (MSU), National Association of Regulatory Utility Commissioners (NARUC), National Association of State Utility Consumer Advocates (NASUCA)

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Regulatory Projects and Appearances

1. In Re: Middlesex Water Company – Petition for Approval of an Increase in Rates for Water Service and Other Tariff Changes.
   (Appearances – New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
   New Jersey Board of Public Utilities – BPU Docket No. WR21050813

2. In Re: New Jersey Natural Gas Company – Petition for an Increase in Gas Base Rates and Changes in its Tariff for Gas Service and for a Change to Depreciation Rates for Gas Property and for Approval of a Base Rate Adjustment Pursuant to the NJ RISE and SAFE II Programs.
   (Appearances: New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
   New Jersey Board of Public Utilities – BPU Docket Nos. GR21030679 and GR21030680.

3. In Re: PECO Energy Company – a division of Exelon Corp., for a General Base Rate Case Filing for Electric Operations
   (Appearances: Accounting and Policy on behalf of the Pennsylvania Office of the Consumer Advocate)
   Pennsylvania Public Utility Commission – Docket No. R-2021-3024601

4. In Re: The Pittsburgh Water and Sewer Authority for approval of increased rates and charges for Water, Wastewater and Stormwater services
   (Appearance: Accounting and Policy, and Regulatory Policy on behalf of the Pennsylvania Office of the Consumer Advocate)
   Pennsylvania Public Utility Commission – Docket Nos. R-2021-3024773 (Water) R-2021-3024774 (Wastewater) and R-2021-3024779 (Stormwater).

5. In Re: Northern States Power Company – 2021 Electric Base Rate Case Increase
   (Appearance: Revenue Requirement on behalf of the Advocacy Staff of the North Dakota Public Service Commission)
   North Dakota Public Service Commission – Case No. PUC-20-441

6. In Re: Public Service Electric and Gas Company – Approval of a Tax Adjustment Clause (TAC).
   (Appearance; Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
   New Jersey Board of Public Utilities – Docket Nos. ER20100685 and GR20100686.

7. In Re: Pike County Light and Power Company – Approval to increase base rates for Electric and Gas Service.
   (Appearance: Revenue Requirement in behalf of the Pennsylvania Office of Consumer Advocate)
   Pennsylvania Public Utility Commission – Docket Nos. R-2020-3022134 (Gas) and R-2020-3022135 (Electric)

8. In Re: Jersey Central Power and Light Company for Approval of JCP&L's Energy Efficiency and Conservation Plan Including Energy Efficiency and Peak Demand Reduction Programs.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. QO19010040 and EO20090620

9. In Re: Atlantic City Electric Company for Approval of an Energy Efficiency Program, Cost Recovery Mechanism, and Other Related Relief for Plan Years One Through Three.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. QO19010040 and EO20090621

10. In Re: Rockland Electric Company for Approval of Its Energy Efficiency and Peak Demand Reduction Programs.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. QO19010040 and EO20090623

11. In Re: Public Service Electric and Gas Company for Approval of Changes in its Electric Green Programs Recovery Charge and its Gas Green Programs Recovery Charge 2020 PSE&G Green Programs Cost Recovery filing
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. ER20060467 and GR20060468

12. In Re: Public Service Electric and Gas Company's 2020/2021 Annual BGSS Commodity Charge filing for its Residential Gas Customers under its Pricing Mechanism and for Changes in its Balance Charge
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR20060379

13. In Re: Public Service Electric and Gas Company's 2020 Annual Margin Adjustment Clause (MAC)
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR20060384

14. In Re: South Jersey Gas Company for Approval to Revise the Rider H Rate Associated with the Tax Cuts and Jobs Act of 2017
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR20060382

15. In Re: Berkshire Gas Company -2019 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts -Department of Public Utilities – DPU 20-GREC-02

16. In Re: Bay States Gas Company d/b/a Columbia Gas – 2019 Gas System Enhancement Program Reconciliation Filing.
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts – Department of Public Utilities – DPU 20-GREC-05

17. In Re: NSTAR Gas Company – 2019 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts – Department of Public Utilities – DPU 20-GREC-06

18. In Re: South Jersey Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service, Changes to Depreciation Rates and Other Tariff Revisions.
(Appearances: Revenue Requirement and Cash Working Capital) on behalf of the New Jersey Division of Rate Counsel.
New Jersey Board of Public Utilities – Docket No. GR20030243

19. In Re: Jersey Central Power & Light Company for Review and Approval of Increased in, and Other Adjustments to Rates and Charges for Electric Services and approval of Other Proposed Tariff Revisions (Appearance: Revenue Requirement, Cash Working Capital, Consolidated Income Taxes, LED Conversion and Reliability Roll-In) on behalf of the New Jersey Division of Rate Counsel.
New Jersey Board of Public Utilities – Docket No. ER20020146

20. In Re: The Pittsburgh Water and Sewer Authority for approval of increased rates and charges for water and wastewater service and for approval of a multi-year rate plan.
(Appearance: Accounting and Policy, Customer Service and Regulatory Policy) on behalf of the Pennsylvania Office of the Consumer Advocate)
Pennsylvania Public Utility Commission – Docket Nos. R-2020-3017951 and R-2020-3017970.

21. In Re: New Jersey-American Water Company, Inc. for approval of Increased Base Tariff Rates and Charges for Water and Wastewater Services and Other Tariff Revisions.
(Appearance: Accounting and Revenue Requirement and Cash Working Capital / Consolidated Income Taxes) on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR19121516

22. In Re: Hawaiian Electric Company, Inc., for approval of a General Rate Increase and Revised Rate Schedules and Rules.
(Appearance: Accounting and Revenue Requirement on behalf of the Hawaiian Division of Consumer Advocacy)
Hawaii Public Utilities Commission – Docket No. 2019-0085

23. In Re: Mount Olive Villages Water Company for approval of an Increase in Rates for Water Service and Other Tariff Changes.
(Appearance: Accounting and Consulting Services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR19060770

24. In Re: Mount Olive Villages Sewer Company for approval of an Increase in Rates for Sewer Service and Other Tariff Changes.
(Appearance: Accounting and Consulting Services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR19060769

25. In Re: Public Service Electric and Gas Company for approval of changes in its Electric Green Programs Recovery and its Gas Green Programs Recovery Charge (2019 PSE&G Green Programs Cost Recovery Filing).
(Appearance: Accounting and Consulting Services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. ER19070764 and GR19070765

26. In Re: Proposed Amendment to N.J.A.C. 14:9- Adoption by reference to the Uniform System of Accounts for Water Utilities and Wastewater Utilities.
(Appearance: Consulting Services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities- Docket Nos. WX19050612 (Water) and WX19050613 (Wastewater)

27. In Re: Public Service Electric and Gas Company's 2019/2020 Annual BGSS Commodity Charge filing for its Residential Gas Customers Under its Periodic Pricing Mechanism and for Changes in its Balancing Charge.
(Appearance: Revenue Requirement and accounting/consulting services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR190600699

28. In Re: Bay States Gas Company d/b/a Columbia Gas of Massachusetts for Approval of a 2018 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts Department of Public Utilities – Docket No. 19-GREC-05

29. In Re: NSTAR Gas Company d/b/a Eversource Energy for Approval of a 2018 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts Department of Public Utilities – Docket No. 19-GREC-06

30. In Re: Public Service Electric and Gas Company for Approval of Gas Rate Base Adjustments Pursuant to its Gas System Modernization Program (April 2019 GSMP) (Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities – Docket No. GR19040522

31. In Re: Kalaeloa Water Company, LLC for Approval of General Rate Case and Revised Rules, Regulations and Rates.
    (Appearance: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
    Hawaii Public Utilities Commission – Docket No. 2019-0057

32. In Re: Elizabethtown Gas Company for Approval of an Increase in Rates and Charges for Gas Service, Changes to Depreciation Rates and Other Tariff Revisions.
    (Appearance: Revenue Requirement and Other Accounting Issues on behalf of the New Jersey Division of Rate Counsel).
    New Jersey Board of Public Utilities – Docket No. GR19040586

33. In Re: Petition of Peoples Natural Gas Company for Approval of an Increase in Rates for Natural Gas Distribution Service.
    (Appearance: Revenue Requirement and Other Accounting Issues on behalf of the Pennsylvania Office of Consumer Advocate)
    Pennsylvania Public Utility Commission – Docket No. R-2018-3006818

34. In Re: Petition of Aqua New Jersey, Inc. for Approval of an Increase in Rates for Water Service and other Tariff Changes.
    (Appearance: Revenue Requirement and other Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities – BPU Docket No. WR18121351

35. In Re: Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future – Energy Efficiency (CEF-EE) Program on a Regulated Basis.
    (Appearance: Revenue Requirement and other Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities – BPU Docket Nos. GO18101112 and EO18101113.

36. In Re: Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future – Energy Vehicle and Energy Storage (CEF-EVES) Program on a Regulated Basis. (Appearance – Revenue Requirement and other Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities – BPU Docket No. EO18101111.

37. In Re: Petition of New Jersey Natural Gas Company- Request for Deferred Accounting Authority for Costs Related to New Information Technology Systems . (Appearance: Impact on Revenues, prudency of costs on behalf of the New Jersey Division of Rate Counsel)

New Jersey Board of Public Utilities – BPU Docket No. GR18101096

38. In Re: Petition for Approval of An Indirect Change in Control of the New Jersey Public Utilities Subsidiaries of SUEZ Water Resources, Inc. and Other Related Approvals. (Appearance: Impact on Rates, Service, Employees, Positive Benefits on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities – BPU Docket No. WM18090982

39. In Re: The Matter of the Merger of Roxbury Water Company into New Jersey American Water Company (Appearance: Impact on Rates, Service and Employees, Positive Benefits on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities – BPU Docket No. WM18080904

40. In Re: The Matter of the Application of Maryland-American Water Company for Authorization to Adjust its Existing Schedule of Tariffs and Rates.
    (Appearance: Revenue Requirement on behalf of the Maryland Office of People's Counsel)
    Maryland Public Service Commission – Case No. 9487

41. In Re: The Matter of the Joint Petition for Approval of an Increase in Rates for Water and Wastewater Service and Other Tariff Changes for SUEZ Water NJ, Inc., Toms River, Inc., Arlington Hill, Inc., West Milford, Inc., Matchaponix, Inc., and Princeton Meadows, Inc. (Appearance: Revenue Requirement and the development of Consolidated Income Taxes on behalf of the NJ Division of Rate Counsel)
    New Jersey Board of Public Utilities – BPU Docket No. WR18050593

42. In Re: The Matter of the Application of Atlantic City Electric Company to Adjust the Level of its Rider RGGI Rate Associated with its Solar Renewable Energy Certificate Financing Program 2018 (Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
    New Jersey Board of Public Utilities – BPU Docket No. ER18050543

43. In Re: The Matter of the Petition of New Jersey Natural Gas Company's Approval of the Cost Recovery Associated with Energy Efficiency Programs (Appearance; Revenue Requirement on behalf of the NJ Division of Rate Counsel)
    New Jersey Board of Public Utilities – BPU Docket No, GR18050585

44. In Re: The Matter of Bay States Gas Company d/b/a Columbia Gas of Massachusetts, 2017 Gas System Enhancement Reconciliation Filing (Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General's Office of Ratepayer Advocacy)
    Commonwealth of Massachusetts – Department of Public Utilities – Docket No. D.P.U. 18-GREC-05.

45. In Re; The Matter of NSTAR Gas Company d/b/a Eversource Energy, Gas System Enhancement Program Reconciliation Filing (Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General's Office of Ratepayer Advocacy)

Commonwealth of Massachusetts – Department of Public Utilities – Docket No. D.P.U. 18-GREC-06.

46. In Re: The Matter of the Merger of SUEZ Water NJ, SUEZ Water Toms River, SUEZ Water Arlington Hills, SUEZ Water West Milford, SUEZ Water Princeton Meadows and SUEZ Water Matchaponix (Appearance: Positive Benefits related to the Merger on behalf of the NJ Division of Rate Counsel)
    New Jersey Board of Public Utilities – BPU Docket No. WR18030266

47. In Re: The Matter of the Columbia Gas of Pennsylvania for a General Rate Increase in Distribution Gas Service (Appearance; Accounting Issues and Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
    Pennsylvania Public Utility Commission – Docket No. R-2018-2647577

48. In Re: The Matter of the New Jersey Board of Public Utilities Consideration of the Tax Cuts and Jobs Act of 2017 – Generic Proceeding (Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
    New Jersey Board of Public Utilities – BPU Docket No. AX18010001

49. In Re: Acquisition of Elizabethtown Gas, a Division of Pivotal Utilities Holdings, Inc. by ETG Acquisition Corp., a Division of South Jersey Industries, Inc., and Related Transactions. (Appearance: Customer Service Issues/Employee and Labor Relations on behalf of the NJ Division of Rate Counsel)
    New Jersey Board of Public Utilities – BPU Docket No. GM17121309.

50. In Re: Middlesex Water Company – Base Rate Case Proceeding for Water Service. (Appearance: revenue requirement on behalf of the NJ Division of Rate Counsel).
    New Jersey Board of Public Utilities – BPU Docket No. WR17101049.

51. In Re: Township of East Brunswick – Sewer Rate Study – (Evaluation of the existing sewer rate structure and examining and quantify costs for future expansion).

52. In Re: Montana-Dakota Utilities – Base Rate Case Proceeding for Gas Service. (Appearance: revenue requirement on behalf of the North Dakota Public Service Commission). NDPSC Docket No. PU-17-295.

53. In Re: Andover Utility Company – Base Rate Case Proceeding for Wastewater Services. (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel).
    New Jersey Board of Public Utilities – BPU Docket No. WR17070726.

54. In Re: Public Service Electric and Gas Company- Approval of Changes in its Electric and Gas Green Programs Recovery Charges "2017 Public Service Electric & Gas Green Programs Cost Recovery Filing. (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel).
    New Jersey Board of Public Utilities – BPU Docket Nos. ER17070724 and GR17070725.

55. In Re: Bay States Gas Company d/b/a Columbia Gas of Massachusetts, 2016 Gas System Enhancement Program Reconciliation Filing, (Appearance: revenue requirement on behalf of the Massachusetts Attorney General's Office of Ratepayer Advocacy).
    Commonwealth of Massachusetts Department of Public Utilities – Docket No. D.P.U. 17-GREC-05.

56. In Re; NSTAR Gas Company d/b/a Eversource Energy, 2016 Gas System Enhancement Program Reconciliation Filing (Appearance: revenue requirement on behalf of the Massachusetts Attorney General's Office of Ratepayer Advocacy.
    Commonwealth of Massachusetts Department of Public Utilities – Docket No. D.P.U. 17-GREC-06.

57. In Re: Petition of Columbia Gas of Maryland – Increase in rates for Distribution Service – (Appearance: revenue requirement on behalf of the Office of People's Counsel) Public Service Commission of Maryland – Case No. 9447

58. In Re: Petition of South Jersey Gas Company – Increase in base rates for gas services – (Appearance: revenue requirement on behalf of the NJ Division of Rate Counsel)
    New Jersey Board of Public Utilities – Docket No. GR17010071

59. In Re: Petition of UGI Penn Natural Gas – Increase in base rates for gas services – (Appearance: revenue requirement on behalf of the Pennsylvania Office of Consumer Advocate)
    Pennsylvania Public Utilities Commission Docket No. R-2016-2580030

60. In Re: Petition of PJM Interconnection, LLC. – Mid-Atlantic Interstate Transmission, LLC. Formula Rate Filing. (Appearance on behalf of the Pennsylvania Office of Consumer Advocate).
    FERC Docket No. ER17-211-000

61. In Re: Petition of Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company for approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff Revisions (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. GR16090826

62. In Re: Petition of SUEZ Water New Jersey, et al – Approval of a Management and Services Agreement pursuant to N.J.S.A 48: 3-7.1 (Appearance on the reasonableness of contract agreements on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. WO16080806

63. In Re: Petition of SUEZ Water Arlington Hills Inc. – Approval of an Increase in Rates for Wastewater Services and other Tariff Changes (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. WR16050510

64. In Re: Petition of Public Service Electric and Gas Company – 2016 Marginal Adjustment Clause (MAC) (Appearance; reconciliation and rate setting on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. GR16060484

65. In Re: Petition of Public Service Electric and Gas Company for Approval of Changes in its Electric Green Programs Recovery Charges and its Gas Green Program Recovery Charges 2016 PSEG Program Cost Recovery Filing (Appearance: reconciliation and rate setting on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket Nos. ER16070613 and GR16070614

66. In Re: Petition of the Mount Olive Village Sewer Company, Inc., for Approval of an Increase in Rates for Service (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. WR16050391

67. In Re: Petition of the Mount Olive Village Water Company, Inc. for Approval of an Increase in Rates for Service (Appearance; revenue requirement on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. WR16050390

68. In Re: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Analysis and Advice to Counsel: computation of the revenue requirement and rate impact on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 16-GREC-01

69. In Re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Appearance: computation of the revenue requirement and rate impact on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 16-GREC-05

70. In Re: Petition for Approval of Gas Infrastructure Contract Between Public Service Company of New Hampshire d/b/a Eversource Energy and Algonquin Gas Transmission, LLC (2016) - (Analysis and Advice to Counsel: compliance with statutes and regulations, review of contract, and ratemaking on behalf of the New Hampshire Office of Consumer Advocate)
    NH Public Utilities Commission Docket No. DE 16-241

71. In Re: Central Maine Power Company, Annual Compliance Filing and Price Change (2016) - (Analysis and Advice to Counsel; tax normalization regulatory asset on behalf of the Maine Office of the Public Advocate)
    ME Public Service Commission Docket No. 2016-00035

72. In Re: Bulletin 2015-10 Generic Proceeding to Establish Parameters for the Next Generation PBR Plans (Appearance: productivity adjustments/performance-based ratemaking on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Proceeding 20414

73. In Re: the Matter of Request by Emera Maine for Approval of a Rate Change (2016) - (Appearance: revenue requirement on behalf of the Maine Office of the Public Advocate)
    Maine Public Utilities Commission Docket No. 15-00360)

74. In Re: the Matter of the Joint Application of the Southern Company, AGL Resources Inc., and Pivotal Holdings, Inc. d/b/a Elkton Gas (2015-2016) - (Analysis and advice to counsel: customer service impacts, employee impacts, supplier diversity on behalf of the Maryland Office of People's Counsel)
    MD PSC Case No. 9404

75. In Re: the Matter of the Merger of Southern Company and AGL Inc. (2015-2016) - (Appearance: customer service impacts and employee impacts on behalf of the NJ Division of Rate Counsel)
    New Jersey BPU Docket No. GM15101196

76. In Re: the Matter of the United Water New Jersey, Inc., for Approval of an Increase in Rates for Water Service and Other Tariff Changes (2015-2016) - (Appearance: revenue requirements, rate base issues and operating income on behalf of the NJ Division of Rate Counsel)
    New Jersey BPU Docket No. WR15101177

77. In Re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Precedent Agreements with Millennium Pipeline Company, LLC (2015) - (Analysis: review of contract and compliance of the Gas Supply Plan on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA D.P.U. 15-130

78. In Re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Agreements for LNG or Liquefaction Services with GDF Suez Gas NA, LLC; Northeast Energy Center, LLC; Metro LNG, L.P.; and National Grid LNG (2015) - (Analysis: review of contract and compliance of the Gas Supply Plan on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA D.P.U. 15-129

79. In Re: Columbia Gas of Massachusetts CY2014 Targeted Infrastructure Reinvestment Factor (TIRF) Compliance Filing (2015) - (Appearance: computation of the revenue requirement impact on the TIRF on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA D.P.U. 15-55

80. In Re: the Matter of the Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its Targeted Infrastructure Reinvestment Factor (TIRF) for CY 2013 (2014) - (Appearance: computation of the revenue requirement impact on the TIRF)
    MA D.P.U. 14-83

81. In Re: the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc. (Atlantic City Electric Company) (2014-2015) - (Appearance: customer service impacts)
    New Jersey BPU Docket No. EM14060581

82. In Re; of the Public Utilities Commission of Ohio, in the Matter of the Application of Aqua Ohio, Inc. to Increase its Rates and Charges for its Waterworks Service. – Revenue and Rates (2014) - (Appearance: operating income, certain rate base issues and income taxes on behalf of the Ohio Office of Consumer Counsel)
    PUCO Case No. 13-2124-WW-AIR

83. In Re: New York Public Service Commission, as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. Revenue Requirement (2013-2014) – (Appearance: revenue requirement, rate base issues and operating income on behalf of the Intervenor, the County of Westchester)
    NYPSC Case Nos. 13-E-0030, 13-G-0031 and 13-S-0032, et al

84. In Re: North Dakota Public Service Commission, - Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota, On-Going Revenue Requirement (2013) - (Appearance: revenue requirement and rate base, operating income, operating and maintenance expenses on behalf of the North Dakota Public Service Commission Staff)
    North Dakota Case No. PU-12-813

85. In the Matter of the Petition of New Jersey American Water Company for Authorization to Implement a Distribution System Improvement Charge (DSIC) Order Denying Petition and Instituting Stakeholder Process (2008) - (Case manager on policy decision and revenue requirement impact on behalf of the Staff of the NJ Board of Public Utilities)
    BPU Docket No. WO08050358

86. In the Matter of the Joint Petition of the City of Trenton, New Jersey and New Jersey-American Water Company, Inc. for Authorization of the Purchase and Sale of the Assets of the Outside Water Utility System ("OWUS") of the City of Trenton, New Jersey and for Other Relief Order Adopting Initial Decision, (2008) - (Case manager on the revenue requirement impact on behalf of the Staff of the NJ Board of Public Utilities)
    BPU Docket No. WM08010063

87. In the Matter of the Petition of United Water New Jersey, United Water Toms River, United Water Lambertville, United Water Mid-Atlantic and Gaz de France for Approval as Need for a Change in Ownership and Control (2007) - (Case manager on customer impact, employee impact and impact on rates on behalf of the Staff of the NJ Board of Public Utilities)

BPU Docket No. WM06110767

88. In the Matter of the Petition of United Water Arlington Hills Sewerage, Inc. for an Increase in Rates for Waste Water Service and Other Tariff Changes (2009) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
    BPU Docket No. WR08100929

89. In the Matter of the Petition of United Water New Jersey Inc. for Approval of an Increase in Rates for Water Service and Other Tariff Changes, (2009) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
    BPU Docket No. WR08090710

90. In the Matter of the Petition of United Water Toms River, Inc. for Approval of an Increase in Rates for Water Service and Other Tariff Changes (2008) - (Case manager on the revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
    BPU Docket No. WR08030139

91. In the Matter of the Joint Petitioners of New Jersey-American Water Company, Inc., S.J. Services, Inc., South Jersey Water Company, Inc. and Pennsgrove Water Supply Company, Inc. for Among Other Things Approval of a Change in Control of South Jersey Water Supply Company, Inc. and Pennsgrove Water Supply Company, Inc. (2007) - (Case manager on the overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
    BPU Docket No. WM07020076

92. In the Matter of the Petition of Aqua, New Jersey, Inc. for Approval of an Increase in Rates for Water Service and Other Tariff Changes (2008) - (Case manager on revenue requirement and the overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
    BPU Docket No. WR0712095

93. I/M/O the Joint Petition of Thames Water, Aqua Holdings GMBH, on Behalf of Itself and Its Parent Holdings Company, RWE Aktiengesellschaft, Thames Water Aqua US Holdings, Inc., American Water works Company Inc., Thames Water Holdings Incorporated, E'town Corporation, New Jersey-American Water Company, Inc., Elizabethtown Water Company, the Mount Holly Water Company and Applied Wastewater Management, Inc. for Confirmation that the Board of Public Utilities Does Not Have Jurisdiction Over, or, Alternatively, for Approval of a Proposed Transaction Involving, Among Other Things, the Sale by Thames Water Aqua Holdings GMBH of Up to 100% of the Shares of the Common Stock of American Waterworks Company, Inc. in One or More Public Offerings (2007) - (Case manager on revenue requirement impacts, effect on rates and effect on service on behalf of the Staff of the NJ Board of Public Utilities)
    BPU Docket No. WM06050388

94. In the Matter of the Petition of Elizabethtown Water Company for Approval of an Increase in Rates for Water Service (2007) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
    BPU Docket No. WR03070510

95. In the Matter of the Petition of New Jersey American Water Company, Inc. for Approval of Increased Tariff Rates and Charges for Water and Sewer Service; Increased Depreciation Rates and Other Tariff Revisions (2008) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
    BPU Docket No. WR08010020

96. In the Matter of Middlesex Water Company for Approval of an Increase in its Rates for Water Service and Other Tariff Changes (2007) - (Case manager on overall revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
    BPU Docket No. WR07040275

97. In the Matter of the Joint Petition of United Water New Jersey, Inc., United Water Arlington Hills, Inc., United Water Hampton, Inc., United Water Vernon Water Hills, Inc., and United Water Lambertville, Inc. for an Increase in Rates and Charges for Water Service and Other Tariff Changes and for Approval to Merge the Operations of the Joint Petitioners into and with United Water New Jersey, Inc. (2007) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
    BPU Docket No. WR07020135

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024601
	:	
PECO Energy Company – Electric Division	:	

VERIFICATION

I, Dante Mugrace, hereby state that the facts set forth in my Direct Testimony, OCA Statement 1, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: June 28, 2021
*311948

Signature: Dante Mugrace
Dante Mugrace

Consultant Address: PCMG and Associates
90 Moonlight Court
Toms River, NJ 08753

OCA Statement 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission v. PECO Energy Company – Electric Division	Docket No. R-2021-3024601

DIRECT TESTIMONY

OF

DAVID J. GARRETT

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

June 28, 2021

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APPENDICES

LIST OF EXHIBITS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David J. Garrett. My business address is 101 Park Avenue, Suite 1125, Oklahoma Company, Oklahoma 73102.

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

A. I am the managing member of Resolve Utility Consulting, LLC. I am an independent consultant specializing in public utility regulation.

Q. Please summarize your educational background and professional experience.

A. I received a B.B.A. degree with a major in Finance, an M.B.A. degree, and a J.D. degree from the University of Oklahoma. I worked in private legal practice for several years before working as assistant general counsel at the Oklahoma Corporation Commission in 2011. At the Oklahoma Corporation Commission, I worked in the Office of General Counsel in regulatory proceedings. In 2012, I worked for the Public Utility Division as a regulatory analyst providing testimony in regulatory proceedings. After leaving the Oklahoma Corporation Commission I formed Resolve Utility Consulting PLLC, where I have represented numerous consumer groups and state agencies in utility regulatory proceedings, primarily in the areas of cost of capital and depreciation. I am a Certified Depreciation Professional with the Society of Depreciation Professionals. I am also a Certified Rate of Return Analyst with the Society of Utility and Regulatory Financial

Analysts. A more complete description of my qualifications and regulatory experience is included in my curriculum vitae.[1]

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

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. Describe the purpose and scope of your testimony in this proceeding.

A. The primary purpose of my testimony is to provide my opinion on the estimated cost of capital and awarded rate of return recommendation for PECO Energy Company – Electric Division ("PECO" or the "Company"). I am responding to the direct testimony of Company witness Paul R. Moul.

Q. Please describe the organization of your testimony.

A. In the executive summary below, I provide an overview of cost of capital issues, my recommendations, and my response to the Company's testimony on these issues. In the sections that follow, I discuss the legal standards governing the awarded return issue, as well as the general concepts involved in estimating the cost of equity. I provide detailed analysis of the Discounted Cash Flow ("DCF") Model, the Capital Asset Pricing Model ("CAPM"), including my results for these models and my responses to Mr. Moul's results. I also address capital structure, which is a key component to the cost of capital.

II. EXECUTIVE SUMMARY

Q. Please summarize your recommendation to the Commission.

A. My testimony can be distilled to the following recommendations:

[1] Exhibit DJG-1.

- The Commission should reject the Company's proposed return on equity ("ROE") of 10.95% as excessive and unsupported. An objective cost of equity analysis shows that PECO's cost of equity is about 7.4%.

- The legal standards governing this issue do not mandate that the awarded ROE equate to the result of a particular financial model, but rather that it be reasonable under the circumstances. We must evaluate this case under the unique circumstances imposed by an unprecedented pandemic, which has had a significant negative impact on the economy of the Commonwealth and the Company's customers. In my opinion, it is never appropriate to use an awarded ROE significantly above a regulated utility's cost of equity; however, that concept is even more important under the unique circumstances. Accordingly, I recommend the Commission award PECO an authorized ROE of 8.5%. Although 8.5% is still clearly above PECO's market-based cost of equity estimate, it represents a gradual yet meaningful move towards market-based cost of equity.

- I recommend the Commission reject PECO's proposed capital structure consisting of 46.59% debt and 53.41% equity. This equity-rich capital structure has the effect of increasing capital costs above a reasonable level. An objective mathematical analysis of PECO's optimal capital structure indicates a debt ratio as high as 55%. Likewise, the average debt ratio of the proxy group is 54%. Thus, PECO's proposed debt ratio is far too low to be considered reasonable. I recommend an imputed capital structure consisting of 50% debt and 50% equity. My adjustments to the Company's proposed ROE and capital structure equate to an overall weighted average rate of return of 6.22%.

My proposed adjustments are illustrated in the table below.[2]

[2] *See also* Exhibit DJG-18.

Figure 1:
OCA Weighted Average Rate of Return Proposal

Capital Component	Proposed Ratio	Cost Rate	Weighted Cost
Long Term Debt	50.0%	3.93%	1.97%
Common Equity	50.0%	8.50%	4.25%
Total	100.0%		6.22%

The details supporting my proposed adjustments are discussed further in my testimony.

Q. Are you recommending any adjustments to PECO's proposed cost of debt?

A. No.

A. <u>Overview and Background</u>

Q. Please explain the concept and significance of the Cost of Capital.

A. The term cost of capital, or Weighted Average Cost of Capital (WACC),[3] refers to the weighted average cost of the components within a company's capital structure, including the costs of both debt and equity. The three primary components of a company's WACC include the following:

1. Cost of Debt
2. Cost of Equity
3. Capital Structure

Determining the cost of debt is relatively straight-forward. Interest payments on bonds are contractual, embedded costs that are generally calculated by dividing total interest

[3] The terms cost of capital and WACC are synonymous and used interchangeably throughout this testimony.

payments by the book value of outstanding debt. Determining the cost of equity, on the other hand, is more complex. Unlike the known, contractual, and embedded cost of debt, there is not any explicitly quantifiable "cost" of equity. Instead, the cost of equity must be estimated through various financial models. Cost of capital is expressed as a weighted average because it is based upon a company's relative levels of debt and equity, as defined by the particular capital structure of that company. The basic WACC equation used in regulatory proceedings is presented as follows:

Equation 1:
Weighted Average Cost of Capital

$$WACC = \left(\frac{D}{D+E}\right)C_D + \left(\frac{E}{D+E}\right)C_E$$

where:	*WACC*	=	*weighted average cost of capital*
	D	=	*book value of debt*
	C_D	=	*embedded cost of debt capital*
	E	=	*book value of equity*
	C_E	=	*market-based cost of equity capital*

Companies in the competitive market often use their WACC as the discount rate to determine the value of capital projects, so it is important that this figure be estimated accurately.

Q. How do experts and regulators typically assess the ROEs awarded to utilities and the corresponding opportunity for shareholders?

A. Investors, company managers, and academics around the world have used models, such as the CAPM and DCF to closely estimate cost of equity for many years, and weigh the results achieved against the results from proxy groups. Each of these concepts will be discussed in more detail later in my testimony.

B. <u>Recommendation</u>

Q. Please summarize your ROE recommendation to the Pennsylvania Public Utility Commission (Commission).

A. Pursuant to the legal and technical standards guiding this issue, the awarded ROE should be based on, or reflective of, the utility's cost of equity. PECO's estimated cost of equity is about 7.4%, when using reasonable inputs. However, legal standards do not mandate the awarded ROE be set exactly equal to the cost of equity. Rather, in *Federal Power Commission v. Hope Natural Gas Co*., the U.S. Supreme Court found that, although the awarded return should be based on a utility's cost of capital, the "end result" should be just and reasonable.[4] Therefore, I recommend the Commission award PECO an ROE of 8.5%. In my opinion, an awarded ROE that is set too far above a regulated utility's cost of equity (which in this case is only about 7.4%) it runs the risk of being at odds with the standards set forth in *Hope* and *Bluefield*. This axiom is heightened under the unique circumstances created by an unprecedented pandemic. In other words, setting the awarded ROE far above the cost of equity results in an excess transfer of wealth from customers to the utility, which is never appropriate. However, it is even more inappropriate given the additional economic hardships the pandemic has imposed on customers.[5]

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[4] *See Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944). Here, the Court states that it is not mandating the various permissible ways in which the rate of return may be determined, but instead indicates that the end result should be just and reasonable. This is sometimes called the "end result" doctrine.

[5] See the direct testimony of OCA witness Noah Eastman for further discussion about the effects of the COVID-19 pandemic on the Company's application in this case.

Q. If 8.5% exceeds PECO's actual cost of equity and still, in your opinion, results in an excessive wealth transfer from shareholders to ratepayers, how can it still be considered a just and reasonable result?

A. The ratemaking concept of "gradualism," though usually applied from ratepayers' standpoint to minimize rate shock, could also be applied illustratively to shareholders. An awarded return as low as 7.4% in any current rate proceeding would represent a stark and substantial movement. While generally reducing awarded ROEs for utilities would move awarded returns closer to market-based costs and so reduce the excess transfer of wealth from ratepayers to shareholders, I believe it is advisable to do so gradually. One of the primary reasons PECO's actual cost of equity is so low is because PECO is a low-risk investment. In general, utility stocks are low-risk investments because movements in their stock prices are not volatile. If the Commission were to make a significant, sudden change in the awarded ROE anticipated by regulatory stakeholders, it could have the undesirable effect of notably increasing the Company's risk profile, which could be in contravention to the *Hope* Court's "end result" doctrine. An awarded ROE of 8.5% represents a good balance between the Supreme Court's indications that awarded ROEs should be based on cost, while also recognizing that the end result must be just and reasonable under the circumstances. An awarded ROE of 8.5% represents a relatively gradual, yet decisive move toward PECO's market-based cost of equity, while still providing PECO's shareholders with the opportunity to earn a return that is more than 100 basis points above PECO's market-based cost of equity (8.5% vs. 7.4%).

Q. Please summarize your recommendation regarding capital structure.

A. The Company proposes an equity-rich capital structure consisting of 53.41% common equity and only 46.59% debt.[6] Unlike competitive companies, which have a natural financial incentive to issue sufficient amounts of debt to maximize profits, regulated utilities do not have the same incentive to issue sufficient amounts of debt. However, even Mr. Moul's own utility proxy group reported a debt ratio of 54%, which is substantially higher than the debt ratio proposed by PECO.[7] In addition, an objective, mathematical analysis of PECO's optimal capital structure (i.e., one that might exist in a competitive environment), indicates a debt ratio as high as 55%.[8] Although there is strong evidence to support an imputed debt ratio of 54% or 55% for PECO, I recommend the Commission impute a debt ratio of 50% in the interest of a more gradual approach.

C. Response to the Company's Testimony

Q. Please provide an overview of the problems you have identified with the Company's testimony regarding cost of equity, capital structure, and the resulting awarded ROE.

A. Mr. Moul proposes a return on equity of 10.95%.[9] Mr. Moul's recommendation is based on the CAPM, DCF Model, and other risk premium models. A summary of Mr. Moul's positions are shown in the figure below.[10]

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[6] Direct Testimony of Paul R. Moul, p. 19, lines 21-22.

[7] Exhibit DJG-16.

[8] Exhibit DJG-15.

[9] Direct Testimony of Paul R. Moul, p. 6, lines 3-4.

[10] *See also* Direct Testimony of Paul R. Moul, Exhibit PRM-1, Sch. 1, p. 1.

Figure 2:
PECO Weighted Average Rate of Return Proposal

Capital Component	Proposed Ratio	Cost Rate	Weighted Cost
Long Term Debt	46.6%	3.93%	1.83%
Common Equity	53.4%	10.95%	5.85%
Total	100.0%		7.68%

However, several of his key assumptions and inputs to these models violate fundamental, widely accepted tenets in finance and valuation. I find several aspects of Mr. Moul's approach and resulting recommendations to be problematic, including the growth rates used in his DCF models and his inflated estimate for the equity risk premium ("ERP") used in his CAPM analysis. In addition, Mr. Moul's own risk premium model overestimates the market risk premium. Finally, Mr. Moul inappropriately adds premium to his cost of equity estimate for management performance, which further inflates a figure that is already overestimated.

Regarding capital structure, Mr. Moul adopts the Company's FPFTY capital structure ratios of 46.59% long-term debt and 53.41% common equity.[11] As discussed in my testimony, the Company does not have a financial incentive to operate with sufficient amounts of debt in its capital structure, and the evidence shows that PECO's proposed debt ratio is too low.

[11] Direct Testimony of Paul R. Moul, p. 19, lines 21-22.

III. LEGAL STANDARDS AND THE AWARDED RETURN

Q. Discuss the legal standards governing the awarded rate of return on capital investments for regulated utilities.

A. In *Wilcox v. Consolidated Gas Co. of New York*, the U.S. Supreme Court first addressed the meaning of a fair rate of return for public utilities.[12] The Court found that "the amount of risk in the business is a most important factor" in determining the appropriate allowed rate of return.[13] As referenced earlier, in two subsequent landmark cases, the Court set forth the standards by which public utilities are allowed to earn a return on capital investments. First, in *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, the Court held:

> 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. . . but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. 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.[14]

Then, in *Federal Power Commission v. Hope Natural Gas Company*, the Court expanded on the guidelines set forth in *Bluefield* and stated:

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[12] *Wilcox v. Consolidated Gas Co. of New York*, 212 U.S. 19 (1909).

[13] *Id.* at 48.

[14] *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692–93 (1923).

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses <u>but also for the capital costs of the business.</u> These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[15]

The cost of capital models I have employed in this case are designed to be in accordance with the foregoing legal standards.

Q. Is it important that the awarded rate of return be based on the Company's actual cost of capital?

A. Yes. The U.S. Supreme Court in *Hope* makes it clear that the allowed return should be based on the actual cost of capital. Moreover, the awarded return must also be fair, just, and reasonable under the circumstances of each case. Among the circumstances that must be considered in each case are the broad economic and financial impacts to the cost of equity and awarded return caused by market forces and other factors. In this case, the COVID-19 pandemic has created a substantial economic hardship to customers, as further discussed in the direct testimony of OCA witness Noah Eastman. As a starting point, however, scholars agree that the actual cost of capital must be considered:

[15] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) (emphasis added) (internal citations omitted).

> Since by definition the cost of capital of a regulated firm represents precisely the expected return that investors could anticipate from other investments while bearing no more or less risk, and since investors will not provide capital unless the investment is expected to yield its opportunity cost of capital, the correspondence of the definition of the cost of capital with the court's definition of legally required earnings appears clear.[16]

The models I have employed in this case closely estimate the Company's true cost of equity. If the Commission sets the awarded return based on my lower and more reasonable rate of return, it will better comply with the U.S. Supreme Court's standards, allow the Company to maintain its financial integrity, and achieve reasonable returns for its investors. On the other hand, if the Commission sets the allowed rate of return much higher than the true cost of capital, as requested by PECO, it will result in an inappropriate transfer of wealth from ratepayers to shareholders.[17]

Q. What does this legal standard mean for determining the awarded return and the cost of capital?

A. The awarded return and the cost of capital are different but related concepts. On the one hand, the legal and technical standards encompassing this issue require that the awarded return reflect the true cost of capital. Yet on the other hand, the two concepts differ in that the legal standards do not mandate that awarded returns exactly match the cost of capital. Instead, awarded returns are set through the regulatory process and may be influenced by various factors other than objective market drivers. By contrast, the cost of capital should be evaluated objectively and be closely tied to economic realities, such as stock prices,

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[16] A Lawrence Kolbe, James A. Read, Jr. & George R. Hall, *The Cost of Capital: Estimating the Rate of Return for Public Utilities* 21 (The MIT Press 1984).

[17] Roger A. Morin, *New Regulatory Finance* 23–24 (Public Utilities Reports, Inc. 2006) (1994) ("[I]f the allowed rate of return is greater than the cost of capital, capital investments are undertaken and investors' opportunity costs are more than achieved. Any excess earnings over and above those required to service debt capital accrue to the equity holders, and the stock price increases. In this case, the wealth transfer occurs from ratepayers to shareholders.").

dividends, growth rates, and, most importantly, risk. The cost of capital can be estimated by financial models used by firms, investors, and academics around the world for decades. The problem is, with respect to regulated utilities, there has been a trend in which awarded returns fail to closely track with market-based cost of capital, as further discussed below. To the extent this occurs, the results are detrimental to ratepayers and the state's economy.

Q. Describe the economic impact that occurs when the awarded return strays too far from the U.S. Supreme Court's time-honored cost of equity standards.

A. When the awarded ROE is set far above the cost of equity, it runs the risk of violating the U.S. Supreme Court's standards. This has the effect of diverting dollars from ratepayers for their internal or business uses that would otherwise support the local or state economy to the utility's shareholders at large. Moreover, establishing an awarded return that far exceeds true cost of capital effectively prevents the awarded returns from changing along with economic conditions. This is especially true given the fact that regulators tend to be influenced by the awarded returns in other jurisdictions, regardless of the various unknown factors influencing those awarded returns. If regulators rely too heavily on the awarded returns from other jurisdictions, they can create a cycle over time that bears little relation to the market-based cost of equity. In fact, this is exactly what we have observed since 1990. This is yet another reason why it is crucial for regulators to put more emphasis on the target utility's actual cost of equity than on the awarded returns from other jurisdictions. Awarded returns may be influenced by settlements and other political factors not based on true market conditions. In contrast, the true cost of equity as estimated through objective models is not influenced by these factors but is instead driven by market-based factors.

Q. Can you illustrate and provide a comparison of the relationship between awarded utility returns and market cost of equity since 1990?

A. Yes. As shown in the figure below, awarded returns for electric and gas utilities have been above the average required market return since 1990.[18] Because utility stocks are consistently far less risky than the average stock in the marketplace, the cost of equity for utility companies is less than the market cost of equity.

To illustrate this fact, the graph in the figure below shows three trend lines. The top two line are the average annual awarded returns since 1990 for U.S. regulated electric and gas utilities. The bottom line is the required market return over the same period. As discussed in more detail later in my testimony, the required market return is essentially the return that investors would require if they invested in the entire market and, as such, the required market return is essentially the cost of equity of the entire market. Since it is undisputed that utility stocks are less risky than the average stock in the market, then the utilities' cost of equity must be less than the market cost of equity.[19] Thus, awarded returns (the solid line) should generally be below the market cost of equity (the dotted line), since awarded returns are supposed to be based on true cost of equity.

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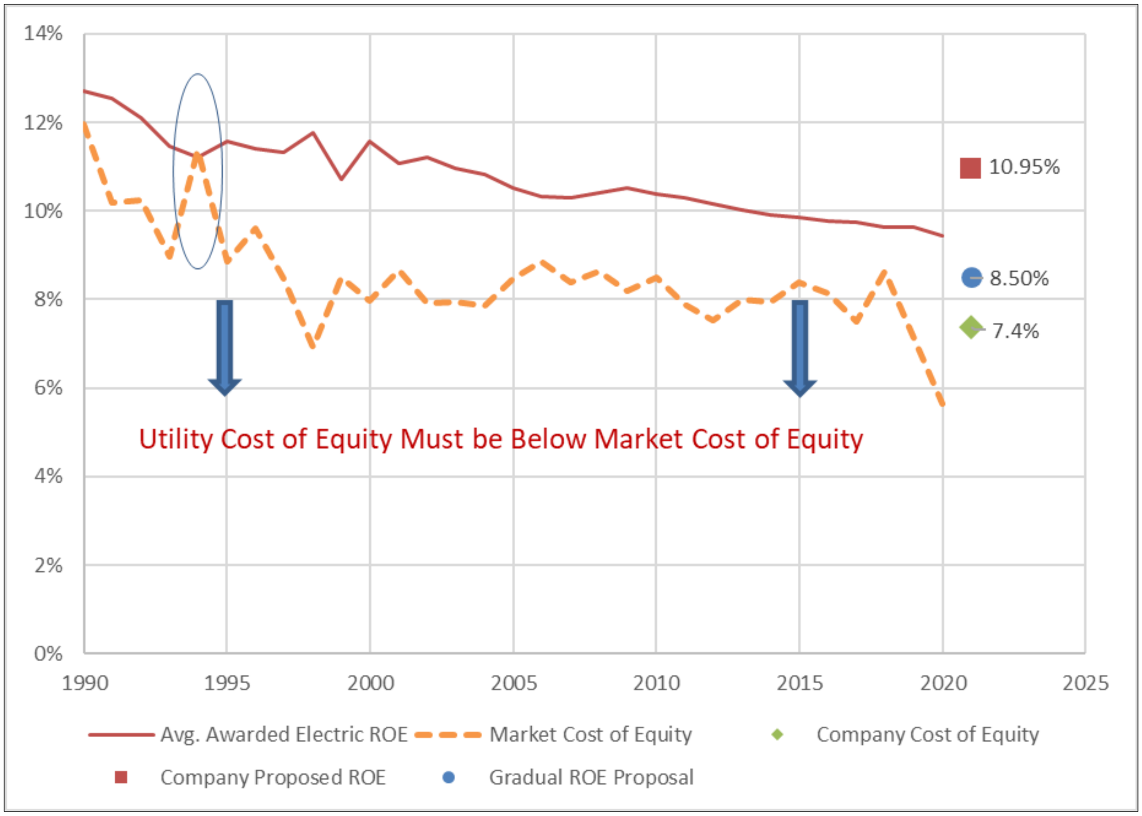
[18] Exhibit DJG-14.

[19] This fact can be objectively measured through a term called "beta," as discussed later in the testimony. Utility betas are less than one, which means utility stocks are less risky than the "average" stock in the market.

Figure 3:
Awarded ROEs vs. Market Cost of Equity



Notwithstanding the data in this graph, awarded ROEs have been consistently above the market cost of equity for many years. Also as shown in this graph, since 1990, there was only one year in which the average awarded ROE was below the market cost of equity. In 1994, regulators awarded ROEs that were the closest to utilities' market-based cost of equity. In my opinion, when awarded ROEs for utilities are below the market cost of equity, regulators more closely conform to the standards set forth by *Hope* and *Bluefield* and minimize the excess wealth transfer from ratepayers to shareholders.

Q. Have other analysts commented on this national phenomenon of awarded ROEs exceeding market-based cost equity for utilities?

A. Yes. In his article published in Public Utilities Fortnightly in 2016, Steve Huntoon observed that even though utility stocks are less risky than the stocks of competitive industries, utility stocks have nonetheless outperformed the broader market.[20] Specifically, Mr. Huntoon notes the following three points which lead to a problematic conclusion:

> 1. Jack Bogle, the founder of Vanguard Group and a Wall Street legend, provides rigorous analysis that the long-term total return for the broader market will be around 7 percent going forward. Another Wall Street legend, Professor Burton Malkiel, corroborates that 7 percent in the latest edition of his seminal work, A Random Walk Down Wall Street.
>
> 2. Institutions like pension funds are validating the first point by piling on risky investments to try and get to a 7.5 percent total return, as reported by the Wall Street Journal.
>
> 3. Utilities are being granted returns on equity around 10 percent.[21]

Other scholars have also observed that awarded ROEs have not appropriately tracked with declining interest rates over the years, and that excessive awarded ROEs have negative economic impacts. In a white paper issued in 2017, Charles S. Griffey stated:

[20] Steve Huntoon, "Nice Work If you can Get It," Public Utilities Fortnightly (Aug. 2016).

[21] *Id*.

> The "risk premium" being granted to utility shareholders is now higher than it has ever been over the last 35 years. Excessive utility ROEs are detrimental to utility customers and the economy as a whole. From a societal standpoint, granting ROEs that are higher than necessary to attract investment creates an inefficient allocation of capital, diverting available funds away from more efficient investments. From the utility customer perspective, if a utility's awarded and/or achieved ROE is higher than necessary to attract capital, customers pay higher rates without receiving any corresponding benefit.[22]

It is interesting that both Mr. Huntoon and Mr. Griffey use the word "sticky" in their articles to describe the fact that awarded ROEs have declined at a much slower rate than interest rates and other economic factors resulting in a decline in capital costs and expected returns on the market. It is not hard to see why this phenomenon of "sticky" ROEs has occurred. Because awarded ROEs are often based primarily on a comparison with other awarded ROEs around the country, the average awarded returns effectively fail to adapt to true market conditions, and regulators seem reluctant to deviate from the average. Once utilities and regulatory commissions become accustomed to awarding rates of return higher than market conditions actually require, this trend becomes difficult to reverse. The fact is, utility stocks are less risky than the average stock in the market, and thus, awarded ROEs should be less than the expected return on the market. However, that is rarely the case. My proposal assists the Commission in "see[ing] the gap between allowed returns and cost of capital,"[23] and reconciling this issue in an equitable manner.

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[22] Charles S. Griffey, "When 'What Goes Up' Does Not Come Down: Recent Trends in Utility Returns," White Paper (February 2017).

[23] Leonard Hyman & William Tilles, "Don't Cry for Utility Shareholders, America," Public Utilities Fortnightly (October 2016).

Q. Summarize the legal standards governing the awarded ROE issue.

A. The Commission should strive to move the awarded return to a level more closely aligned with the Company's actual, market-derived cost of capital while keeping in mind the following two legal principles outlined below.

1. Risk is the most important factor when determining the awarded return. The awarded return should be commensurate with those returns on investments of corresponding risk.

The legal standards articulated in *Hope* and *Bluefield* demonstrate that the U.S. Supreme Court understands one of the most basic, fundamental concepts in financial theory: the more (or less) risk an investor assumes, the more (or less) return the investor requires. Since utility stocks are low risk, the return required by equity investors should be relatively low. I have used financial models to closely estimate the Company's cost of equity, and these financial models account for risk. The cost of equity models confirm the industry experiences relatively low levels of risk by producing relatively low cost of equity results. In turn, the awarded ROE in this case should reflect PECO's relatively low market risk.

2. The awarded return should be sufficient to assure financial soundness and integrity under efficient management.

Because awarded returns in the regulatory environment have not closely tracked market-based trends and commensurate risk, utility companies have been able to remain more than financially sound, perhaps despite management inefficiencies. In fact, the transfer of wealth from ratepayers to shareholders has been so far removed from actual cost-based drivers that a utility could remain financially sound even under relatively inefficient management. Therefore, regulatory commissions should strive to set utilities' returns based on actual market conditions to promote prudent and efficient management and minimize economic waste.

IV. GENERAL CONCEPTS AND METHODOLOGY

Q. Discuss your approach to estimating the cost of equity in this case.

A. While a competitive firm must estimate its own cost of capital to assess the profitability of competing capital projects, regulators determine a utility's cost of capital to establish a fair rate of return. The legal standards set forth above do not include specific guidelines regarding the models that must be used to estimate the cost of equity for utilities. Over the years, however, regulatory commissions have consistently relied on several models. The models I have employed in this case have been the two most widely used and accepted in regulatory proceedings for many years. The specific inputs and calculations for these models are described in more detail below.

Q. Please explain why you used multiple models to estimate the cost of equity.

A. These models attempt to measure the return on equity required by investors by estimating several different inputs. It is preferable to use multiple models because the results of any one model may contain a degree of imprecision, especially depending on the reliability of the inputs used at the time of conducting the model. By using multiple models, the analyst can compare the results of the models and look for outlying results and inconsistencies. Likewise, if multiple models produce a similar result, it may indicate a narrower range for the cost of equity estimate.

Q. Please discuss the benefits of choosing a proxy group of companies in conducting cost of capital analyses.

A. The cost of equity models in this case can be used to estimate the cost of capital of any individual, publicly traded company. There are advantages, however, to conducting cost of capital analysis on a proxy group of companies that are comparable to the target company. First, it is better to assess the financial soundness of a utility by comparing it to a group of other financially sound utilities. Second, using a proxy group provides more reliability and confidence in the overall results because there is a larger sample size. Finally, the use of a proxy group is often a pure necessity when the target company is a subsidiary that is not publicly traded. This is because the financial models used to estimate the cost of equity require information from publicly traded firms, such as stock prices and dividends.

Q. Describe the proxy group you selected in this case.

A. In this case, I chose to use the same proxy group used by Mr. Moul. There could be reasonable arguments made for the inclusion or exclusion of a particular company in a proxy group; however, the cost of equity results are influenced far more by the underlying assumptions and inputs to the various financial models than the composition of the proxy group.[24] By using the same proxy group, we can remove a relatively insignificant variable from the equation and focus on the primary factors driving PECO's cost of equity estimate.

V. RISK AND RETURN CONCEPTS

Q. Discuss the general relationship between risk and return.

A. Risk is among the most important factors for the Commission to consider when determining the allowed return. Thus, it is necessary to understand the relationship between risk and return. There is a direct relationship between risk and return: the more (or less) risk an investor assumes, the larger (or smaller) return the investor will demand.

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[24] Exhibit DJG-2.

There are two primary types of risk: firm-specific risk and market risk. Firm-specific risk affects individual companies, while market risk affects all companies in the market to varying degrees.

Q. Discuss the differences between firm-specific risk and market risk.

A. Firm-specific risk affects individual companies, rather than the entire market. For example, a competitive firm might overestimate customer demand for a new product, resulting in reduced sales revenue. This is an example of a firm-specific risk called "project risk."[25] There are several other types of firm-specific risks, including: (1) "financial risk" – the risk that equity investors of leveraged firms face as residual claimants on earnings; (2) "default risk" – the risk that a firm will default on its debt securities; and (3) "business risk" – which encompasses all other operating and managerial factors that may result in investors realizing less than their expected return in that particular company. While firm-specific risk affects individual companies, market risk affects all companies in the market to varying degrees. Examples of market risk include interest rate risk, inflation risk, and the risk of major socio-economic events. When there are changes in these risk factors, they affect all firms in the market to some extent.[26]

Analysis of the U.S. market in 2001 provides a good example for contrasting firm-specific risk and market risk. During that year, Enron Corp.'s stock fell from $80 per share to its low when the company filed bankruptcy at the end of the year. If an investor's portfolio had held only Enron stock at the beginning of 2001, this irrational investor would

[25] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 62–63 (3rd ed., John Wiley & Sons, Inc. 2012).

[26] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 149 (9th ed., McGraw-Hill/Irwin 2013).

have lost the entire investment by the end of the year due to assuming the full exposure of Enron's firm-specific risk (in that case, imprudent management). On the other hand, a rational, diversified investor who invested the same amount of capital in a portfolio holding every stock in the S&P 500 would have had a much different result that year. The rational investor would have been relatively unaffected by the fall of Enron because his or her portfolio included about 499 other stocks. Each of those stocks, however, would have been affected by various market risk factors that occurred that year. Thus, the rational investor would have incurred a relatively minor loss due to market risk factors, while the irrational investor would have lost everything due to firm-specific risk factors.

Q. Can equity investors reasonably minimize firm-specific risk?

A. Yes. A fundamental concept in finance is that firm-specific risk can be eliminated through diversification.[27] If someone irrationally invested all his or her funds in one firm, he or she would be exposed to all the firm-specific risk and the market risk inherent in that single firm. Rational investors, however, are risk-averse and seek to eliminate risk they can control. Investors can eliminate firm-specific risk by adding more stocks to their portfolio through a process called "diversification." There are two reasons why diversification eliminates firm-specific risk.

First, each stock in a diversified portfolio represents a much smaller percentage of the overall portfolio than it would in a portfolio of just one or a few stocks. Thus, any firm-

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[27] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 179–80 (3rd ed., South Western Cengage Learning 2010).

specific action that changes the stock price of one stock in the diversified portfolio will have only a small impact on the entire portfolio.[28]

The second reason why diversification eliminates firm-specific risk is that the effects of firm-specific actions on stock prices can be either positive or negative for each stock. Thus, in large diversified portfolios, the net effect of these positive and negative firm-specific risk factors will be essentially zero and will not affect the value of the overall portfolio.[29] Firm-specific risk is also called "diversifiable risk" because it can be easily eliminated through diversification.

Q. Is it well-known and accepted that, because firm-specific risk can be easily eliminated through diversification, the market does not reward such risk through higher returns?

A. Yes. Because investors eliminate firm-specific risk through diversification, they know they cannot expect a higher return for assuming the firm-specific risk in any one company. Thus, the risks associated with an individual firm's operations are not rewarded by the market. In fact, firm-specific risk is also called "unrewarded" risk for this reason. Market risk, on the other hand, cannot be eliminated through diversification. Because market risk cannot be eliminated through diversification, investors expect a return for assuming this type of risk. Market risk is also called "systematic risk." Scholars recognize the fact that market risk, or systematic risk, is the only type of risk for which investors expect a return for bearing:

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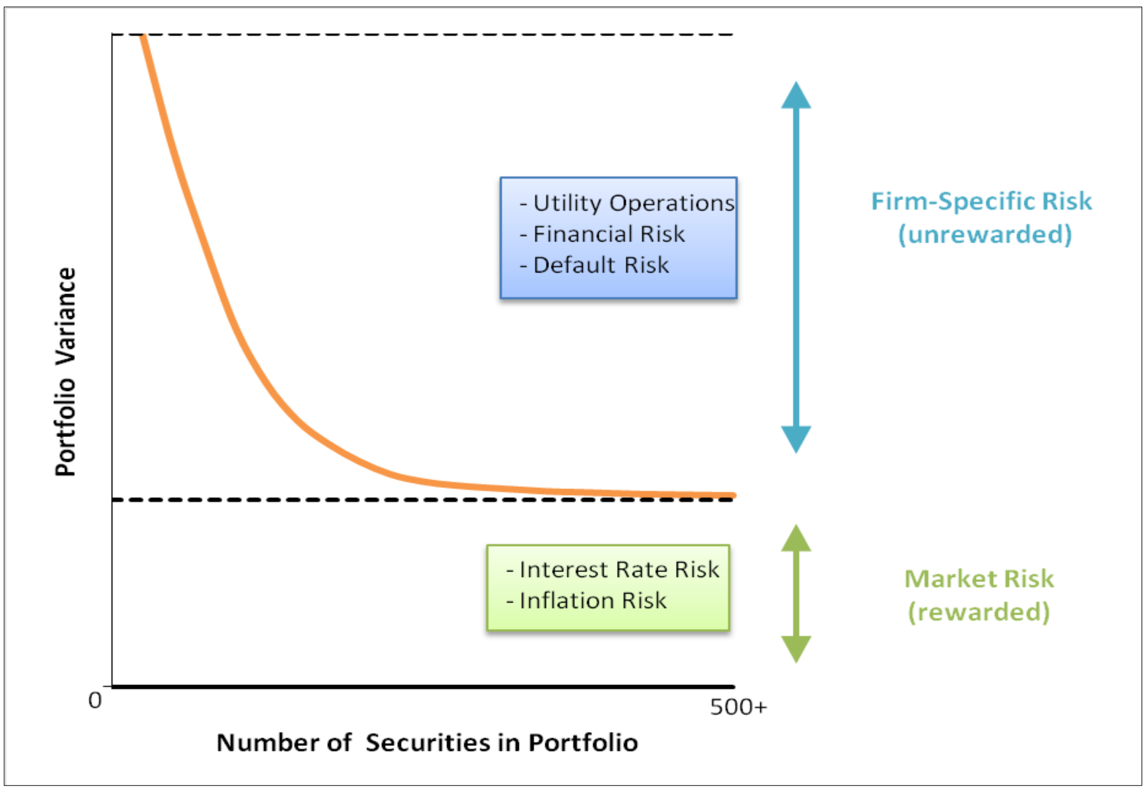
[28] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 64 (3rd ed., John Wiley & Sons, Inc. 2012).

[29] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 64 (3rd ed., John Wiley & Sons, Inc. 2012).

> If investors can cheaply eliminate some risks through diversification, then we should not expect a security to earn higher returns for risks that can be eliminated through diversification. Investors can expect compensation only for bearing systematic risk (i.e., risk that cannot be diversified away).[30]

These important concepts are illustrated in the figure below. Some form of this figure is found in many financial textbooks.

Figure 4:
Effects of Portfolio Diversification



This figure shows that as stocks are added to a portfolio, the amount of firm-specific risk is reduced until it is essentially eliminated. No matter how many stocks are added, however, there remains a certain level of fixed market risk. The level of market risk will

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[30] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180 (3rd ed., South Western Cengage Learning 2010) (emphasis added).

vary from firm to firm. Market risk is the only type of risk that is rewarded by the market and is thus the primary type of risk the Commission should consider when determining the allowed return.

Q. Describe how market risk is measured.

A. Investors who want to eliminate firm-specific risk must hold a fully diversified portfolio. To determine the amount of risk that a single stock adds to the overall market portfolio, investors measure the covariance between a single stock and the market portfolio. The result of this calculation is called "beta."[31] Beta represents the sensitivity of a given security to the market as a whole. The market portfolio of all stocks has a beta equal to one. Stocks with betas greater than 1.0 are relatively more sensitive to market risk than the average stock. For example, if the market increases (or decreases) by 1.0%, a stock with a beta of 1.5 will, on average, increase (or decrease) by 1.5%. In contrast, stocks with betas of less than 1.0 are less sensitive to market risk, such that if the market increases (or decreases) by 1.0%, a stock with a beta of 0.5 will, on average, only increase (or decrease) by 0.5%. Thus, stocks with low betas are relatively insulated from market conditions. The beta term is used in the CAPM to estimate the cost of equity, which is discussed in more detail later.[32]

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[31] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180–81 (3rd ed., South Western Cengage Learning 2010).

[32] Though it will be discussed in more detail later, Exhibit DJG-8 shows that the average beta of the proxy group was less than 1.0. This confirms the well-known concept that utilities are relatively low-risk firms.

Q. Are public utilities characterized as defensive firms that have low betas, have low market risk, and are relatively insulated from overall market conditions?

A. Yes. Although market risk affects all firms in the market, it affects different firms to varying degrees. Firms with high betas are affected more than firms with low betas, which is why firms with high betas are riskier. Stocks with betas greater than one are generally known as "cyclical stocks." Firms in cyclical industries are sensitive to recurring patterns of recession and recovery known as the "business cycle."[33] Thus, cyclical firms are exposed to a greater level of market risk. Securities with betas less than one, on the other hand, are known as "defensive stocks." Companies in defensive industries, such as public utility companies, "will have low betas and performance that is comparatively unaffected by overall market conditions."[34] In fact, financial textbooks often use utility companies as prime examples of low-risk, defensive firms.[35] The figure below compares the betas of several industries and illustrates that the utility industry is one of the least risky industries in the U.S. market.[36]

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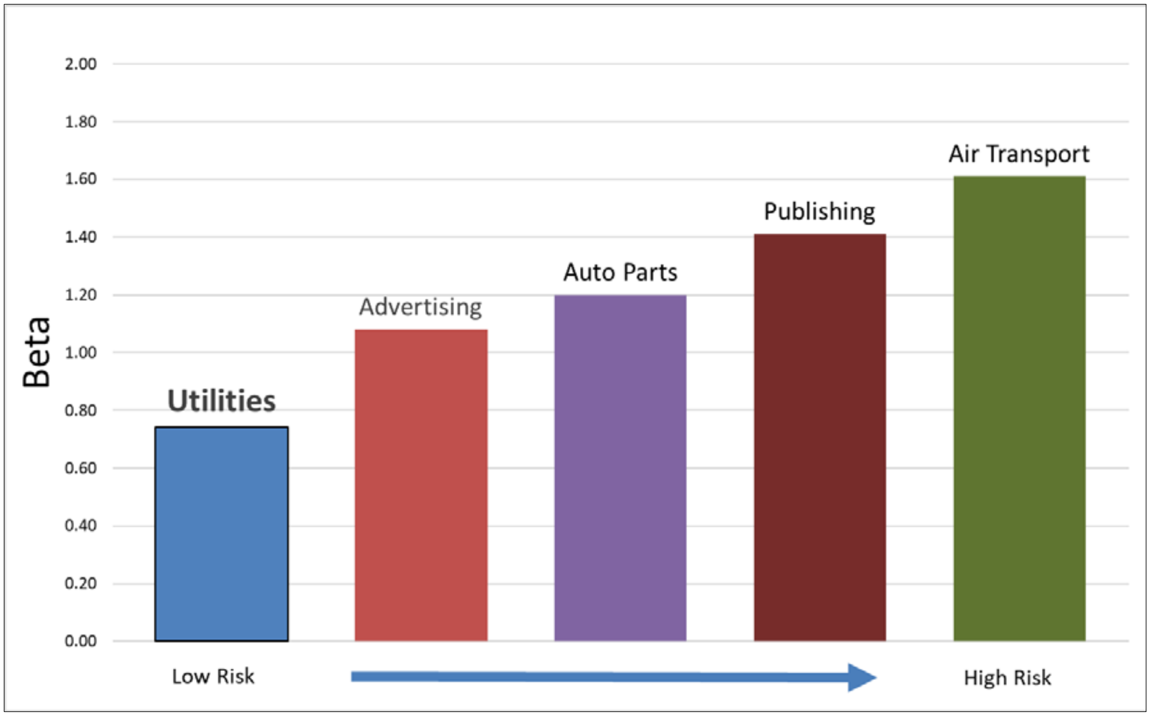
[33] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 382 (9th ed., McGraw-Hill/Irwin 2013).

[34] Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 383 (9th ed., McGraw-Hill/Irwin 2013).

[35] *See e.g.*, Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 382 (9th ed., McGraw-Hill/Irwin 2013); *see also* Aswath Damodaran, Investment Valuation: Tools and Techniques for Determining the Value of Any Asset 196 (3rd ed., John Wiley & Sons, Inc. 2012).

[36] *See* Betas by Sector (US) at http://pages.stern.nyu.edu/~adamodar/. The exact beta calculations are not as important as illustrating the well-known fact that utilities are low-risk companies. The fact that the utility industry is one of the lowest risk industries in the country should not change from year to year.

Figure 5:
Beta by Industry



The fact that utilities are defensive firms that are exposed to little market risk is beneficial to society. When the business cycle enters a recession, consumers can be assured that their utility companies will be able to maintain normal business operations and provide safe and reliable service under prudent management. Likewise, utility investors can be confident that utility stock prices will not fluctuate widely. So, while it is preferable for utilities to be defensive firms that experience little market risk and relatively insulated from market conditions, this should also be appropriately reflected in PECO's awarded return.

VI. <u>DCF ANALYSIS</u>

Q. Describe the DCF Model.

A. The DCF Model is based on a fundamental financial model called the "dividend discount model," which maintains that the value of a security is equal to the present value of the future cash flows it generates. Cash flows from common stock are paid to investors in the form of dividends. There are several variations of the DCF Model. These versions, along with other formulas and theories related to the DCF Model are discussed in more detail in Appendix A. For this case, I chose to use the Quarterly Approximation DCF Model because it accounts for the quarterly growth of dividends (as opposed to annual growth). I also used this variation of the DCF Model in the interest of reasonableness, as it produces the highest cost of equity estimates compared with the other DCF Model variations.

Q. Describe the inputs to the DCF Model.

A. There are three primary inputs in the DCF Model: (1) stock price; (2) dividend; and (3) the long-term growth rate. The stock prices and dividends are known inputs based on recorded data, while the growth rate projection must be estimated. The formula is presented as follows:

Equation 2:
Quarterly Approximation Discounted Cash Flow Model

$$K = \left[\frac{d_0(1+g)^{1/4}}{P_0} + (1+g)^{1/4}\right]^4 - 1$$

where:	K	=	*discount rate / required return*
	d_0	=	*current quarterly dividend per share*
	P_0	=	*stock price*
	g	=	*expected growth rate of future dividends*

I discuss each of these inputs separately below.

A. <u>Stock Price</u>

Q. How did you determine the stock price input of the DCF Model?

A. For the stock price (P_0), I used a 30-day average of stock prices for each company in the proxy group.[37] Analysts sometimes rely on average stock prices for longer periods (e.g., 60, 90, or 180 days). According to the efficient market hypothesis, however, markets reflect all relevant information available at a particular time, and prices adjust instantaneously to the arrival of new information.[38] Past stock prices, in essence, reflect outdated information. The DCF Model used in utility rate cases is a derivation of the dividend discount model, which is used to determine the current value of an asset. Thus, according to the dividend discount model and the efficient market hypothesis, the value for the "P_0" term in the DCF Model should technically be the current stock price, rather than an average.

Q. Why did you use a 30-day average for the current stock price input?

A. Using a short-term average of stock prices for the current stock price input adheres to market efficiency principles while avoiding any irregularities that may arise from using a single current stock price. In the context of a utility rate proceeding there is a significant length of time from when an application is filed, and testimony is due. Choosing a current stock price for one particular day could raise a separate issue concerning which day was chosen to be used in the analysis. In addition, a single stock price on a particular day may be unusually high or low. It is arguably ill-advised to use a single stock price in a model

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[37] Exhibit DJG-3.

[38] *See* Eugene F. Fama, *Efficient Capital Markets: A Review of Theory and Empirical Work*, Vol. 25, No. 2 The Journal of Finance 383 (1970).

that is ultimately used to set rates for several years, especially if a stock is experiencing some volatility. Thus, it is preferable to use a short-term average of stock prices, which represents a good balance between adhering to well-established principles of market efficiency while avoiding any unnecessary contentions that may arise from using a single stock price on a given day. The stock prices I used in my DCF analysis are based on 30-day averages of adjusted closing stock prices for each company in the proxy group.[39]

B. <u>Dividend</u>

Q. Describe how you determined the dividend input of the DCF Model.

A. The dividend term in the Quarterly Approximation DCF Model is the current quarterly dividend per share (d_0). I obtained the most recent quarterly dividend paid for each proxy company.[40] The Quarterly Approximation DCF Model assumes that the company increases its dividend payments each quarter. Thus, the model assumes that each quarterly dividend is greater than the previous one by $(1 + g)^{0.25}$. This expression could be described as the dividend quarterly growth rate, where the term "g" is the growth rate and the exponential term "0.25" signifies one quarter of the year.

Q. Does the Quarterly Approximation DCF Model result in the highest cost of equity in this case relative to other DCF Models, all else held constant?

A. Yes. The Quarterly Approximation DCF Model I employed in this case results in a higher DCF cost of equity estimate than the annual or semi-annual DCF Models due to the

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[39] Exhibit DJG-3. Adjusted closing prices, rather than actual closing prices, are ideal for analyzing historical stock prices. The adjusted price provides an accurate representation of the firm's equity value beyond the mere market price because it accounts for stock splits and dividends.

[40] Exhibit DJG-4. Nasdaq Dividend History, http://www.nasdaq.com/quotes/dividend-history.aspx.

quarterly compounding of dividends inherent in the model. In essence, the Quarterly Approximation DCF Model I used results in the highest cost of equity estimate, all else held constant.

Q. Are the stock price and dividend inputs for each proxy company a significant issue in this case?

A. No. Although my stock price and dividend inputs are more recent than those used by Mr. Moul, there is not a statistically significant difference between them because utility stock prices and dividends are generally quite stable. This is another reason that cost of capital models such as the CAPM and the DCF Model are well-suited to be used for utilities. The differences between my DCF Model and Mr. Moul's DCF Model are primarily driven by differences in our growth rate estimates, which are further discussed below.

C. <u>Growth Rate</u>

Q. Summarize the growth rate input in the DCF Model.

A. The most critical input in the DCF Model is the growth rate. Unlike the stock price and dividend inputs, the growth rate input (g) must be estimated. As a result, the growth rate is often the most contentious DCF input in utility rate cases. The DCF model used in this case is based on the constant growth valuation model. Under this model, a stock is valued by the present value of its future cash flows in the form of dividends. Before future cash flows are discounted by the cost of equity, however, they must be "grown" into the future by a long-term growth rate. As stated above, one of the inherent assumptions of this model is that these cash flows in the form of dividends grow at a constant rate forever. Thus, the growth rate term in the constant growth DCF model is often called the "constant," "stable," or "terminal" growth rate. For young, high-growth firms, estimating the growth rate to be used in the model can be especially difficult, and may require the use of multi-stage growth models. For mature, low-growth firms such as utilities, however, estimating the terminal growth rate is more transparent. The growth term of the DCF Model is one of the most important, yet apparently most misunderstood, aspects of cost of equity estimations in utility regulatory proceedings. Therefore, I have devoted a more detailed explanation of this issue in the following sections, which are organized as follows:

(1) The Various Determinants of Growth

(2) Reasonable Estimates for Long-Term Growth

(3) Quantitative vs. Qualitative Determinants of Utility Growth: Circular References, "Flatworm" Growth, and the Problem with Analysts' Growth Rates

(4) Growth Rate Recommendation

1. <u>The Various Determinants of Growth</u>

Q. Describe the various determinants of growth.

A. Although the DCF Model directly considers the growth of dividends, there are a variety of growth determinants that should be considered when estimating growth rates. It should be noted that these various growth determinants are used primarily to determine the short-term growth rates in multi-stage DCF models. For utility companies, it is necessary to focus primarily on long-term growth rates, which are discussed in the following section. That is not to say that these growth determinants cannot be considered when estimating long-term growth; however, as discussed below, long-term growth must be constrained much more than short-term growth, especially for young firms with high growth opportunities. Additionally, I briefly discuss these growth determinants here because it may reveal some of the source of confusion in this area.

A. Historical Growth

Looking at a firm's actual historical experience may theoretically provide a good starting point for estimating short-term growth. However, past growth is not always a good indicator of future growth. Some metrics that might be considered here are a historical growth in revenues, operating income, and net income. Since dividends are paid from earnings, estimating historical earnings growth may provide an indication of future earnings and dividend growth. In general, however, revenue growth tends to be more consistent and predictable than earnings growth because it is less likely to be influenced by accounting adjustments.[41]

B. Analyst Growth Rates

Analyst growth rates refer to short-term projections of earnings growth published by institutional research analysts such as Value Line and Bloomberg. A more detailed discussion of analyst growth rates, including the problems with using them in the DCF Model to estimate utility cost of equity, is provided in a later section.

C. Fundamental Determinants of Growth

Fundamental growth determinants refer to firm-specific financial metrics that arguably provide better indications of near-term sustainable growth. One such metric for fundamental growth considers the return on equity and the retention ratio. The idea behind

[41] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 279 (3rd ed., John Wiley & Sons, Inc. 2012).

this metric is that firms with high ROEs and retention ratios should have greater opportunities for growth.[42]

Q. Did you use any of these growth determinants in your DCF Model?

A. No. Primarily, these growth determinants discussed above would provide better indications of short- to mid-term growth for firms with average to high growth opportunities. Utilities, however, are mature, low-growth firms. While it may not be unreasonable on its face to use any of these growth determinants for the growth input in the DCF Model, we must keep in mind that the stable growth DCF Model considers only <u>long-term</u> growth rates, which are constrained by certain economic factors, as discussed further below.

2. <u>Reasonable Estimates for Long-Term Growth</u>

Q. Describe what is meant by long-term growth.

A. In order to make the DCF Model a viable, practical model, an infinite stream of future cash flows must be estimated and then discounted back to the present. Otherwise, each annual cash flow would have to be estimated separately. Some analysts use "multi-stage" DCF Models to estimate the value of high-growth firms through two or more stages of growth, with the final stage of growth being constant. However, it is not necessary to use multi-stage DCF Models to analyze the cost of equity of regulated utility companies. This is because regulated utilities are already in their "terminal," low growth stage. Unlike most competitive firms, the growth of regulated utilities is constrained by physical service

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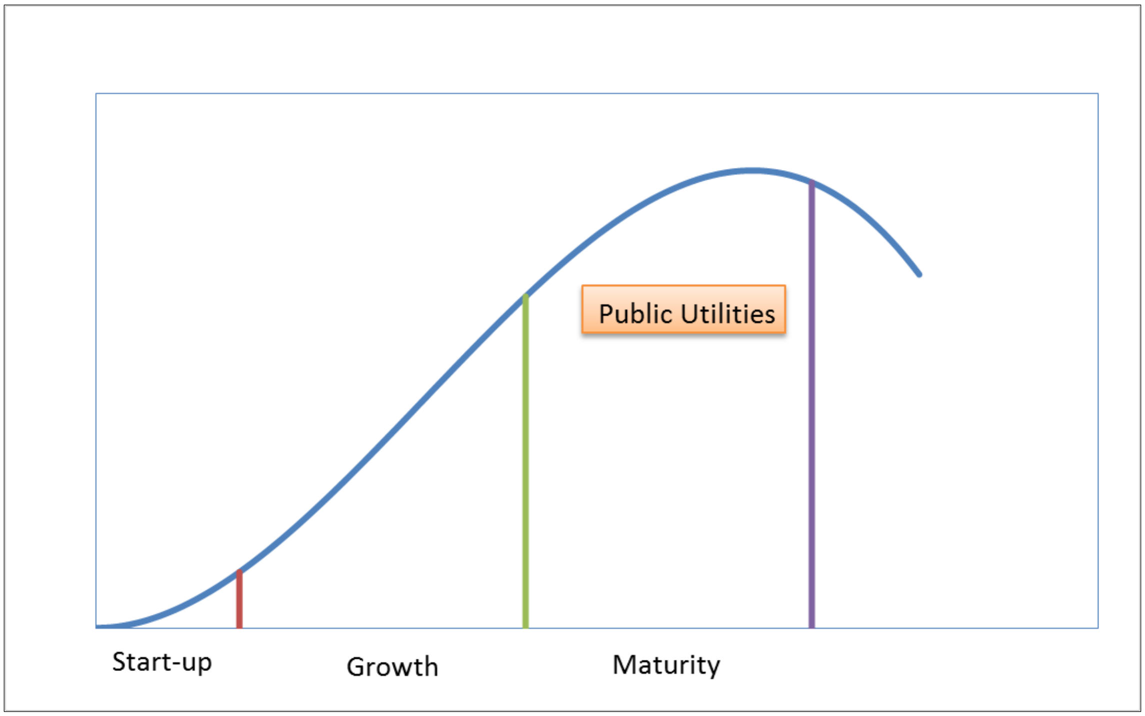
[42] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 279 (3rd ed., John Wiley & Sons, Inc. 2012).

territories and limited primarily by ratepayer and load growth within those territories. The figure below illustrates the well-known business/industry life-cycle pattern.

Figure 6:
Industry Life Cycle



In an industry's early stages, there are ample opportunities for growth and profitable reinvestment. In the maturity stage however, growth opportunities diminish, and firms choose to pay out a larger portion of their earnings in the form of dividends instead of reinvesting them in operations to pursue further growth opportunities. Once a firm is in the maturity stage, it is not necessary to consider higher short-term growth metrics in multi-stage DCF Models; rather, it is sufficient to analyze the cost of equity using a stable growth DCF Model with one terminal, long-term growth rate.

Q. Is it true that the terminal growth rate cannot exceed the growth rate of the economy, especially for a regulated utility company?

A. Yes. A fundamental concept in finance is that no firm can grow forever at a rate higher than the growth rate of the economy in which it operates.[43] Thus, the terminal growth rate used in the DCF Model should not exceed the aggregate economic growth rate. This is especially true when the DCF Model is conducted on public utilities because these firms have defined service territories. As stated by Dr. Damodaran: "[i]f a firm is a purely domestic company, either because of internal constraints . . . or external constraints (such as those imposed by a government), the growth rate in the domestic economy will be the limiting value."[44]

In fact, it is reasonable to assume that a regulated utility would grow at a rate that is <u>less</u> than the U.S. economic growth rate. Unlike competitive firms, which might increase their growth by launching a new product line, franchising, or expanding into new and developing markets, utility operating companies with defined service territories cannot do any of these things to grow. Gross Domestic Product ("GDP") is one of the most widely used measures of economic production and is used to measure aggregate economic growth. According to the Congressional Budget Office's Budget Outlook, the long-term forecast for nominal U.S. GDP growth is about 4%, which includes an inflation rate of 2%.[45] For mature companies in mature industries, such as utility companies, the terminal growth rate

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[43] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 306 (3rd ed., John Wiley & Sons, Inc. 2012).

[44] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 306 (3rd ed., John Wiley & Sons, Inc. 2012).

[45] Congressional Budget Office Long-Term Budget Outlook, https://www.cbo.gov/publication/56977 (last accessed June 22, 2021).

will likely fall between the expected rate of inflation and the expected rate of nominal GDP growth. Thus, PECO's terminal growth rate is between 2% and 4%.

Q. Is it reasonable to assume that the terminal growth rate will not exceed the risk-free rate?

A. Yes. In the long term, the risk-free rate will converge on the growth rate of the economy. For this reason, financial analysts sometimes use the risk-free rate for the terminal growth rate value in the DCF model.[46] I discuss the risk-free rate in further detail later in this testimony.

Q. Please summarize the various long-term growth rate estimates that can be used as the terminal growth rate in the DCF Model.

A. The reasonable long-term growth rate determinants are summarized as follows:

1. Nominal GDP Growth
2. Real GDP Growth
3. Inflation
4. Current Risk-Free Rate

Any of the foregoing growth determinants could provide a basis for a reasonable input for the terminal growth rate in the DCF Model for a utility company, including PECO. In general, we should expect that utilities will, at the very least, grow at the rate of projected inflation. However, the long-term growth rate of any U.S. company, especially utilities, will be constrained by nominal U.S. GDP growth.

[46] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 307 (3rd ed., John Wiley & Sons, Inc. 2012).

3. <u>Qualitative Growth: The Problem with Analysts' Growth Rates</u>

Q. Describe the differences between "quantitative" and "qualitative" growth determinants.

A. Assessing "quantitative" growth simply involves mathematically calculating a historic metric for growth (such as revenues or earnings) or calculating various fundamental growth determinants using certain figures from a firm's financial statements (such as ROE and the retention ratio). However, any thorough assessment of company growth should be based upon a "qualitative" analysis. Such an analysis would consider specific strategies that company management will implement to achieve real sustainable growth in earnings. Therefore, it is important to begin the analysis of PECO's growth rate with this simple, qualitative question: how is this regulated utility going to achieve a real sustained growth in earnings? If this question were asked of a competitive firm, there could be several answers depending on the type of business model, such as launching a new product line, franchising, rebranding to target a new demographic, or expanding into a developing market. Regulated utilities, however, cannot engage in these potential growth opportunities.

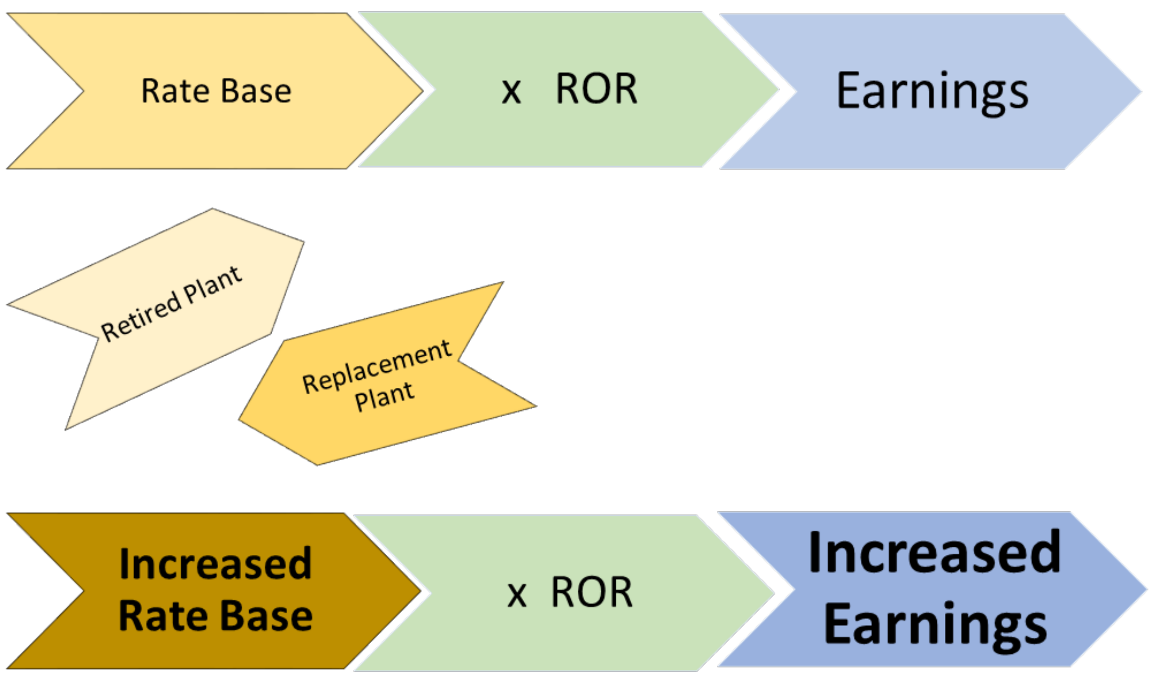
Q. Why is it especially important to emphasize real, qualitative growth determinants when analyzing whether a growth rate is fair for a regulated utility?

A. While qualitative growth analysis is important regardless of the entity being analyzed, it is especially important in the context of utility ratemaking. This is because the rate base rate of return model inherently possesses two factors that can contribute to distorted views of utility growth when considered exclusively from a quantitative perspective. These two factors are: (1) rate base and (2) the awarded ROE. I will discuss each factor further below. It is important to keep in mind that the ultimate objective of this analysis is to provide a foundation upon which to base the fair rate of return for the utility. Thus, we should strive to ensure that each individual component of the financial models used to estimate the cost of equity are also fair. If we consider only quantitative growth determinants, it may lead to projected growth rates that are overstated and ultimately unfair, because they result in inflated cost of equity estimates.

Q. How does rate base relate to growth determinants for utilities?

A. Under the rate base rate of return model, a utility's rate base is multiplied by its awarded rate of return to produce the required level of operating income. Therefore, increases to rate base generally result in increased earnings. Thus, utilities have a natural financial incentive to increase rate base. In short, utilities have a financial incentive to increase rate base regardless of whether such increases are driven by a corresponding increase in demand. A good, relevant example of this is seen in the early retirement of old, but otherwise functional coal plants in response to environmental regulations and replacing them with new generation assets. Under these circumstances, utilities have been able to increase their rate bases by a far greater extent than what any concurrent increase in demand would have required. In other words, utilities grew their earnings by simply retiring old assets and replacing them with new assets. This is not "real" or "sustainable" growth. If the tail of a flatworm is removed and regenerated, it does not mean the flatworm actually grew. Likewise, if a competitive, unregulated firm announced plans to close production plants and replace them with new plants, it would not be considered a real determinant of growth unless analysts believed this decision would directly result in increased market share for the company and a real opportunity for sustained increases in revenues and earnings. In the case of utilities, the mere replacement of "old plant" with "new plant" does not increase market share, attract new ratepayers, create franchising opportunities, or allow utilities to penetrate developing markets, but may result in short-term, quantitative earnings growth. However, this "flatworm growth" in earnings was merely the quantitative byproduct of the rate base rate of return model, and not an indication of real or qualitative growth and, therefore, using that data alone to estimate a growth rate is not fair. The following diagram in the figure below illustrates this concept.

Figure 7:
Analysts' Earnings Growth Projections: The "Flatworm Growth" Problem

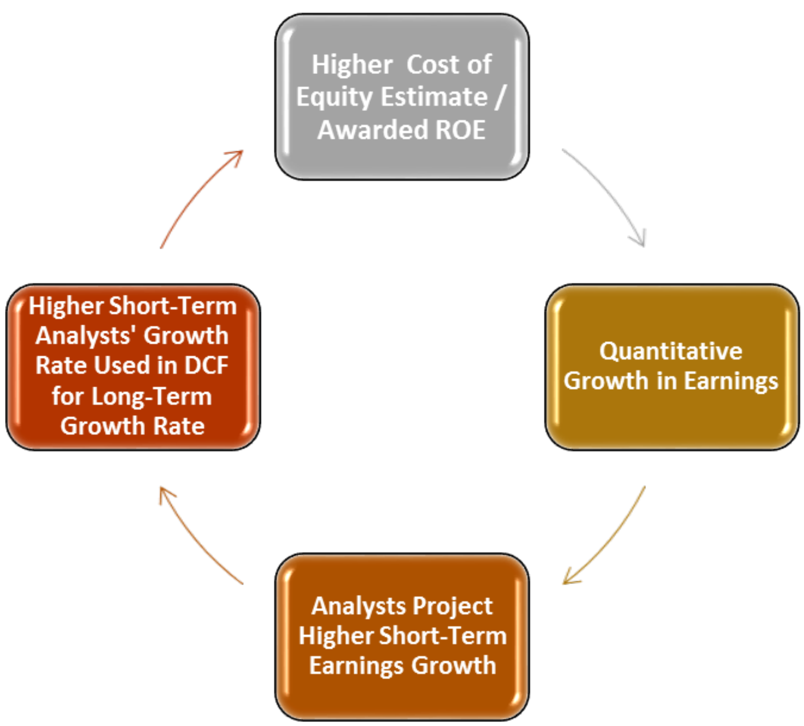


Of course, utilities might sometimes add "new plant" to meet a modest growth in ratepayer demand. However, as the foregoing discussion demonstrates, it would be more appropriate to consider load growth projections and other qualitative indicators, rather than mere increases to rate base or earnings, to attain a fair assessment of growth.

Q. Please discuss the other way in which analysts' earnings growth projections do not provide indications of real, qualitative growth for regulated utilities.

A. If we give undue weight to analysts' projections for utilities' earnings growth, it will not provide an accurate reflection of real, qualitative growth because a utility's earnings are heavily influenced by the ultimate figure that all this analysis is supposed to help us estimate: the awarded return on equity. This creates a circular reference problem or feedback loop. In other words, if a regulator awards an ROE that is above market-based cost of capital (which is often the case, as discussed above), this could lead to higher short-term growth rate projections from analysts. If these same inflated, short-term growth rate estimates are used in the DCF Model (as they often are by utility witnesses), it could lead to higher awarded ROEs; and the cycle continues, as illustrated in the figure below.

Figure 8:
Analysts' Earnings Growth Projections: The "Circular Reference" Problem



Therefore, it is not advisable to simply consider the quantitative growth projections published by analysts, as this practice will not necessarily provide fair indications of real, sustainable utility growth.

Q. Are there any other problems with relying on analysts' growth projections?

A. Yes. While the foregoing discussion shows two reasons why we cannot rely on analysts' growth rate projections to provide fair, qualitative indicators of utility growth in a stable growth DCF Model, the third reason is perhaps the most obvious and undisputable. Various institutional analysts—such as Zacks, Value Line, and Bloomberg—publish estimated projections of earnings growth for utilities. These estimates are short-term growth rate projections, ranging from 3 to 10 years. However, many utility ROE analysts inappropriately insert these short-term growth projections into the DCF Model as if they were *long-term* growth rate projections. For example, assume that an analyst at Bloomberg estimates that a utility's earnings will grow by 7% per year over the next 3 years. This analyst may have based this short-term forecast on a utility's plans to replace depreciated rate base (*i.e.*, "flatworm" growth) or on an anticipated awarded return that is above market-based cost of equity (*i.e.*, the "circular reference" problem). When a utility witness uses this figure in a DCF Model, however, it is the witness, not the Bloomberg analyst, that is testifying to the regulator that the utility's earnings will qualitatively grow by 7% per year over the long-term, which is an unrealistic assumption and a fundamentally different conclusion than that of the Bloomberg analyst.

4. <u>Long-Term Growth Rate Recommendation</u>

Q. Describe the growth rate input used in your DCF Model.

A. I considered various qualitative determinants of growth for PECO, along with the maximum allowed growth rate under basic principles of finance and economics. The following chart in the figure below shows three of the long-term growth determinants discussed in this section.[47]

Figure 9:
Terminal Growth Rate Determinants

Terminal Growth Determinants	Rate
Nominal GDP	3.8%
Real GDP	1.8%
Inflation	2.0%
Risk Free Rate	2.3%
Highest	**3.8%**

For the long-term growth rate in my DCF model, I selected the maximum, reasonable long-term growth rate of 3.8%, which means my model assumes that PECO's qualitative growth in earnings will qualitatively match the nominal growth rate of the entire U.S. economy over the long run – a charitable assumption.

[47] Exhibit DJG-5.

Q. Is your growth rate input especially reasonable in light of PECO's company-specific, qualitative growth rate indicators?

A. Yes. As discussed above, from a qualitative perspective, utilities in general do not experience any significant growth. This is because they are primarily limited to the population and demand growth within their defined and limited service territories. Not surprisingly, PECO's own qualitative growth estimates for total customers and total load are less than 1.0%, as shown in the table below.[48]

Figure 10:
Terminal Growth Rate Determinants

Company-Specific Growth Factors	Rate
Total Load (2020 - 2025)	0.8%
Total Customers (2020 - 2025)	0.6%
Average	**0.7%**

Thus, by imputing a long term growth rate of 3.8% for PECO, I have essentially assumed a growth rate more than five times greater than PECO's own qualitative growth indicators. Consequently, my DCF cost of equity estimate is not underestimated.

Q. Please describe the final results of your DCF Model.

A. I used the Quarterly Approximation DCF Model discussed above to estimate PECO's cost of equity capital. I obtained an average of reported dividends and stock prices from the proxy group, and I used a reasonable terminal growth rate estimate for PECO. My DCF

[48] *See also* Exhibit DJG-5; *see also* response to OCA-IV-10.

Model cost of equity estimate for PECO is 7.4%.[49] This result is not surprising given reasonable estimates for the current expected return on the market portfolio (discussed later in my testimony) and the fact that each company in the proxy group is less risky than the average company in the market portfolio.

D. Response to Mr. Moul's DCF Model

Q. Mr. Moul's DCF Model yielded a notably higher result. Did you find any problems with his analysis?

A. Yes. Mr. Moul's DCF Model produced cost of equity result of 9.23%, and a result of 10.66% with Mr. Moul's "leverage adjustment."[50] As mentioned earlier, the results of Mr. Moul's DCF Model are overstated primarily because of a fundamental error regarding his growth rate inputs. In addition, Mr. Moul's decision to add a leverage adjustment to his DCF result is inappropriate.

Q. Are you proposing any adjustments to Mr. Moul's dividend yields?

A. No. Again, the primary contentious issues regarding Mr. Moul's DCF Model are his estimates for the long-term growth rate and his leverage adjustment.

Q. Describe the problems with Mr. Moul's assumed long-term growth input.

A. Mr. Moul assumes an average projected growth rate of 5.15% in his DCF Model.[51] In arriving at this growth rate input, Mr. Moul considered growth rates as high as 10.5% for the proxy group,[52] which is <u>more than double</u> the long-term nominal U.S. GDP growth.

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[49] Exhibit DJG-6.

[50] Direct Testimony of Paul R. Moul, p. 22, lines 18-20.

[51] Direct testimony of Paul R. Moul, Exhibit PRM-1, Sch. 1, p. 2.

[52] Direct testimony of Paul R. Moul, Exhibit PRM-1, Sch. 9.

This means Mr. Moul's growth rate assumption violates the basic principle that no company can grow at a greater rate than the economy in which it operates over the long-term, especially a regulated utility company with a defined service territory. Furthermore, Mr. Moul relies on short-term, quantitative growth estimates published by analysts to support his assumptions. Mr. Moul acknowledges that his growth rate projections cover only a five-year period.[53] This period of time is not sufficient for a long-term estimate. As discussed above, these analysts' estimates are inappropriate to use in the DCF Model as long-term growth rates because they are estimates for short-term growth. For example, Mr. Moul assumes a long-term growth rate estimate of 10.5% for NextEra Energy (among other estimates), as reported by Value Line Investment Survey.[54] This means that an analyst at Value Line apparently thinks that NextEra's dividends will quantitatively increase by 10.5% each year over the next <u>several</u> years (*i.e.*, the short-term). However, it is Mr. Moul, not the commercial analyst, who is suggesting to the Commission that NextEra's dividends will increase by 10.5% (<u>more than double</u> U.S. GDP growth) each year, every year, for many decades into the future (*i.e.*, long-term growth).[55] Again, Mr. Moul is extrapolating the analyst's conclusions well beyond what the analyst actually said. Furthermore, this assumption is simply not realistic, and it contradicts fundamental concepts of long-term growth. Many of Mr. Moul's other short-term growth rate estimates also exceed projected U.S. GDP growth.

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[53] Direct testimony of Paul R. Moul, p. 28, lines 2-5.

[54] Direct testimony of Paul R. Moul, Exhibit PRM-1, Sch. 9.

[55] Technically, the constant growth rate in the DCF Model grows dividends each year to infinity. Yet even if we assumed that the growth rate applied to only a few decades, the annual growth rate would still be too high to be considered realistic.

Q. Please describe Mr. Moul's leverage adjustment.

A. According to Mr. Moul, a leverage adjustment is necessary when "the DCF return applies to a capital structure used for ratemaking that is computed with book-value weighting rather than market-value weighting."[56]

Q. Have you ever seen or heard of a witness apply a leverage adjustment like the one Mr. Moul is proposing?

A. No. I have testified in numerous proceedings on the issue of cost of capital and other regulatory issues and have reviewed extensive amounts of testimony from many witnesses on cost of capital issues. Yet I cannot recall a witness applying a "leverage adjustment" in the way Mr. Moul is proposing in this case – even from other utility witnesses.

Q. Do you agree with Mr. Moul's leverage adjustment?

A. No. I disagree with Mr. Moul's leverage adjustment for several reasons. First, the DCF cost of equity result of 10.66% due to Mr. Moul's leverage adjustment is so unrealistically high on its face that the adjustment should be completely disregarded for that reason alone. As discussed later in my testimony, there are very reliable and reasonable ways to estimate a market-based "ceiling" above which the cost of equity of a low-risk utility company such as PECO cannot be. Several key market metrics show that this ceiling is likely no higher than 8.0%.[57] Even Mr. Moul's base DCF Model result of 9.23% far exceeds this market "ceiling." Any type of premium or adjustment that has an increasing effect on a figure that is clearly overestimated should be disregarded.

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[56] Direct testimony of Paul R. Moul, p. 34, lines 4-8.

[57] *See* Exhibit DJG-13.

Second, while Mr. Moul is generally correct that increasing a firm's leverage can have an increasing effect on its cost of equity, this impact has already been accounted for in the cost of equity models we use. Both the DCF Model and CAPM (discussed in more detail below) have been used by the financial community for decades to estimate cost of equity. In simply looking at these highly-regarded models, we see there is no separate input or assumption to account for the marginal effects of leverage. This is because this type of financial risk is already accounted for in the models (i.e., no separate adjustment is necessary). Perhaps this is yet another reason why I have never seen this type of adjustment proposed by an ROE witness. In the CAPM, the betas we use as part of the formula are already "levered," meaning that a company's leverage is already accounted for in its overall risk profile. However, Mr. Moul still "re-leveraged" the Value Line betas as part of his leverage adjustment.[58] This approach is incorrect. Moreover, Mr. Moul's estimate of PECO's unlevered betas is unreasonably high. Mr. Moul estimates an "unlevered" (i.e., 100% equity) of 7.24%, but a more reasonable calculation shows an unlevered beta of only 5.25%.[59] Regardless, it is not necessary to "re-lever" Value Line betas from their starting point (i.e., without unlevering them first) to use in the CAPM. However, I performed a similar unlevering / relevering of PECO's estimated beta as part of my capital structure discussed later in my testimony. When using reasonable inputs to the model, I arrive at a cost of equity estimate of only 7.1% when using a re-levered beta at a debt ratio of 45% (which is reflective of PECO's actual debt ratio),[60] which is much less than Mr. Moul's

[58] Direct testimony of Paul R. Moul, pp. 41-42.

[59] *See* Exhibit DJG-15.

[60] *See id*.

10.66% cost of equity estimate. The evidence presented here clearly demonstrates that Mr. Moul's base DCF Model results are overstated; any premium or adjustment that increases =a result that is already overestimated should be disregarded.

VII. CAPM ANALYSIS

Q. Describe the CAPM.

A. The CAPM is a market-based model founded on the principle that investors expect higher returns for incurring additional risk.[61] The CAPM estimates this expected return. The various assumptions, theories, and equations involved in the CAPM are discussed further in Appendix B. Using the CAPM to estimate the cost of equity of a regulated utility is consistent with the legal standards governing the fair rate of return. The U.S. Supreme Court has recognized that "the amount of risk in the business is a most important factor" in determining the allowed rate of return,[62] and that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[63] The CAPM is a useful model because it directly considers the amount of risk inherent in a business. It is arguably the strongest of the models usually presented in rate cases because, unlike the DCF Model, the CAPM directly measures the most important component of a fair rate of return analysis – risk.

[61] William F. Sharpe, *A Simplified Model for Portfolio Analysis* 277–93 (Management Science IX 1963).

[62] *Wilcox*, 212 U.S. at 48.

[63] *Hope Natural Gas Co.*, 320 U.S. at 603.

Q. Describe the inputs for the CAPM.

A. The basic CAPM equation requires only three inputs to estimate the cost of equity: (1) the risk-free rate; (2) the beta coefficient; and (3) the equity risk premium. Here is the CAPM formula:

Equation 3:
Basic CAPM

Cost of Equity = Risk-free Rate + (Beta × Equity Risk Premium)

Each input is discussed separately below.

A. <u>The Risk-Free Rate</u>

Q. Explain the risk-free rate.

A. The first term in the CAPM is the risk-free rate (R_F). The risk-free rate is simply the level of return investors can achieve without assuming any risk. The risk-free rate represents the bare minimum return that any investor would require on a risky asset. Even though no investment is technically void of risk, investors often use U.S. Treasury securities to represent the risk-free rate because they accept that those securities essentially contain no default risk. The Treasury issues securities with different maturities, including short-term Treasury Bills, intermediate-term Treasury Notes, and long-term Treasury Bonds.

Q. Is it preferable to use the yield on long-term Treasury bonds for the risk-free rate in the CAPM?

A. Yes. In valuing an asset, investors estimate cash flows over long periods of time. Common stock is viewed as a long-term investment, and the cash flows from dividends are assumed to last indefinitely. Thus, short-term Treasury Bill yields are rarely used in the CAPM to represent the risk-free rate. Short-term rates are subject to greater volatility and thus can lead to unreliable estimates. Instead, long-term Treasury bonds are usually used to represent the risk-free rate in the CAPM. I considered a 30-day average of daily Treasury yield curve rates on 30-year Treasury Bonds in my risk-free rate estimate, which resulted in a risk-free rate of 2.3%.[64]

B. The Beta Coefficient

Q. How is the beta coefficient used in this model?

A. As discussed above, beta represents the sensitivity of a given security to movements in the overall market. The CAPM states that in efficient capital markets, the expected risk premium on each investment is proportional to its beta. Recall that a security with a beta greater (or less) than one is more (or less) risky than the market portfolio. An index such as the S&P 500 Index is used as a proxy for the market portfolio. The historical betas for publicly traded firms are published by various institutional analysts. Beta may also be calculated through a linear regression analysis, which provides additional statistical information about the relationship between a single stock and the market portfolio. As discussed above, beta also represents the sensitivity of a given security to the market as a whole. The market portfolio of all stocks has a beta equal to one. Stocks with betas greater than 1.0 are relatively more sensitive to market risk than the average stock. For example, if the market increases (or decreases) by 1.0%, a stock with a beta of 1.5 will, on average, increase (or decrease) by 1.5%. In contrast, stocks with betas of less than 1.0 are less sensitive to market risk. For example, if the market increases (or decreases) by 1.0%, a stock with a beta of 0.5 will, on average, only increase (or decrease) by 0.5%.

[64] Exhibit DJG-7.

Q. Describe the source for the betas you used in your CAPM analysis.

A. I used betas recently published by Value Line Investment Survey. The average beta for the proxy group is less than 1.0. Thus, we have an objective measure to prove the well-known concept that utility stocks are generally less risky than the average stock in the market. While there is evidence suggesting that betas published by sources such as Value Line may actually overestimate the risk of utilities (and thus overestimate the CAPM), I used the betas published by Value Line to be conservative.[65]

C. The Equity Risk Premium

Q. Describe the Equity Risk Premium (ERP).

A. The final term of the CAPM is the ERP, which is the required return on the market portfolio less the risk-free rate ($R_M - R_F$). In other words, the ERP is the level of return investors expect above the risk-free rate in exchange for investing in risky securities. Many experts would agree that "the single most important variable for making investment decisions is the equity risk premium."[66] Likewise, the ERP is arguably the single most important factor in estimating the cost of capital in this matter. There are three basic methods that can be used to estimate the ERP: (1) calculating a historical average; (2) taking a survey of experts; and (3) calculating the implied ERP. I will discuss each method in turn, noting advantages and disadvantages of these methods.

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[65] Exhibit DJG-8; *see also* Appendix B for a more detailed discussion of raw beta calculations and adjustments.

[66] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 4 (Princeton University Press 2002).

1. <u>Historical Average</u>

Q. Describe the historical ERP.

A. The historical ERP may be calculated by simply taking the difference between returns on stocks and returns on government bonds over a certain period of time. Many practitioners rely on the historical ERP as an estimate for the forward-looking ERP because it is easy to obtain. However, there are disadvantages to relying on the historical ERP.

Q. What are the limitations of relying solely on a historical average to estimate the current or forward-looking ERP?

A. Many investors use the historic ERP because it is convenient and easy to calculate. What matters in the CAPM model, however, is not the actual risk premium from the past, but rather the current and forward-looking risk premium.[67] Some investors may think that a historic ERP provides some indication of the prospective risk premium; however, there is empirical evidence to suggest the prospective, forward-looking ERP is actually <u>lower</u> than the historical ERP. In a landmark publication on risk premiums around the world, *Triumph of the Optimists*, the authors suggest through extensive empirical research that the prospective ERP is lower than the historical ERP.[68] This is due in large part to what is known as "survivorship bias" or "success bias" – a tendency for failed companies to be excluded from historical indices.[69] From their extensive analysis, the authors make the following conclusion regarding the prospective ERP: "[t]he result is a forward-looking,

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[67] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 330 (3rd ed., South Western Cengage Learning 2010).

[68] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 194 (3rd ed., South Western Cengage Learning 2010).

[69] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 34 (Princeton University Press 2002).

geometric mean risk premium for the United States . . . of around 2½ to 4 percent and an arithmetic mean risk premium . . . that falls within a range from a little below 4 to a little above 5 percent."[70] Indeed, these results are lower than many reported historical risk premiums. Other noted experts agree:

> The historical risk premium obtained by looking at U.S. data is biased upwards because of survivor bias. . . . The true premium, it is argued, is much lower. This view is backed up by a study of large equity markets over the twentieth century (*Triumph of the Optimists*), which concluded that the historical risk premium is closer to 4%.[71]

Regardless of the variations in historic ERP estimates, many scholars and practitioners agree that simply relying on a historic ERP to estimate the risk premium going forward is not ideal. Fortunately, "a naïve reliance on long-run historical averages is not the only approach for estimating the expected risk premium."[72]

Q. Did you rely on the historical ERP as part of your CAPM analysis in this case?

A. No. Due to the limitations of this approach, I relied on the ERP reported in expert surveys and the implied ERP method discussed below.

2. <u>Expert Surveys</u>

Q. Describe the expert survey approach to estimating the ERP.

A. As its name implies, the expert survey approach to estimating the ERP involves conducting a survey of experts including professors, analysts, chief financial officers, and other executives around the country and asking them what they think the ERP is. The IESE

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[70] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 194 (Princeton University Press 2002).

[71] Aswath Damodaran, *Equity Risk Premiums: Determinants, Estimation and Implications – The 2015 Edition* 17 (New York University 2015).

[72] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 330 (3rd ed., South Western Cengage Learning 2010).

Business School conducts such a survey each year. Their 2021 expert survey reported an average ERP of 5.6%.[73]

3. Implied ERP

Q. Describe the implied ERP approach.

A. The third method of estimating the ERP is arguably the best. The implied ERP relies on the stable growth model proposed by Gordon, often called the "Gordon Growth Model," which is a basic stock valuation model widely used in finance for many years.[74] This model is a mathematical derivation of the DCF Model. In fact, the underlying concept in both models is the same: the current value of an asset is equal to the present value of its future cash flows. Instead of using this model to determine the discount rate of one company, we can use it to determine the discount rate for the entire market by substituting the inputs of the model. Specifically, instead of using the current stock price (P_0), we will use the current value of the S&P 500 (V_{500}). Similarly, instead of using the dividends of a single firm, we will consider the dividends paid by the entire market. Additionally, we should consider potential dividends. In other words, stock buybacks should be considered in addition to paid dividends, as stock buybacks represent another way for the firm to transfer free cash flow to shareholders. Focusing on dividends alone without considering stock buybacks could understate the cash flow component of the model, and ultimately understate the

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[73] Pablo Fernandez, Pablo Linares & Isabel F. Acin, *Market Risk Premium used in 171 Countries in 2016: A Survey with 6,932 Answers*, at 3 (IESE Business School 2015), copy available at http://www.valumonics.com/wp-content/uploads/2017/06/Discount-rate-Pablo-Fern%C3%A1ndez.pdf. IESE Business School is the graduate business school of the University of Navarra. IESE offers Master of Business Administration (MBA), Executive MBA and Executive Education programs. IESE is consistently ranked among the leading business schools in the world.

[74] Myron J. Gordon and Eli Shapiro, *Capital Equipment Analysis: The Required Rate of Profit* 102–10 (Management Science Vol. 3, No. 1 Oct. 1956).

implied ERP. The market dividend yield plus the market buyback yield gives us the gross cash yield to use as our cash flow in the numerator of the discount model. This gross cash yield is increased each year over the next five years by the growth rate. These cash flows must be discounted to determine their present value. The discount rate in each denominator is the risk-free rate (R_F) plus the discount rate (K). The following formula shows how the implied return is calculated. Since the current value of the S&P is known, we can solve for K: the implied market return.[75]

Equation 4:
Implied Market Return

$$V_{500} = \frac{CY_1(1+g)^1}{(1+R_F+K)^1} + \frac{CY_2(1+g)^2}{(1+R_F+K)^2} + \cdots + \frac{CY_5(1+g)^5 + TV}{(1+R_F+K)^5}$$

where: V_{500} = *current value of index (S&P 500)*
$CY_{1\text{-}5}$ = *average cash yield over last five years (includes dividends and buybacks)*
g = *compound growth rate in earnings over last five years*
R_F = *risk-free rate*
K = *implied market return (this is what we are solving for)*
TV = *terminal value* $= CY_5\,(1+R_F)\,/\,K$

The discount rate is called the "implied" return here because it is based on the current value of the index as well as the value of free cash flow to investors projected over the next five years. Thus, based on these inputs, the market is "implying" the expected return; or in other words, based on the current value of all stocks (the index price), and the projected value of future cash flows, the market is telling us the return expected by investors for investing in the market portfolio. After solving for the implied market return (K), we simply subtract the risk-free rate from it to arrive at the implied ERP.

[75] *See* Exhibit DJG-9 for detailed calculation.

Equation 5:
Implied Equity Risk Premium

$$Implied\ Expected\ Market\ Return - R_F = Implied\ ERP$$

Q. Discuss the results of your implied ERP calculation.

A. After collecting data for the index value, operating earnings, dividends, and buybacks for the S&P 500 over the past six years, I calculated the dividend yield, buyback yield, and gross cash yield for each year. I also calculated the compound annual growth rate (g) from operating earnings. I used these inputs, along with the risk-free rate and current value of the index to calculate a current expected return on the entire market of 7.2%. I subtracted the risk-free rate to arrive at the implied equity risk premium of 4.9%.[76] Dr. Damodaran, one of the world's leading experts on the ERP, promotes the implied ERP method discussed above. He calculates monthly and annual implied ERPs with this method and publishes his results. Dr. Damodaran's average ERP estimate for June 2021 using several implied ERP variations was 4.5%.[77]

Q. What are the results of your final ERP estimate?

A. For the final ERP estimate I used in my CAPM analysis, I considered the results of the ERP surveys along with the implied ERP calculations and the ERP reported by Duff & Phelps.[78] The results are presented in the following figure:

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[76] Exhibit DJG-9.

[77] Aswath Damodaran, *Implied Equity Risk Premium Update*, DAMODARAN ONLINE http://pages.stern.nyu.edu/~adamodar/.

[78] Exhibit DJG-10.

Figure 11:
Equity Risk Premium Results

IESE Business School Survey	5.6%
Duff & Phelps Report	5.5%
Damodaran (average)	4.5%
Damodaran (COVID Adjusted)	4.2%
Garrett	4.9%
Average	**4.9%**
Highest	**5.6%**

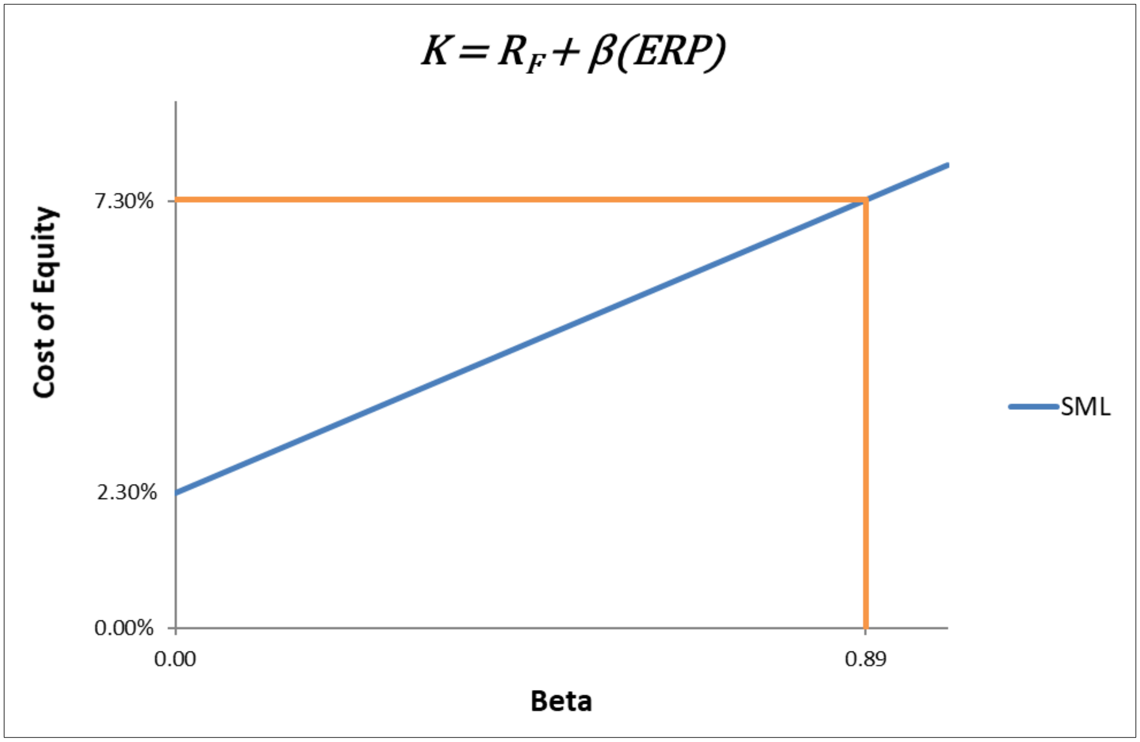
While it would be arguably reasonable to select any one of these ERP estimates to use in the CAPM, to be conservative, I selected the highest ERP estimate of 5.6% to use in my CAPM analysis. All else held constant, a higher ERP used in the CAPM will result in a higher cost of equity estimate.

Q. Please explain the final results of your CAPM analysis.

A. Using the inputs for the risk-free rate, beta coefficient, and ERP discussed above, I estimate that PECO's CAPM cost of equity is 7.3%.[79] The CAPM may be displayed graphically through what is known as the Security Market Line ("SML"). The following figure shows the expected return (cost of equity) on the y-axis, and the average beta for the proxy group on the x-axis. The SML intercepts the y-axis at the level of the risk-free rate. The slope of the SML is the equity risk premium.

[79] Exhibit DJG-11.

Figure 12:
CAPM Graph



The SML provides the rate of return that will compensate investors for the beta risk of that investment. Thus, at an average beta of 0.89 for the proxy group, the estimated CAPM cost of equity for PECO is 7.3%.

D. <u>Response to Mr. Moul's CAPM Analysis</u>

Q. Mr. Moul's CAPM analysis yields notably higher results. Did you find specific problems with Mr. Moul's CAPM assumptions and inputs?

A. Yes, I did. Mr. Moul's estimates a CAPM cost of equity of 11.65%,[80] which is considerably higher than my estimate. The primary problems with Mr. Moul's CAPM cost of equity result stem primarily from his beta and EPR inputs, as further discussed below.

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[80] Exhibit HW-1, Sch. 17, p. 1.

1. Beta

Q. Describe Mr. Moul's beta input to the CAPM.

A. Mr. Moul used a beta of 1.1 in his CAPM.[81] This beta is much higher than the average beta reported by Mr. Moul's proxy group, which is only 0.9.[82] The difference between a beta of 0.9 and 1.1 is significant, especially considering the fact that the beta of the entire market is 1.0. The betas reported by Value Line show that the proxy group is less risky than the market average, while the inflated beta derived by Mr. Moul would indicate the proxy group of utilities is riskier than the market average.

Q. Do you recall ever seeing a cost of capital witness use an average beta of greater than 1.0 to estimate the cost of equity for a utility company?

A. No. Again, I have reviewed dozes of cost of capital testimonies dating back many years, and I cannot recall ever seeing a witness use a beta of greater than 1.0 as the beta in their CAPM. Very rarely, an individual utility company might show a Value Line beta of greater than 1.0, but I have never seen the average beta of the utility proxy group (i.e., the beta an analyst essentially uses in the CAPM) be greater than one.

Q. Do you agree with Mr. Moul's beta input?

A. No. By using a beta of greater than one, Mr. Moul is implying that PECO is riskier than the average company in the U.S. market. Such a proposition contradicts any objective or intuitive understanding of a regulated utility's position and operations in the U.S. market. In fact, it is more accurate to say that PECO, and its utility peers, are among the least risky companies in the world. PECO is a regulated monopoly with a captive customer base who

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[81] Direct Testimony of Paul R. Moul, p. 44, lines 11-14.

[82] Direct Testimony of Paul R. Moul, Exhibit PRM-1, Sch. 10.

provides an essential product with a relatively inelastic demand – operating under a regulatory framework that would essentially prevent it from experiencing financial failure. Competitive firms in the market do not enjoy the same risk-mitigating framework and protections. I have also discussed my disagreement with Mr. Moul's beta input from a technical perspective when I addressed his leverage adjustment above. In short, it is inappropriate to use Value Line betas as a starting point and increasing them to account for leverage. If Value Line betas are unlevered and then relevered, and reasonable inputs are used in the CAPM (including the ERP discussed below), then a more accurate estimate of PECO's cost of equity would be 7.1% (using a re-levered beta at a debt ratio of 45% – which is reflective of PECO's actual debt ratio).[83] This result is much lower than Mr. Moul's 11.65% cost of equity estimate. The Commission should reject Mr. Moul's CAPM results for his beta input alone. However, his estimate for the ERP is also unreasonably high, as further discussed below.

2. <u>Equity Risk Premium</u>

Q. Did Mr. Moul rely on a reasonable measure for the ERP?

A. No, he did not. Mr. Moul used an input of 8.77% for the ERP, which is not realistic.[84] The ERP is one of three inputs in the CAPM equation, and it is one of the most important factors for estimating the cost of equity in this case. As discussed above, I used three widely accepted methods for estimating the ERP, including consulting expert surveys, calculating

[83] *See* Exhibit DJG-15.

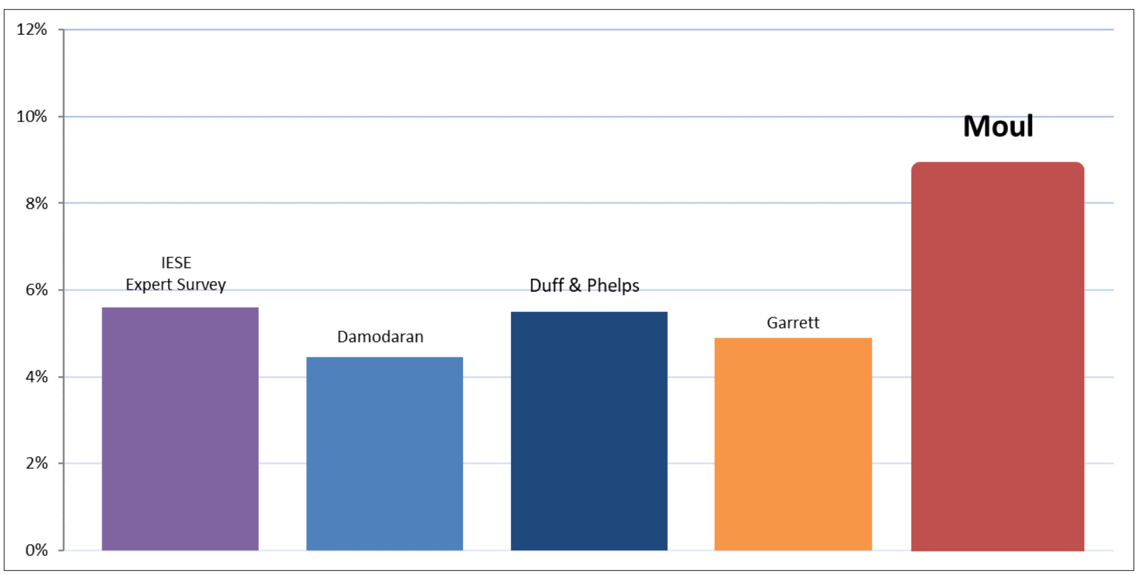
[84] Direct Testimony of Paul R. Moul, p. 44, lines 9-10.

the implied ERP based on aggregate market data, and considering the ERPs published by reputable analysts. The highest ERP found from my research and analysis is only 5.6%.

Q. Please discuss and illustrate how Mr. Moul's ERP compares with other estimates for the ERP.

A. The 2020 IESE Business School expert survey reports an average ERP of 5.6%. Similarly, Duff & Phelps recently estimated an ERP of 5.5%. Dr. Damodaran, one of the leading experts on the ERP, recently estimated an ERP of only 4.5%.[85] The chart in the following figure illustrates that Mr. Moul's ERP estimate is far out of line with other reasonable, objective estimates for the ERP.[86]

Figure 13:
Equity Risk Premium Comparison



[85] Aswath Damodaran, *Implied Equity Risk Premium Update*, DAMODARAN ONLINE, http://pages.stern.nyu.edu/~adamodar/. Dr. Damodaran estimates several ERPs using various assumptions.

[86] The ERP estimated by Dr. Damodaran is the highest of several ERP estimates under slightly differing assumptions.

When compared with other independent sources for the ERP, as well as my estimate, Mr. Moul's ERP estimate is clearly not within the range of reasonableness. As a result, his CAPM cost of equity estimate is overstated.

VIII. OTHER COST OF EQUITY ISSUES

Q. Are there any other issues raised in the Company's testimony to which you would like to respond?

A. Yes. In his testimony, Mr. Moul suggests that certain firm-specific risks and other factors should have an increasing effect on the cost of equity, apparently beyond that which is indicated by the CAPM and DCF Model. Mr. Moul also relies on comparable and expected earnings to support his cost of equity estimate.

A. Firm-Specific Business Risks

Q. Describe Mr. Moul's testimony regarding business risks.

A. In his Direct Testimony, Mr. Moul suggests that the Company is exposed to additional risks beyond those inherent in the proxy group. According to Mr. Moul, such risks include regulatory risks, changing market conditions, and uncertainty in the financial structure of the electric business.[87]

Q. Do you agree with Mr. Moul that these firm-specific risk factors should influence PECO's cost of equity or awarded ROE?

A. No. All companies face business risks, including the other utilities in the proxy group; business risks are not unique to PECO. As discussed above, it is a well-known concept in finance that firm-specific risks are unrewarded by the market. This is largely because firm-

[87] *See* Direct testimony of Paul R. Moul, p. 9, lines 1-12.

specific risk can be eliminated through portfolio diversification. Scholars widely recognize the fact that market risk, or "systematic risk," is the only type of risk for which investors expect a return for bearing.[88]

Unlike interest rate risk, inflation risk, and other market risks that affect all companies in the stock market, the risk factors discussed by Mr. Moul are merely business risks specific to PECO. Investors do not require an additional term for these firm-specific business risks. Another way to consider this issue is to look at the CAPM and DCF Model. Did the creators of these highly regarded cost of equity models, which have been relied upon for decades by companies and investors to make crucial business decisions, simply neglect to add an input for business risks? Of course not. The DCF Model considers stock price, dividends, and a long-term growth rate. The CAPM considers the risk-free rate, beta, and the equity risk premium. Neither model includes an input for business risks due to the well-known truth that investors do not expect a return for such risks. Therefore, the Company's firm-specific business risks, while perhaps relevant to other issues in the rate case, have no meaningful effect on the cost of equity estimate. Rather, it is market risk that is rewarded by the market, and this concept is thoroughly addressed in my CAPM analysis discussed above. Thus, the Commission should reject any additional premium Mr. Moul has added to an already overstated cost of equity estimate to account for any firm-specific risks. This concept was also discussed and illustrated above in my testimony.[89]

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[88] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180 (3rd ed., South Western Cengage Learning 2010).

[89] *See* Section IV above.

B. <u>Comparable Earnings</u>

Q. Please summarize Mr. Moul's comparable earnings approach.

A. Mr. Moul also analyzed the returns realized by non-regulated companies as an indication of PECO's cost of equity.[90] The results of his comparable earnings approach indicate a cost of equity for PECO of 12.6%.[91]

Q. Do you agree with Mr. Moul's analyses?

A. No. There are two notable problems with Mr. Moul's comparable earnings approach: (1) earned returns do not indicate the cost of equity; and (2) there is no marginal value in analyzing competitive firms beyond those of the utility proxy group in terms of assessing a comparable risk profile. First, the earned return of any company should have a meaningful effect on its cost of equity. Conceptually, "earned" returns and "expected" returns are different from each other. For example, we might conduct a cost of equity analysis on Walmart's stock and determine that, based on the risk inherent in that investment, we should "expect" a 10% return on our investment (i.e., the cost of equity from Walmart's perspective). Suppose that Walmart, however, has a bad year and only "earned" a 5% ROE. This does not mean that going forward we will now "expect" a return of only 5% on our equity investment in Walmart. Likewise, the same would be true if Walmart had a good year and earned a 20% return. In finance, the "expected" return on equity as investor (which is synonymous with the "cost" of equity from the company's perspective) is simply based on the risk inherent in that investment, and is not directly

[90] Direct testimony of Paul R. Moul, pp. 44-48.

[91] *Id*. at p. 48, lines 1-2.

influenced by the company's actual, earned return for any given period of time. Thus, Mr. Moul's analysis of earned returns does not add any value for assessing the cost of equity for PECO beyond the results of the CAPM and DCF Model.

The second problem with Mr. Moul's comparable earnings approach is that it uses the earned returns of non-regulated, non-utility companies as an indication of PECO's cost of equity. Despite the title of Mr. Moul's model, competitive, non-utility companies are decisively *incomparable* to PECO. Primarily, the risk profiles of competitive firms will tend to be higher than those of low-risk utilities; thus, their cost of equity estimates will generally be higher. Not surprisingly, the results of Mr. Moul's "comparable" earnings approach are higher than those produced by the models he conducted on the utility proxy group.[92] There is simply no marginal value added to the process of estimating utility cost of equity by using non-utility, non-regulated firms in a proxy group that should contain firms with relatively similar risk profiles to the regulated utility being analyzed. Moreover, the results of Mr. Moul's comparable earnings approach is *more than 500 basis points* above a reasonable estimate for PECO's market-based cost of equity. In addition, Mr. Moul's results are more than 400 basis points above the current "ceiling" for utility cost of equity, which is discussed further below.

[92] Direct Testimony of Paul R. Moul, Exhibit PRM-1, Sch. 1, p. 2.

C. <u>Management Performance Premium</u>

Q. Please describe Mr. Moul's management performance premium.

A. Mr. Moul includes an additional 0.25% to his cost of equity estimate "in recognition of the exemplary performance of the Company's management."[93]

Q. Do you agree with Mr. Moul's management performance premium?

A. No. Such a premium is completely unrelated to PECO's cost of equity estimate. In financial textbooks, treatises, and other authoritative literature, I have not seen anyone suggest that this type of premium should be added to a cost of equity estimate. It is inappropriate to add an arbitrary and unsupported premium on top of awarded ROE recommendation that is at least 300 basis points higher than PECO's actual cost of equity.

Q. Did the Commission recently reject a management performance premium in the PECO Gas case?

A. Yes. In the recent rate case for the PECO Gas division, PECO Gas proposed a 25-basis point premium for management effectiveness.[94] The Commission found that "such an upward adjustment is contrary to the public interest."[95] The Company's management performance claim in this case encompasses activities commenced as early as 2010 or projected to occur well past the end of the FPFTY.[96] Similarly, communications tools implemented by PECO in 2015 and 2018 came several years after introduction by another

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[93] Direct Testimony of Paul R. Moul, p. 2, lines 6-7.

[94] Pa. PUC v. PECO Energy – Gas Div., Docket No. R-2020-3018929, Order at 161-168 (June 22, 2021) (PECO Gas Order).

[95] *Id*. at p. 167.

[96] OCA-XI-3 (Reduction in interruptions in CEMI areas discussed by PECO Witness McDonald direct page 15 based on comparison of 2010-2014 and 2016-2018 measures); OCA-XI-9 (PECO Witness McDonald's direct page 19 discussion of 26,000 poles relates to plans for 2023-2025); OCA-XI-11 (Two of the 6 substation retirements discussed by PECO Witness McDonald direct page 19 will be retired by the end of the FPFTY).

Exelon affiliate.[97] OCA witness Roger Colton's review of the Company's customer service performance does not support the Company's claim. The Company already has an obligation to provide service that is safe, adequate, reasonable and efficient. I recommend the Commission deny the Company's proposed management performance premium in this case for the same reasons that it was denied in the PECO Gas case.

IX. COST OF EQUITY SUMMARY

Q. Please summarize the results of the CAPM and DCF Model discussed above.

A. The following figure shows the cost of equity results from each model I employed in this case.[98]

Figure 14:
Cost of Equity Summary

Model	Cost of Equity
Discounted Cash Flow Model	7.4%
Capital Asset Pricing Model	7.3%
Average	**7.4%**

The average cost of equity resulting from my DCF Model and the CAPM is 7.4%.

[97] OCA-XI-12 (ComEd was the first Exelon utility to launch a mobile application in 2012. PECO first deployed in February 2018. ComEd was the first Exelon utility to develop two-way outage text features in 2012. PECO first deployed this in October 2015).

[98] Exhibit DJG-12.

Q. Is there a market indicator that you can use to test the reasonableness of your cost of equity estimate?

A. Yes, there is. The CAPM is a risk premium model based on the fact that all investors will require, at a minimum, a return equal to the risk-free rate when investing in equity securities, plus a premium, much like the ERP, on top of the risk-free rate to compensate them for the risk they have assumed. This could also be called the market cost of equity. It is undisputed that the cost of equity of utility stocks must be less than the total market cost of equity, again, because utility stocks are less risky than the average stock in the market. Therefore, the market cost of equity gives us a "ceiling" below which PECO's actual cost of equity must lie.

Q. Describe how you estimated the market cost of equity.

A. In estimating the market cost of equity, I relied on the same methods discussed above to estimate the ERP: (1) consulting expert surveys; and (2) calculating the implied ERP. The results of my market cost of equity analysis are presented in the following figure:[99]

Figure 15:
Market Cost of Equity Summary

Source	Estimate
IESE Survey	7.9%
Damodaran	6.8%
Garrett	7.2%
Highest	7.9%

[99] *See also* Exhibit DJG-13.

As shown in this figure, the highest market cost of equity from these sources is only 7.9%. Therefore, it is not surprising that the CAPM and DCF Model indicate a cost of equity for PECO of only 7.4%. In other words, any cost of equity estimates for PECO, or any regulated utility, that is above the market cost of equity should be viewed as unreasonably high. By contrast, Mr. Moul suggests a cost of equity for PECO in this case that is more than 300 basis points above the market cost of equity, which is simply unrealistic and excessive (7.9% vs. 10.95%).

Q. Do you have any other remarks about the cost of equity summary?

A. Yes. I would note that it is quite remarkable that the two cost of equity models in this case, the CAPM and DCF Model, produced nearly identical results. It is especially noteworthy considering the very different inputs used for each model. Again, the DCF Model considers stock prices, dividends, and a long-term growth rate. On the other hand, the CAPM considers the risk-free rate, beta, and the equity risk premium. The inputs to each model are very different, and yet the cost of equity estimates produced by each model are nearly identical.

Q. Please comment on the Commission's preference for DCF Model results.

A. It is my understanding that in prior cases, the Commission has indicated a preference for the results of the DCF Model to estimate cost of equity, while using the CAPM results as an alternative to verify the reasonableness of the results. As discussed above, when reasonable inputs are used in both models (as applied to the proxy group in this case under current market conditions), the results of the models are essentially the same. Again, the results of the DCF Model indicate a cost of equity for PECO of 7.4%[100] Similarly, the results of the CAPM indicate a cost of equity of 7.3%.[101]

X. CAPITAL STRUCTURE

Q. Describe in general the concept of a company's capital structure.

A. "Capital structure" refers to the way a company finances its overall operations through external financing. The primary sources of long-term, external financing are debt capital and equity capital. Debt capital usually comes in the form of contractual bond issues that require the firm to make payments, while equity capital represents an ownership interest in the form of stock. Because a firm cannot pay dividends on common stock until it satisfies its debt obligations to bondholders, stockholders are referred to as "residual claimants." The fact that stockholders have a lower priority to claims on company assets increases their risk and the required return relative to bondholders. Thus, equity capital has a higher cost than debt capital. Firms can reduce their WACC by recapitalizing and increasing their debt financing. In addition, because interest expense is deductible, increasing debt also adds value to the firm by reducing the firm's tax obligation.

Q. Is it true that, by increasing debt, competitive firms can add value and reduce their WACC?

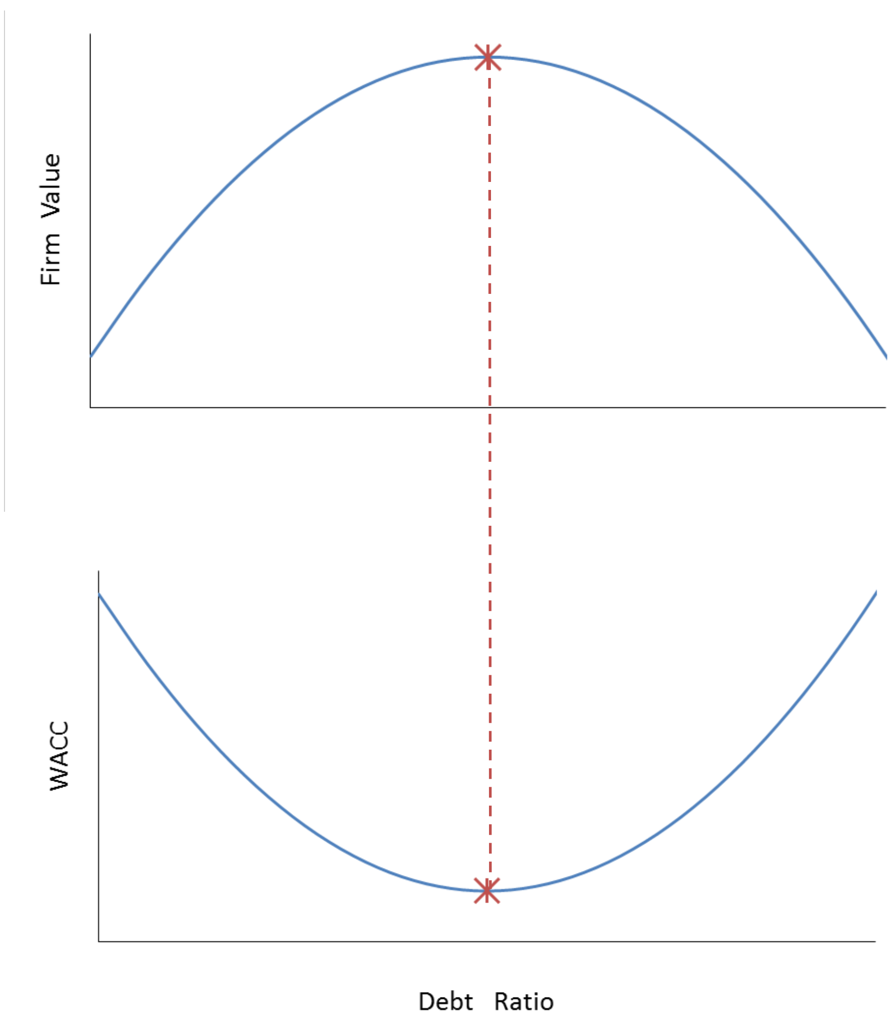
A. Yes, it is. A competitive firm can add value by increasing debt. After a certain point, however, the marginal cost of additional debt outweighs its marginal benefit. This is because the more debt the firm uses, the higher interest expense it must pay, and the

[100] Exhibit DJG-6.

[101] *Id*.

likelihood of loss increases. This also increases the risk of non-recovery for both bondholders and shareholders, causing both groups of investors to demand a greater return on their investment. Thus, if debt financing is too high, the firm's WACC will increase instead of decrease. The following figure illustrates these concepts.

Figure 16:
Optimal Debt Ratio



As shown in this figure, a competitive firm's value is maximized when the WACC is minimized. In both graphs, the debt ratio is shown on the x-axis. By increasing its debt ratio, a competitive firm can minimize its WACC and maximize its value. At a certain point, however, the benefits of increasing debt do not outweigh the costs of the additional risks to both bondholders and shareholders, as each type of investor will demand higher returns for the additional risk they have assumed.[102]

Q. Does the rate base rate of return model effectively incentivize utilities to operate at the optimal capital structure?

A. No. While it is true that competitive firms maximize their value by minimizing their WACC, this is not the case for regulated utilities. Under the rate base rate of return model, a higher WACC results in higher rates, all else held constant. The basic revenue requirement equation is as follows:

Equation 6:
Revenue Requirement for Regulated Utilities

$$RR = O + d + T + \boldsymbol{r}(A - D)$$

$$\begin{array}{lcll} \textit{where:} & RR & = & \textit{revenue requirement} \\ & O & = & \textit{operating expenses} \\ & d & = & \textit{depreciation expense} \\ & T & = & \textit{corporate tax} \\ & \boldsymbol{r} & = & \boldsymbol{\textit{weighted average cost of capital (WACC)}} \\ & A & = & \textit{plant investments} \\ & D & = & \textit{accumulated depreciation} \end{array}$$

As shown in this equation, utilities can increase their revenue requirement by <u>increasing</u> their WACC, not by minimizing it. Thus, because there is no incentive for a regulated utility to minimize its WACC, a commission standing in the place of competition must ensure that the regulated utility is operating at the lowest reasonable WACC.

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[102] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 440-41 (3rd ed., South Western Cengage Learning 2010).

Q. Can utilities generally afford to have higher debt levels than other industries?

A. Yes. Because regulated utilities have large amounts of fixed assets, stable earnings, and low risk relative to other industries, they can afford to have relatively higher debt ratios (or "leverage"). As aptly stated by Dr. Damodaran:

> Since financial leverage multiplies the underlying business risk, it stands to reason that firms that have high business risk should be reluctant to take on financial leverage. It also stands to reason that firms that operate in stable businesses should be much more willing to take on financial leverage. Utilities, for instance, have historically had high debt ratios but have not had high betas, mostly because their underlying businesses have been stable and fairly predictable.[103]

Note that the author explicitly contrasts utilities with firms that have high underlying business risk. Because utilities have low levels of risk and operate a stable business, they should generally operate with relatively high levels of debt to achieve their optimal capital structure.

Q. Are the capital structures of the proxy group a source that can be used to assess a prudent capital structure?

A. Yes. However, while the capital structures of the proxy group might provide some indication of an appropriate capital structure for the utility being studied, it is preferable to also consider additional types of analyses. The average debt ratios of a utility proxy group will likely be lower than what would be observed in a pure competitive environment. As I explain above, this is because utilities do not have a financial incentive to operate at the optimal capital structure.

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[103] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 196 (3rd ed., John Wiley & Sons, Inc. 2012).

Q. How can utility regulatory commissions help overcome the fact that utilities do not have a natural financial incentive to minimize their cost of capital?

A. While under the rate base rate of return model utilities do not have a natural financial incentive to minimize their cost of capital, competitive firms, in contrast, can and do maximize their value by minimizing their cost of capital. Competitive firms minimize their cost of capital by including a sufficient amount of debt in their capital structures. They do not do this because it is required by a regulatory body, but rather because their shareholders demand it in order to maximize value. The Commission can provide this incentive to PECO by acting as a surrogate for competition and setting rates consistent with a capital structure that is similar to what would be appropriate in a competitive, as opposed to a regulated, environment.

Q. Please describe the analyses you conducted to assess a reasonable regulatory capital structure for PECO.

A. I conducted several types of analyses of PECO's optimal capital structure for ratemaking purposes. First, I performed a quantitative analysis that considers PECO's WACC at various debt ratios to see which debt ratio indicates a minimized WACC. Second, I considered the debt ratios of the proxy group. Finally, I also looked at the debt ratios reported from thousands of other firms across the country to compare PECO's proposed debt ratio to the observed debt ratios in other industries. These approaches are discussed in more detail below.

Q. Describe an objective approach to estimating a company's optimal capital structure.

A. My analysis of the optimal capital structure includes objective methods to measure the effects of increasing debt on both the cost of debt and cost of equity. I will discuss the effects of increasing the debt ratio on each type of security separately.

Cost of Debt

As discussed above, increasing the debt ratio will increase the cost of debt. To objectively measure how much the cost of debt increases, I considered the spreads above the risk-free rate for various levels of bond ratings and interest coverage ratios. The following table shows increasing interest rates for debt based on different bond rating levels.

Figure 17:
Bond Rating Spreads

Ratings Table			
Coverage Ratio	Bond Rating	Spread	Interest Rate
8.5 - 10.00	Aaa/AAA	0.69%	2.99%
6.5 - 8.49	Aa2/AA	0.85%	3.15%
5.5 - 6.49	A1/A+	1.07%	3.37%
4.25 - 5.49	A2/A	1.18%	3.48%
3.0 - 4.24	A3/A-	1.33%	3.63%
2.5 - 2.99	Baa2/BBB	1.71%	4.01%
2.25 - 2.49	Ba1/BB+	2.31%	4.61%
2.0 - 2.24	Ba2/BB	2.77%	5.07%
1.75 - 1.99	B1/B+	4.05%	6.35%
1.5 - 1.74	B2/B	4.86%	7.16%
1.25 - 1.49	B3/B-	5.94%	8.24%
0.8 - 1.24	Caa/CCC	9.46%	11.76%

As shown in this table, the spreads over the risk-free rate gradually increase as bond ratings fall.[104] The spread is added to the risk-free rate to obtain the interest rates shown in the far-right column. This concept is somewhat comparable to the interest rate a mortgage lender would charge a borrower. The mortgage lender's advertised rate is usually the lowest rate, or the "prime" rate, which is available to borrowers with stellar credit scores. As credit scores decrease, however, the offered interest rate will increase. The bond ratings in this figure are based on various levels of interest coverage ratios shown in the far-left column. The interest coverage ratio, as its name implies, is a metric used by financial analysts to gauge a firm's ability to pay its interest expense from its available earnings before interest and taxes (EBIT). (Likewise, the mortgage lender would consider the borrower's personal income-debt ratio). The formula for the interest coverage ratio is as follows:

Equation 7:
Interest Coverage Ratio

$$\frac{Earnings\ before\ Interest\ and\ Taxes}{Interest\ Expense}$$

As the debt ratio rises, the interest coverage ratio falls, the bond ratings increase, and the cost of debt increases. Now that we have an objective way of measuring how increasing the debt ratio affects the cost of debt, we need to measure how increasing the debt ratio affects the cost of equity.

[104] The link between interest coverage ratios and ratings was developed by looking at all rated companies in the U.S. The default spreads are obtained from traded bonds. The spreads are added to the risk-free rate to obtain the interest rates in the table. Aswath Damodaran, *Ratings, Interest Coverage Ratios and Default Spread*, N.Y. UNIV. (Jan. 2019) http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/ratings.htm.

Cost of Equity

As with the cost of debt, increasing the debt ratio also increases the cost of equity. To objectively measure how much the cost of equity increases, I first calculated the Company's unlevered beta. The unlevered beta is determined by the assets owned by the firm and removes the effects of financial leverage. As leverage increases, equity investors bear increasing amounts of risk, leading to higher betas. Before the effects of financial leverage can be accounted for, however, the effects of leverage must first be removed, which is accomplished through the unlevered beta equation:[105]

Equation 8:
Unlevered Beta

$$\beta_U = \frac{\beta_L}{\left[1 + (1 - T_c)\left(\frac{D}{E}\right)\right]}$$

where:	β_U	=	*unlevered beta (or "asset" beta)*
	β_L	=	*average levered beta of proxy group*
	T_C	=	*corporate tax rate*
	D	=	*book value of debt*
	E	=	*book value of equity*

Using this equation, the beta for the firm can be unlevered, and then "re-levered" based on various debt ratios (by rearranging this equation to solve for β_L). So, by using the Bond Rating Spreads table and the unlevered beta equation, the costs of both debt and equity can be increased in correspondence with increasing the debt ratio, until the ideal capital structure is found: where the weighted average cost of capital is minimized.

[105] Garrett, Exh. DJG-11 (Aswath Damodaran, INVESTMENT VALUATION: TOOLS AND TECHNIQUES FOR DETERMINING THE VALUE OF ANY ASSET (John Wiley & Sons, Inc. 3d. ed. 2012)).

Q. Describe the results of your optimal capital structure analysis.

A. I analyzed the Company's optimal capital structure based on the approach discussed above. The following table presents different levels of PECO's weighted average cost of capital (WACC) based on increasing debt ratios.[106]

Figure 18:
PECO's WACC at Various Debt Ratios

Debt Ratio	Levered Beta	Cost of Equity	Proposed ROE	Coverage Ratio	After-tax Debt Cost	Optimal WACC	WACC at 8.5% ROE
0%	0.527	5.25%	8.50%	∞	2.31%	5.25%	8.50%
20%	0.631	5.84%	8.50%	8.30	2.49%	5.17%	7.30%
30%	0.705	6.25%	8.50%	5.53	2.66%	5.17%	6.75%
40%	0.804	6.81%	8.50%	4.15	2.87%	5.23%	6.25%
45%	0.867	7.16%	8.50%	3.69	2.87%	5.23%	5.97%
50%	0.943	7.58%	8.50%	3.32	2.87%	5.23%	5.68%
55%	1.035	8.10%	8.50%	3.02	2.87%	5.22%	5.40%
60%	1.151	8.75%	8.50%	2.77	3.17%	5.40%	5.30%

In the figure above, the column on the far left shows increasing levels of debt ratios. At a debt ratio of 0%, the utility's beta is completely unlevered. As the debt ratio in the far-left column increases, both the cost of equity and the cost of debt increase; however, the weighted average cost of capital generally decreases to a certain point. This table indicates that at my recommended 8.5% ROE, the Company's overall weighted average cost of capital would be minimized at a debt ratio of about 55%.[107] This model is not intended to produce an exact mathematical calculation of PECO's most appropriate debt ratio (where WACC is minimized), but rather provides another objective indication that PECO's

[106] Exhibit DJG-15.

[107] In the table, the WACC is further minimized at a debt ratio of 60%. While debt ratios this high are not uncommon in other industries, and may arguably be appropriate for some regulated utilities, in this particular model, a debt ratio of 60% corresponds with a credit rating that is below investment grade.

proposed debt ratio is far too low to be considered reasonable. This conclusion is further solidified by looking at the other two approaches for estimating PECO's appropriate capital structures – the proxy group and competitive industry comparisons – which are further discussed below.

Q. Please describe the debt ratios of the proxy group.

A. Again, Mr. Moul and I used the same proxy group of utilities for our cost of capital analyses. The proxy group of utilities reported an average debt ratio of 54%, which is considerably higher than PECO's proposed debt ratio.[108]

Q. Did you also look at other competitive firms around the country to compare their debt ratios?

A. Yes. In fact, there are currently more than 3,000 firms in various industries across the country with debt ratios of 50% or greater, with an average debt ratio of 64 percent.[109] The following figure shows a sample of these industries, with debt ratios of at least 57%.

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[108] Exhibit DJG-16.

[109] Exhibit DJG-17.

Figure 19:
Industries with Debt Ratios of 57% or Greater

Industry	# Firms	Debt Ratio
Financial Svcs. (Non-bank & Insurance)	235	95%
Retail (Building Supply)	15	88%
Hospitals/Healthcare Facilities	32	84%
Air Transport	17	84%
Advertising	61	81%
Hotel/Gaming	66	77%
Brokerage & Investment Banking	39	77%
Auto & Truck	19	75%
Retail (Automotive)	30	74%
Food Wholesalers	18	74%
Retail (Special Lines)	85	72%
Recreation	69	71%
Bank (Money Center)	7	68%
Retail (Grocery and Food)	14	68%
Transportation	21	68%
Computers/Peripherals	52	68%
Packaging & Container	26	67%
Broadcasting	29	65%
Rubber& Tires	3	64%
Beverage (Soft)	41	64%
Chemical (Basic)	48	62%
Oil/Gas Distribution	57	62%
Cable TV	13	61%
R.E.I.T.	238	61%
Apparel	51	61%
Trucking	35	61%
Computer Services	116	61%
Retail (Distributors)	85	60%
Telecom (Wireless)	16	**60%**
Power	55	**60%**
Farming/Agriculture	32	59%
Business & Consumer Services	169	59%
Aerospace/Defense	72	59%
Utility (Water)	17	**59%**
Telecom. Services	58	59%
Retail (Online)	75	58%
Software (Internet)	36	57%
Household Products	140	57%
Construction Supplies	46	57%
Total / Average	**2,238**	**67%**

Many of the industries shown here, like public utilities, are generally well-established industries with large amounts of capital assets. The shareholders of these industries demand higher debt ratios in order to maximize their profits. There are several notable industries that are relatively comparable to public utilities in some respects. For example, the Wireless Telecom, Water Utility, Power, and Cable T.V. industries have average debt ratios of about 60%. These debt ratios, as well as the average debt ratio of the utility proxy group, are notably higher than PECO's proposed debt ratio of only 46.59%.

Q. What is your recommendation regarding the Company's capital structure?

A. The objective analysis above, as well as the proxy group analysis, strongly indicates that PECO's proposed debt ratio is too low to be considered fair for ratemaking. An insufficiently low debt ratio causes the weighted average cost of capital to be unreasonably high. The table below compares the various debt ratios discussed in my testimony, and it highlights the unreasonableness of PECO's proposed debt ratio.

Figure 20:
Debt Ratio Comparison

Source	Debt Ratio
Cable TV	61%
Telecom (Wireless)	60%
Power	60%
Utility (Water)	59%
Optimal Capital Structure Analysis	55%
Proxy Group of Utilities	54%
Garrett Proposal	**50%**
Company's Proposal	**47%**

Based on my findings, I recommend the Commission impute a capital structure for ratemaking purposes consisting of 50% debt and 50% equity. Although my findings indicate PECO's debt ratio should arguably be higher than 50%, I am recommending a 50% debt ratio in the interest of reasonableness and gradualism.

Q. If the Commission were to adopt PECO's proposed debt ratio, would that decision further reduce PECO's low-risk profile?

A. Yes. As illustrated in the optimal capital structure table above, increasing the debt ratio to an optimal level effectively minimizes the weighted average cost of capital. However, if PECO's authorized ROE is higher than its cost of equity, it will increase the WACC beyond its lowest optimal level. Thus, if the Commission were to approve PECO's low debt ratio, it should also strongly consider a meaningful reduction in its authorized ROE.

Q. Does this conclude your testimony?

A. Yes. To the extent I have not addressed an issue or proposal raised by the Company in this proceeding, it should not be construed that I agree with the same.

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APPENDIX A:

DISCOUNTED CASH FLOW MODEL THEORY

The Discounted Cash Flow ("DCF") Model is based on a fundamental financial model called the "dividend discount model," which maintains that the value of a security is equal to the present value of the future cash flows it generates. Cash flows from common stock are paid to investors in the form of dividends. There are several variations of the DCF Model. In its most general form, the DCF Model is expressed as follows:[110]

Equation 9:
General Discounted Cash Flow Model

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_n}{(1+k)^n}$$

where:	P_0	=	*current stock price*
	$D_1 \ldots D_n$	=	*expected future dividends*
	k	=	*discount rate / required return*

The General DCF Model would require an estimation of an infinite stream of dividends. Because this would be impractical, analysts use more feasible variations of the General DCF Model, which are discussed further below.

The DCF Models rely on the following four assumptions:[111]

1. Investors evaluate common stocks in the classical valuation framework; that is, they trade securities rationally at prices reflecting their perceptions of value;

2. Investors discount the expected cash flows at the same rate (K) in every future period;

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[110] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 410 (9th ed., McGraw-Hill/Irwin 2013).

[111] *See* Roger A. Morin, *New Regulatory Finance* 252 (Public Utilities Reports, Inc. 2006) (1994).

3. The K obtained from the DCF equation corresponds to that specific stream of future cash flows alone; and

4. Dividends, rather than earnings, constitute the source of value.

The General DCF can be rearranged to make it more practical for estimating the cost of equity. Regulators typically rely on some variation of the Constant Growth DCF Model, which is expressed as follows:

Equation 10:
Constant Growth Discounted Cash Flow Model

$$K = \frac{D_1}{P_0} + g$$

where:	K	=	*discount rate / required return on equity*
	D_1	=	*expected dividend per share one year from now*
	P_0	=	*current stock price*
	g	=	*expected growth rate of future dividends*

Unlike the General DCF Model, the Constant Growth DCF Model solves for the required return (*K*) directly. In addition, by assuming that dividends grow at a constant rate, the dividend stream from the General DCF Model may be substituted with a term representing the expected constant growth rate of future dividends (*g*). The Constant Growth DCF Model may be considered in two parts. The first part is the dividend yield (D_1/P_0), and the second part is the growth rate (*g*). In other words, the required return in the DCF Model is equivalent to the dividend yield plus the growth rate.

In addition to the four assumptions listed above, the Constant Growth DCF Model relies on the following four additional assumptions:[112]

[112] *See* Roger A. Morin, *New Regulatory Finance* 254–56 (Public Utilities Reports, Inc. 2006) (1994).

1. The discount rate (K) must exceed the growth rate (g);

2. The dividend growth rate (g) is constant in every year to infinity;

3. Investors require the same return (K) in every year; and

4. There is no external financing; that is, growth is provided only by the retention of earnings.

Because the growth rate in this model is assumed to be constant, it is important not to use growth rates that are unreasonably high. In fact, the constant growth rate estimate for a regulated utility with a defined service territory should not exceed the growth rate for the economy in which it operates.

The basic form of the Constant Growth DCF Model described above is sometimes referred to as the "Annual" DCF Model. This is because the model assumes an annual dividend payment to be paid at the end of every year, as well as an increase in dividends once each year. In reality, however, most utilities pay dividends on a quarterly basis. The Constant Growth DCF equation may be modified to reflect the assumption that investors receive successive quarterly dividends and reinvest them throughout the year at the discount rate. This variation is called the Quarterly Approximation DCF Model.[113]

Equation 11:
Quarterly Approximation Discounted Cash Flow Model

$$K = \left[\frac{d_0(1+g)^{1/4}}{P_0} + (1+g)^{1/4}\right]^4 - 1$$

where:	K	=	*discount rate / required return*
	d_0	=	*current quarterly dividend per share*
	P_0	=	*stock price*
	g	=	*expected growth rate of future dividends*

[113] *See* Roger A. Morin, *New Regulatory Finance* 348 (Public Utilities Reports, Inc. 2006) (1994).

The Quarterly Approximation DCF Model assumes that dividends are paid quarterly, and that each dividend is constant for four consecutive quarters. All else held constant, this model results in the highest cost of equity estimate for the utility in comparison to other DCF Models because it accounts for the quarterly compounding of dividends. There are several other variations of the Constant Growth (or Annual) DCF Model, including a Semi-Annual DCF Model, which is used by the Federal Energy Regulatory Commission ("FERC"). These models, along with the Quarterly Approximation DCF Model, have been accepted in regulatory proceedings as useful tools for estimating the cost of equity.

APPENDIX B:

CAPITAL ASSET PRICING MODEL THEORY

The Capital Asset Pricing Model ("CAPM") is a market-based model founded on the principle that investors demand higher returns for incurring additional risk.[114] The CAPM estimates this required return. The CAPM relies on the following assumptions:

1. Investors are rational, risk-adverse, and strive to maximize profit and terminal wealth;

2. Investors make choices based on risk and return. Return is measured by the mean returns expected from a portfolio of assets; risk is measured by the variance of these portfolio returns;

3. Investors have homogenous expectations of risk and return;

4. Investors have identical time horizons;

5. Information is freely and simultaneously available to investors;

6. There is a risk-free asset, and investors can borrow and lend unlimited amounts at the risk-free rate;

7. There are no taxes, transaction costs, restrictions on selling short, or other market imperfections; and

8. Total asset quality is fixed, and all assets are marketable and divisible.[115]

While some of these assumptions may appear to be restrictive, they do not outweigh the inherent value of the model. The CAPM has been widely used by firms, analysts, and regulators for decades to estimate the cost of equity capital.

The basic CAPM equation is expressed as follows:

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[114] William F. Sharpe, *A Simplified Model for Portfolio Analysis* 277-93 (Management Science IX 1963).

[115] *Id.*

Equation 12:
Capital Asset Pricing Model

$$K = R_F + \beta_i(R_M - R_F)$$

where:	K	=	*required return*
	R_F	=	*risk-free rate*
	β	=	*beta coefficient of asset i*
	R_M	=	*required return on the overall market*

There are essentially three terms within the CAPM equation that are required to calculate the required return (K): (1) the risk-free rate (R_F); (2) the beta coefficient (β); and (3) the equity risk premium ($R_M - R_F$), which is the required return on the overall market less the risk-free rate.

Raw Beta Calculations and Adjustments.

A stock's beta equals the covariance of the asset's returns with the returns on a market portfolio, divided by the portfolio's variance, as expressed in the following formula:[116]

Equation 13:
Beta

$$\beta_i = \frac{\sigma_{im}}{\sigma_m^2}$$

where:	β_i	=	*beta of asset i*
	σ_{im}	=	*covariance of asset i returns with market portfolio returns*
	σ^2_m	=	*variance of market portfolio*

Betas that are published by various research firms are typically calculated through a regression analysis that considers the movements in price of an individual stock and movements in the price of the overall market portfolio. The betas produced by this regression analysis are considered "raw" betas. There is empirical evidence that raw betas should be adjusted to account

[116] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180–81 (3rd ed., South Western Cengage Learning 2010).

for beta's natural tendency to revert to an underlying mean.[117] Some analysts use an adjustment method proposed by Blume, which adjusts raw betas toward the market mean of one.[118] While the Blume adjustment method is popular due to its simplicity, it is arguably arbitrary, and some would say not useful at all. According to Dr. Damodaran: "While we agree with the notion that betas move toward 1.0 over time, the [Blume adjustment] strikes us as arbitrary and not particularly useful."[119] The Blume adjustment method is especially arbitrary when applied to industries with consistently low betas, such as the utility industry. For industries with consistently low betas, it is better to employ an adjustment method that adjusts raw betas toward an industry average, rather than the market average. Vasicek proposed such a method, which is preferable to the Blume adjustment method because it allows raw betas to be adjusted toward an industry average, and also accounts for the statistical accuracy of the raw beta calculation.[120] In other words, "[t]he Vasicek adjustment seeks to overcome one weakness of the Blume model by not applying the same adjustment to every security; rather, a security-specific adjustment is made depending on the statistical quality of the regression."[121] The Vasicek beta adjustment equation is expressed as follows:

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[117] *See* Michael J. Gombola and Douglas R. Kahl, *Time-Series Processes of Utility Betas: Implications for Forecasting Systematic Risk* 84–92 (Financial Management Autumn 1990).

[118] See Marshall Blume, *On the Assessment of Risk*, Vol. 26, No. 1 The Journal of Finance 1 (1971).

[119] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 187 (3rd ed., John Wiley & Sons, Inc. 2012).

[120] Oldrich A. Vasicek, *A Note on Using Cross-Sectional Information in Bayesian Estimation of Security Betas* 1233–1239 (Journal of Finance, Vol. 28, No. 5, December 1973).

[121] 2012 Ibbotson Stocks, Bonds, Bills, and Inflation Valuation Yearbook 77–78 (Morningstar 2012).

Equation 14:
Vasicek Beta Adjustment

$$\beta_{i1} = \frac{\sigma^2_{\beta_{i0}}}{\sigma^2_{\beta 0} + \sigma^2_{\beta_{i0}}}\beta_0 + \frac{\sigma^2_{\beta 0}}{\sigma^2_{\beta 0} + \sigma^2_{\beta_{i0}}}\beta_{i0}$$

where:	β_{i1}	=	*Vasicek adjusted beta for security i*
	β_{i0}	=	*historical beta for security i*
	β_0	=	*beta of industry or proxy group*
	$\sigma^2_{\beta 0}$	=	*variance of betas in the industry or proxy group*
	$\sigma^2_{\beta i0}$	=	*square of standard error of the historical beta for security i*

The Vasicek beta adjustment is an improvement on the Blume model because the Vasicek model does not apply the same adjustment to every security. A higher standard error produced by the regression analysis indicates a lower statistical significance of the beta estimate. Thus, a beta with a high standard error should receive a greater adjustment than a beta with a low standard error. As stated in Ibbotson:

> While the Vasicek formula looks intimidating, it is really quite simple. The adjusted beta for a company is a weighted average of the company's historical beta and the beta of the market, industry, or peer group. How much weight is given to the company and historical beta depends on the statistical significance of the company beta statistic. If a company beta has a low standard error, then it will have a higher weighting in the Vasicek formula. If a company beta has a high standard error, then it will have lower weighting in the Vasicek formula. An advantage of this adjustment methodology is that it does not force an adjustment to the market as a whole. Instead, the adjustment can be toward an industry or some other peer group. <u>This is most useful in looking at companies in industries that on average have high or low betas</u>.[122]

Thus, the Vasicek adjustment method is statistically more accurate and is the preferred method to use when analyzing companies in an industry that has inherently low betas, such as the utility industry. The Vasicek method was also confirmed by Gombola, who conducted a study

[122] 2012 Ibbotson Stocks, Bonds, Bills, and Inflation Valuation Yearbook 78 (Morningstar 2012).

specifically related to utility companies. Gombola concluded that "[t]he strong evidence of auto-regressive tendencies in <u>utility</u> betas lends support to the application of adjustment procedures such as the . . . adjustment procedure presented by Vasicek."[123] Gombola also concluded that adjusting raw betas toward the market mean of 1.0 is <u>too high</u>, and that "[i]nstead, they should be adjusted toward a value that is less than one."[124] In conducting the Vasicek adjustment on betas in previous cases, it reveals that utility betas are even lower than those published by Value Line.[125] Gombola's findings are particular important here, because his study was conducted specifically on utility companies. This evidence indicates that using Value Line's betas in a CAPM cost of equity estimate for a utility company may lead to overestimated results. Regardless, adjusting betas to a level that is <u>higher</u> than Value Line's betas is not reasonable, and it would produce CAPM cost of equity results that are too high.

[123] Michael J. Gombola and Douglas R. Kahl, *Time-Series Processes of Utility Betas: Implications for Forecasting Systematic Risk* 92 (Financial Management Autumn 1990) (emphasis added).

[124] Michael J. Gombola and Douglas R. Kahl, *Time-Series Processes of Utility Betas: Implications for Forecasting Systematic Risk* 91–92 (Financial Management Autumn 1990) (emphasis added).

[125] *See e.g.* Responsive Testimony of David J. Garrett, filed March 21, 2016 in Cause No. PUD 201500273 before the Corporation Commission of Oklahoma (OG&E's 2015 rate case), at pp. 56–59.

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EDUCATION

University of Oklahoma — Norman, OK
Master of Business Administration — 2014
Areas of Concentration: Finance, Energy

University of Oklahoma College of Law — Norman, OK
Juris Doctor — 2007
Member, American Indian Law Review

University of Oklahoma — Norman, OK
Bachelor of Business Administration — 2003
Major: Finance

PROFESSIONAL DESIGNATIONS

Society of Depreciation Professionals
Certified Depreciation Professional (CDP)

Society of Utility and Regulatory Financial Analysts
Certified Rate of Return Analyst (CRRA)

The Mediation Institute
Certified Civil / Commercial & Employment Mediator

WORK EXPERIENCE

Resolve Utility Consulting PLLC — Oklahoma City, OK
Managing Member — 2016 – Present
Provide expert analysis and testimony specializing in depreciation and cost of capital issues for clients in utility regulatory proceedings.

Oklahoma Corporation Commission — Oklahoma City, OK
Public Utility Regulatory Analyst — 2012 – 2016
Assistant General Counsel — 2011 – 2012
Represented commission staff in utility regulatory proceedings and provided legal opinions to commissioners. Provided expert analysis and testimony in depreciation, cost of capital, incentive compensation, payroll and other issues.

Perebus Counsel, PLLC — Oklahoma City, OK
Managing Member — 2009 – 2011
Represented clients in the areas of family law, estate planning, debt negotiations, business organization, and utility regulation.

Moricoli & Schovanec, P.C. — Oklahoma City, OK
Associate Attorney — 2007 – 2009
Represented clients in the areas of contracts, oil and gas, business structures and estate administration.

TEACHING EXPERIENCE

University of Oklahoma — Norman, OK
Adjunct Instructor – "Conflict Resolution" — 2014 – Present
Adjunct Instructor – "Ethics in Leadership"

Rose State College — Midwest City, OK
Adjunct Instructor – "Legal Research" — 2013 – 2015
Adjunct Instructor – "Oil & Gas Law"

PUBLICATIONS

American Indian Law Review — Norman, OK
"Vine of the Dead: Reviving Equal Protection Rites for Religious Drug Use" — 2006
(31 Am. Indian L. Rev. 143)

VOLUNTEER EXPERIENCE

Calm Waters — Oklahoma City, OK
Board Member — 2015 – 2018
Participate in management of operations, attend meetings, review performance, compensation, and financial records. Assist in fundraising events.

Group Facilitator & Fundraiser — 2014 – 2018
Facilitate group meetings designed to help children and families cope with divorce and tragic events. Assist in fundraising events.

St. Jude Children's Research Hospital — Oklahoma City, OK
Oklahoma Fundraising Committee — 2008 – 2010
Raised money for charity by organizing local fundraising events.

PROFESSIONAL ASSOCIATIONS

Oklahoma Bar Association 2007 – Present

Society of Depreciation Professionals 2014 – Present
Board Member – President 2017
Participate in management of operations, attend meetings, review performance, organize presentation agenda.

Society of Utility Regulatory Financial Analysts 2014 – Present

SELECTED CONTINUING PROFESSIONAL EDUCATION

Society of Depreciation Professionals — Austin, TX
"Life and Net Salvage Analysis" — 2015
Extensive instruction on utility depreciation, including actuarial and simulation life analysis modes, gross salvage, cost of removal, life cycle analysis, and technology forecasting.

Society of Depreciation Professionals — New Orleans, LA
"Introduction to Depreciation" and "Extended Training" — 2014
Extensive instruction on utility depreciation, including average lives and net salvage.

Society of Utility and Regulatory Financial Analysts — Indianapolis, IN
46th Financial Forum. "The Regulatory Compact: Is it Still Relevant?" — 2014
Forum discussions on current issues.

New Mexico State University, Center for Public Utilities — Santa Fe, NM
Current Issues 2012, "The Santa Fe Conference" — 2012
Forum discussions on various current issues in utility regulation.

Michigan State University, Institute of Public Utilities — Clearwater, FL
"39th Eastern NARUC Utility Rate School" — 2011
One-week, hands-on training emphasizing the fundamentals of the utility ratemaking process.

New Mexico State University, Center for Public Utilities — Albuquerque, NM
"The Basics: Practical Regulatory Training for the Changing Electric Industries" — 2010
One-week, hands-on training designed to provide a solid foundation in core areas of utility ratemaking.

The Mediation Institute — Oklahoma City, OK
"Civil / Commercial & Employment Mediation Training" — 2009
Extensive instruction and mock mediations designed to build foundations in conducting mediations in civil matters.

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Indiana Utility Regulatory Commission	Southern Indiana Gas Company, d/b/a Vectren Energy Delivery of Indiana, Inc.	45447	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 51415	Depreciation rates, service lives, net salvage	Cities Advocating Reasonable Deregulation
New Mexico Public Regulatory Commission	Avangrid, Inc., Avangrid Networks, Inc., NM Green Holdings, Inc., PNM, and PNM Resources	20-00222-UT	Ring fencing and capital structure	The Albuquerque Bernalillo County Water Utility Authority
Indiana Utility Regulatory Commission	Indiana Gas Company, d/b/a Vectren Energy Delivery of Indiana, Inc.	45468	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Utilities Commission of Nevada	Nevada Power Company and Sierra Pacific Power Company, d/b/a NV Energy	20-07023	Construction work in progress	MGM Resorts International, Caesars Enterprise Services, LLC, and the Southern Nevada Water Authority
Massachusetts Department of Public Utilities	Boston Gas Company, d/b/a National Grid	D.P.U. 20-120	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Public Service Commission of the State of Montana	ABACO Energy Services, LLC	D2020.07.082	Cost of capital and authorized rate of return	Montana Consumer Counsel
Maryland Public Service Commission	Washington Gas Light Company	9651	Cost of capital and authorized rate of return	Maryland Office of People's Counsel
Florida Public Service Commission	Utilities, Inc. of Florida	20200139-WS	Cost of capital and authorized rate of return	Florida Office of Public Counsel
New Mexico Public Regulatory Commission	El Paso Electric Company	20-00104-UT	Cost of capital, depreciation rates, net salvage	City of Las Cruces and Doña Ana County
Public Utilities Commission of Nevada	Nevada Power Company	20-06003	Cost of capital, awarded rate of return, capital structure, earnings sharing	MGM Resorts International, Caesars Enterprise Services, LLC, Wynn Las Vegas, LLC, Smart Energy Alliance, and Circus Circus Las Vegas, LLC
Wyoming Public Service Commission	Rocky Mountain Power	20000-578-ER-20	Cost of capital and authorized rate of return	Wyoming Industrial Energy Consumers
Florida Public Service Commission	Peoples Gas System	20200051-GU 20200166-GU	Cost of capital, depreciation rates, net salvage	Florida Office of Public Counsel
Wyoming Public Service Commission	Rocky Mountain Power	20000-539-EA-18	Depreciation rates, service lives, net salvage	Wyoming Industrial Energy Consumers

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Public Service Commission of South Carolina	Dominion Energy South Carolina	2020-125-E	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Pennsylvania Public Utility Commission	The City of Bethlehem	2020-3020256	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Railroad Commission of Texas	Texas Gas Services Company	GUD 10928	Depreciation rates, service lives, net salvage	Gulf Coast Service Area Steering Committee
Public Utilities Commission of the State of California	Southern California Edison	A.19-08-013	Depreciation rates, service lives, net salvage	The Utility Reform Network
Massachusetts Department of Public Utilities	NSTAR Gas Company	D.P.U. 19-120	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Georgia Public Service Commission	Liberty Utilities (Peach State Natural Gas)	42959	Depreciation rates, service lives, net salvage	Public Interest Advocacy Staff
Florida Public Service Commission	Florida Public Utilities Company	20190155-EI 20190156-EI 20190174-EI	Depreciation rates, service lives, net salvage	Florida Office of Public Counsel
Illinois Commerce Commission	Commonwealth Edison Company	20-0393	Depreciation rates, service lives, net salvage	The Office of the Illinois Attorney General
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 49831	Depreciation rates, service lives, net salvage	Alliance of Xcel Municipalities
Public Service Commission of South Carolina	Blue Granite Water Company	2019-290-WS	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Railroad Commission of Texas	CenterPoint Energy Resources	GUD 10920	Depreciation rates and grouping procedure	Alliance of CenterPoint Municipalities
Pennsylvania Public Utility Commission	Aqua Pennsylvania Wastewater	A-2019-3009052	Fair market value estimates for wastewater assets	Pennsylvania Office of Consumer Advocate
New Mexico Public Regulation Commission	Southwestern Public Service Company	19-00170-UT	Cost of capital and authorized rate of return	The New Mexico Large Customer Group; Occidental Permian
Indiana Utility Regulatory Commission	Duke Energy Indiana	45253	Cost of capital, depreciation rates, net salvage	Indiana Office of Utility Consumer Counselor

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Maryland Public Service Commission	Columbia Gas of Maryland	9609	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel
Washington Utilities & Transportation Commission	Avista Corporation	UE-190334	Cost of capital, awarded rate of return, capital structure	Washington Office of Attorney General
Indiana Utility Regulatory Commission	Indiana Michigan Power Company	45235	Cost of capital, depreciation rates, net salvage	Indiana Office of Utility Consumer Counselor
Public Utilities Commission of the State of California	Pacific Gas & Electric Company	18-12-009	Depreciation rates, service lives, net salvage	The Utility Reform Network
Oklahoma Corporation Commission	The Empire District Electric Company	PUD 201800133	Cost of capital, authorized ROE, depreciation rates	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results
Arkansas Public Service Commission	Southwestern Electric Power Company	19-008-U	Cost of capital, depreciation rates, net salvage	Western Arkansas Large Energy Consumers
Public Utility Commission of Texas	CenterPoint Energy Houston Electric	PUC 49421	Depreciation rates, service lives, net salvage	Texas Coast Utilities Coalition
Massachusetts Department of Public Utilities	Massachusetts Electric Company and Nantucket Electric Company	D.P.U. 18-150	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Oklahoma Corporation Commission	Oklahoma Gas & Electric Company	PUD 201800140	Cost of capital, authorized ROE, depreciation rates	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results
Public Service Commission of the State of Montana	Montana-Dakota Utilities Company	D2018.9.60	Depreciation rates, service lives, net salvage	Montana Consumer Counsel and Denbury Onshore
Indiana Utility Regulatory Commission	Northern Indiana Public Service Company	45159	Depreciation rates, grouping procedure, demolition costs	Indiana Office of Utility Consumer Counselor
Public Service Commission of the State of Montana	NorthWestern Energy	D2018.2.12	Depreciation rates, service lives, net salvage	Montana Consumer Counsel
Oklahoma Corporation Commission	Public Service Company of Oklahoma	PUD 201800097	Depreciation rates, service lives, net salvage	Oklahoma Industrial Energy Consumers and Wal-Mart
Nevada Public Utilities Commission	Southwest Gas Corporation	18-05031	Depreciation rates, service lives, net salvage	Nevada Bureau of Consumer Protection

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Public Utility Commission of Texas	Texas-New Mexico Power Company	PUC 48401	Depreciation rates, service lives, net salvage	Alliance of Texas-New Mexico Power Municipalities
Oklahoma Corporation Commission	Oklahoma Gas & Electric Company	PUD 201700496	Depreciation rates, service lives, net salvage	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results
Maryland Public Service Commission	Washington Gas Light Company	9481	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel
Indiana Utility Regulatory Commission	Citizens Energy Group	45039	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Utility Commission of Texas	Entergy Texas, Inc.	PUC 48371	Depreciation rates, decommissioning costs	Texas Municipal Group
Washington Utilities & Transportation Commission	Avista Corporation	UE-180167	Depreciation rates, service lives, net salvage	Washington Office of Attorney General
New Mexico Public Regulation Commission	Southwestern Public Service Company	17-00255-UT	Cost of capital and authorized rate of return	HollyFrontier Navajo Refining; Occidental Permian
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 47527	Depreciation rates, plant service lives	Alliance of Xcel Municipalities
Public Service Commission of the State of Montana	Montana-Dakota Utilities Company	D2017.9.79	Depreciation rates, service lives, net salvage	Montana Consumer Counsel
Florida Public Service Commission	Florida City Gas	20170179-GU	Cost of capital, depreciation rates	Florida Office of Public Counsel
Washington Utilities & Transportation Commission	Avista Corporation	UE-170485	Cost of capital and authorized rate of return	Washington Office of Attorney General
Wyoming Public Service Commission	Powder River Energy Corporation	10014-182-CA-17	Credit analysis, cost of capital	Private customer
Oklahoma Corporation Commission	Public Service Co. of Oklahoma	PUD 201700151	Depreciation, terminal salvage, risk analysis	Oklahoma Industrial Energy Consumers
Public Utility Commission of Texas	Oncor Electric Delivery Company	PUC 46957	Depreciation rates, simulated analysis	Alliance of Oncor Cities

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Nevada Public Utilities Commission	Nevada Power Company	17-06004	Depreciation rates, service lives, net salvage	Nevada Bureau of Consumer Protection
Public Utility Commission of Texas	El Paso Electric Company	PUC 46831	Depreciation rates, interim retirements	City of El Paso
Idaho Public Utilities Commission	Idaho Power Company	IPC-E-16-24	Accelerated depreciation of North Valmy plant	Micron Technology, Inc.
Idaho Public Utilities Commission	Idaho Power Company	IPC-E-16-23	Depreciation rates, service lives, net salvage	Micron Technology, Inc.
Public Utility Commission of Texas	Southwestern Electric Power Company	PUC 46449	Depreciation rates, decommissioning costs	Cities Advocating Reasonable Deregulation
Massachusetts Department of Public Utilities	Eversource Energy	D.P.U. 17-05	Cost of capital, capital structure, and rate of return	Sunrun Inc.; Energy Freedom Coalition of America
Railroad Commission of Texas	Atmos Pipeline - Texas	GUD 10580	Depreciation rates, grouping procedure	City of Dallas
Public Utility Commission of Texas	Sharyland Utility Company	PUC 45414	Depreciation rates, simulated analysis	City of Mission
Oklahoma Corporation Commission	Empire District Electric Company	PUD 201600468	Cost of capital, depreciation rates	Oklahoma Industrial Energy Consumers
Railroad Commission of Texas	CenterPoint Energy Texas Gas	GUD 10567	Depreciation rates, simulated plant analysis	Texas Coast Utilities Coalition
Arkansas Public Service Commission	Oklahoma Gas & Electric Company	160-159-GU	Cost of capital, depreciation rates, terminal salvage	Arkansas River Valley Energy Consumers; Wal-Mart
Florida Public Service Commission	Peoples Gas	160-159-GU	Depreciation rates, service lives, net salvage	Florida Office of Public Counsel
Arizona Corporation Commission	Arizona Public Service Company	E-01345A-16-0036	Cost of capital, depreciation rates, terminal salvage	Energy Freedom Coalition of America
Nevada Public Utilities Commission	Sierra Pacific Power Company	16-06008	Depreciation rates, net salvage, theoretical reserve	Northern Nevada Utility Customers

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Oklahoma Corporation Commission	Oklahoma Gas & Electric Co.	PUD 201500273	Cost of capital, depreciation rates, terminal salvage	Public Utility Division
Oklahoma Corporation Commission	Public Service Co. of Oklahoma	PUD 201500208	Cost of capital, depreciation rates, terminal salvage	Public Utility Division
Oklahoma Corporation Commission	Oklahoma Natural Gas Company	PUD 201500213	Cost of capital, depreciation rates, net salvage	Public Utility Division

Proxy Group Summary

Company	Ticker	Market Cap. ($ millions)	Market Category	Value Line Safety Rank	Financial Strength
AVANGRID, Inc	AGR	16,000	Large Cap	2	B++
Consolidated Edison Inc	ED	27,000	Large Cap	1	A+
Duke Energy Corporation	DUK	77,000	Large Cap	2	A
Eversource Energy	ES	30,000	Large Cap	1	A
Exelon Corp	EXC	44,000	Large Cap	3	B+
FirstEnergy Corp	FE	21,000	Large Cap	3	B+
NextEra Energy Inc	NEE	150,000	Large Cap	1	A+
PPL Corp	PPL	22,000	Large Cap	2	B++
Public Service Enterprise Group Inc	PEG	32,000	Large Cap	1	A++

Value Line Investment Survey

DCF Stock and Index Prices

Exhibit DJG-3

Ticker	^GSPC	AGR	ED	DUK	ES	EXC	FE	NEE	PPL	PEG
30-day Average	4174	51.21	77.34	100.54	84.04	44.70	37.37	74.30	29.15	62.50
Standard Deviation	35.2	0.84	0.98	1.67	2.15	0.74	0.59	2.12	0.21	0.68
04/21/21	4173	51.84	77.59	100.13	88.89	45.27	36.41	77.56	29.46	63.55
04/22/21	4135	51.47	77.34	99.13	87.59	44.68	35.98	77.91	28.95	62.92
04/23/21	4180	51.02	76.69	98.90	87.54	44.51	36.32	77.83	29.16	62.94
04/26/21	4188	50.82	76.11	98.25	87.14	44.25	36.31	77.52	29.18	62.16
04/27/21	4187	49.87	75.44	97.67	86.40	44.14	36.49	76.87	28.89	62.10
04/28/21	4183	49.60	75.46	97.63	84.84	44.21	37.03	76.68	29.00	62.40
04/29/21	4211	50.05	75.95	98.60	84.48	44.49	37.33	76.81	29.27	63.09
04/30/21	4181	50.48	76.65	99.73	85.60	44.54	37.53	77.10	29.13	63.16
05/03/21	4193	50.54	76.98	99.75	85.80	44.49	37.93	76.30	29.14	63.65
05/04/21	4165	51.21	77.35	99.82	85.50	44.38	37.40	75.29	29.08	63.19
05/05/21	4168	50.23	76.13	98.41	82.99	43.14	37.49	73.39	28.92	61.31
05/06/21	4202	50.53	77.09	99.58	83.73	44.08	37.42	73.62	28.84	62.57
05/07/21	4233	50.54	77.32	99.90	83.47	44.28	37.52	74.14	29.25	63.15
05/10/21	4188	51.20	79.06	102.75	84.84	44.12	37.65	74.41	29.48	63.28
05/11/21	4152	50.97	78.56	102.64	83.42	44.05	37.20	73.68	29.34	62.25
05/12/21	4063	49.89	77.13	100.25	82.09	42.73	36.44	71.16	28.60	60.70
05/13/21	4113	51.29	78.50	103.00	84.10	44.41	37.48	72.25	29.04	62.15
05/14/21	4174	51.56	78.19	103.06	84.51	45.09	37.61	72.74	29.26	62.52
05/17/21	4163	51.10	77.96	102.45	83.46	45.09	37.71	71.52	29.16	62.29
05/18/21	4128	51.10	77.74	102.49	83.67	45.65	37.67	71.91	29.33	62.11
05/19/21	4116	51.44	77.98	101.16	83.25	45.54	37.40	72.28	29.37	61.98
05/20/21	4159	51.86	78.42	102.27	83.76	45.74	37.69	73.90	29.34	62.58
05/21/21	4156	52.36	78.96	102.86	84.09	45.84	38.01	74.05	29.50	63.02
05/24/21	4197	52.49	78.38	102.31	83.30	46.03	37.92	73.64	29.45	63.46
05/25/21	4188	51.76	77.81	101.31	82.33	44.91	37.62	72.98	29.11	62.19
05/26/21	4196	52.16	78.00	101.11	81.50	45.17	37.58	73.08	29.15	62.30
05/27/21	4201	52.10	76.87	100.01	81.15	44.60	37.87	72.62	29.05	62.03
05/28/21	4204	52.24	77.24	100.22	81.19	45.12	37.91	72.83	29.11	62.12
06/01/21	4202	51.97	76.43	100.08	79.91	45.14	38.02	72.12	29.00	62.03
06/02/21	4208	52.70	76.79	100.68	80.74	45.20	38.14	72.71	28.95	61.67

All prices are adjusted closing prices reported by Yahoo! Finance, http://finance.yahoo.com

DCF Dividend Yields

Exhibit DJG-4

Company	Ticker	[1] Dividend	[2] Stock Price	[3] Dividend Yield
AVANGRID, Inc	AGR	0.440	51.21	0.86%
Consolidated Edison Inc	ED	0.775	77.34	1.00%
Duke Energy Corporation	DUK	0.965	100.54	0.96%
Eversource Energy	ES	0.603	84.04	0.72%
Exelon Corp	EXC	0.383	44.70	0.86%
FirstEnergy Corp	FE	0.390	37.37	1.04%
NextEra Energy Inc	NEE	0.385	74.30	0.52%
PPL Corp	PPL	0.415	29.15	1.42%
Public Service Enterprise Group Inc	PEG	0.510	62.50	0.82%
Average		**$0.54**	**$62.35**	**0.91%**

[1] 2021 Q2 reported quarterly dividends per share. Nasdaq.com

[2] Average stock price from Exhibit DJG-3

[3] = [1] / [2] (quarterly dividend yield)

DCF Terminal Growth Rate Determinants

Terminal Growth Determinants	Rate	
Nominal GDP	3.8%	[1]
Real GDP	1.8%	[2]
Inflation	2.0%	[3]
Risk Free Rate	2.3%	[4]
Highest	**3.8%**	

[1],[2] [3] CBO, The 2021 Long-Term Budget Outlook, p. 34
[4] From Exhibit DJG-7

Company-Specific Growth Factors	Rate	
Total Load (2020 - 2025)	0.8%	[1]
Total Customers (2020 - 2025)	0.6%	[4]
Average	**0.7%**	

See response to OCA-IV-10

DCF Final Results

Exhibit DJG-6

[1]	[2]	[3]	[4]
Dividend (d_0)	Stock Price (P_0)	Growth Rate (g)	**DCF Result**
\$0.54	\$62.35	3.80%	**7.4%**

[1] Average proxy dividend from Exhibit DJG-4

[2] Average proxy stock price from Exhibit DJG-3

[3] Highest growth determinant from Exhibit DJG-5

[4] Quarterly DCF Approximation = $[d_0(1 + g)^{0.25}/P_0 + (1 + g)^{0.25}]^4 - 1$

CAPM Risk-Free Rate

Date	Rate
04/21/21	2.26%
04/22/21	2.24%
04/23/21	2.25%
04/26/21	2.24%
04/27/21	2.29%
04/28/21	2.29%
04/29/21	2.31%
04/30/21	2.30%
05/03/21	2.30%
05/04/21	2.27%
05/05/21	2.25%
05/06/21	2.24%
05/07/21	2.28%
05/10/21	2.32%
05/11/21	2.35%
05/12/21	2.40%
05/13/21	2.39%
05/14/21	2.35%
05/17/21	2.36%
05/18/21	2.37%
05/19/21	2.38%
05/20/21	2.34%
05/21/21	2.33%
05/24/21	2.31%
05/25/21	2.26%
05/26/21	2.27%
05/27/21	2.29%
05/28/21	2.26%
06/01/21	2.30%
06/02/21	2.28%
Average	**2.30%**

*Daily Treasury Yield Curve Rates on 30-year T-bonds, http://www.treasury.gov/resources-center/data-chart-center/interest-rates/

CAPM Beta Coefficient

Company	Ticker	Beta
AVANGRID, Inc	AGR	0.85
Consolidated Edison Inc	ED	0.75
Duke Energy Corporation	DUK	0.85
Eversource Energy	ES	0.90
Exelon Corp	EXC	0.95
FirstEnergy Corp	FE	0.85
NextEra Energy Inc	NEE	0.90
PPL Corp	PPL	1.10
Public Service Enterprise Group Inc	PEG	0.90
Average		0.89

Betas from Value Line Investment Survey

CAPM Implied Equity Risk Premium Estimate

Exhibit DJG-9

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Year	Market Value	Operating Earnings	Dividends	Buybacks	Earnings Yield	Dividend Yield	Buyback Yield	Gross Cash Yield
2015	17,900	885	382	572	4.95%	2.14%	3.20%	5.33%
2016	19,268	920	397	536	4.77%	2.06%	2.78%	4.85%
2017	22,821	1,066	420	519	4.67%	1.84%	2.28%	4.12%
2018	21,027	1,282	456	806	6.10%	2.17%	3.84%	6.01%
2019	26,760	1,305	485	729	4.88%	1.81%	2.72%	4.54%
2020	31,659	1,019	480	520	3.22%	1.52%	1.64%	3.16%

Cash Yield	4.67%	[9]
Growth Rate	2.85%	[10]
Risk-free Rate	2.30%	[11]
Current Index Value	4,174	[12]

	[13]	[14]	[15]	[16]	[17]
Year	1	2	3	4	5
Expected Dividends	200	206	212	218	224
Expected Terminal Value					4688
Present Value	187	179	172	165	3471
Intrinsic Index Value	4174	[18]			
Required Return on Market	7.2%	[19]			
Implied Equity Risk Premium	$\boxed{\textbf{4.9\%}}$	[20]			

[1-4] S&P Quarterly Press Releases, data found at https://us.spindices.com/indices/equity/sp-500, Q4 2018

[1] Market value of S&P 500

[5] = [2] / [1]

[6] = [3] / [1]

[7] = [4] / [1]

[8] = [6] + [7]

[9] = Average of [8]

[10] = Compound annual growth rate of [2] = (end value / beginning value)^$^{1/4}$-1

[11] Risk-free rate from DJG-1-7

[12] 30-day average of closing index prices from DJG-1-3 (^GSPC column)

[13-16] Expected dividends = [9]*[12]*(1+[10])^n ; Present value = expected dividend / (1+[11]+[19])^n

[17] Expected terminal value = expected dividend * (1+[11]) / [19] ; Present value = (expected dividend + expected terminal value) / (1+[11]+[19])^n

[18] = Sum([13-17]) present values.

[19] = [20] + [11]

[20] Internal rate of return calculation setting [18] equal to [12] and solving for the discount rate

CAPM Equity Risk Premium Results

IESE Business School Survey	5.6%	[1]
Duff & Phelps Report	5.5%	[2]
Damodaran (average)	4.5%	[3]
Damodaran (COVID Adjusted)	4.2%	[4]
Garrett	4.9%	[5]
Average	**4.9%**	
Highest	**5.6%**	

CAPM Final Results

		[1]	[2]	[3]	[4]
Company	Ticker	Risk-Free Rate	Value Line Beta	Risk Premium	CAPM Results
AVANGRID, Inc	AGR	2.30%	0.850	5.6%	7.1%
Consolidated Edison Inc	ED	2.30%	0.750	5.6%	6.5%
Duke Energy Corporation	DUK	2.30%	0.850	5.6%	7.1%
Eversource Energy	ES	2.30%	0.900	5.6%	7.3%
Exelon Corp	EXC	2.30%	0.950	5.6%	7.6%
FirstEnergy Corp	FE	2.30%	0.850	5.6%	7.1%
NextEra Energy Inc	NEE	2.30%	0.900	5.6%	7.3%
PPL Corp	PPL	2.30%	1.100	5.6%	8.5%
Public Service Enterprise Group Inc	PEG	2.30%	0.900	5.6%	7.3%
Average			0.894		**7.3%**

[1] From DJG-7, risk-free rate exhibit
[2] From DJG-8, beta exhibit
[3] From DJG-10, equity risk premium exhibit
[6] = [1] + [2] * [3]

Cost of Equity Summary

Model	Cost of Equity
Discounted Cash Flow Model	7.4%
Capital Asset Pricing Model	7.3%
Average	**7.4%**

Market Cost of Equity

Source	Estimate	
IESE Survey	7.9%	[1]
Damodaran	6.8%	[2]
Garrett	7.2%	[3]
Highest	7.9%	

[1], [2], [3] ERPs from DJG-10 + riskfree rate from DJG-7

Market Cost of Equity vs. Awarded Returns

	[1]		[2]		[3]		[4]	[5]	[6]	[7]
	Electric Utilities		Gas Utilities		Total Utilities		S&P 500	T-Bond	Risk	Market
Year	ROE	#	ROE	#	ROE	#	Returns	Rate	Premium	COE
1990	12.70%	38	12.68%	33	12.69%	71	-3.06%	8.07%	3.89%	11.96%
1991	12.54%	42	12.45%	31	12.50%	73	30.23%	6.70%	3.48%	10.18%
1992	12.09%	45	12.02%	28	12.06%	73	7.49%	6.68%	3.55%	10.23%
1993	11.46%	28	11.37%	40	11.41%	68	9.97%	5.79%	3.17%	8.96%
1994	11.21%	28	11.24%	24	11.22%	52	1.33%	7.82%	3.55%	11.37%
1995	11.58%	28	11.44%	13	11.54%	41	37.20%	5.57%	3.29%	8.86%
1996	11.40%	18	11.12%	17	11.26%	35	22.68%	6.41%	3.20%	9.61%
1997	11.33%	10	11.30%	12	11.31%	22	33.10%	5.74%	2.73%	8.47%
1998	11.77%	10	11.51%	10	11.64%	20	28.34%	4.65%	2.26%	6.91%
1999	10.72%	6	10.74%	6	10.73%	12	20.89%	6.44%	2.05%	8.49%
2000	11.58%	9	11.34%	13	11.44%	22	-9.03%	5.11%	2.87%	7.98%
2001	11.07%	15	10.96%	5	11.04%	20	-11.85%	5.05%	3.62%	8.67%
2002	11.21%	14	11.17%	19	11.19%	33	-21.97%	3.81%	4.10%	7.91%
2003	10.96%	20	10.99%	25	10.98%	45	28.36%	4.25%	3.69%	7.94%
2004	10.81%	21	10.63%	22	10.72%	43	10.74%	4.22%	3.65%	7.87%
2005	10.51%	24	10.41%	26	10.46%	50	4.83%	4.39%	4.08%	8.47%
2006	10.32%	26	10.40%	15	10.35%	41	15.61%	4.70%	4.16%	8.86%
2007	10.30%	38	10.22%	35	10.26%	73	5.48%	4.02%	4.37%	8.39%
2008	10.41%	37	10.39%	32	10.40%	69	-36.55%	2.21%	6.43%	8.64%
2009	10.52%	40	10.22%	30	10.39%	70	25.94%	3.84%	4.36%	8.20%
2010	10.37%	61	10.15%	39	10.28%	100	14.82%	3.29%	5.20%	8.49%
2011	10.29%	42	9.92%	16	10.19%	58	2.10%	1.88%	6.01%	7.89%
2012	10.17%	58	9.94%	35	10.08%	93	15.89%	1.76%	5.78%	7.54%
2013	10.03%	49	9.68%	21	9.93%	70	32.15%	3.04%	4.96%	8.00%
2014	9.91%	38	9.78%	26	9.86%	64	13.52%	2.17%	5.78%	7.95%
2015	9.85%	30	9.60%	16	9.76%	46	1.38%	2.27%	6.12%	8.39%
2016	9.77%	42	9.54%	26	9.68%	68	11.77%	2.45%	5.69%	8.14%
2017	9.74%	53	9.72%	24	9.73%	77	21.61%	2.41%	5.08%	7.49%
2018	9.64%	37	9.62%	26	9.63%	63	-4.23%	2.68%	5.96%	8.64%
2019	9.64%	67					31.22%	1.92%	5.20%	7.12%
2020	9.43%	43					18.01%	0.93%	4.72%	5.65%

[1], [2], [3] Average annual authorized ROE for electric and gas utilities, RRA Regulatory Focus: Major Rate Case Decisions

[3] = [1] + [2]

[4], [5], [6] Annual S&P 500 return, 10-year T-bond Rate, and equity risk premium published by NYU Stern School of Business

[7] = [5] + [6] ; Market cost of equity represents the required return for investing in all stocks in the market for a given year

Optimal Capital Structure Analysis

Inputs		
Operating Income	527,584	[1]
Interest Expense	147,490	[2]
Book Debt	4,004,144	[3]
Book Equity	4,533,100	[4]
Debt / Capital	46.90%	[5]
Debt / Equity	88%	[6]
Debt Cost	3.72%	[7]
Tax Rate	21%	[8]
Unlevered Beta	0.53	[9]
Risk-free Rate	2.30%	[10]
Equity Risk Premium	5.6%	[11]
Coverage Ratio	3.58	[12]
Bond Rating	A2	[13]

Ratings Table

[14] Coverage Ratio	[15] Bond Rating	[16] Spread	[17] Interest Rate
8.5 - 10.00	Aaa/AAA	0.69%	2.99%
6.5 - 8.49	Aa2/AA	0.85%	3.15%
5.5 - 6.49	A1/A+	1.07%	3.37%
4.25 - 5.49	A2/A	1.18%	3.48%
3.0 - 4.24	A3/A-	1.33%	3.63%
2.5 - 2.99	Baa2/BBB	1.71%	4.01%
2.25 - 2.49	Ba1/BB+	2.31%	4.61%
2.0 - 2.24	Ba2/BB	2.77%	5.07%
1.75 - 1.99	B1/B+	4.05%	6.35%
1.5 - 1.74	B2/B	4.86%	7.16%
1.25 - 1.49	B3/B-	5.94%	8.24%
0.8 - 1.24	Caa/CCC	9.46%	11.76%

Optimal Capital Structure Calculation

[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]
Debt Ratio	D/E Ratio	Levered Beta	Cost of Equity	Proposed ROE	Debt Level	Interest Expense	Coverage Ratio	Pre-tax Debt Cost	After-tax Debt Cost	Optimal WACC	WACC at 8.5% ROE
0%	0%	0.527	5.25%	8.50%	0	0	∞	2.93%	2.31%	5.25%	8.50%
20%	25%	0.631	5.84%	8.50%	1,707,449	63,551	8.30	3.15%	2.49%	5.17%	7.30%
30%	43%	0.705	6.25%	8.50%	2,561,173	95,327	5.53	3.37%	2.66%	5.17%	6.75%
40%	67%	0.804	6.81%	8.50%	3,414,897	127,102	4.15	3.63%	2.87%	5.23%	6.25%
45%	82%	0.867	7.16%	8.50%	3,841,760	142,990	3.69	3.63%	2.87%	5.23%	5.97%
50%	100%	0.943	7.58%	8.50%	4,268,622	158,878	3.32	3.63%	2.87%	5.23%	5.68%
55%	122%	1.035	8.10%	8.50%	4,695,484	174,766	3.02	3.63%	2.87%	5.22%	5.40%
60%	150%	1.151	8.75%	8.50%	5,122,346	190,654	2.77	4.01%	3.17%	5.40%	5.30%

[1], [2] See respoonse to OCA-IV-14(a)(b) (000's)
[3], [4] See response to OCA-IV-14(c)(d) (000's)
[5] = [3] / ([3] + [4])
[6] = [3] / [4]
[7] See response to OCA-IV-14(e)
[8] Corporate tax rate, Sch. H-9
[9] Average beta / (1+(1 - [8])*[6])
[10] From DJG risk-free rate exhibit
[11] From DJG equity risk premium exhibit

[12] = [1] / [2]
[13] Company bond rating
[14] Ranges of coverage ratios
[15] Moody's / S&P bond ratings
[16] NYU spread over risk-free rate
[17] = [16] + [10] = est. debt cost
[18] = debt / total capital
[19] = [18] / (1 - [18])
[20] = [9] * (1 + (1 - [8]) * [6]

[21] = [10] + [20] * [11]
[22] Recommended awarded ROE
[23] = [18] * ([3] + [4]); (000's)
[24] = [22] * [7]; (000's)
[25] = [1] / [23]
[26] Debt cost given coverage ratio per Ratings Table
[27] = [25] * (1 - [8])
[28] = ([18] * [26]) + ((1 - [18]) * [21])
[29] = ([18] * [26]) + ((1 - [18]) * [22])

Proxy Company Debt Ratios

Company	Ticker	Debt Ratio
AVANGRID, Inc	AGR	41%
Consolidated Edison Inc	ED	52%
Duke Energy Corporation	DUK	54%
Eversource Energy	ES	52%
Exelon Corp	EXC	52%
FirstEnergy Corp	FE	75%
NextEra Energy Inc	NEE	54%
PPL Corp	PPL	62%
Public Service Enterprise Group Inc	PEG	48%
Average		54%

Debt ratios from Value Line Investment Survey

Competitive Industry Debt Ratios

Industry	# Firms	Debt Ratio
Financial Svcs. (Non-bank & Insurance)	235	95%
Retail (Building Supply)	15	88%
Hospitals/Healthcare Facilities	32	84%
Air Transport	17	84%
Advertising	61	81%
Hotel/Gaming	66	77%
Brokerage & Investment Banking	39	77%
Auto & Truck	19	75%
Retail (Automotive)	30	74%
Food Wholesalers	18	74%
Retail (Special Lines)	85	72%
Recreation	69	71%
Bank (Money Center)	7	68%
Retail (Grocery and Food)	14	68%
Transportation	21	68%
Computers/Peripherals	52	68%
Packaging & Container	26	67%
Broadcasting	29	65%
Rubber& Tires	3	64%
Beverage (Soft)	41	64%
Chemical (Basic)	48	62%
Oil/Gas Distribution	57	62%
Cable TV	13	61%
R.E.I.T.	238	61%
Apparel	51	61%
Trucking	35	61%
Computer Services	116	61%
Retail (Distributors)	85	60%
Telecom (Wireless)	16	60%
Power	55	60%
Farming/Agriculture	32	59%
Business & Consumer Services	169	59%
Aerospace/Defense	72	59%
Utility (Water)	17	59%
Telecom. Services	58	59%
Retail (Online)	75	58%
Software (Internet)	36	57%
Household Products	140	57%
Construction Supplies	46	57%
Real Estate (Operations & Services)	61	56%
Building Materials	42	56%
Transportation (Railroads)	6	56%
Coal & Related Energy	29	56%
Chemical (Diversified)	5	56%
Office Equipment & Services	22	55%
Environmental & Waste Services	86	54%
Auto Parts	52	53%
Drugs (Biotechnology)	547	52%
Real Estate (Development)	25	52%
Publishing & Newspapers	29	52%
Green & Renewable Energy	25	52%
Retail (General)	17	52%
Shoe	11	50%
Total / Average	**3,195**	**64%**

http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/dbtfund.htm

Exhibit DJG-18

Weighted Average Rate of Return Proposal

Capital Component	Proposed Ratio	Cost Rate	Weighted Cost
Long Term Debt	50.0%	3.93%	1.97%
Common Equity	50.0%	8.50%	4.25%
Total	100.0%		6.22%

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024601
	:	
PECO Energy Company – Electric Division	:	

VERIFICATION

I, David J. Garrett, hereby state that the facts set forth in my Direct Testimony, OCA Statement 2, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: June 28, 2021
*311949

Signature: ______________________
David J. Garrett

Consultant Address: Resolve Utility Consulting, PLLC
101 Park Avenue
Suite 1125
Oklahoma City, OK 73102

OCA STATEMENT 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket Number R-2021-3024601
PECO Energy Company—Electric Division	:	

DIRECT TESTIMONY
OF
CLARENCE L. JOHNSON

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

June 28, 2021

DIRECT TESTIMONY OF CLARENCE JOHNSON

Table of Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Clarence L. Johnson. My business address is 3707 Robinson Ave, Austin, Texas 78722.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am presenting testimony on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS YOUR CURRENT EMPLOYMENT?

A. I am self-employed as a consultant providing technical analysis, advice, and testimony regarding energy and utility regulatory issues.

Q. DO YOU HAVE PREVIOUS EXPERIENCE AS AN EXPERT ON REGULATED UTILITY MATTERS?

A. Yes. I have over 37 years of experience as a utility regulatory expert, including 25 years as director of regulatory analysis for the Texas Office of Public Utility Counsel ("OPC"). As a consultant, I have provided expert advice, assistance, and testimony on utility-related issues to a number of parties. My clients have included state consumer advocate offices, customer groups, and various coalitions of municipalities in Texas. Municipalities in Texas act as original jurisdiction regulators over electric utility rates within city boundaries. I have previously filed testimony in PECO, FirstEnergy, and Duquesne electric rate cases in Pennsylvania.

Q. HAVE YOU PROVIDED AN ATTACHMENT WHICH DETAILS YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. Please see Attachment A.

Q. PLEASE OUTLINE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have a B.S. in Political Science and a M.A. in Urban Studies from the University of Houston. My graduate degree is in an interdisciplinary program offered by the University of Houston's College of Social Science, which incorporated substantial training in economics, including course work in the application of cost-benefit analysis to public policy. During my 25-year tenure at OPC, I gained experience in virtually all phases of economic review required for the ratemaking process. I was chairman of the Economics and Finance Committee of the National Association of State Utility Consumer Advocates ("NASUCA") and served as a presenter for NASUCA's workshops and panels on cost allocation and rate design, demand-side management incentives, market power and electric utility competition. Also, at various times, I have undergone training in specific subjects, such as electric wholesale market design, cogeneration engineering and Electric Reliability Council of Texas ("ERCOT") operations.

I have previously filed testimony in approximately 150 proceedings at the Public Utility Commission of Texas, Texas Railroad Commission, Pennsylvania Public Utility Commission, Maryland Public Service Commission and Connecticut Public Utility Regulatory Authority.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A. My testimony will address cost allocation and rate design issues pertaining to PECO's ("Company") base rate increase requested in this docket. For purposes of comparability, my analysis generally utilizes the revenue requirements and schedules filed by the Company. My use of PECO's filed costs and revenues should not be construed as agreement or acceptance of the Company's requested revenues. Other witnesses retained by OCA will address the Company's proposed revenue requirements.

Q. WHAT DOCUMENTS HAVE YOU REVIEWED IN PREPARING THIS TESTIMONY?

A. I reviewed relevant testimony and exhibits in PECO's rate case filing. I also propounded interrogatories to the Company and reviewed the responses and accompanying attachments.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My recommendations are as follows:

- I recommend a demand allocation of secondary lines, poles, and underground facilities. The Company's 100% customer classification of secondary facilities (except for transformers) is unreasonable because the classification ignores the fact that secondary lines and underground cables are designed to meet maximum area demand.
- I recommend a customer allocation for the portion of Other Revenues arising from returned check charges and connection charges.

- For purposes of the class cost of service study and revenue distribution, Rate R and Rate RH should be treated as a single class. Non-coincident peak (NCP) demands in the cost study should be adjusted to reflect the combined class.
- The class revenue distribution should recognize cost study results, but the ultimate revenue allocation should be constrained by rate moderation. My recommendation uses the Company's proposed class revenue increases as a starting point, but makes adjustments to move the revenue allocation into closer alignment with my CCOS study.
- The Company proposes a 35% increase in the residential customer charge (from $9.99 to $13.49). This is an excessive and unreasonable increase which adversely affects low usage customers, reduces customers' control over their electric bill, and discourages customers from undertaking energy efficiency measures. My analysis indicates that a customer charge of $8.37 would recover costs which vary directly with the number of customers. My primary recommendation is to maintain the current $9.99 customer charge. Given that the current customer charge exceeds direct costs, the customer charge in the alternative could be reduced below $9.00 to recognize energy conservation considerations.
- OCA witness Mr. Colton has presented a recommendation that Universal Service costs should be allocated to all customer classes. I have developed an allocation presentation that shows the impact of his recommendation.

III. CLASS COST OF SERVICE STUDY

A. Overview

Q. WHAT IS A CLASS COST OF SERVICE STUDY (CCOSS)?

A. The CCOSS is a fully allocated cost study which distributes the Company's costs to customer classes. The intent of the study is to allocate costs based on cost causation, generally resulting in a portion of costs allocated on causal measures and the remainder of indirect costs following those costs. The CCOSS is at best a general benchmark for evaluating customer class cost responsibility. The CCOSS can provide guidance to the regulator, but considerations other than the CCOSS also are appropriate in determining the ultimate allocation of costs among customer classes. The CCOSS provides rates of return for each customer class at current and proposed class rates. Sometimes the class rates of return are divided by the total retail rate of return to arrive at a relative rate of return (RROR). The relative rate of return (or unitized return) at present rates may be used as a benchmark for guiding the direction of revenue changes at the class level. The CCOSS also provides class revenues based upon equalized rates of return (all classes' revenue produce the proposed overall retail rate of return). The class revenues at equalized rates of return can be used as a rough target for apportioning class revenue increases, but the results at equalized rates of return do not necessarily dictate the exact levels of class revenues. The class revenues may depart from equalized rates of return in order to recognize rate gradualism, relative risks associated with serving each class, or other non-cost considerations. However, the resulting revenues indicated by the CCOSS may provide useful information regarding the equitable distribution of a system revenue increase among customer classes.

Q. HOW IS THE COST CAUSATION CRITERION APPLIED IN THE CCOSS?

A. Some costs are incurred directly to serve only an individual customer or set of customers. For example, substations are sometimes dedicated to serving an individual customer and can be directly assigned.

However, the provision of electric utility service is predominated by common and joint costs, which either support the overall enterprise or produce shared benefits for all or most customers. These costs often are assigned based upon indirect, and often weak, measures of causation. For example, overhead costs, such as Board of Director fees, might be allocated based upon measures as diverse as revenues, labor costs, energy sales, plant or demand. No single objective economic basis supports the allocation of these costs; therefore, the allocation decisions are subjective or based on ratemaking conventions. Ideally, the analyst selects a method that best recognizes the manner in which customer classes' characteristics contributed to the incurrence of utility investments and expenses. The manner in which a utility plans and installs an investment often informs the analyst's evaluation of causal factors related to classification or allocation of the investment.

The three major steps of the embedded cost of service study are functionalization, classification, and allocation. Functionalization is the procedure for separating costs into functional segments, such as generation, transmission, and distribution. The next two accounting steps, classification and allocation, facilitate the recognition of causation. The classification procedure, which pools costs into general categories of causation (i.e., demand, customer, energy), is an intermediate step in determining the allocation factors that are used to divide costs among jurisdictions and customer classes. The allocation step determines the appropriate percentage of a particular FERC account which is attributed to each customer class.

Q. CAN YOU PROVIDE MORE DETAIL REGARDING THE DEVELOPMENT OF ALLOCATION FACTORS FOR DISTRIBUTION COST OF SERVICE STUDIES?

A. Yes. The principal external allocation factors in the CCOSS are customer, demand, and energy allocators. Customer allocators are based on class customer count as a percentage of total retail customer count. Sometimes weighting factors are applied to the customer count in order to reflect differences in cost per customer. For instance, customer allocators applied to service drops may be weighted to reflect the differences in the cost of average service drops for each customer class.

The predominant demand allocation factor for the distribution system is non-coincident peak demand (NCP). NCP is based on the maximum hour of demand for the class. Since classes incur peak demand in different time periods, the NCP method is said to reflect demand diversity on the system. Each class' demand allocator is the ratio of the class maximum kW demand relative to the sum of all classes' maximum demands. Energy allocation factors, based on kWh usage, are not used by PECO for distribution costs in the CCOSS.

Indirect costs in the CCOSS usually are allocated on the basis of internal allocation factors which "follow" the allocation of direct costs. An example is the labor allocator, which may be used to allocate administrative & general expenses; the labor allocator will be driven by the labor portion of accounts which are classified as customer, demand, or both. A substantial portion of the customer and demand costs in the CCOSS will consist of indirect costs which are not inherently customer or demand related, but follow the customer/demand classification of other accounts. This explains in part why the results of a CCOSS frequently are sensitive to small changes in the customer/demand classification for certain accounts.

Q. PLEASE DESCRIBE YOUR REVIEW OF THE CCOSS PRESENTED BY THE COMPANY.

A. I evaluated the studies for consistency and accuracy in the allocation of costs among classes. Based on my review, the allocation or classification of several CCOSS elements were identified as insufficiently justified or warranting improvement. My testimony proposes modifications to the treatment of those costs in the CCOSS, discussed in subsections III.(B) through III.(E) below. These changes affect my recommendations with respect to class revenue distribution. My recommendations focus on a limited number of CCOSS issues; omission of other issues should not be construed as agreement with all other aspects of the Company's cost studies. The OCA does not agree with the proposed revenue requirements in the CCOSS, therefore, the revised versions of the CCOSS should be used only to examine class cost relationships rather than absolute revenue levels.

Q. DID YOU MODIFY THE COMPANY'S CCOSS TO REFLECT YOUR PROPOSED REVISIONS?

A. Yes. PECO provided OCA with a live version of the CCOSS in Excel format after execution of a protective order; the model was developed by a PECO consultant and is considered to be proprietary information; however, the output of the model is publicly available. After revising certain inputs in the model, the resulting modified CCOSS output is used in my rate design analysis to develop a recommended allocation of any proposed revenue increase among customer classes.

B. Secondary Distribution Plant

Q. WHAT PORTION OF THE DISTRIBUTION PLANT ALLOCATION WILL YOU ADDRESS?

A. This section of my testimony will propose changes to PECO's classification of secondary poles, overhead conductors, and underground conductors/conduit, which I will refer to in the aggregate as "secondary lines." I do not dispute the Company's classification of secondary transformers as demand-related.[1]

Q. HOW DOES PECO CLASSIFY SECONDARY LINES?

A. PECO witness Jamison (PECO St. No. 6) classifies secondary lines as 100% customer-related, meaning that these infrastructure costs are allocated among customer classes in proportion to the number of customers. This assumes that the cost of secondary poles and lines vary solely on the basis of number of customer locations served. The impact of a customer allocation is particularly severe for residential customers. The secondary voltage

[1] In my view, it is reasonable to classify transformers as partly demand-related and partially energy-related, because costs are incurred to reduce energy losses as well as size the transformer for maximum demand. However, in this case, I have accepted the Company's 100% demand classification of transformers, given the relatively small impact of a partial energy classification.

customer allocation factor for the two residential classes is 88% compared to the secondary demand allocation factor of 72%.

Q. DO YOU AGREE WITH THE COMPANY'S ALLOCATION OF SECONDARY LINES TO CUSTOMER CLASSES?

A. No. My recommendation is to classify secondary conductors, poles, and underground facilities as 100% demand-related, and allocate the costs on secondary NCP demands, in the same manner as the Company allocated secondary transformers. The Company's proposed classification of secondary lines as customer-related should be rejected because the jointly used distribution system is sized and designed to provide adequate capacity to meet maximum demands. The objective of distribution system planning is to provide reliable service; as a result, distribution facilities must be sized to meet the maximum demand that will be placed on the facility, and failure to do so can result in outages, burned-out equipment, and voltage dropping outside of acceptable limits.

Q. WHY SHOULD SECONDARY LINES BE CLASSIFIED AS DEMAND-RELATED?

A. The secondary lines are sized to meet local maximum demand. As stated in PECO Response to OCA Set II-28:

> When forecasting demand for a new customer (or group of customers), a number of items are considered in the engineering analysis performed to estimate the peak demand *to size the secondary lines required to serve each customer…*Existing secondary lines may be replaced due to load growth from new or existing customers, material condition or voltage issues. If the replacement is due to load-related issues, actual load readings or meter data are used *to determine secondary wire size*. (emphasis added)

The response identifies factors used to estimate the peak demand on secondary lines: intended use of the customer's facilities (such as residential or commercial, and if it is commercial, the types uses for the space); HVAC requirements; customer's connected load; and building size (square footage and number of floors). The Company states that large loads with high starting currents are considered in sizing secondary lines and may require the installation of larger conductors.[2] Given the causal relationship between local end use demands and sizing the secondary lines, secondary lines should be classified and allocated on NCP demands.

Q. DOES COMPANY WITNESS JAMISON'S TESTIMONY PROVIDE EXPLANATION OR SUPPORT FOR CLASSIFYING SECONDARY LINES AS 100% CUSTOMER-RELATED?

A. No. The testimony does not explain why none of the secondary lines are classified as demand-related. The Company chose to consider secondary plant as customer-related and primary plant as demand-related.[3]

Q. DID THE COMPANY PROVIDE AN ANALYSIS TO SUPPORT ITS CLASSIFICATION OF SECONDARY LINES AS CUSTOMER-RELATED?

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[2] PECO Response to OCA II-28.

[3] PECO Statement 6 at 14.

A. No. Ms. Jamison's testimony points out that special studies, such as a minimum size study, are sometimes used to determine customer classification percentages, but goes on to state that PECO did not perform such a study.[4]

Q. PLEASE EXPLAIN WHY YOUR RECOMMENDATION IS SUPERIOR TO 100% CUSTOMER CLASSIFICATION OF SECONDARY LINES.

A. In my opinion, the customer classification of distribution plant should be limited to service drops and meters, since these facilities are located on or close to the customer's premises. The remaining distribution plant should be classified as demand-related. There is little dispute that jointly-used distribution plant must be sized to accommodate maximum demand, and local demand is the most straightforward and readily measured method of allocating the plant. My recommendation is consistent with the following description of regulatory practice in a recently updated electric utility cost allocation manual:

> The most common method [for apportioning distribution facilities between demand and customer] used is the "basic customer method" which classifies all wires, transformers, and poles as demand-related, and meters, meter reading, and billing as customer-related. This general approach is used by more than 30 states."[5]

The manual continues, pointing out that many jurisdictions have accepted or mandated the basic customer classification, including Arkansas, California, Colorado, Illinois, Iowa, Massachusetts, Texas, and Washington.[6] The states' regulatory preference for the "basic customer method" is logical. Meters and service lines are located on or near

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4 Ibid.

5 "Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). Electric cost allocation for a new era: A manual. Montpelier, VT: Regulatory Assistance Project. At 145.

6 Ibid.

the customer's premises. The remaining distribution facilities radiate outward from the customer's location and are part of an integrated electrical system which is designed and sized to support aggregations of load which may be nearly equivalent to the demand of the total system as the lines approach major substations. By classifying all of facilities except those located on the customer's property as demand-related, the regulatory authorities avoid the complications associated with relying upon minimum system studies.[7]

Q. IF THE COMPANY HAD PREPARED A MINIMUM SIZE STUDY, WOULD IT HAVE SUPPORTED THE COMPANY'S CLASSIFICATION OF SECONDARY FACILITIES?

A. No. First, I do not agree with the rationale for the minimum system (sometimes called "minimum size") concept. By way of background, the minimum system study attempts to develop the cost of a hypothetical distribution system with no load carrying capability, and uses the resulting theoretical cost to split plant accounts into customer and demand percentages. Most such studies identify minimum size plant components or perform a regression analysis to determine the hypothetical costs. The hypothetical nature of the studies frequently leads to dispute. The study, by its nature, can produce a wide range of results, depending on the assumptions made by the analyst. Furthermore, the process of identifying zero or minimum load components is subjective and may lead to double-counting of customer class demands. As a result, the study results are likely to overstate the cost responsibility of classes with below average usage per customer.

[7] The Manual concludes: "The basic customer method for classification is by far the most equitable solution for the vast majority of utilities." Ibid.

Second, even if a minimum system study had been performed, some portion – perhaps a majority – of the secondary lines would be classified as demand-related. Therefore, even this rationale does not support a 100% customer classification of secondary lines as proposed by PECO. Moreover, the methodology has several severe flaws, and should not be adopted in this case. Among the notable flaws in the minimum system concept: minimum size wires and poles in the studies frequently are oversized and do not represent the smallest facilities which could be installed; the minimum system includes load carrying capacity and therefore results in double-counting each class' demand usage; and the concept ignores the fact that an increase in customers frequently does not result in an increase in the size or cost of the secondary distribution system.

Q. DO THE SHORTCOMINGS OF THE MINIMUM SYSTEM CONCEPT REVEAL SIMILAR FLAWS IN PECO'S ALLOCATION OF SECONDARY LINES AS CUSTOMER-RELATED?

A. Yes. Ms. Jamison's testimony states that "some costs fit neatly into one of three classifications;" but she provides no evidence that secondary distribution meets that criteria.[8] Even if non-demand related costs can be identified, the causation for those costs is unlikely to be purely customer-related. Dr. James Bonbright's critique of the minimum distribution system concept is frequently cited by cost analysts:

> [T]he annual costs of this phantom, minimum sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs…. Their inclusion among the

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[8] PECO Statement No. 6 at 13-14.

> customer costs is defended on the ground that, since they vary directly with area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary indirectly with the number of customers.
>
> What this last-named cost imputation overlooks, of course is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Indeed, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.[9]

The implication of Dr. Bonbright's conclusion is that this "residual" cost of the distribution system is not closely related to either demand or customer factors, but instead varies on the basis of less easily discerned geographic variables such as customer density or topography.[10] These factors are consistent with Dr. Bonbright's conclusion that the portion of distribution investment identified as "customer-related" should instead be regarded as inherently un-allocable.[11] Since secondary lines clearly are designed to meet maximum demand, a 100% demand classification is more reasonable than the 100% customer classification used by PECO. Moreover, my recommendation is consistent with allocating those costs in proportion to the remaining allocable costs, a typical method for allocating costs without a clear causal basis. The Company's own CCOSS indicates that over 60% of distribution plant is demand-related. Because distribution investment is

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9 *Principals of Public Utility Rates*, Columbia University Press, James Bonbright (1961) at 347-348.

10 In addition to spatial density, other factors that are not related to customer count, such as economies of scale, efficiencies of stocking standard components, and life cycle cost optimization, may be intervening variables.

11 Bonbright at 347-348.

overwhelmingly allocable on a demand basis, classifying the residual un-allocable amount as demand-related achieves basically the same result.

Q. DO EMPIRICAL STUDIES SHOW THAT DISTRIBUTION COSTS VARY WITH CUSTOMERS?

A. No. Empirical analyses have reported that distribution plant and customer sales accounts are correlated with load density, but are not significantly affected by the number of customers served.[12]

Q. WOULD YOU CHARACTERIZE THE PECO SERVICE AREA AS RELATIVELY DENSELY POPULATED?

A. Yes. PECO has a highly urbanized service area. Unlike electric utilities which serve predominantly rural areas, where lines and components must be provided to serve only a few secondary customers, secondary facilities in a dense urban area are shared by many customers served by the localized facilities. This characteristic makes the customer classification an even weaker measure of cost causation. The load density permits the utility to more fully exploit the economies of scale associated with the secondary delivery system. For example, in densely developed areas like Center City Philadelphia, PECO typically installs underground conduits and cables with spare ducts installed for future use. As a result, additional customers can be added at little or no incremental cost.

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[12] "Antitrust in the Electric Industry," by Leonard Weiss, *Promoting Competition in Regulated Markets*, Phillips, Almarin, Ed., The Brookings Institution (1975) at 145; "The Economics of Electric Distribution System Costs and Investments," by David Lessels, *Public Utilities Fortnightly*, Dec. 4, 1980 at 37-40.

Q. DO YOU AGREE WITH THE COMPANY'S CLASSIFICATION OF PRIMARY DISTRIBUTION PLANT AS DEMAND-RELATED?

A. Yes. Primary distribution facilities are upstream of secondary facilities and tend to serve aggregated loads of customers taking power at different voltages. The principal objective of primary facilities is to transmit power from distribution substations to localized service areas. Therefore, system demand is the principal cost causation driver of primary costs.

Q. WHAT IS THE IMPACT OF CHANGING THE CLASSIFICATION OF SECONDARY LINES FROM CUSTOMER TO DEMAND?

A. The most notable impact is improvement in the residential class cost of service result. The relative rate of return (RROR) measures the class rate of return as a ratio of the distribution system rate of return. The comparison below shows the RROR at present rates for the standard residential class, and indicates that the cost study result moves from below average to above average if the secondary lines are classified on a demand basis.

Residential RROR at Present Rates	
PECO Filed	89%
As Adjusted	103%

C. Other Revenues

Q. DO YOU RECOMMEND AN ADJUSTMENT TO THE COMPANY'S ALLOCATION OF REVENUES?

A. Yes. I propose an adjustment to the allocation of Other Revenues. Other Revenues consist of revenues produced by several fees and charges which are treated as a credit to class costs in the CCOSS. The Company's response to OSBA-I-13 identifies the source components of the $20.3 million in Other Revenues: make ready revenues; theft of service revenues; solar application fees; distribution system operations revenue; connect/reconnect fees; and return check charges.

Q. HOW DOES THE COMPANY ALLOCATE OTHER REVENUES?

A. The Company allocates Other Revenues to customer classes based on distribution plant.

Q. DO YOU AGREE WITH THE USE OF A DISTRIBUTION PLANT ALLOCATOR?

A. The distribution plant allocator is reasonable for most of the revenues included in Other Revenues. However, two components of Other Revenues are more appropriately allocated to customer classes based on the customer allocator. My recommendation is to allocate $3.9 million in connection charges and returned check fees on a customer basis.

Q. WHAT IS THE BASIS FOR YOUR CONCLUSION THAT THE CUSTOMER ALLOCATOR IS A BETTER METHOD FOR ASSIGNING CONNECTION AND RETURNED CHECK CHARGE REVENUES TO CLASSES?

A. The Company provided the amounts paid for these charges in response to OCA-X-16. The customer allocator appears to be a more reasonable indicator of customer class contributions to these revenue sources. The table below shows the percentage of payments by residential, commercial/industrial customers, and street lighting for reconnection and returned check fees. Comparing these percentages to the customer and distribution plant allocators indicates that the customer allocation is a closer representation of customer class responsibility for the charges.

	Residential	Commercial & Industrial	Lighting
Connection Fees Paid	95%	5%	0.0%
Returned Check Fees	92%	8%	0.0%
Distribution Plant Allocator	62%	38%	0%
Customer Allocator	90%	9%	1%

Q. DID YOU ADJUST THE CCOSS TO ALLOCATE THESE REVENUES ON THE CUSTOMER ALLOCATOR?

A. Yes. Connection and returned check revenues are removed from other revenues and allocated separately on a customer basis. In my view, this adjustment more accurately reflects cost causation. The remaining components of other revenues are allocated on the same Distribution Plant allocator used by the Company.

D. Treatment of Residential Class in CCOSS

Q. HAVE YOU MADE ANY REVISIONS TO THE CUSTOMER CLASSES WHICH ARE ALLOCATED COSTS IN THE CCOSS?

A. Yes. I have combined the two residential classes, Rate R and Rate RH, into a consolidated residential class for purposes of cost allocation. Both classes consist of residential electric customers who use electricity for domestic purposes. The Rate RH is available to residential customers who heat their home with electricity. The existence of the two separate tariffs is a vestige of the previous bundled electricity service, whereby space heating customers received a differential rate in the winter. As a practical matter, the RH tariff could be considered a sub-class of the broader residential class. Allocation to a single residential class facilitates allocation of the revenue increase in a manner that recognizes the rate relationship between the two tariffs.

Q. IF RATES R AND RH ARE CONSOLIDATED FOR ALLOCATION PURPOSES, WILL THIS AFFECT THE ALLOCATION OF COSTS?

A. Yes. Distribution demand allocators are based on class non-coincident peak (NCP) demands. If two classes are combined, usually the total NCP demands for the combined class will be lower than the sum of NCP demands for two separate classes. This is due to greater diversity in hourly peaks which generally accompany a larger class size. In this case, combining Rate R and Rate RH results in a 7.4% reduction in the combined NCP demands for the residential class.[13] Incorporating this diversity benefit is appropriate because it reflects an actual cost savings which arises when space heating and non-space heating customers reside in the same localized area. The demand estimation used to size distribution equipment will incorporate the load diversity in the local area. For example, space heating customers' maximum demand could occur in the winter, while the regular residential customers' maximum demand likely occurs in the summer. Together, the summer maximum demand may be sufficient to accommodate the space heating customers' winter demand without the need to increase the sizing of equipment for winter usage. My CCOSS includes this reduction to the residential NCP demands.

[13] PECO Response to OCA-X-2.

E. Results of Revised CCOSS

Q. HOW DID YOU EVALUATE THE IMPACT OF THE RECOMMENDED CLASS COST OF SERVICE MODIFICATIONS?

A. I revised the Company's confidential CCOSS model in accordance with III. (A) – (D). A summary of the results for the OCA class cost of service are shown on Schedule CJ-1. The revenue requirements reflect the Company's request. My use of the class cost of service results does not imply agreement with the Company's proposed revenue requirement. Instead, the Company's revenue requirements is utilized in order to provide an apples-to-apples comparison.

Q. PLEASE SHOW THE DIFFERENCES IN RELATIVE RATES OF RETURN AT PRESENT RATES.

A. The table below is based on the distribution CCOSS filed by the Company and the CCOSS revised by OCA. The relative rate of return ("RROR") shows the extent that classes' present revenues produce rates of return, which are higher or lower than the system earned rate of return. A RROR above 100% indicates a class that is above average, in terms of compensatory rates, and a RROR below 100% indicates a class that is below average. The RROR, below, reflects present rates. The increase at equalized rate of return is shown on Schedule CJ-1.

Company CCOSS	**Res**	**GS**	**Primary**	**HT**	**EP**	**Lights**
RROR-As Filed	90%	117%	113%	114%	148%	171%
OCA CCOSS						
OCA RROR	107%	69%	102%	104%	135%	274%

Q. PLEASE SUMMARIZE THE COMPARISON OF THE RESULTS OF THE CLASS COST OF SERVICE STUDIES.

A. The OCA CCOSS moves the position of the residential class from below cost in the Company study to well above cost after OCA's modifications. The principal change in relative rates of return for other classes pertains to General Service. The General Service class is above cost in the Company's study and falls below cost in the OCA CCOSS. The OCA CCOSS will inform my recommended distribution of the proposed revenue increase, but it is not determinative of recommended revenue changes. The class increase associated with equalized rates of return can and should be constrained by rate moderation considerations.

Q. DID YOU PERFORM AN ADDITIONAL CCOS STUDY WHICH PERTAINS TO OCA WITNESS COLTON'S RECOMMENDATION?

A. Yes. In OCA St. 4, Mr. Colton recommended that Universal Service costs should be reallocated to all customer classes instead of directly assigned to residential classes. Section VI of my testimony will address the impact of his recommendation. As part of his recommendation, CAP administrative cost and LIURP would be removed from the CCOS study and allocated as part of Universal Service costs. Therefore, Schedule CJ-1 also presents RROR results when those expenses are excluded from the CCOS study.

IV. CLASS REVENUE DISTRIBUTION

Q. IS THE CLASS COST OF SERVICE STUDY AN ABSOLUTE DETERMINANT OF THE DISTRIBUTION OF THE SYSTEM REVENUE INCREASE AMONG CLASSES?

A. No. The cost of service study results should be tempered by gradualism considerations. In addition, because the class cost of service results should be viewed as a snapshot of cost conditions that can change over time, gradualism can address the possibility that cost-based rates may be a moving target. Moreover, because the CCOSS may be quite sensitive to changes in allocation or classification choices, "cost based rates" are best viewed as representing a reasonable band around the CCOS results, rather than exact price points.

Q. ARE YOU AWARE OF UNUSUAL CIRCUMSTANCES WHICH SHOULD BE CONSIDERED IN DETERMINING THE RESIDENTIAL CLASS' SHARE OF THE TOTAL REVENUE INCREASE?

A. Yes. The unique circumstances of the pandemic may affect the accuracy of cost allocation in the CCOS. In the CCOS study, distribution demand costs are allocated among customer classes based on each class' highest hourly demand for the period October 1, 2019 – September 30, 2020.[14] This period is likely to be affected by economic changes and disruption caused by the pandemic. As a general matter, residential demands reflect work-at-home and stay at home impact and commercial demands reflect an abrupt economic

[14] PECO Response to OCA II-15.

decline during the pandemic. Comparing class NCP demand in the 2021 and 2018 CCOS studies, combined residential demand increased by 5.5%, commercial classes (GS, PD, HT) decreased by 7.4% - 13.9%, and electric propulsion decreased by 16.9%. As a result, the residential combined demand allocation share increased by 7.4%, and allocation shares for GS, PD, HT, and EP decreased by 5%, 13%, 9%, and 43%, respectively. The CCOSS is intended to reflect cost relationships which are likely to exist when rates are in effect. In these unusual circumstances, the 2021 CCOSS is unlikely to reflect the class cost relationships in the future after pandemic economic impact has diminished. Because the CCOSS likely overstates the residential share of distribution costs due to a temporary economic aberration, the Commission should avoid assigning the residential class an excessive share of any revenue increase simply to meet a target relative rate of return in the CCOSS.

Q. HOW DID YOU DEVELOP YOUR RECOMMENDED REVENUE DISTRIBUTION?

A. I have accepted the Company's proposed class revenue allocation as a starting point for developing my class revenue distribution. My principal adjustment is to align the Company's proposal in the direction of my proposed CCOSS. The most significant change in my CCOSS affects secondary classes, increasing General Service (GS) revenue responsibility and decreasing regular Residential required revenues. Given the substantial revenue impact that my study implies for the GS class, I placed a moderation cap of 140% of system average increase for GS. At the Company's proposed revenue requirement, the 140% cap produces a 25.6% revenue increase for GS. In order to shift the residential revenue increase in the direction of my CCOSS, I have decreased the regular Residential class percentage revenue increase to 16.2%. Within the constraints of the 140% percentage cap for GS, I also adjusted the Company's PD and HT revenue increases downward to reflect that those classes' present revenues are above cost. Finally, my recommendation is that no class should receive a revenue reduction at the same time that all other classes are receiving significant revenue increases. This eliminates the Company's proposed revenue reduction for the lighting class.

Q. HAVE YOU PREPARED A SCHEDULE SETTING OUT THE OCA'S PROPOSED REVENUE DISTRIBUTION?

A. Yes. Schedule CJ-2 shows my proposed allocation of the distribution revenue increase to customer classes. A comparison of the proposed distribution revenue increase, based on an 18.3% distribution system increase is shown below.

Distribution Revenue Increase Allocation ($000)

Company	Res	GS	Primary	HT	EP	Lights
Percent Incr.	16.9%	22.4%	21.3%	23.9%	0.3%	-1.52%
Rev Increase	157,730	54,471	1,635	37,702	26	-495
OCA						
Percent Incr.	16.2%	25.6%	18.7%	17.52%	0.3%	0.0%
Rev Increase	151,480	62,177	1,435	36,001	26	0

Q. DO YOU EXPECT THE OVERALL PROPOSED DISTRIBUTION REVENUE INCREASE TO BE LESS THAN THE COMPANY'S FILED REQUEST?

A. Yes. In OCA St. 1, the OCA presents revenue requirement testimony which proposes downward adjustments to the system revenue requirement. I recommend that the class results should be proportionately scaled back by the adopted revenue requirement adjustments.

V. RESIDENTIAL CUSTOMER CHARGE

Q. WHAT IS PECO'S PROPOSAL REGARDING THE RESIDENTIAL CUSTOMER CHARGE?

A. The Company proposes to increase the residential customer charge from the current level of $9.99 to $13.49. This is a 35% increase in the monthly charge.

Q. DO YOU AGREE WITH THE INCREASE PROPOSED FOR THE CUSTOMER CHARGE?

A. No. The customer charge does not provide price signals which are particularly relevant to resource allocation. In the ratemaking process, the customer charge level is closely linked to the utility's usage rates (per kWh and per kW), since costs which are not collected through the customer charge will be recovered through the usage rates. Because the electric utility cost structure is dominated by costs which vary with changes in demand and annual electric load over the long run, the usage-sensitive rate is the primary source of meaningful price signals. A lower customer charge ensures that a greater proportion of costs are recovered through a usage-sensitive price. A lower customer charge is more consistent with energy conservation goals and provides pricing policies appropriate for consumption of finite natural resources. In addition, a policy that minimizes the customer charge is more equitable to low usage and low income residential customers.[15]

Q. TAKING INTO ACCOUNT THE POLICY CONSIDERATIONS RELEVANT TO THE CUSTOMER CHARGE LEVEL, WHAT IS AN APPROPRIATE BENCHMARK FOR SETTING THE CUSTOMER CHARGE?

A. The customer charge should recover costs which directly vary with the number of customers, and this is the appropriate benchmark for determining whether the customer charge is compensatory. Public policy supports the use of a narrow measure of costs for the monthly fixed charge. The only economic pricing function of a customer charge is to ration access to the utility system; and public policy favors expansion, rather than limitation, of public access to regulated monopoly essential service. There is ample reason to base the customer charge on the following components: O&M expense for (1) meters, meter reading, and customer accounting; (2) return, income tax and depreciation on meter and service investment (plus any investment directly related to customer accounting); and (3) minus credits for customer deposits and related deferred federal income taxes. In my view, general overhead, such as administrative and general expense, and customer classified costs which are only weakly related to customer count, should be excluded from the customer charge computation, because these costs do not vary directly with number of customers.[16] The customer charge is compensatory so long as it recovers the expenses

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15 See also, OCA St. 4, OCA witness Colton.

16 The calculation of direct customer costs for my customer charge analysis includes limited general plant and employee benefit expense related to amount of direct customer–related personnel.

which are required to maintain the residential customer on the system. As stated by the Company, if a customer terminates service and is not replaced by another customer at the same premises, the only savings in customer-related costs would be the costs of "billing, meter reading and maintenance costs, and credit and collection costs."[17] These are the costs which vary directly with customer count, and are narrower in scope than the basic customer charge cost described above. As noted by the Company, associated overhead costs continue to be incurred when the customer leaves the system,[18] which confirms that the general overhead costs do not vary with the number of customers. My understanding is that the Commission historically favors a "basic customer cost" composed of costs for meter/service drops, meter reading, and billing.[19] I recommend that the Commission continue the approach taken in those historical cases which relied on the basic customer cost to evaluate the customer charge.

Q. HAVE YOU PERFORMED AN ANALYSIS OF THE APPROPRIATE BENCHMARK FOR EVALUATING PECO'S RESIDENTIAL CUSTOMER CHARGE?

A. Yes. I performed an analysis of costs which vary with customers, limited to meter/service drops, meter reading, billing, appropriate components of call center costs, and employee overhead (general plant and benefits) limited to those personnel. The customer accounting

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[17] PECO Response to OCA Set X-3.

[18] Ibid.

[19] *See e.g. Re: West Pennsylvania Power Co.*, 69 PUR4th 470 (1985); *Re: West Pennsylvania Power Co.*, 119 PUR4th 110 (1990); In addition, the direct cost method is also supported by *PPL Gas Utilities Corporation* (2007) Docket No. R-00061398 and *Columbia Gas of Pennsylvania* (2011) Docket No. R-2010-2201974.

cost includes call center calls limited to billing, initiating/terminating service, and credit. The residential customer charge developed by this analysis is **$8.37**. Because the current customer charge, $9.99, exceeds this cost, the residential customer charge recovers direct customer costs and contributes a 14% margin to common costs. Detail regarding my analysis of the customer charge is shown on Schedule CJ-3.

Q. DID YOU MAKE ADJUSTMENTS TO THE ACCOUNTS WHICH YOU INCLUDED IN THE CUSTOMER CHARGE ANALYSIS?

A. Yes. Based on the Company's identification of call center calls in PECO's Response to OCA-II-34(a), I calculated the call center percentages related to residential billing, residential stop/start/transfer, CAP billing assistance, and financial arrangements. Using this percentage, my analysis reduced the call center cost included in the customer charge by approximately 36%. This reduction eliminated calls related to subjects such as commercial customer assistance, emergencies, and suppliers. My calculation also excludes uncollectible expense from the residential customer charge because the amount of uncollectible expense is determined by the size of customer bills which are unpaid. The inclusion of uncollectible expense in the customer charge occurs because uncollectible expense is recorded in customer accounting; however, the act of recording the expense in a customer account does not mean that the cost varies directly with number of customers.[20] Moreover, residential uncollectibles are overwhelmingly associated with unpaid variable charges. Residential distribution revenues are comprised of 90% variable rates, and bills

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[20] Note that the NARUC Electric Utility Cost Allocation Manual (CAM) specifically excludes uncollectibles from the customer classification. CAM at 103.

of uncollectible accounts probably include a higher percentage of variable charges.[21] Furthermore, the uncollectible expense in Account 904 includes retail transmission and energy functional components of unpaid bills.[22] In addition, I have excluded customer service and sales expense (FERC Accounts 908 – 916), which are indirect costs largely unrelated to billing. The largest component of this cost is LIURP,[23] and there is no reason that this cost should be recovered through the customer charge instead of the kWh rate. LIURP is an energy conservation program that targets low income customers, and therefore is more closely related to the volumetric rate. In addition, the advertising, promotional, and economic development expenses recorded in these accounts are not appropriately recovered through a monthly customer charge.

Q. DOES ENERGY CONSERVATION POLICY FAVOR THE USE OF THE BASIC CUSTOMER CHARGE CALCULATION?

A. Yes. In weighing the appropriateness of limited or broad calculations of the customer charge, the Commission should consider the effect on energy efficiency policies. A high customer charge tends to inhibit energy conservation. Minimizing the customer charge provides the ratepayer with a greater ability to control his/her bill on the basis of usage. For that reason, an excessive customer charge can promote wasteful energy consumption. Pennsylvania's policy favoring energy efficiency, as evidenced by directives requiring

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[21] See, PECO Response to OCA-X-8a, which presents customer charge as percentage of residential bill.

[22] PECO Response to OCA-X-9.

[23] Attachment IE-II-RS (D) (e) Tab Account 908.

utility funded energy conservation programs, provides convincing support for utilizing a basic customer charge benchmark. Public utilities have an incentive to propose fixed charges because the charges produce less financial risk; however, they do not propose to compensate customers for the lower risk through a reduction in the allowable return on equity. Without such explicit compensation to ratepayers, the utilities' frequent argument in favor of the "revenue stability" aspect of fixed charges is not a reasonable policy basis for adopting methods that produce high customer charges.

Q. CAN YOU PROVIDE AN ILLUSTRATION OF THE IMPACT OF CUSTOMER CHARGE METHODS ON ENERGY EFFICIENCY CHOICES?

A. Yes. I performed a comparison of the net life cycle savings, as measured by the present value of bill savings net of appliance purchase price, for an Energy Star heat pump relative to a less-efficient heat pump option.[24] The heat pump is eligible for an incentive pursuant to PECO's energy conservation program, and I included the effect of the incentive. I prepared a comparison of net life cycle savings for purchasing the more efficient appliance based on maintaining the current customer charge versus the claimed customer charge justified by the Company's CCOSS ($14.91),[25] assuming the Company's proposed residential revenue requirement is accepted.[26] Assuming a constant residential class revenue requirement, the lower current customer charge places higher revenue recovery on

[24] I utilized Energy Star spreadsheets which were developed for the EPA and U.S. Department of Energy to calculate "net life cycle energy cost savings," which is based on the discounted bill savings, net of higher appliance purchase cost, over the life of the energy efficient appliance. The spreadsheet also calculates a payback period for purchasing the efficient appliance.

[25] Attachment OCA-II-17 (a).

[26] This analysis is based on the total bill, which is derived from proposed generation, transmission, and distribution residential revenues.

the energy rate component, thereby increasing the incentive for customers to engage in energy efficiency actions. The difference in the residential variable energy resulting from different customer charge levels is almost one cent per kWh in this example. The higher customer charge level produces 8% lower net life cycle savings and a 10% longer payback period. These measures reflect the cost-benefit comparison that consumers would consider in choosing to opt for the more energy efficient appliance. This analysis illustrates that increasing the customer charge can discourage energy efficiency by increasing the consumer's payback period.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RESIDENTIAL CUSTOMER CHARGE?

A. My primary recommendation is to maintain the residential customer charge at the current $9.99 level. The current residential customer exceeds my estimate of basic customer costs. Therefore, my position is that the ultimate revenue increase for the residential class should be recovered through the variable energy charge. If the Commission finds that residential rate design policy should be more reflective of energy conservation and low income equity criteria, the residential customer charge can be reduced below its current level, so long as it exceeds the basic customer charge of $8.37.

VI. UNIVERSAL SERVICE CHARGES

Q. WILL YOU DISCUSS AN ISSUE RAISED BY OCA WITNESS MR. COLTON?

A. Yes. Mr. Colton recommends a change in the treatment of universal service cost, principally CAP and LIURP. In particular, he proposes to allocate the cost among all customer classes, rather than the Company's practice of assigning the cost to Rate R and Rate RH customer classes. My testimony will present information regarding the potential impact of the proposed allocation.

Q. HAVE YOU IDENTIFIED THE AMOUNT OF UNIVERSAL SERVICE COSTS?

A. Yes. Under the Company's filed case, the costs of CAP credits are assigned to residential classes as part of the proof of revenues used to develop rates. In addition, the cost of CAP administration and LIURP are included in Accounts 903 and 908 and allocated in the CCOS study only to Rate R and RH. The total cost is $99.4 million, comprised of $88.1 million of CAP credits and $11.3 million of expense in Accounts 903 and 908.[27] Mr. Colton's recommendation is to allocate these costs through a universal service fund rider to customer classes on a revenue basis.

Q. HAVE YOU PREPARED A SCHEDULE WHICH PRESENTS THE ALLOCATION IMPACT OF MR. COLTON'S RECOMMENDATION?

A. Yes. Schedule CJ-4 sets out an allocation of the universal service cost on the basis of PECO distribution revenues. The revenue allocation is based on PECO's proposed class distribution revenues set out in Corrected JAB-1.[28] Schedule CJ-4 presents the amount of universal service costs allocated to each customer class, the effective charge per kWh for each class, the average monthly universal service charge for each class, and the average monthly universal service charge as a percentage of the average transmission-distribution bill for each customer class. In addition, for comparison Schedule CJ-4 shows the class

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[27] Corrected JAB-4R and JAB-4RH; OSBA I-5.

[28] The revenue allocator can be modified after the Commission adopts a final class revenue allocation.

shares of universal service cost if the allocation had been based upon a uniform kWh rate instead of revenues.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes.

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RESULTS OF RECOMMENDED CCOSS ADJUSTMENTS

Thousands of Dollars	TOTAL ELECTRIC DIVISION	RESIDENTIAL	GENERAL SERVICE	PRIMARY DISTRIBUTION	HIGH TENSION	ELECTRIC PROPULSION	LIGHTING
Current Revenues	$ 1,372,001	$ 932,173	$ 242,879	$ 7,694	$ 157,654	$ 8,118	$ 23,483
As Filed CCOSS:							
Proposed Rev Incr.-Equalized	$ 251,058	$ 197,545	$ 31,352	$ 1,056	$ 22,354	$ 112	$ (1,360)
Proposed Percent at Cost	18.30%	21.19%	12.91%	13.72%	14.18%	1.37%	-5.79%
Ratio to Sys Avg. Increase	100.00%	115.8%	70.5%	75.0%	77.5%	7.5%	-31.7%
RROR Present Revs		90.03%	117.0%	113.3%	114.4%	148.1%	171.2%
As Adjusted:							
Proposed Rev Incr.-Equalized	$ 251,058	$ 135,340	$ 90,712	$ 1,429	$ 29,688	$ 466	$ (6,579)
Proposed Percent at Cost	18.30%	14.52%	37.35%	18.58%	18.83%	5.75%	-28.01%
Ratio to Sys Avg. Increase	100.00%	79.34%	204.1%	101.5%	102.9%	31.4%	-153.1%
RROR Present Revs		107.2%	68.8%	101.7%	104.0%	136.1%	273.8%

Note: Increase Amounts Based on Company Requested Revenue Requirements for Comparability.
Class Revenue Increase Subject to Scale Back Based on Final Revenue Requirements.

Relative Rates of Return:

	RESIDENTIAL	GENERAL SERVICE	PRIMARY DISTRIBUTION	HIGH TENSION	ELECTRIC PROPULSION	LIGHTING
Company CCOSS w/o CAP Admin.	91.7%	114.75%	111.31%	111.94%	144.57%	167.53%
Adjusted CCOSS w/o CAP Admin.	108.2%	67.6%	100.0%	101.7%	132.9%	267.8%

Note: Impact of Removing $11.3 Million of CAP Administrative & LIURP Expense From CCOSS

ALLOCATION OF DISTRIBUTION REVENUES

CLASS REVENUE INCREASES PROPOSED BY PECO

Rate Class	Current Distribution Revenue	PECO Proposed Distribution Revenue	PECO Requested Rev Increase	Percentage Increase	Ratio to System Average
Residential (R)	$ 778,130,690	$ 910,222,895	$ 132,092,205	17.0%	92.8%
Residential Heating (RH)	$ 154,041,920	$ 179,680,699	$ 25,638,779	16.6%	91.0%
General Service (GS)	$ 242,879,465	$ 297,350,981	$ 54,471,517	22.4%	122.6%
Primary Distribution (PD)	$ 7,694,222	$ 9,329,801	$ 1,635,579	21.3%	116.2%
High Tension (HT)	$ 157,653,660	$ 195,355,885	$ 37,702,225	23.9%	130.7%
Electric Propulsion (EP)	$ 8,117,629	$ 8,143,655	$ 26,026	0.3%	1.8%
Lighting	$ 23,483,070	$ 22,988,006	$ (495,064)	-2.1%	-11.5%
Total	$ 1,372,000,656	$ 1,623,071,922	$ 251,071,266	18.3%	

ADJUSTMENT TO PECO PROPOSED REVENUE INCREASE

Rate Class	Current Distribution Revenue	Adjustment to Revenue Allocation	Adjusted Class Rev Increase	Percentage Increase	Ratio to System Average
Residential (R)	$ 778,130,690	$ (6,300,000)	$ 125,792,205	16.2%	88.3%
Residential Heating (RH)	$ 154,041,920	$ -	$ 25,638,779	16.6%	91.0%
General Service (GS)	$ 242,879,465	$ 7,705,626	$ 62,177,143	25.6%	139.9%
Primary Distribution (PD)	$ 7,694,222	$ (200,000)	$ 1,435,579	18.7%	102.0%
High Tension (HT)	$ 157,653,660	$ (1,700,700)	$ 36,001,525	22.8%	124.8%
Electric Propulsion (EP)	$ 8,117,629	$ -	$ 26,026	0.3%	1.8%
Lighting	$ 23,483,070	$ 495,073	$ -	0.0%	0.0%
Total	$ 1,372,000,656	$ 0	$ 251,071,266	18.3%	
Residential Combined					
As Adjusted	$ 932,172,611	$ (6,300,000)	$ 151,430,983	16.2%	
Per PECO	$ 932,172,611	$ 1,089,903,594	$ 157,730,983	16.9%	

PECO Customer Charge Analysis

	Rate Base		
1	Meters & Services	$	521,014
2	A389-399, Customer	$	43,246
3	AMI Software	$	70,140
4	Accum. Depreciation	$	307,257
5	Deferred Income Taxes	$	44,269
6	Cust. Deposits & Advances	$	17,999
	[1+2+3-4-5-6]		
7	Sub Total Rate Base	$	264,875
8	**Return and Income Taxes**	$	23,927
	Expenses		
9	Meter O&M	$	3,801
10	A932 & 926 Expense	$	6,089
11	Customer Accounts	$	96,094
12	Exclude Uncollect.	$	(28,767)
13	Call Center Adjustment	$	(4,308)
14	Exclude CAP Administration	$	(5,200)
15	Depreciation & Amort.	$	41,870
	[Sum 9 thru 14]		
16	**Total Expenses**	$	109,580
	[8+15]		
17	**Basic Customer Charge Cost**	$	133,507
18	Billing Units	$	15,959,674
	[16/17]		
	Residential Customer Charge	**$**	**8.37**

Allocation of Universal Service Costs On Class Distribution Revenues

	PECO ELECTRIC DIVISION	RESIDENTIAL	RESIDENTIAL HEATING	GENERAL SERVICE	PRIMARY DISTRIBUTION	HIGH TENSION	ELECTRIC PROPULSION	LIGHTING
Revenue Allocator	100.0%	56.1%	11.1%	18.3%	0.6%	12.0%	0.5%	1.4%
Total CAP Discount	$ 88,109,150	$ 49,411,837	$ 9,754,043	$ 16,141,824	$ 506,472	$ 10,604,977	$ 442,082	$ 1,247,914
Admin & LIURP	$ 11,300,000	$ 6,337,069	$ 1,250,956	$ 2,070,189	$ 64,955	$ 1,360,089	$ 56,697	$ 160,045
CAP TOTAL	$ 99,409,150	$ 55,748,906	$ 11,004,999	$ 18,212,014	$ 571,427	$ 11,965,066	$ 498,779	$ 1,407,959
Cost per kWh	$ 0.00269	$ 0.00514	$ 0.00399	$ 0.00231	$ 0.00169	$ 0.00084	$ 0.00087	$ 0.00801
Average Per Bill		$ 3.49	$ 4.66	$ 9.74	$ 116.71	$ 370.75	$ 1,072.64	$ 9.35
Percent Per T&D Bill		5.63%	5.50%	5.44%	5.60%	5.27%	5.15%	6.11%
Res & RH w/o reallocation		$ 5.49	$ 5.00					
Res & RH Reduction		$ (1.99)	$ (0.35)					

Comparison of Revenue Allocation to kWh Allocation

CAP Total at	**System Rate**	**R**	**RH**	**GS**	**Primary**	**HT**	**EP**	**Lighting**
Uniform kWh Rate	$ 0.0027	$ 29,230,226	$ 7,424,055	$ 21,266,479	$ 913,460	$ 38,557,227	$ 1,544,164	$ 473,539
Difference w/ Rev Allocation		$ (26,518,680)	$ (3,580,945)	$ 3,054,465	$ 342,033	$ 26,592,161	$ 1,045,385	$ (934,420)

SUMMARY OF QUALIFICATIONS

CLARENCE JOHNSON

EDUCATION

Bachelor of Science, Political Science, University of Houston.

Master of Arts, College of Social Science (Interdisciplinary/Urban Studies), University of Houston.

EXPERIENCE

Mr. Johnson has more than 35 years experience as an expert witness and analyst related to electric and telecommunications utility issues.

CURRENT EMPLOYMENT

Mr. Johnson currently provides professional consulting and analytical analyses regarding regulatory and public policies related to public utilities and the energy industry.

PREVIOUS EMPLOYMENT 1983-2008

From September 1983 to June 2008, Mr. Johnson was a Regulatory Analyst for the Office of Public Utility Counsel. He was the professional staff person with primary responsibility for advising the Public Counsel on economic and regulatory policy issues. His responsibilities included: presenting expert testimony on regulatory matters; research related to rate filings of regulated public utilities; acting as a non-testifying expert and advising attorneys in cross-examination of witnesses and development of trial exhibits for utility regulatory proceedings; analyzing policies and practices for regulating public utilities; and preparing comments on proposed Public Utility Commission rules; assisting financial and economic staff in the development and preparation of testimony; providing expert testimony on selected issues; preparation of reports to the Legislature regarding the utility regulatory process.

EMPLOYMENT BEFORE 1983

During the period 1977 to 1983, Mr. Johnson extensively engaged in analysis and supervision of public interest advocacy programs. He directed two non-profit corporations involved in public policy research from 1978 to 1980 and 1982 to 1983, respectively; responsibilities included overall management of the corporations, negotiation and management of grants and contracts, supervision of research activities, and presentations of research findings to legislative and administrative governmental entities. From 1980 to 1982, he also performed policy analysis and substantive research on the impact of governmental policies for two publicly-funded entities. His responsibilities for the statewide support center for legal services programs in Texas assessed the effect of federal and state regulatory changes upon indigent clients. As an analyst for the Texas State Senate's Natural Resources

Committee, Mr. Johnson was responsible for research related to low-level radioactive waste disposal and low-head hydropower, and the committee's staff's interim report on energy conservation.

AWARDS Mr. Johnson was the recipient of the first annual Texas Outstanding Public Service Award in 1988.

MEMBERSHIP American Economics Association.

TESTIMONY ON BEHALF OF TEXAS OFFICE OF PUBLIC UTILITY COUNSEL

Docket No. 6588, Re Southwestern Bell Telephone Company,
Subject: Declassification of Documents.

Docket Nos. 7195 and 6755, Re Gulf States Utilities Company,
Subject: Rate Design/Cost Allocation.

Docket No. 7510, Re West Texas Utilities Company,
Subject: Rate Design/Cost Allocation.

Docket No. 8095, Re Texas-New Mexico Power Company,
Subject: Rate Design/Cost Allocation.

Docket No. 8363, Re El Paso Electric Company,
Subject: Rate Design/Cost Allocation.

Docket No. 8425, Re Houston Lighting & Power Company,
Subject: Revenue Requirements.

Docket No. 8425, Re Houston Lighting & Power Company,
Subject: Rate Design/Cost Allocation.

Docket No. 8646, Re Central Power and Light Company,
Subject: Revenue Requirements.

Docket No. 8646, Re Central Power and Light Company,
Subject: Rate Design/Cost Allocation.

Docket No. 8646, Re Central Power and Light Company,
Subject: Interim Rate Relief.

Docket No. 8555, Proceedings Concerning Houston Lighting & Power Company on Remand From Cause No. C-5705 and Cause No. 352,044,
Subject: Determination of Remand Amount.

Docket No. 8928, Re Texas-New Mexico Power Company,
Subject: Rate Design/Cost Allocation.

Docket No. 8585, Re Southwestern Bell Telephone Company,
Subject: Revenue Requirements/Affiliates.

Docket No. 8585, Re Southwestern Bell Telephone Company,
Subject: Reply, Revenue Requirements/Affiliates.

Docket No. 8585, Re Southwestern Bell Telephone Company,
Subject: Reply, Rate Design.

Docket No. 8585, Southwestern Bell Telephone Company,
Subject: Proposed Non-Unanimous Stipulation.

Docket No. 9300, Texas Utilities Electric Company,
Subject: Revenue Requirement.

Docket No. 9300, Texas Utilities Electric Company,
Subject: Cost Allocation and Rate Design.

Docket No. 9300, Texas Utilities Electric Company,
Subject: Prudence of Plant Acquisition.

Docket No. 9561, Central Power and Light Company,
Subject: Revenue Requirement.

Docket No. 9561, Central Power and Light Company,
Subject: Cost Allocation and Rate Design.

Docket No. 9578, Sugar Land Telephone Company,
Subject: Inquiry into Sale.

Docket No. 9850, Houston Lighting & Power Company,
Subject: Revenue Requirement.

Docket No. 9850, Houston Lighting & Power Company,
Subject: Cost Allocation and Rate Design.

Docket No. 9850, Houston Lighting & Power Company,
Subject: Settlement Testimony: Revenue Requirement and Rate Design.

Docket No. 9981, Central Telephone Company,
Subject: Revenue Requirement/Affiliates.

Docket No. 10894, Gulf States Utilities Company,
Subject: Affiliate Transactions/Power Purchases.

Docket No. 11735, Texas Utilities Electric Company,
Subject: Revenue Requirement and Rate Design.

Docket No. 11892, General Counsel's Original Petition for Generic Proceeding Regarding Purchased Power,
Subject: Impact of Purchased Power on Cost of Capital.

Docket No. 12700, El Paso Electric Company,
Subject: Acquisition, Revenue Requirement and Rate Design.

Docket No. 12957, Houston Lighting & Power Company,
Subject: Contract Pricing Tariff.

Docket No. 13100, Texas Utilities Electric Company,
Subject: Competitive Pricing Tariffs.

Docket No. 13575, Texas Utilities Electric Company,
Subject: Demand Side Management and Purchase Power Recovery.

Docket No. 12065, Houston Lighting & Power Company,
Subject: Revenue Requirement/Plant Cancellation/Prudence.

Docket No. 12065, Houston Lighting & Power Company,
Subject: Cost Allocation and Rate Design.

Docket No. 13943, Gulf Coast Power Connect,
Subject: Transmission Line CCN.

Docket No. 13575, TUEC Application for Relief Regarding Recovery Solicitations,
Subject: DSM and Purchase Power Cost Recovery.

Docket No. 13369, West Texas Utilities Company,
Subject: Cost Allocation and Rate Design.

Docket No. 14435, Southwestern Electric Power Co.,
Subject: Rate Design.

Docket No. 14716, Texas Utilities Electric Company,
Subject: Wholesale Competitive Rate.

Docket No. 14965, Central Power and Light Company,
Subject: Cost Allocation, Rate Design and Competitive Issues.

Docket No. 14965,	Central Power and Light Company,
Subject:	Reply, Cost Allocation, Rate Design and Competitive Issues.
Docket No. 15560,	Texas-New Mexico Power Company,
Subject:	Competitive Issues.
Docket No. 16705,	Entergy Gulf States, Inc.,
Subject:	Cost Allocation, Rate Design and Competitive Issues.
Docket No. 16705,	Entergy Gulf States, Inc.,
Subject:	Reply, Cost Allocation, Rate Design and Competitive Issues.
Docket No. 16995,	Central Southwest Corp.,
Subject:	Integrated Resource Planning.
Docket No. 17751,	Texas-New Mexico Power Company,
Subject:	Rate Design and Competitive Issues.
Docket No. 18845,	CPL, WTU, and SWEPCO,
Subject:	Integrated Resource Planning.
Docket No. 21527,	TXU Financing Order,
Subject:	Cost Allocation.
Docket No. 21528,	CPL Financing Order,
Subject:	Cost Allocation.
Docket No. 21591,	Sharyland Utilities Initial Rates & Tariffs,
Subject:	Deferrals.
Docket No. 21956,	Reliant Business Separation Plan,
Subject:	Price to Beat and Capacity Auction.
Docket No. 22344,	Generic Rate Design and Customer Classification for TDUs,
Subject:	Rate Design.
Docket No. 22349,	TNMP Unbundling,
Subject:	Competitive Transition Charge and Revenue Requirements/Cost Allocation/Rate Design.

Docket No. 22350,	TXU Unbundling,
Subject:	Competitive Transition Charge.
Docket No. 22351,	Southwestern Public Service Company Unbundling,
Subject:	Cost Allocation/Rate Design.
Docket No. 22352,	Central Power & Light Company,
Subject:	Competitive Transition Charge.
Docket No. 22355,	Reliant Unbundling,
Subject:	Non-Bypassable Charges and Competitive Transition Charge/Cost Allocation/Rate Design.
Docket No.22356,	Entergy Gulf States Utilities Unbundling,
Subject:	Revenue Requirements/Cost Allocation/Competitive Transition Charge/Settlement Rate Design.
Docket No. 24194,	Application of TNMP to Establish Price to Beat Fuel Factor,
Subject:	Fuel and purchased power costs.
Docket No. 25230,	Joint Application for Approval of Stipulation Regarding TXU Electric Company Transition to Competition Issues,
Subject:	Retail Clawback Provisions of Non-Unanimous Agreement.
Docket No. 25314,	Application of West Texas Utilities Company and Mutual Energy WTU to Establish a Fuel Reconciliation Methodology for Southwest Power Pool (SPP) Customers,
Subject:	Fuel Cost Method.
Docket No. 24336,	Application of Entergy Gulf States, Inc. for Approval of Price to Beat Factor,
Subject:	Unaccounted for Energy.
Docket No. 23320,	Petition of ERCOT for Approval of the ERCOT Administrative Fee,
Subject:	ERCOT Fee Structure.
Docket No. 26194,	El Paso Electric Company Fuel Reconciliation,
Subject:	Purchased Power and Off-System Sales.

Docket No. 27576,	Application of Texas-New Mexico Power Company for Reconciliation of Fuel Costs,
Subject:	Fuel Reconciliation.
Docket No. 28813,	Inquiry Into Rates of Cap Rock Energy,
Subject:	Revenue Requirements/Cost Allocation/Rate Design.
Docket No. 28840,	Application of AEP Texas Central Company for Change in Rates,
Subject:	Cost Allocation/Rate Design/Affiliate Transactions.
Docket No. 30485,	Application of CenterPoint Energy Houston Electric, LLC For A Financing Order,
Subject:	Transition Charge Recovery.
Docket No. 30143,	Petition of El Paso Electric Company to Reconcile Fuel Costs (Initial and Rebuttal Testimonies),
Subject:	Fuel Reconciliation.
Docket No. 30706,	Application of CenterPoint Energy Houston Electric, LLC for A Competition Transition Charge,
Subject:	Competitive Transition Charge Structure.
Docket No. 31315,	Application of Entergy Gulf States, Inc. for Approval of Incremental Purchased Capacity Recovery Rider,
Subject:	Purchase Power Capacity Rates.
Docket No. 31544,	Application of Entergy Gulf States, Inc. for Recovery of Transition to Competition Costs,
Subject:	Allocation of Transition Costs.
Docket No. 31994,	Application of Texas-New Mexico Power Company's to Establish a Competition Transition Charge Pursuant to P.U.C. Subst. R. 25.263(N),
Subject:	Competition Transition Charge.
Docket No. 32475,	Application of AEP Texas Central Company for a Financing Order,
Subject:	Securitization of Stranded Costs.

Docket No. 32758,	Application of AEP Texas Central Company for a Competition Transition Charge Pursuant to P.U.C. Subst. R. 25.263(n),
Subject:	Competitive Transition Charge.
Docket No. 32795,	Staff's Petition to Initiate Generic Proceeding to Re-Allocate Stranded Costs Pursuant to PURA § 39.253(f),
Subject:	Stranded Costs Allocation.
Docket No. 32907,	Application of Entergy Gulf States, Inc. for Determination of Hurricane Reconstruction Costs,
Subject:	Cost Allocation.
Docket No. 32766,	Application of Southwestern Public Service Company for: (1) Authority to Change Rates; (2) Reconciliation of its Fuel Costs for 2004 and 2005; (3) Authority to Revise the Semi-Annual Formulae Originally Approved in Docket No. 27751 Used to Adjust its Fuel Factors; and (4) Related Relief,
Subject:	Cost Allocation/Rate Design.
Docket No. 33586,	Application of Entergy Gulf States, Inc. for a Financing Order,
Subject:	Financing Order Allocation.
Docket No. 32710,	Application of Entergy Gulf States, Inc. for Authority to Reconcile Fuel and Purchased Power Costs,
Subject:	Capacity Rider Allocation.
Docket No. 31461,	Application of AEP Texas North Company for a Competition Transition Charge Under to Subst. R. §25.263(N),
Subject:	Competition Transition Charge.
Docket No. 32795,	Staff's Petition to Initiate a Generic Proceeding to Re-Allocate Stranded Costs Pursuant to PURA § 39.253(f),
Subject:	Stranded Cost Allocation.
Docket No. 33309,	Application of AEP Texas Central Company for Authority to Change Rates,
Subject:	Rate Design and Energy Efficiency Costs.

Docket No. 33310,	Application of AEP Texas North Company for Authority to Change Rates,
Subject	Energy Efficiency Costs and Riders.
Docket No. 32902,	CenterPoint Energy Houston Electric, LLC Compliance Tariff,
Subject:	Allocation of Stranded Costs.
Docket No. 34077,	Joint Report and Application of Oncor and EFH Pursuant to § 14.101,
Subject:	Leveraged buyout of utility.
Docket No. 35105,	Compliance Tariff Filing of AEP Texas,
Subject:	Allocation of Stranded Costs.
Docket No. 35038,	Texas-New Mexico Power Company Tariff Filing in Compliance with the Final Order in Docket No. 33106,
Subject:	Allocation of Stranded Costs.
Docket No. 34800,	Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs,
Subject:	Cost Allocation & Rate Design.
*Docket No. 37482,	Application of Entergy Texas for a PCRF,
Subject:	Purchase Power.
*Docket No. 37744,	Application of Entergy Texas, Inc. for Authority to Change Rates,
Subject:	Cost allocation, rate design, proposed riders, & storm damage expense.
*Docket No. 38951,	Application of Entergy Texas, Inc. for Approval of CGS Tariff,
Subject:	Rate Design, Competitive Tariffs.
*Docket No. 46454,	Application of SPS for Revision of EECRF[1],
Subject:	Recovery of energy efficiency costs.

[1] Asterick (*) denotes testimony for Texas OPC as a consultant.

TESTIMONY ON BEHALF OF STEERING COMMITTEE OF ONCOR CITIES	Docket No. 35634, Subject:	Re Oncor Electric Delivery's Request for an Energy Efficiency Cost Recovery Factor, Energy Efficiency Cost Recovery.
	Docket No. 36958, Subject:	Application of Oncor Electric Delivery Company LLC for 2010 Energy Efficiency Cost Recovery Factor, Energy Efficiency Cost Recovery.
	Docket No. 39375, Subject:	Application of Oncor Electric Delivery Company LLC for 2012 EECRF, Energy Efficiency Cost Recovery.
TESTIMONY ON BEHALF OF ALLIANCE OF XCEL MUNICI-PALITIES	Docket No. 35664, Subject:	Application of SPS to Revise Interruptible Credit Option Tariff, Interruptible Rate Avoided Costs.
	Docket No. 35763, Subject:	Application of SPS to Change Rates and Reconcile Fuel and Purchased Power Costs, Energy Efficiency, Renewable Energy Credits, Power Cost Credits, and Interruptible Credits.
	Docket No. 37173, Subject:	Petition for Declaratory Order of Southwestern Public Service Company Regarding the Generation Demand Charge as a Cap on Compensation for Interruptible Resources Interruptible Curtailable Option ("ICO").
	Docket No. 43695, Subject:	Application of SPS to Change Base Rates, Cost Allocation / Rate Design/ Jurisdictional.
	Docket No. 47527, Subject:	Application of SPS to Change Base Rates, Cost Allocation / Rate Design/ Jurisdictional
TESTIMONY ON BEHALF OF CERTAIN TNMP CITIES	Docket No. 36025, Subject:	Application of TNMP for Authority to Change Rates, Cost Allocation and Rate Design.
	Docket No. 39362, Subject:	Application of TNMP for 2012 EECRF, Energy Efficiency Cost Recovery.

TESTIMONY ON BEHALF OF ST.LAWRENCE COTTON GROWERS	Docket No. 41474,	Application of Sharyland Utilities for Unbundled Delivery Rates,
	Subject:	Cost Allocation, Rate Design, Unbundling.
TESTIMONY ON BEHALF OF LIVE OAK TENANTS	Docket No.41987,	Complaint Against Live Oak Resort,
	Subject:	Sub Metering Complaint Case.
TESTIMONY ON BEHALF OF GULF COAST COALITION OF CITIES	Docket No. 38339,	Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates,
	Subject:	Cost Allocation, Rate Design, Riders.
TESTIMONY ON BEHALF OF PENNYSLVANIA OFFICE OF CONSUMER ADVOCATE	Docket No. R-2010-2161575, et. al.,	PECO Energy Co.-Electric Division Base Rate Case,
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2010-2179522,	Duquesne Light Company Base Rate Case,
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2014-248745,	Met Edison General Base Rate Case,
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2014-2478743,	Penelec Power General Base Rate Case,
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2014-2478744,	Penn Power General Base Rate Case,
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2014-248752,	West Penn Power General Base Rate Case,

	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2016-2537349	Met Edison General Base Rate Case,
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2016-2537352	Penelec Power General Base Rate Case,
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2016-2537355,	Penn Power General Base Rates,
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2016-2537359	West Penn Power General Base Rate Case,
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2018-3000164	PECO General Rate Case
	Subject:	Cost Allocation and Rate Design

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TESTIMONY ON BEHALF OF SWEPCO CITIES	Docket No. 40443,	Application of SWEPCO for Rate Change,
	Subject:	Cost Allocation, Rate Design, Fuel Rule, Revs.
TESTIMONY ON BEHALF OF SWEPCO CITIES (CARD)	Docket No. 46449,	Application of SWEPCO for Rate Change,
	Subject:	Cost Allocation, Rate Design, Transmission.

Gas Utility (Railroad Commission):

TESTIMONY FOR CITY OF EL PASO	Docket No.10506	Texas Gas Services Co.-West Texas
	Subject:	Cost Allocation, Rate Design

TESTIMONY FOR CONNECTICUT CONSUMER COUNSEL	Docket No.14-05-06,	CL&P Rate Increase Application,
	Subject:	Cost Allocation, Rate Design, Decoupling.
TESTIMONY FOR TEXAS COAST UTILITIES COALITION	Docket No.44572,	Centerpoint Application for DCRF,
	Subject:	Distribution Cost Recovery Factor.
	Docket No. 47320,	Centerpoint Application for DCRF,
	Subject:	Distribution Cost Recovery Factor.
TESTIMONY FOR CITY OF EL PASO	Docket No.44941,	El Paso Electric Co. Rate Request,
	Subject:	Cost Allocation, Rate Design.
	Docket No. 46831	EPEC Rate Case
	Subject:	Cost Allocation/Rate Design
	Docket No. 48181	EPEC Community Solar Waiver
	Subject:	Regulatory Policy
TESTIMONY FOR TEXAS OPUC (2014 or later)	Docket No.44620,	Sharyland Utilities Good Cause Request,
	Subject:	Transmission Cost Recovery.
	Docket No. 45414, (base rate)	Sharyland Utilities Rate Inquiry,
	Subject:	Rev Req/Allocation/Rate Design.
	Docket No. 46025, (fuel)	Southwestern Public Service Co.,
	Subject:	Fuel and Purchased Power.
	Docket No. 48371,	Entergy Texas Rate Application
		Class Allocation/Rate Design/Riders
	Docket No. 49616,	Southwestern Public Service Co.
	Subject:	Fuel Factor Methodology

Docket No. 50058, El Paso Electric Co. Fuel Reconciliation
Subject: Off System Sales Margin in Fuel

Docket No. 51625, Southwestern Public Service Co.
Subject: Fuel Factor Methodology; Gas Prices

TESTIMONY FOR CITIES SERVED BY AEP	Docket No.49494, Subject:	Application of AEP Texas to Adjust Rates Cost Allocation/Rate Design
TESTIMONY FOR MD. OFFICE OF PEOPLE COUNSEL	Case No.9610, Subject:	Application of Baltimore Gas & Electric Co. Gas/Electric Cost Allocation/Rate Design

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024601
	:	
PECO Energy Company – Electric Division	:	

VERIFICATION

I, Clarence L. Johnson, hereby state that the facts set forth in my Direct Testimony, OCA Statement 3, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: June 28, 2021
*311952

Signature: ______________________
Clarence L. Johnson

Consultant Address: CJ Energy Consulting
3707 Robinson Avenue
Austin, TX 78722

OCA Statement No. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2021-3024601
PECO Energy Company – Electric Division	:	

Direct Testimony of
Roger D. Colton

On Behalf of:
Office of Consumer Advocate
Statement No. 4

June 28, 2021

Table of Contents

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, MA 02478.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a principal in the firm of Fisher Sheehan & Colton, Public Finance and General Economics of Belmont, Massachusetts. In that capacity, I provide technical assistance to a variety of federal and state agencies, consumer organizations and public utilities on rate and customer service issues involving water/sewer, natural gas and electric utilities.

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

A. I am testifying on behalf of the Office of Consumer Advocate.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I work primarily on low-income utility issues. This involves regulatory work on rate and customer service issues, as well as research into low-income usage, payment patterns, and affordability programs. At present, I am working on various projects in the states of Rhode Island, New York, Maryland, Pennsylvania, Tennessee, Kentucky, Ohio, Michigan, and Missouri. My clients include state agencies (e.g., Pennsylvania Office of Consumer Advocate, Maryland Office of People's Counsel, Illinois Office of Attorney General), federal agencies (e.g., the U.S. Department of Health and Human Services), community-based organizations (e.g., National Immigration Law Center, Natural Resources Defense Council, Advocacy Centre Tenants Ontario), and private utilities (e.g., Unitil Corporation d/b/a Fitchburg Gas and Electric Company, Entergy Services, Xcel Energy d/b/a Public Service of Colorado). In addition to state-specific and utility-specific work, I engage in national work throughout the United States. For example, in 2007, I was part of a team that performed a multi-sponsor public/private national study of low-income energy assistance programs. In 2020, I completed a study of water affordability in twelve U.S. cities for the London-based newspaper, The Guardian. A brief description of my professional background is provided in Appendix A.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. After receiving my undergraduate degree in 1975 (Iowa State University), I obtained further training in both law and economics. I received my law degree in 1981 (University of Florida). I received my Master's Degree (regulatory economics) from the MacGregor School in 1993.

Q. HAVE YOU EVER PUBLISHED ON PUBLIC UTILITY REGULATORY ISSUES?

A. Yes. I have published three books and more than 80 articles in scholarly and trade journals, primarily on low-income utility and housing issues. I have published an equal number of technical reports for various clients on energy, water, telecommunications and other associated low-income utility issues. A description of my publications is included in Appendix A.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS OR OTHER UTILITY COMMISSIONS?

A. Yes. I have testified before the Pennsylvania Public Utility Commission ("PUC" or "Commission") on numerous occasions regarding utility issues affecting low-income customers and customer service. I have also testified in regulatory proceedings in more than 35 states and various Canadian provinces on a wide range of utility issues. A list of the jurisdictions in which I have testified is provided in Appendix A.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR DIRECT TESTIMONY.

A. The purpose of my Direct Testimony is as follows.

- First, I examine the need for PECO to continue to respond to the ongoing economic crisis associated with the COVID-19 health pandemic.

- Second, I examine the reasonableness of PECO's proposal to increase its residential customer charge.

- Third, I examine the reasonableness of PECO's CAP outreach directed toward its low-income customers.

- Fourth, I examine the allocation of PECO's universal service costs between and amongst customer classes.

- Fifth, I examine certain elements of customer service, customer satisfaction, and employee "community involvement" used by PECO to support its proposed equity adder for exemplary management;

- Finally, I examine the reasonableness of PECO's proposal to implement a "fraud/theft investigation charge."

Summary of Recommendations

Q. PLEASE PROVIDE A SUMMARY OF THE RECOMMENDATIONS YOU MAKE IN YOUR DIRECT TESTIMONY.

A. Based on the data and analysis presented throughout my Direct Testimony, I recommend:

- that the PECO COVID-19 Residential Relief Program (RRP) be approved with four minor modifications.

- that PECO be authorized to expand its RRP budget to the extent that the budget is exhausted before June 31, 2022. PECO approaches its proposal as though the economic crisis is a thing of the past, which simply needs to be remedied over a reasonably brief period of time. What we know instead, however, based on Pennsylvania data, is that the economic crisis not only continues through today, but may well be expanding as customers exhaust their savings and/or exhaust their credit lines as resources to pay normal household expenses. PECO should be allowed to respond to that ongoing economic crisis without further need to return to the Commission to litigate a request for permission to continue to deliver remedial benefits as (and to the extent that) the economic crisis continues.

- that OCA witness Clarence Johnson's residential customer charge proposal be adopted.

- that PECO be directed to provide a detailed plan addressing how it intends to expand its CAP outreach to expand CAP participation for customers with annual income less than 50% of Poverty. Consistent with the Commissioners' statement in the recent decision in Columbia's base rate case at Docket No. R-2020-3018835, that Plan should include not only a discussion of the activities that the Company intends to take, it should also include quantitative outcomes by which the success (or lack thereof) can be measured. The Company should be directed to identify specific outcome metrics by which it will measure the utilization of its outreach methods. It should be directed to identify the specific community partners with whom it is working along with the specific populations which the partnerships are intended to reach.

- that the PECO universal service costs be allocated among all customer classes as set forth in the Direct Testimony of OCA witness Clarence Johnson (OCA St. 3, Schedule CJ-4).

- that the equity adder requested by PECO be disapproved as recommended by OCA witness David Garrett.

- that the proposed fraud/theft investigation charge proposed by PECO be disapproved.

Part 1. Response to Ongoing COVID-19 Economic Crisis.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. This section of my testimony is intended to supplement the analysis set forth in the Direct Testimony of OCA Witness Noah Eastman. In this section of my testimony, I document the ongoing economic emergency facing residential customers as caused by the past and ongoing impacts of the COVID-19 pandemic. I review the PECO proposed response to that economic emergency and recommend modifications. (PECO St. 10, at 3 – 6).

Q. PLEASE EXPLAIN THE DATA UPON WHICH YOU BASE YOUR DISCUSSION OF COVID-19 IMPACTS IN PENNSYLVANIA.

A. I base my discussion of Pennsylvania below largely on the Census Bureau's Phase 3.1 PULSE Survey. According to the Census Bureau, "[t]he Household Pulse Survey is designed to deploy quickly and efficiently, collecting data to measure household experiences during the coronavirus pandemic." Data collection for Phase 3 of the Household Pulse Survey ran from October 28, 2020 – March 29, 2021 and is now closed. Data collection for the next Phase of the survey (Phase 3.1) began on April 14, 2021.

Q. IS THE DATA FROM THE PULSE SURVEY THAT YOU EXAMINE SPECIFIC TO THE PECO SERVICE TERRITORY?

A. No. While the Census releases data on various metropolitan areas, including Philadelphia, it does not release data on geographic areas that could be aggregated into the PECO service territory. Accordingly, I examine state-specific data for Pennsylvania as a whole. The data I examine is primarily from Week 30 (May 12 through May 24, 2021).[1]

Q. WHAT DO YOU CONCLUDE ABOUT PENNSYLVANIA EMPLOYMENT INCOME AS IT IS RELATED TO COVID-19?

A. The Census PULSE Survey documents that a large number of Pennsylvania residents report they have lost employment income even in the "past four weeks" (i.e., at the time of the survey). Table 1 shows that as recently as Week 30 of the PULSE Survey (May 12 through May 24, 2021), more than 1.6 million Pennsylvania residents (16.5%) reported losing employment income in the past four weeks. The Table shows further that, substantially more than 1.2 million Pennsylvania residents ***expect*** to lose employment income "in the next 4 weeks." More than one-in-six Pennsylvania residents, in other words, have lost income and an additional one-in-twelve expect to lose income in the next four weeks.

[1] All PULSE Survey data cited in my testimony can be accessed at:https://www.census.gov/programs-surveys/household-pulse-survey/data.html#phase3.1 (last accessed June 2, 2021).

Table 1. Experienced and Expected Loss of Employment Income (Pennsylvania) (PULSE Survey)				
	Experienced Loss of Employment Income in Last Four Weeks			
	Week 30			
	Total	Yes	No	% Yes
Total	9,760,505	1,606,120	8,090,145	16.5%
	Expected Loss of Employment Income in next 4 weeks			
	Week 30			
	Total	Yes	No	% Yes
Total	9,760,505	1,247,222	8,432,238	12.8%

On a percentage basis, this loss of employment income was over-represented in the lower income brackets in Pennsylvania. Table 2 shows the proportionate representation of Pennsylvania residents who have experienced a loss of income in the last four weeks. By "proportionate representation," I mean that I first determine the percentage of total population in each income range. I then compare the percentage of population in each income range reporting a loss of employment income. Those income ranges which are over-represented in the income ranges having lost employment income are highlighted in yellow. With the exception of residents with income between $35,000 and $49,999, the income ranges that disproportionately experienced a loss of employment income were those incomes less than $75,000. Persons in the income range of $25,000 to $34,999 were the most over-represented in that population having experienced a loss of employment income. Of Pennsylvania residents who have experienced a loss of employment income in the last four weeks, more than 14% fell in that income range even though that income range represented only 8% of the total population reporting data. This further supports the conclusion that the economic crisis associated with COVID-19 is not simply a "low-income" issue, but instead reaches beyond those households with income at or below 150% of Poverty Level.

Table 2. Loss of Employment Income by Household Income (in the last four weeks)
(Income Range as Percent of Total) (PULSE Survey)
(yellow shade: income ranges disproportionately represented in loss of employment income)

	Week 30	
	Total	Yes
<$25,000	9.3%	11.9%
$25,000 - $34,999	8.3%	14.1%
$35,000 - $49,999	6.9%	6.9%
$50,000 - $74,999	13.3%	15.3%
$75,000 - $99,999	9.3%	7.0%
$100,000 - $149,999	11.1%	5.8%
$150,000 - $199,999	3.6%	2.2%
$200,000 and above	4.6%	0.5%
Sum of those reporting	100%	100%

Based on this data, it is necessary to conclude that while the loss of employment income certainly disproportionately affects the lowest income households, that loss of employment income is not ***exclusively*** a low-income phenomenon.

Q. HOW HAS COVID-19 AFFECTED THE ABILITY OF PENNSYLVANIA RESIDENTS TO PAY THEIR USUAL HOUSEHOLD EXPENSES?

A. Pennsylvania residents have continuing difficulties in paying for their basic living expenses under COVID-19. The Census PULSE survey reports on the "difficulty paying for usual household expenses during the coronavirus pandemic." Table 3 presents the data for Pennsylvania. As this Table shows, the economic conditions for Pennsylvania residents are still dire. In Week 30 of the PULSE Survey, 993,000 Pennsylvania residents had a "very difficult" time in paying for usual household expenses in the past seven days. Moreover, the combined total of people reporting that they found it either "very difficult" or "somewhat difficult" to pay for usual household expenses in Week 30 was 24.6%, nearly one-in-four of all Pennsylvania residents.

In contrast, the percentage of Pennsylvania residents reporting that they found it "not at all difficult" to pay for their usual household expenses in the past seven days during the coronavirus pandemic still remained at just over 50% of the total population reporting. Only half of all Pennsylvania residents, in other words, found it "not at all" difficult to pay their usual household expenses, even at the end of May 2021.

Table 3. Difficulty in Paying for Usual Household Expenses in Past 7 Days During the Coronavirus Pandemic (PULSE Survey) (Pennsylvania) (Total = 9,760,505)[2]

Week 30 (in millions)

Not at All	A Little	Somewhat	Very
4.790	2.054	1.248	0.993
52.7%	22.6%	13.7%	10.9%

As with the data on the loss of employment income, the data on difficulties in paying for usual household expenses during the coronavirus pandemic shows a marked difference based on income levels. The data is set forth in Table 4 below. Not surprisingly, the biggest reduction in the percentage having a "very difficult" time in paying for usual household expenses occurs in the income groups with the largest percentage of population having such difficulties in the first instance. Within the population of

[2] Percentage is of those reporting.

households with income less than $25,000, more than one-in-four (28.6%) of households report having a "very difficult" time in paying their bills.

The "very difficult" data, however, does not tell the entire story. Nearly three-fifths of the population with income less than $25,000 report having a "very difficult" or a "somewhat difficult" time (27.9% + 28.6% = 56.5%) in paying for usual household expenses in the past seven days. Problems in the next two income ranges also remain very prevalent. Nearly half (47.1%) of households with income between $25,000 and $34,999 (26.6% + 20.5%) have a "somewhat" or "very" difficult times paying their usual household expenses. 30.7% in the income range of $35,000 to $49,999) report having a "somewhat difficult" or "very difficult" time in paying usual household expenses in the past seven days as of Week 30. Even in the income range as high as $50,000 to $74,999, nearly one-in-five (19.7%) Pennsylvania residents report having either a "somewhat difficult" or a "very difficult" time paying for their usual household expenses.

Table 4. Difficulty in Paying for Usual Household Expenses in Past 7 Days During the Coronavirus Pandemic by Annual Income (PULSE Survey) (Week 30) (Pennsylvania) (Total = 9,760,505)[3]

		Week 30			
		Not at All	A Little	Somewhat	Very
<$25,000	907,637	19.7%	23.8%	27.9%	28.6%
$25-$34,999	813,121	26.5%	26.3%	26.6%	20.5%
$35 - $49,999	678,228	45.2%	24.2%	13.6%	17.1%
$50 - $74,999	1,294,422	56.6%	23.7%	9.9%	9.8%
$75 - $99,999	905,899	60.5%	14.0%	18.8%	6.7%
$100 - $149,999	1,081,575	74.5%	16.5%	3.7%	5.3%
$150 - $199,999	354,392	83.7%	13.1%	3.2%	0.0%
$200,000+	449,135	89.1%	9.9%	0.5%	0.5%

Q. WHAT DO YOU CONCLUDE?

A. Even as the public vaccination against the coronavirus becomes more widespread, the economic crisis caused by the COVID-19 pandemic continues to significantly harm Pennsylvania residents, including PECO customers. The economic impacts will result in a long-term economic disruption for customers of PECO.

Q. WHAT IS THE FIRST LONG-TERM ECONOMIC IMPACT OF COVID-19?

A. The resolution of the COVID-19 health crisis will not end the economic crisis facing low-income customers. One analysis by the Center on Poverty and Social Policy at Columbia University projects the longer-term effects of the COVID-19 economic crisis.[4] The

[3] Percentage is of those reporting.

[4] Parolin and Wimer (April 16, 2020). Forecasting Estimates of Poverty During the COVID-19 Crisis: Poverty Rates in the United States Could Reach Highest Levels in Over 50 Year, available at

Columbia University research center forecasted poverty rates under three alternative unemployment scenarios: 10 percent; 20 percent, and 30 percent. The Center assumed that such high levels of unemployment lasted for two different scenarios: (1) one quarter, and (2) one year. The Center used the "Supplemental Poverty Measure" (SPM), which differs somewhat from the Federal Poverty Level.[5]

The Center began with a projected SPM of 12.4% in February 2020, the lowest recorded poverty rate since 2001. Its projected poverty rates after the onset of the COVID-19 pandemic, however:

> point to higher poverty rates today. If unemployment rates rise to 10 percent, comparable to the unemployment rate during the peak of the Great Recession, we project that poverty rates would rise to 15 percent. This is approximately the same rate of poverty observed in 2010. (note omitted). If unemployment rates rise to 20 percent, we project a poverty rate of 16.9 percent—the highest rate of poverty since 1967, the first year for which reliable estimates of poverty are available. Finally, if annual unemployment rates rise to 30 percent, we project a poverty rate of 18.9 percent. This would mark the highest rate of poverty over the past 50 years.[6]

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https://www.povertycenter.columbia.edu/news-internal/coronavirus-forecasting-poverty-estimates, (last accessed June 4, 2021).

[5] In simplified terms, the Census Bureau explains that the Supplemental Poverty Measure, "takes into account family resources and expenses not included in the official measure as well as geographic variation. First, it adds the value of in-kind benefits that are available to buy basic goods to cash income. In-kind benefits include nutritional assistance, subsidized housing and home energy assistance. Then it subtracts necessary expenses for critical goods and services not included in the thresholds from resources. Necessary expenses that are subtracted include income taxes, Social Security payroll taxes, child care and other work-related expenses, child support payments to another household, and contributions toward the cost of medical care and health insurance premiums." What is the Supplemental Poverty Measure and How Does it Differ from the Official Measure, available at, https://www.census.gov/newsroom/blogs/random-samplings/2018/09/what_is_the_suppleme.html (last accessed June 4, 2021).

[6] Id., at 4 - 5.

Two observations are appropriate. First, unemployment in Pennsylvania did not reach the 20% or 30% levels represented by the two upper ranges in this analysis. Accordingly, the 20% and 30% unemployment scenarios are set aside for this discussion. Even with the lowest scenario, however, the Center stated: "under an optimistic scenario, in which employment rates return to pre-crisis levels during the summer of 2020, annual SPM poverty rates are still projected to reach levels comparable to the Great Recession."[7] Second, and in contrast, employment rates, as we now know, did *not* return to the pre-crisis levels in the summer of 2020.

This increase in Poverty is important for purposes of this proceeding because it is not likely to be resolved in the short-term. The long-term danger arises because when people lose their jobs, the long-lasting effects are not just on their income. Moreover, with the COVID-19 pandemic, it is generally recognized that many of the jobs that have been lost will never come back. One recent research paper from the Becker Freidman Institute for Economics at the University of Chicago estimates that between 32% and 42% of COVID-19 induced layoffs will be permanent.[8]

Q. IS THERE A SECOND ECONOMIC IMPACT THAT SHOULD BE CONSIDERED IN THIS PROCEEDING?

A. Yes. Nearly 40% of U.S. households, including nearly all low-wage workers, fall into a category referred to as "liquid asset poor." "Liquid asset poor" is a term-of-art that refers

[7] Forecasting Estimates of Poverty, supra, at 9.

[8] Davis et al. (June 2020). COVID-19 is also a Reallocation Shock, available at: https://bfi.uchicago.edu/wp-content/uploads/BFI_WP_202059.pdf (last accessed June 4, 2021).

to households who lack sufficient liquid assets to replace income in order to subsist at the Poverty Level for three months in the absence of income. According to a Pew Research Center report, "only about one-in-four (23%) [lower income adults] say they have rainy day funds set aside that would cover their expenses for three months in case of an emergency such as job loss, sickness or an economic downturn, compared with 48% of middle-income and 75% of upper-income adults." [9]

As the COVID-19 economic crisis moves into a more prolonged period, the impact of the lack of savings will become increasingly pronounced, with low-income customers, in particular, unable to draw on resources to pay day-to-day bills. A Pew Research Center study published in late September reported that half of all adults who said they had lost a job due to the coronavirus were still unemployed "roughly six months since the coronavirus outbreak sent shockwaves through the U.S. economy."[10] Moreover, according to Pew, even those who did not lose their job, but who nonetheless lost income, were still in bad economic shape. Pew reported:

> Of those who say they personally lost a job, half say they are still unemployed, a third have returned to their old job and 15% are in a different job than before. Lower-income adults who were laid off due to the coronavirus are less likely to be working now than middle- and upper-income

[9] Parker, Horowitz and Brown (April, 2020). About Half of Lower-Income Americans Report Household Job or Wage Loss Due to COVID-19, Pew Research Center: Washington D.C. Available at https://www.pewsocialtrends.org/2020/04/21/about-half-of-lower-income-americans-report-household-job-or-wage-loss-due-to-covid-19/ (last accessed June 4, 2021).

[10] Parker, Minkin and Bennett (September 24, 2020). Economic Fallout from COVID-19 Continues to Hit Lower-Income Americans the Hardest, at 1, Pew Research Center (Washington D.C.). (hereafter COVID-19 Economic Fallout), https://www.pewsocialtrends.org/2020/09/24/economic-fallout-from-covid-19-continues-to-hit-lower-income-americans-the-hardest/ (last accessed June 4, 2021).

> adults who lost their jobs (43% vs. 58%). Adults ages 18 to 29 are less likely than those 30 to 64 to have returned to their previous job.
>
> Even if they didn't lose a job, many workers have had to reduce their hours or take a pay cut due to the economic fallout from the pandemic. About a third of all adults (32%) say this has happened to them or someone in their household, with 21% saying this happened to them personally. Most workers who've experienced this (60%) are earning less now than they were before the coronavirus outbreak, while 34% say they are earning the same now as they were before the outbreak and only 6% say they are earning more.[11]

Pew continues, however, to note that "lower-income adults who lost their jobs because of the coronavirus outbreak are more likely than those with middle or upper incomes to remain unemployed. Some 56% of workers with lower incomes who lost their job because of the coronavirus outbreak say they are currently unemployed, compared with 42% of middle- and upper-income adults."[12]

This long-term job loss is significant because one of the long-term economic implications of the job loss and other loss of income is just now becoming more evident. Economic difficulties, particularly for lower-income households, will prevail for an extended period of time not only because these households have been forced to use their emergency savings, but also because they have been forced to incur substantial debt during the COVID-19 pandemic to date. According to Pew:

> Those affected by coronavirus related job loss or pay cuts are much more likely than those who have not experienced these setbacks to have drawn on additional resources. Fully 46% of adults who say they or someone in their household have either been laid off or taken a pay cut as a result of the

[11] Id., at 5, 7, 8.

[12] Id., at 7 – 8.

> coronavirus outbreak say they have used money from a savings or retirement account to pay their bills, compared with 17% of those who have not experienced these setbacks.[13]

As the COVID-19 economic crisis continues, these households are now running out of savings to draw down. A Bankrate survey found that "of households with income below $50,000, about 44% say their savings has dropped, compared with 27% of those earning above that amount. . ." Bankrate reported that 27% of Americans say that they now have emergency savings that would last less than three months; 20% say their emergency savings would last from three to five months; and 25% say their emergency savings would last six months.[14]

Q. HAVE YOU EXAMINED DATA SPECIFIC TO THE COMMONWEALTH OF PENNSYLVANIA?

A. Yes. The discussion below is based on the U.S. Census Bureau's "Pulse Survey" as I discussed above. As in my discussion above, I examine data from Week 30 (May 12 through May 24, 2021) (from Phase 3.1).

Q. WHAT DO YOU KNOW ABOUT PENNSYLVANIA?

A. The problems posed by consumers being forced to use credit and/or savings to pay household bills during the pandemic can be seen from data specific to Pennsylvania. And they continue through today. According to the Census Bureau's PULSE Survey, in Week

[13] Covid-19 Economic Fallout, supra note 10, at 12.

[14] Survey: Nearly 3 times as many Americans say they have less emergency savings versus more since pandemic, available at https://www.bankrate.com/banking/savings/emergency-savings-survey-2020/ (last accessed June 4, 2021).

30 of the PULSE Survey, households using such resources had substantially greater difficulties in meeting their household needs. While 18.7% of Pennsylvania residents using credit cards or loans, and 22.3% drawing down savings (or selling assets), found it "very difficult" to pay "usual household expenses," only 6.2% using their usual pre-pandemic income sources did so. While 23.3% (money from savings or selling assets) to 14.6% (credit cards or loans) of Pennsylvania residents found it "somewhat difficult" to pay their "usual household expenses," only 13.9% using their normal pre-pandemic incomes sources did so.

In total, one-third of Pennsylvania residents who have been forced to use credit cards or loans (14.6% + 18.7% = 33.3%), and nearly half forced to draw down savings or sell assets (23.3% + 22.3% = 45.6%), found it either "somewhat" or "very" difficult to pay their usual household expenses during the pandemic (Week 30). In contrast, only 19.2% using savings or selling assets found it "not at all difficult" to pay their usual household expenses, compared to 61.0% of those who could use their normal pre-pandemic income sources.

Table 5. Difficulty paying for usual household expenses during the coronavirus pandemic (Pennsylvania) (PULSE Survey)					
Used in last seven days to meet spending needs	Total # Reporting	Not at all difficult	A little difficult	Somewhat difficult	Very difficult
			PULSE Survey: Week 27		
Regular income sources like those used before the pandemic	6,802,372	61.0%	22.4%	10.3%	6.2%
Credit cards or loans	2,249,120	43.5%	23.2%	14.6%	18.7%
Money from savings or selling assets	1,314,349	19.2%	35.2%	23.3%	22.3%
Borrowing from friends or family	645,730	5.5%	6.9%	21.9%	65.8%
Money saved from deferred or forgiven payments (to meet spending needs)	121,532	24.6%	15.5%	25.5%	34.5%

Q. WHAT DO YOU CONCLUDE?

A. The conclusion to be drawn from this data is that low-wage households are far from achieving any post-pandemic economic stability. Even as the public health crisis associated with COVID-19 is mitigated through widespread vaccination in the coming months, the associated economic crisis will continue. It is that economic crisis, far more than the public health crisis, that PECO should address. It is the ongoing *economic* crisis that will adversely affect the ability-to-pay of PECO customers.

Q. HAS PECO PROPOSED TO TAKE ANY ACTION TO ADDRESS THE ECONOMIC IMPACTS ASSOCIATED WITH THE COVID-19 PANDEMIC?

A. Yes. On March 23, 2021, PECO filed a petition with the PUC seeking approval of a COVID-19 Emergency Grant Program for low-income customers. The Program would convert unspent LIURP funds from 2020 into grants for residential customers at or below 200% of the Federal Poverty Level. Each qualifying customer would receive a grant of up to $1,000, with remaining arrears spread over a 5-year payment plan. The program budget ($3.7 million) is proposed to be split, with half available in 2021 and half available in 2022. (PECO St. 10, at 5). While I generally approve of that PECO proposal on many grounds --it provides arrearage relief and recognizes that the economic crisis may well continue through 2022, without need for any increase in universal service spending due to its reliance on unspent LIURP funds-- and believe that my testimony above supports the substance of that proposal; the merits of that program proposal are not at issue in this rate case. My lack of discussion of that proposal should not be construed as anything other than a recognition that it is subject to a separate proceeding.

Having said that, PECO is *also* proposing a Residential Relief Program (RRP) as part of this proceeding. (PECO St. 10, at 5). The RRP proposed in this proceeding would provide assistance to qualifying customers who have been adversely affected by COVID-19. Such customers must provide proof of a loss of employment since March 2020 or receipt of a federal COVID-19 relief check. They must have an existing arrears and not be enrolled in PECO's CAP. PECO proposes to provide a bill credit equal to 25% of the customer's arrearage or $400, whichever is less. As with the previous program proposal, any remaining arrears would be spread over a five year payment plan. If a customer *may* be eligible for universal service programs, the Company will also inform the customer of such programs. (PECO St. 10, at 5). The proposed budget is $3.0 million, with 90% of that devoted to bill credits (and the remaining 10% devoted to administrative costs). (Id.)

Q. HOW DOES THE COVID-19 TESTIMONY YOU PRESENT ABOVE RELATE TO THE PECO RESPONSE TO COVID-19?

A. The testimony I present above provides a solid basis for this PECO proposal. This base rate proceeding provides an opportunity for PECO to build a reasonable response to the *ongoing* economic crisis that has been generated by COVID-19. Having moved to address the underlying health needs, it is now time to implement continuing emergency relief. The testimony above presents a compelling needs assessment in support of such relief. I have demonstrated above that, through Week 30 of the Census Bureau's PULSE Survey:

- Pennsylvania residents have lost income since the beginning of the COVID-19 pandemic (Table 2), with these losses substantial for households with an annual income up to $100,000;
- Significant numbers of Pennsylvania households report continuing to have a "somewhat" or "very" difficult time paying their usual household expenses (Table 3);
- When higher income households are excluded, the percentage reporting having a "somewhat" or "very" difficult time in paying their usual household expenses significantly increases (Table 4);

Moreover, we know from the data I have presented above that in Week 30 of the PULSE Survey (May 12 through May 24, 2021), significant numbers of Pennsylvania residents have been forced to use credit cards or loans to pay their usual household expenses such as utility bills, and that these residents continue to find it "somewhat difficult" or "very difficult" to pay those usual household expenses. (Table 5). We know that Pennsylvania residents have continued to be forced to use their savings (or to sell assets) to pay their usual household expenses (Table 5 and accompanying text). We know that these savings are running out and that the use of credit card debt has become non-sustainable.

Q. IS THERE ADDITIONAL DATA DEMONSTRATING THAT THE ECONOMIC CRISIS BROUGHT ABOUT BY COVID-19 IS AN ONGOING CRISIS?

A. Yes. The data for Pennsylvania indicates that the economic crisis brought about by COVID-19 is independent of the health crisis. The economic crisis which I discuss in more detail above is continuing through the date on which this Testimony is written.

In my discussion above, I discuss the results from the Census PULSE Survey. The Table below presents the PULSE Survey results starting with the Week 27 and extending through the most recent PULSE Survey results available as of the date of this Testimony (Week 30: data released June 2, 2021).

Table 6. Percent of Households (PA) Having "Very Difficult" Time Paying Usual Household Expenses in COVID-19 Pandemic (Households with Income < $50,000) (Census PULSE Survey)

	Week of PULSE Survey			
Income Range	Week 27	Week 28	Week 29	Week 30
< $25,000	26.9%	34.0%	21.4%	28.6%
$25,000 - $34,999	6.9%	16.6%	19.0%	20.5%
$35,000 - $49,999	5.0%	2.6%	15.3%	17.1%

As can be seen, despite improvements in the response to the underlying health crisis, there has *not* been a continuous improvement in the economic conditions:

- The percentage of households with income below $25,000 having a "very difficult" time was 28.6% in Week 30, compared to 26.9% in Week 27.

- The percentage of households with income between $25,000 and $35,000 having a "very difficult" time was 20.5% in Week 30, compared to 6.9% in Week 27.
- The percentage of households with income between $35,000 and $50,000 having a "very difficult" time was 17.1% in Week 30, compared to 5.0% in Week 27.

If you exclude those households who are well-off, difficulties have increased in recent weeks. The adverse economic impacts first identified during the height of the COVID-19 health crisis continue even today.

Q. WHAT DO YOU RECOMMEND?

A. While I recommend approval of the PECO COVID-19 Residential Relief Program, I recommend the following minor modifications. I offer these recommendations with the recognition that they may not be "modifications" to the PECO program as contemplated by the Company, as much as they are further elaboration on the on-the-ground implementation of the proposed RRP. My proposed modifications include:

- Bill credits provided through the RRP should be limited not merely to customers who "have an arrears" (PECO St. 10, at 5), but to customers who have an arrears that exceed $200. Bill credits should be provided to customers who, in the absence of such credits, would likely be unable to retire their arrears. Arrearages lower than the minimum amount should be made subject to the extended payment plan proffered by PECO. By creating a minimum credit, the budget proposed by PECO will be extended to either more customers or for a longer period of time.

- PECO's proposal to establish eligibility on the basis of "loss of employment" is too narrow. As I establish above, many households (i.e., PECO customers) may lose employment income without having "lost employment." These customers may have, for example, been furloughed without being laid off. These customers may have experienced reduced hours, without having "lost employment." The focus should be on "lost income" rather than on "lost employment."
- PECO should carefully track the number of its RRP recipients who subsequently become a CAP participant. A customer who subsequently becomes a CAP participant would, of course, have any arrearages incurred prior to CAP enrollment made subject to arrearage forgiveness. To the extent that a customer is enrolled in CAP, with the customer's pre-program arrearages subject to arrearage forgiveness, those dollars of credit should be paid as CAP costs rather than from the proposed RRP budget. The RRP budget should not be used to pay for arrears that would be subject to forgiveness through CAP. Rather the RRP dollars should be restricted to providing benefits to customers that would otherwise not have a source of benefits to redress their COVID-19 related payment difficulties.

Finally, I recommend that PECO be authorized to expand its RRP budget to the extent that the budget is exhausted before June 31, 2022. PECO approaches its proposal as though the economic crisis is a thing of the past, which simply needs to be remedied over a reasonably brief period of time. What we know instead, however, based on the Pennsylvania data presented above, is that the economic crisis not only continues through today, but may well be expanding as customers exhaust their savings and/or exhaust their credit lines as resources to pay normal household expenses. PECO should be allowed to respond to that ongoing economic crisis without further need to return to the Commission to litigate a request for permission to continue to deliver remedial benefits as (and to the extent that) the economic crisis continues as it appears it may well be doing. Overall, with the minor modifications I propose above, I recommend that PECO's RRP proposal be approved.

Part 2. Proposed Increase in Residential Customer Charge.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my Direct Testimony, I assess the disproportionately adverse impacts that the Company's proposed increase in its residential customer charge will have on low-income customers. PECO proposes to increase its fixed monthly customer charge from $9.99 to $13.49, an increase of $3.50 per month, or $42 per year. The size of the residential customer charge is important to all residential customers because it is an "unavoidable" fixed monthly charge. The increased customer charge, however, has a particularly adverse impact on low-income customers. Accordingly, I recommend that OCA witness Clarence Johnson's residential customer charge proposal be adopted.

A. Harms to Low-Income Customers.

Q. WHY DOES THE PECO CAP NOT PROTECT LOW-INCOME CUSTOMERS FROM THE HARMS OF THE INCREASED CUSTOMER CHARGE?

A. It is not reasonable to expect PECO to know who all of its low-income customers are. Unless the customer has occasion to have contact with the Company, in circumstances where the customer's income would be an input into decision-making, PECO would not identify someone as being "low-income." Accordingly, PECO has confirmed the low-income status of only some of its customer base. According to PECO, in the most recent month for which it had data, the Company had confirmed the low-income status of 138,014 (OCA-I-1). This is a decrease from the October 2019 number (149,614) of Confirmed Low-Income customers PECO has identified. Given that the number of Confirmed Low-Income (CLI) customers PECO has identified has substantially decreased (by 7.8%) just since October 2019 ([149,614 – 138,014] / 149,614 = 0.0780), it is increasingly difficult for low-income customers to be protected from the harms of an increased customer charge.

In its most recent Universal Service data filed with BCS (2020), PECO estimated a total low-income population (below 150% of Poverty) of 274,966 (CAUSE-PA-1-12). PECO has, in other words, confirmed the low-income status of only 50% of its estimated low-income population base (138,014 / 274,966 = 0.502).

Q. AMONGST THOSE CONFIRMED LOW-INCOME CUSTOMERS, PLEASE EXPLAIN WHY THE PECO CUSTOMER ASSISTANCE PROGRAM (CAP)

WILL NOT ADDRESS THE INCREASED UNAFFORDABILITY ATTRIBUTED TO THE INCREASED CUSTOMER CHARGE?

A. PECO's CAP reaches a relatively small proportion of its low-income customer base. According to PECO, the Company has a CAP participation of 116,064. (OCA-01-001(c)). PECO further reports that it has 274,966 total estimated low-income residential customers. (CAUSE-PA-1-12). Using this data, I find that PECO has enrolled 42.2% of its estimated low-income customers in CAP (116,064 / 274,966 = 0.422).

Q. DOES CAP ENROLLMENT PROTECT CUSTOMERS FROM BEING ADVERSELY AFFECTED BY THE INCREASE IN THE FIXED MONTHLY CUSTOMER CHARGE?

A. No. PECO has different aspects to its CAP program: the percentage of income component; and the percentage of bill (i.e., budget bill) component. According to the Company, its enrollment by program component for the past twelve months (April 2020 through March 2021) was as set forth in the Table immediately below.

Table 7. CAP Participation (April 2020 through March 2021)
By CAP Program Component (OCA-1-1)

202103	202102	202101	202012	202011	202010	202009	202008	202007	202006	202005	202004
CAP Participants who Participate in CAP Budget Billing											
44,552	44,714	44,676	44,590	44,724	44,859	45,102	45,274	45,271	44,905	44,956	45,004
Total CAP Participants											
116,064	115,701	115,510	115,359	114,879	114,637	114,714	114,553	114,410	113,936	113,559	113,235
Percent of CAP Participants on CAP Budget Billing											
38.4%	38.6%	38.7%	38.7%	38.9%	39.1%	39.3%	39.5%	39.6%	39.4%	39.6%	39.7%

As can be seen in this Table, consistently, two-out-of-five (40%) PECO CAP participants participate in the "Budget Billing" program component. Through this CAP design, CAP participants pay a percentage of the bill at standard residential rates. If residential rates increase, in other words, the CAP participant's payment will increase correspondingly.

Q. WHAT DO YOU CONCLUDE?

A. I conclude that PECO's CAP program protects a small percentage of its low-income customer base from the harms of an increased customer charge. PECO has confirmed the low-income status of a relatively small percentage of its estimated low-income population. Out of those Confirmed Low-Income customers, the Company has enrolled a relatively small percentage in CAP. Out of those CAP participants, a small majority are enrolled in a CAP program component that would protect the customer against bill increases, with the remainder being enrolled in the CAP program component that would not protect customers from the harm of an increased customer charge. As can be seen, it would be an error to assert that low-income customers will see no adverse impact from the increased fixed customer charge because they are protected by the PECO CAP program.

Q. WHY IS IT SIGNIFICANT THAT PECO UNDER-ENROLLS ITS CONFIRMED LOW-INCOME CUSTOMER POPULATION INTO ITS CAP PROGRAM?

A. The under-enrollment of the PECO confirmed low-income population into CAP is significant because the Company's confirmed low-income population has substantially greater payment difficulties than does the residential population as a whole. Table 8 sets forth the data from the BCS annual report on universal service programs and collections performance.[15]

Table 8. Average Arrears (PECO) (2014 – 2019)		
	Residential	Confirmed Low-Income
2014	$379.67	$660.69
2015	$334.54	$617.32
2016	$285.85	$537.34
2017	$271.63	$493.45
2018	$272.23	$537.64
2019	$305.63	$711.17

Table 8 shows that the Confirmed Low-Income customers of PECO are substantially more seriously in arrears than are residential customers generally. Indeed, the difference is even greater than shown. The "Residential" class has, as one sub-component, the "Confirmed Low-Income" customers. The higher numbers for the Confirmed Low-Income customers, in other words, will pull the Residential customer numbers upwards. If the comparison was between customers who are Confirmed Low-Income versus those who are *not* Confirmed Low-Income, the differences would be even greater.

Table 9 below shows the ratio of the payment difficulties of Confirmed Low-Income customers to Residential customers generally as presented in the annual BCS report. The average arrears for Confirmed Low-Income customers was from 74% (2014) to 133% (2019) higher than the average arrears for Residential customers for PECO. As can be seen,

[15] BCS (annual). Universal Service Programs and Collections Performance. available at: http://www.puc.state.pa.us/filing_resources/universal_service_reports.aspx (last accessed May 29, 2021).

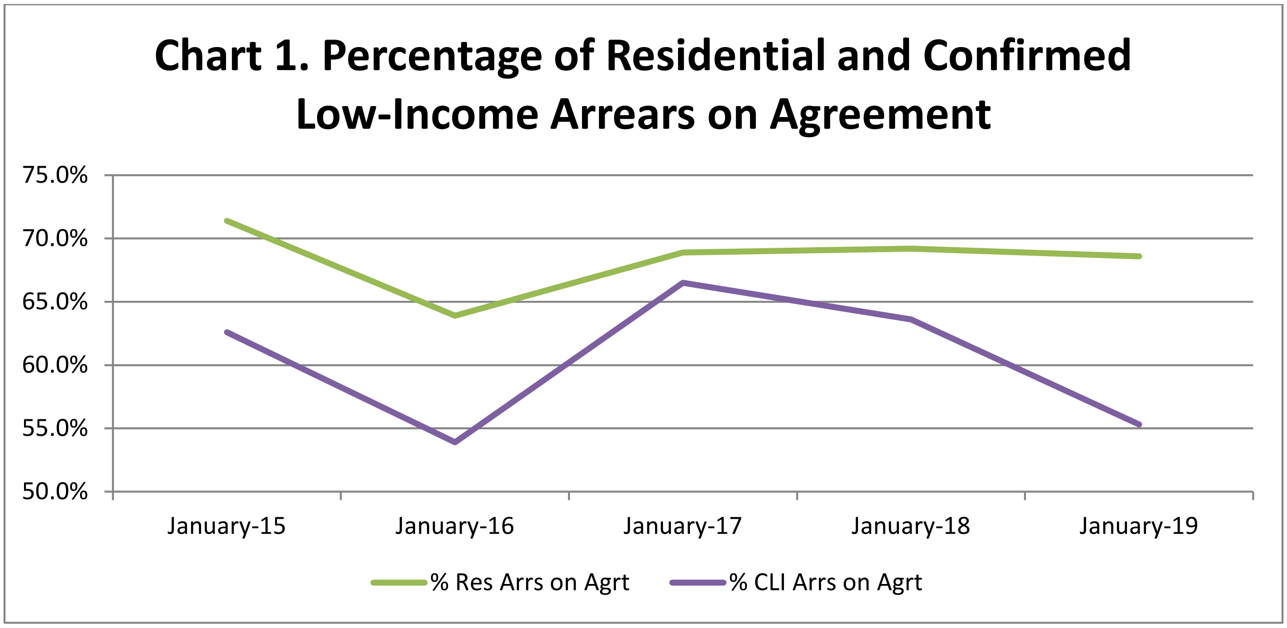
while Confirmed Low-Income customers are in arrears, they are also deeper in arrears than residential customers overall.

Table 9. Ratio Confirmed Low-Income (numerator) to Residential (denominator) Average Arrears of Accounts in Arrears (PECO) (2014 – 2019)

PECO	Average Arrears of Accounts in Arrears (Confirmed Low-Income / Residential)
2014	174%
2015	185%
2016	188%
2017	182%
2018	197%
2019	233%

Q. HAVE YOU HAD OCCASION TO REVIEW OTHER DATA THAT CONCERNS THE PAYMENT DIFFICULTIES EXPERIENCED BY CONFIRMED LOW-INCOME CUSTOMERS?

A. Yes. Chart 1, shown below, is significant in several respects. It demonstrates that PECO's Confirmed Low-Income customers are much less likely than residential customers as a whole to have revenue in arrears that are subject to payment arrangements. Arrears present a lower risk to the utility and its ratepayers when those arrears are made subject to an agreement. Chart 1 presents the relative percentage of the dollars owed by residential customers and Confirmed Low-Income customers that are subject to an agreement. While more than half of the arrears of both residential and Confirmed Low-Income customers are subject to agreement, the Chart indicates that Confirmed Low-Income arrears are substantially *less* likely to be on agreement. Even more evident is that while the percentage of residential arrears subject to an agreement has remained relatively constant in the five years considered, the percentage of Confirmed Low-Income arrears subject to agreement have declined considerably. While as recently as 2017, 65% of the CLI arrears were subject to agreement, by 2019, that percentage had declined to only 55%.



As can be seen from each individual metric above, not only do PECO Confirmed Low-Income customers have deeper arrearages they have more widespread arrears as well.

Q. HOW DOES THIS ARREARAGE DATA RELATE TO THE PROPOSAL TO INCREASE THE COMPANY'S FIXED MONTHLY RESIDENTIAL CUSTOMER CHARGE?

A. This data relates to the Company's fixed monthly residential customer charge because PECO is now proposing to increase the level of the fixed monthly customer charge that cannot be controlled by reducing consumption. PECO is proposing to substantially increase the unavoidable fixed monthly charge, resulting in a disproportionately high percentage bill increase, precisely to the population of customers who have the most difficulties in paying their bills with which to begin.

Q. WHAT IS THE FINANCIAL IMPACT TO CONFIRMED LOW-INCOME CUSTOMERS?

A. An increase in the fixed customer charge of $3.50 per month represents an increase in the fixed customer charge of $42.00 per year ($3.50/month x 12 months = $42.00). Given the Company's estimated number of low-income customers (269,005: PECO USECP, at 2), this would be an increase in unavoidable annual customer charges of $11.298 million (269,005 x $42.00 = $11,298,210) to PECO's low-income population.

Q. CAN YOU PUT THAT CUSTOMER CHARGE INCREASE INTO SOME CONTEXT?

A. Yes. From May 2020 through April 2021, PECO customers received $11.6 million in LIHEAP cash grants. (OCA-1-9). Just the increase in the fixed customer charge, standing alone, (not the *total* fixed charge, simply the *increase* in the fixed charge), in other words, would represent 98% of the *total* LIHEAP cash grants received by PECO customers in that time period. Moreover, the amount of funding that PECO customers have been receiving in LIHEAP cash grants has been declining in recent years.

Q. PLEASE SUMMARIZE HOW THE INCREASED CUSTOMER CHARGE WILL HARM LOW-INCOME CUSTOMERS.

A. I conclude that the PECO proposal to increase its customer charge will harm low-income customers in each of the following ways (with each bullet below incorporating every other bullet):

- It will increase both the breadth and depth of arrears, each of which imposes additional utility costs on low-income households along with the social consequences appurtenant thereto.

- It will increase the incidence of service disconnections for nonpayment, along with the increased utility costs on low-income households in addition to the social consequences appurtenant thereto.

- It will increase in the incidence of the threat of service disconnections for nonpayment, along with the increased utility costs and social consequences appurtenant thereto.

- It will dilute the efficacy of federal fuel assistance (i.e., LIHEAP) benefits, along with the increased utility costs on low-income households, in addition to the social consequences appurtenant thereto.

- It will increase Home Energy Insecurity, along with the resulting utility costs on low-income households, in addition to the social consequences appurtenant thereto.[16]

- A reduction in the ability of low-income households to respond to inability-to-pay by reducing usage, and to reduce the consequences of inability-to-pay, along with the resulting utility costs on low-income households, in addition to the social consequences appurtenant thereto.

B. Low-Incomes and PECO Residential Usage.

Q. PLEASE EXPLAIN THE BASIS FOR YOUR CONCLUSION THAT LOW-INCOME CUSTOMERS ARE DISPROPORTIONATELY LOW-USE CUSTOMERS.

A. While low-income households tend to have less efficient energy consumption than do residential customers generally on a per square foot of housing basis, because they live in

[16] See, Colton, Measuring the Outcomes of Home Energy Assistance Programs through a Home Energy Insecurity Scale, which, by this reference thereto, is incorporated herein as if fully set forth, available at http://fsconline.com/05_FSCLibrary/lib2.html (last accessed June 4, 2021).

much smaller housing units, they tend also to have lower overall electricity consumption. The most recent data published by the U.S. Department of Energy (DOE) in its 2015 Residential Energy Consumption Survey (RECS), as presented in Table 10, shows the data for total electricity usage in the Northeast (RECS, Table CE2.2).[17]

Table 10. Per Household Electric Use by Income (Northeast)
(2015 Residential Energy Consumption Survey) (Table CE2.2)

2015 Annual Household Income	mmBtu	kWh
Less than $20,000	19.8	5,796
$20,000 to $39,999	24.1	7,057
$40,000 to $59,000	26.3	7,704
$60,000 to $79,999	31.5	9,227
$80,000 to $99,999	30.5	8,935
$100,000 to $119,999	37.1	10,882
$120,000 - $139,999	31.5	9,242
$140,000 or more	38.4	11,257

It does not matter which specific end-use is being examined. At lower income levels, electricity usage is noticeably lower. The average household data by end-use, in million BTU, for Northeast households using the end-use (2015 RECS, Table CE4.7), is presented immediately below.

[17] The 2015 RECS data referenced in Table 10 and Table 11 can be accessed at: https://www.eia.gov/consumption/residential/data/2015/ (last accessed June 10, 2021).

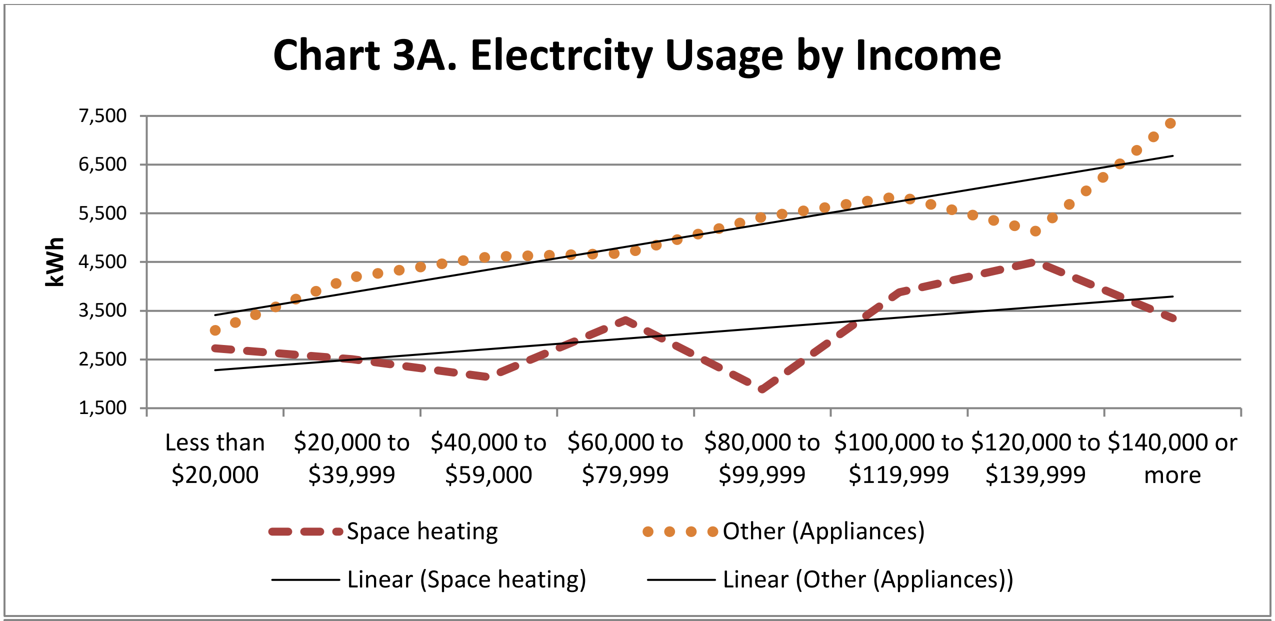
Table 11. Electricity Consumption by End-Use and Income (mmBtu) (Northeast)
(2015 Residential Energy Consumption Survey) (Table CE4.7)

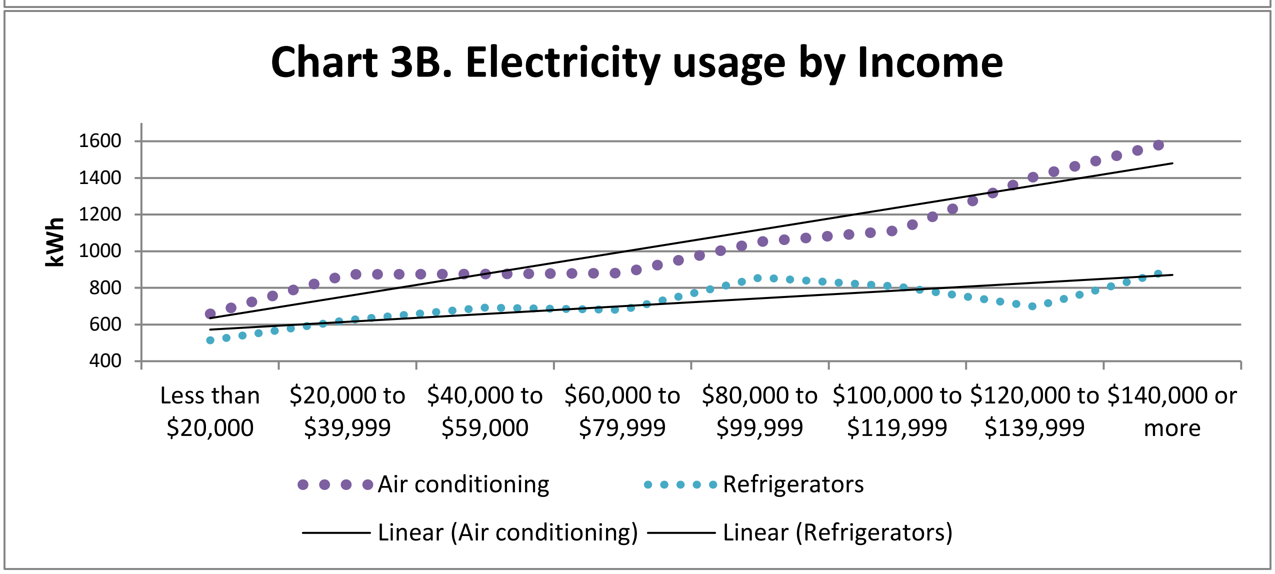
2015 Annual Household Income	Total	Space heating	Water heating	Air conditioning	Refrigerators	Other
Less than $20,000	5,796	2,728	2,902	658	514	3,097
$20,000 to $39,999	7,057	2,506	2,592	873	625	4,186
$40,000 to $59,000	7,704	2,136	3,322	876	692	4,611
$60,000 to $79,999	9,227	3,305	3,528	880	680	4,679
$80,000 to $99,999	8,935	1,886	2,763	1,052	857	5,420
$100,000 to $119,999	10,882	3,876	2,822	1,113	808	5,850
$120,000 to $139,999	9,242	4,507	3,231	1,408	698	5,132
$140,000 or more	11,257	3,347	3,277	1,598	898	7,387

The relationship can readily be seen. As income increases, electricity usage increases as well.

Q. IS THERE ANOTHER WAY TO VIEW THIS DATA?

A. Yes. Charts 3A and 3B present the identical information below, except in graph form. In addition to the kWh usage at each income level in these Charts, the Chart presents a trend line for each end use. The trend line for each end use clearly indicates that as income increases, so, too, does electricity usage increase. Chart 3A presents the data for space heating and "other" (which includes appliances). Chart 3B presents the data for air conditioning and refrigerators.





Q. DOES THE DEPARTMENT OF ENERGY PROVIDE DATA THAT HELPS TO EXPLAIN WHY LOW-INCOME CUSTOMERS TEND ALSO TO BE LOW USE CUSTOMERS?

A. The RECS data clearly shows that electricity consumption increases as the size of a housing unit increases. The related housing characteristics support this conclusion. Residents of single family housing units have greater consumption than residents of multi-family housing. Renters have lower consumption than do homeowners. And occupants of homes with more rooms have higher electricity consumption than occupants of dwellings with fewer rooms.

It is *not* my testimony, in other words, that because low-income customers in the Northeast have lower electricity consumption, low-income customers in Pennsylvania also do (since PECO of Pennsylvania is part of the Northeast). My analysis identifies what factors tend to result in lower electricity consumption as supported by the RECS data. I then review the extent to which those factors are, in fact, associated with low-income status in the PECO service territory.

Q. PLEASE EXPLAIN YOUR CONCLUSION THAT PECO CONFIRMED LOW-INCOME CUSTOMERS ARE DISPROPORTIONATELY LOW-USE CUSTOMERS.

A. In the PECO service territory, there is a relationship between the presence of low-income households and the housing attributes which the Department of Energy / Energy Information Administration (DOE/EIA) has identified, through its Residential Energy Consumption Survey (RECS), as being associated with lower electricity consumption.

Q. WHAT IS THE RELATIONSHIP BETWEEN THE SIZE OF A HOUSING UNIT AND ELECTRICITY CONSUMPTION?

A. The RECS reports that smaller housing units tend to use less electricity than do larger housing units. The DOE data is set forth in Table 12 below. As can be seen, as housing units get bigger (in terms of square footage of space), electricity usage becomes greater as well.

Table 12. Per Household Average Site Fuel Consumption in the Northeast Region British Thermal Units (Btu) and kWh (2015 RECS Table CE2.2)		
Housing Unit Characteristics and Electricity Usage Indicators	Per Household (million Btu)	Per Household (kWh)
Total Square Footage		
Fewer than 1000	16.3	4,775
1,000 to 1,499	22.3	6,542
1,500 to 1,999	30.7	8,987
2,000 to 2,499	31.2	9,155
2,500 to 2,999	31.9	9,356
3,000 or more	40.4	11,843

Housing units with fewer than 1,000 square feet have electricity usage (in physical units of energy) of 4,775 kWh. In contrast, housing units with 3,000 or more square feet have electricity usage of 11,843 kWh. Housing units with between 2,000 and 3,000 square feet are in between (9,155 to 9,356 kWh).

Q. IS THERE A RELATIONSHIP BETWEEN LOW-INCOME STATUS AND THE SIZE OF HOUSING UNITS IN THE PECO SERVICE TERRITORY?

A. Yes. The Census Bureau does not directly report data on the size of housing units (in square feet). However, conclusions can be drawn about the size of a housing unit by looking at the number of rooms in the unit, as well as by looking at the number of bedrooms in a housing unit. A housing unit with more rooms is more likely to be "larger" while a housing unit with fewer rooms will be "smaller." Similarly, a housing unit with more bedrooms will be larger while a housing unit with fewer bedrooms will be smaller. The data is set forth in the Figures below.

As the Figure immediately below shows, while 35 zip codes within the three highest deciles of low-income penetration also fall within the three highest deciles of penetrations of smaller housing units (i.e., fewer than three rooms), only 10 zip codes within the three deciles with the smallest percentages of low-income households fall within the three deciles with the highest penetration of smaller housing units (blue-shaded cells). Similarly, 34 of the zip codes with the lowest penetration of small housing units also fall within the deciles with the lowest penetration of low-income population, while only 10 zip codes fall within the three deciles with the highest penetration of low-income households and the lowest penetration of small housing units.

Deciles of Population < 150% FPL	Deciles of Percentage of Small Housing Units (<3 Rooms): 3 Lowest	Deciles of Percentage of Small Housing Units (<3 Rooms): 3 Highest
3 Lowest	34	10
3 Highest	10	35

Figure 1. Population Below 150% FPL vs. Housing Units with <3 Rooms

Even more compelling is the observation that while three (3) zip codes with low penetrations of low-income population fall within the three lowest deciles of the smallest numbers of median rooms, 47 zip codes with high percentages of low-income population fall within the three deciles with the lowest percentage of small housing units. Conversely, while 49 zip codes with the smallest percentage of low-income population fall in the three deciles with the largest median number of rooms, only four (4) zip codes with high percentages of low-income population also have large housing sizes. Clearly, as the percentage of lower-income households increases in the PECO service territory, so, too, does the percentage of smaller housing units increase.

		Deciles of Median Number of Rooms	
		3 Lowest	3 Highest
Deciles of Population < 150% FPL	3 Lowest	3	49
	3 Highest	47	4

Figure 2. Population Below 150% FPL vs. Median Number of Rooms

Q. WHAT DO YOU CONCLUDE?

A. Based on the data and discussion presented above, I conclude that low-income households in the PECO service territory are disproportionately likely to live in homes that consume lower levels of electricity. As a result, the PECO proposal to substantially increase its fixed monthly customer charge will disproportionately impose adverse impacts on low-income customers.

Ultimately, based on this discussion, along with my initial discussion of the adverse impacts that will accrue to low-income customers of PECO, I recommend that the residential customer charge recommended by OCA witness Clarence Johnson be adopted.

Part 3. Addressing Low-Income Needs.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I consider the extent to which PECO is adequately addressing the affordability needs of the Company's low-income customers. In the Commission's 2019 Final Order regarding the Revised CAP Policy Statement (Docket No. M-2019-3012599) (hereafter "Final Order"), the PUC found that:

- "While there is no specific regulatory mandate that each utility must enroll a certain percentage of low-income households in CAP, the near uniform disparity between the total number of potential income-qualified households and those actually receiving assistance calls into question the overall adequacy of consumer education and outreach." (Final Order, supra, at 78).

- "This fact pattern does not convince us that needs are being met, but rather it illuminates the need for increased awareness. We have noted in various USECP proceedings the necessity for utilities to develop more robust efforts to reach customers, particularly the very marginal, for enrollment in universal service programs." (Id.)

The Commission has, in other words, specifically found that the existing performance of utilities "calls into question the adequacy" of outreach; that existing performance "does not convince us that needs are being met"; and that existing performance demonstrates "the necessity for utilities to develop more robust efforts to reach customers." It is thus appropriate to review PECO's performance in relation to these explicit Commission findings.

A. Effective CAP Outreach.

Q. HAVE YOU HAD OCCASION TO REVIEW THE EXTENT TO WHICH PECO IS PROVIDING ADEQUATE CAP OUTREACH TO ITS LOW-INCOME CUSTOMERS?

A. Yes. In reviewing this data, remember what the PUC stated in its Decision and Order in the most recent Columbia Gas rate case.[18] It is not merely the activities that a utility is pursuing that should be the subject of review. It is the *results* of those activities. The PUC said in its Columbia Gas decision that "we expect Columbia will address these additional outreach efforts *and corresponding results*. . ." (emphasis added).

First, after matching PECO CAP participation rates for zip codes with Census data, I compared the number of households receiving either Food Stamps (SNAP) or Cash Public Assistance to the number of customers enrolled in CAP. If PECO enrolled each household who is currently enrolled in Food Stamps/Cash Public Assistance into CAP, the Company would have an additional 240,000 CAP participants. Of course, PECO would *not* enroll this entire population. Nonetheless, it is unreasonable to conclude that this large population who has evidenced their willingness to receive benefits through Food Stamps and/or public assistance would, as a group, decide *not* to participate in CAP should they be given an informed choice to do so.

[18] Pennsylvania PUC v. Columbia Gas of Pennsylvania, Docket No. R-2020-3018835.

It is not merely the total that indicates the problem, however. A problem with targeted outreach is seen when one reviews individual Zip Codes. A sample of the ten (10) Zip Codes with the highest Public Assistance (PA)/Food Stamp (FS) participation is presented in Table 13 below. As can be seen, in these Zip Codes in this Table, while there are nearly 78,000 (77,779) households who have applied for and been found eligible for Food Stamps and/or Cash Assistance,[19] PECO has enrolled only 40,110 customers in CAP.[20] Overall, in 205 of the 228 PECO Zip Codes, there are more Food Stamp/PA recipients than there are CAP participants. In 140 Zip Codes, there are more than 100 more Public Assistance/Food Stamp recipients than CAP recipients, while in 56 Zip Codes there are more than 500 more PA/Food Stamp recipients. In 41 Zip Codes, there are more than 1,000 more FS/PA recipients than CAP recipients (representing more than 91,000 households who are receiving PA/FS but not CAP).

[19] Both such programs have maximum income eligibility lower than the maximum income eligibility for CAP.

[20] It is not possible to determine the extent to which, if at all, the CAP enrollment and the Food Stamp/PA enrollment overlap.

Table 13. Number of PECO CAP Participants vs. Number of Food Stamp and/or Cash Public Assistance Participants (by Top 10 Zip Codes by PA/FS Participants)

Zip Code	Food Stamp/PA Recipients	Total CAP Participants
19133	5,589	2,739
19149	5,684	2,577
19132	5,894	3,839
19144	6,377	3,018
19139	7,272	4,044
19120	8,953	4,233
19143	9,019	4,935
19140	9,039	5,119
19124	9,722	5,129
19134	10,250	4,477

Similar results can be seen if one examines household receiving Supplemental Security Income (SSI). In PECO's Zip Codes, there are more than 15,000 more households receiving Supplemental Security Income (SSI) than there are CAP recipients. For example, the ten Zip Codes identified in Table 14 below are those ten Zip Codes where the difference is the greatest. In these ten Zip Codes while there are 10,575 SSI recipients, there are 5,493 CAP participants.

Table 14. Number of PECO CAP Participants vs. Number of SSI Recipients (by selected Zip Codes)			
Zip Code	SSI Recipients	CAP Participants	Difference
19103	363	37	326
19123	837	511	326
60120	784	0	784
19134	5,194	4,477	717
17057	434	0	434
19901	834	0	834
14904	496	0	496
19446	629	258	371
19047	550	210	340
60586	454	0	454

Q. IS THERE ANY SPECIFIC POPULATION THAT PECO COULD BENEFICIALLY PURSUE AS AN OUTREACH PARTNER?

A. Yes. The Commission's recent Columbia Gas Order, previously cited, stated in relevant part: "the Company needs to determine whether it has exhausted all grassroots community-based avenues to identify new low-income customers. For example, besides the community-based organizations Columbia Gas already is working with, are there other local organizations it can partner with, such as. . .schools. . .to implement more fully its outreach strategies?" (Docket No. R-2020-3018835, Opinion and Order, at 173).

Schools are important community CAP outreach partners in that individual school districts have the ability to identify children in need. Moreover, the prevalence of children in Poverty in particular school districts would allow PECO to select school districts that it would be beneficial for the Company to work with in particular. There are, for example, seven Zip Codes where more than half of all children age 6 to 17 (deemed to be "school age") live with income below the Poverty Level (19104 (53%), 19133 (52%), 19121 (66%), 19134 (55%), 19139 (51%), 19140 (51%), 19124 (50%)). The 20 Zip Codes in the PECO service territory with the highest rate of Poverty within the population of children age 6 through 17 have a Poverty rate within this population of children ranging from 34% to 66%. These 20 Zip Codes, standing by themselves, represent more than 40% of the total population in the PECO service territory with income at or below 150% of Poverty Level.

Q. WHAT DO YOU CONCLUDE?

A. I conclude that there is substantial opportunity for PECO to increase the use of community partners through which to engage in CAP outreach. Given the harms that I have identified accruing to the low-income population from the PECO proposed increase in its customer charge, along with the payment difficulties that are prevalent in the Company's Confirmed Low-Income population, expanding outreach, the necessity of which has been identified in the Commission's 2019 Final Order with respect to its Revised CAP Policy Statement, would be appropriate. The Company should be directed to identify specific outcome metrics by which it will measure the utilization of its outreach methods. It should be directed to identify the specific community partners with whom it is working along with the specific populations which the partnerships are intended to reach.

B. Reaching the Population Below 50% of Poverty.

Q. HAVE YOU HAD OCCASION TO EXAMINE WHETHER PECO TARGETS ITS LOWEST INCOME CUSTOMERS FOR CAP OUTREACH?

A. Yes. The Table below shows the data. According to the most recent Census data (American Community Survey, ACS, 2019), 30.9% of the population in PECO's service territory with income below 150% of Poverty, in fact, have income at or below 50% of Poverty. That lowest income population is under-represented in the PECO CAP. In 2019, and for each year going back to at least 2015, the percentage of CAP recipients with income at or below 50% of the Poverty Level reached only 22%. Clearly, there is an under-representation. Even as the Company revised its CAP structure, such that it would be less likely that customers with higher incomes would participate, the percentage of CAP participants in the range of 100 to 150% of Poverty decreased, but the percentage of CAP participants in the range below 50% of Poverty did not increase.

Table 15. PECO CAP Participation by Poverty Level
(2015 – 2019) (BCS Annual Report on Universal Service Programs and Collections Statistics)

	CAP Participation (#s)			CAP Participation (%)		
	0 – 50%	51 – 100%	101 – 150%	0 – 50%	51 – 100%	101 – 150%
2015	31,002	65,942	43,525	22.1%	46.9%	31.0%
2016	30,399	64,441	42,001	22.2%	47.1%	30.7%
2017	28,556	60,672	37,172	22.6%	48.0%	29.4%
2018	25,951	57,045	33,329	22.3%	49.0%	28.7%
2019	25,109	55,465	31,582	22.4%	49.5%	28.2%
ACS Population				30.9%	35.2%	33.9%

The data in the Table immediately above also shows that PECO has experienced a continuing decline in CAP participation within the population with income less than 50%

of Poverty. While the 2015 participation with incomes at this level was 31,000, by 2017, that participation had decreased to only 28,556. In both 2018 and 2019, participation within the population of customers with income less than 50% of Poverty declined even further each year.

The under-representation of the lowest income range (i.e., below 50% of Poverty) is of particular concern. Because of their low-income, these customers are most likely to have electricity bills that represent a high percentage of income (i.e., what is known as a "bill burden" or bill as a percentage of income). They are, accordingly, more likely to have the payment troubles that I have identified above. These high burdens are the problem addressed by enrollment in CAP. The customers in this lowest income range, however, are not enrolling in the Company's CAP in a percentage which reflects their percentage in the total population.

Q. HOW MIGHT PECO TARGET OUTREACH TO ITS LOWEST INCOME CUSTOMERS?

A. PECO could reasonably target outreach to the geographic areas which have the largest percentage of population with income at or below 50% of Poverty. Of the PECO Zip Codes for which I have Census data, for example, if PECO targeted outreach to the 20 with the highest percentages of population having income less than 50% of Poverty, it would reach 42% of the total population with income that low. If it targeted the 25 zip codes with the highest percentage, it would reach nearly half (47.2%) of the population with the lowest income.

PECO could reasonably target outreach to the geographic areas which have the largest populations of customers with income sources associated with the lowest levels of income. Consider, for example, Supplemental Security Income (SSI). In 2020, the maximum SSI benefit was $783, or 74% of the Federal Poverty Level. The average SSI benefit, however, was only $446. If one compares the 25 PECO Zip Codes with the highest numbers of SSI recipients to the 25 Zip Codes with the highest percentage of population with income less than 50% of Poverty, there is an overlap of 20 (i.e., only five zip codes have large numbers of SSI recipients but do not also have the highest percentage of population with income below 50% of Poverty).

PECO could reasonably target outreach to geographic areas which have the largest populations receiving Food Stamps or Public Assistance. The PECO service territory has 228 Zip Codes that I used in developing my testimony. Of those 228 Zip Codes, if PECO were to target CAP outreach efforts and initiatives:

- In the 25 Zip Codes with the largest population of Supplemental Security Income (SSI) recipients, it would reach 145,635 of the 266,134 population with income below 50% of Poverty (55%).[21]
- In the 25 Zip Codes with the largest population participating in Food Stamps (SNAP) / Public Assistance, it would reach 150,354 of the 266,134 population with income below 50% of Poverty (56%).

[21] Note that there is a difference between "population" (i.e., persons) and "customers."

Q. WHAT IS THE SIGNIFICANCE OF THIS OVERLAP IN LOW-INCOME POPULATION?

A. If PECO were to enroll, in the 25 Zip Codes with the highest percentage of population participating in Public Assistance/Food Stamps at the same rate as the total population enrolls in Cash Public Assistance/Food Stamps, it would enroll an additional 71,600 CAP participants. Remember, this does not involve enrolling *__everyone__* in those Zip Codes. It simply involves enrolling at the same rate as Cash Public Assistance/Food Stamps. Given the disproportionate presence of a population with income below 50% of Poverty in those Zip Codes, PECO could advance its compliance with the Commission directive to target that extremely low-income population.

Q. WHY IS IT IMPORTANT FOR PECO TO TARGET OUTREACH TO ITS POPULATION WITH INCOME AT OR BELOW 50% OF POVERTY LEVEL?

A. There are two responses to this question. First, it is important for PECO to target outreach to its population with income at or below 50% of Poverty Level because the Commission has directed utilities to do so. In its Final Order adopting the Revised CAP Policy Statement in 2019, the PUC stated quite explicitly that:

> While utilities have flexibility as to the contents of their plans, the plans should reflect focused consumer education and outreach efforts, tailored to the demographics of their individual service territories, spanning the duration of the universal service plan period. *__In particular, these plans should identify efforts to educate and enroll eligible and interested customers at or below 50% of the FPIG.__*

Final Order, at 79, Docket M-2019-3012599 (emphasis added). In addition, people with low incomes and high energy burdens can most benefit from PECO rate assistance.

Q. WHAT DO YOU RECOMMEND?

A. Based on the data and discussion above, I recommend that PECO be directed to provide a detailed plan addressing how it intends to expand its CAP outreach to expand CAP participation for customers with annual income less than 50% of Poverty. Consistent with the Commissioners' statement in the recent decision in Columbia's last base rate case, cited above, that Plan should include not only a discussion of the activities that the Company intends to take, it should also include quantitative outcomes by which the success (or lack thereof) can be measured.

Part 4. Allocation of Universal Service Costs.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I recommend that the PECO universal service costs be allocated among all customer classes. Arguments that non-residential customers do not contribute to the need for universal service programs, nor do they benefit from such programs, are demonstrably in error.

Q. DID PECO ADDRESS THE ALLOCATION OF UNIVERSAL SERVICE COSTS IN ITS FILING?

A. Yes. PECO witness Lauren Feldhake recommended that universal service costs be allocated exclusively to the residential class. (PECO St. 10, at 9). Witness Feldhake "noted" that the PUC had rejected an OCA proposal to allocate universal service costs to all customer classes in a recent Columbia Gas decision. (Id., citing Opinion and Order, *Pa. P.U.C. v. Columbia Gas of Pa., Inc.*, Docket No. R-2020-3018835 (Order entered Feb. 19, 2021), pp. 258-261). She failed to point out, however, that the PUC explicitly stated in that Order that its decision was limited to the facts presented in that proceeding. (Id., at 261). For example, the Commission observed that OCA did "not propose a specific recovery rate design method." (Id.) That decision, in other words, is not precedential, and certainly not controlling, of this proceeding. The Joint Statement of Chairman Gladys Brown Dutrieuille and Vice Chairman David Sweet further indicated that the Columbia Gas decision was limited to the facts of that case. In the recent PECO Gas rate case decision (Docket No. R-2020-3018929), the PUC reached a similar decision. (Opinion and Order, at 265, June 22, 2021). Similarly, a Joint Statement of Chairman Gladys Brown Dutrieuille and Vice Chairman David Sweet was issued noting that its decision was limited to the facts of the PECO Gas case.

Q. WHY SHOULD THE COMMISSION CONSIDER THE ALLOCATION OF UNIVERSAL SERVICE COSTS IN THIS PROCEEDING?

A. In its 2019 Final Order in the PUC's generic investigation into energy affordability in Pennsylvania (Docket M-2019-3012599),[22] the Commission explicitly acknowledged that, historically, it allocated universal service costs exclusively to residential customers, but then stated that "our review of Pennsylvania's current universal service model in the *Review* and *Energy Affordability* proceedings has provided reasons to reconsider this position. (Final Order, at 92). The Commission observed that "[t]he current cost-

[22] http://www.puc.pa.gov/about_puc/consolidated_case_view.aspx?Docket=M-2019-3012599 (November 5, 2019) (last accessed June 8, 2021).

recovery method for universal services, including CAP costs, is putting a significant burden on residential customer bills. . .” (Id.). The Commission’s decision to substantially reduce the definition of an “affordable” burden will create even more universal service costs and increase that “significant burden” even more. According to the Commission:

> Given the significant past increase in EDC universal service spending – and the anticipated increases in both EDC and NGDC universal spending through 2021 – the Commission is concerned that recovering CAP costs (as well as other universal service costs) from only residential ratepayers will continue to make electric and/or natural gas bills increasingly unaffordable for non-CAP customers, especially those with incomes between 151-200% of the FPIG.

(Id., at 95). I agree with these observations. There is a substantial population of PECO customers who have difficulties in paying their utility bills without being sufficiently “low-income” to qualify for CAP. The current CAP costs could prove to be a problem for these customers, and those costs will increase in the future, both for the reasons identified in the Commission’s Final Order (pages 94 – 95) and for the reason that the Commission has reduced the percentage of income payments to be charged to CAP customers.

As I will establish below, the Commission reached an appropriate conclusion when it stated in its Final Order that “[t]he Commission agrees that poverty, poor housing stock, and other factors that contribute to households struggling to afford utility service are not just “residential class” problems. Further, helping low-income families maintain utility service and remain in their homes is also a benefit to the economic climate of a community.” (Id., at 96).

The Commission stated in its Final Order that "the Commission finds it appropriate to consider recovery of the costs of CAP costs from all ratepayer classes. Utilities and stakeholders are advised to be prepared to address CAP cost recovery in utility-specific rate cases consistent with the understanding that the Commission will no longer routinely exempt non-residential classes from universal service obligations. . ." (Id., at 99, notes omitted).[23] The discussion below is consistent with this Commission guidance.

Q. WHAT IS DIFFERENT IN THIS PROCEEDING FROM THE COLUMBIA GAS AND PECO GAS PROCEEDINGS?

A. Responding to the evidentiary basis the Commission found lacking in Columbia and PECO Gas, OCA presents a substantively expanded evidentiary basis in this proceeding in support of the allocation of universal service costs over all customer classes. In addition to evidence demonstrating that such allocation is not "caused" exclusively by the residential class, and that PECO's universal service programs actually benefit the businesses served by PECO, OCA witness Clarence Johnson presents a specific cost allocation. Mr. Johnson's testimony demonstrates that the allocation of universal service costs will have a de minimis impact on non-residential classes. The allocation of universal service costs, as proposed in this proceeding, accordingly, will have no adverse impact on businesses served by PECO.

[23] The Commission observed that it was not making "a final precedential decision regarding cost recovery in this docket. We are merely providing that the recovery of CAP costs in particular can be fully explored in utility rate cases henceforth. " (Id., at note 150).

A. Multi-Class Allocation of Universal Service Costs Will Not Harm Businesses.

Q. HAVE YOU CONSIDERED THE IMPACT OF UNIVERSAL SERVICE COST ALLOCATION ON BUSINESS?

A. Yes. My review examined the states of Maine, Maryland, New Hampshire, New Jersey, Ohio, Illinois, Colorado and Nevada. My review found that all eight states who have Percentage of Income Payment Programs, or PIPP-based programs allocate the cost responsibility for their programs over all customer classes.

Q. HAVE YOU HAD OCCASION TO CONSIDER THE IMPACT ON THE BUSINESS CLIMATE OF STATES MAKING MULTI-CLASS ALLOCATIONS OF UNIVERSAL SERVICE COSTS?

A. Yes. PECO Energy Company is part of Exelon Utilities a multi-state electric distribution company. In turn, in addition to PECO, Exelon Utilities owns an electric distribution utility in Illinois (ComEd) and a combination electric/natural gas utility in Maryland (BGE). Both Illinois and Maryland have universal service programs the costs of which are allocated amongst all customer classes, not exclusively the residential class. In its Final Order setting forth the Revised CAP Policy Statement, the Pennsylvania observed:

> . . .as noted by multiple parties in the *Review* proceeding, many states recover the cost of utility low-income programs from all ratepayer classes, including New York, New Jersey, Ohio, Illinois, Maine, and New Hampshire. We are not aware that this practice has negatively impacted the business climate of any these states.

(Final Order, at 98, internal citation omitted). As an Exelon company, with sister utilities in at least two of those states (Illinois, Maryland), PECO has no such information either.

OCA asked PECO to "provide a single copy of each evaluation, assessment, report or similar document prepared by or on behalf of an Exelon natural gas and/or electric distribution utility in Maryland or Illinois within the past five years assessing the impact on business competitiveness of allocating universal service costs to: (a) Industrial customers in the state of the primary domicile of the utility; (b) small business customers in the state of the primary domicile of the utility. " PECO responded:

> PECO does not have any evaluation, assessment, report, or similar document prepared by or on behalf of an Exelon natural gas and/or electric distribution utility in Maryland or Illinois within the past five years assessing the impact on business competitiveness of allocating universal service costs to industrial or small business customers." (OCA-I-41).

Moreover, there is no empirical support for any speculation that businesses might relocate due to an allocation of universal service costs to all customer classes. OCA asked PECO to provide a complete list of industrial customers who relocated from the service territory of an Exelon natural gas and/or electric utility in Maryland or Illinois within the past five years because of the financial burden of paying costs associated with the Illinois and/or Maryland low-income affordable rate program(s)." PECO responded:

> PECO does not have a list of industrial customers who relocated from the service territory of an Exelon natural gas and/or electric utility in Maryland or Illinois within the past five years because of the financial burden of paying costs associated with the Illinois and/or Maryland low-income affordable rate program(s). (OCA-I-42).

Finally, there is no empirical support for any speculation that business might be less competitive due to the allocation of universal service costs to all customer classes. OCA asked PECO to "provide a single copy of all reports, evaluations or other written documents submitted to Maryland and/or Illinois regulators within the past five years documenting an adverse competitive impact on industrial and/or small business customers of an Exelon natural gas and/or electric distribution utility, which adverse competitive impacts were attributed to the allocation of the costs of low-income rate affordability programs in those states amongst customer classes in addition to the residential class." PECO responded:

> PECO does not have any reports, evaluations or other written documents submitted to Maryland and/or Illinois regulators within the past five years documenting an adverse competitive impact on industrial and/or small business customers of an Exelon natural gas and/or electric distribution utility, which adverse competitive impacts were attributed to the allocation of the costs of low-income rate affordability programs in those states amongst customer classes in addition to the residential class. (OCA-I-43).

If the allocation of universal service costs to all customer classes has an adverse impact on business, that adverse impact should show up ***somewhere*** in those states which do allocate costs over all customer classes. However, just as the Commission "is not aware" of any information indicating that the allocation of universal service costs to all customer classes will adversely affect businesses in the states where such multi-class allocation occurs, PECO, the very utility that is part of the family of utilities that serves those states, has no such information either.

Q. DOES THE COST ALLOCATION RECOMMENDATION, AS SET FORTH IN THE DIRECT TESTIMONY OF OCA WITNESS CLARENCE JOHNSON, ADDRESS THE COMPETITIVENESS OF PENNSYLVANIA BUSINESS, IN PARTICULAR, IN ANY OTHER FASHION?

A. Yes. The specific universal service cost allocation set forth in the testimony of myself and Mr. Johnson provides reduced cost responsibility as compared to the multi-class cost allocation approved in other states. In the states which have universal service programs designed most closely to Pennsylvania's, electric universal service costs are collected on a uniform kWh basis amongst all customer classes. In Ohio, for example, in the most recent Public Utilities Commission of Ohio order establishing the level of the PIP Rider for each Ohio utility, each of the seven electric utilities have a uniform kWh charge over all customer classes.[24] This process has been used for at least the past fifteen years. [25]

Similarly, the New Jersey Board of Public Utilities (BPU) allocates the costs of that state's Universal Service Fund (USF) over all customer classes. Unlike Ohio, New Jersey establishes a uniform rate (per kWh, per CCF) for the entire state. However, like Ohio, New Jersey also establishes a uniform rate irrespective of customer class.[26] In New Jersey, this process has been in use for at least 17 years.[27]

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[24] In the Matter of the Application of the Ohio Development Services Agency for an Order Approving Adjustments to the Universal Service Fund Rider of Jurisdictional Ohio Electric Distribution Utilities, Docket No. 20-1103-EL-USF, entered December 16, 2020 (for each utility, a different rate is applied to usage exceeding 833,000 kWh per month). Available at http://dis.puc.state.oh.us/CaseRecord.aspx?CaseNo=20-1103 (last accessed June 23, 2021).

[25] Id.

[26] In the Matter of the 2020/2021 Annual Compliance Filings for the Universal Service Fund ("USF") Program Factor within the Societal Benefits Charge Rate, Docket EO20060392, Order Approving Interim USF Rates and Lifeline Rates, September 30, 2020. Available at https://www.nj.gov/bpu/pdf/boardorders/2020/20200923/2O%20-%20ORDER%20USF%20Lifeline%20Rate.pdf (last accessed June 23, 2021).

[27] Id.

The OCA has protected the competitiveness of Pennsylvania business by proposing a cost allocation method specific to Pennsylvania. Unlike the multi-class cost-allocations in other states with universal service programs similar to Pennsylvania's, the OCA methodology provide for a non-uniform cost amongst the customer classes, with businesses paying lower rates than they would if a uniform charge were employed. The difference in results resulting from OCA's proposal to use a lower rate is presented in more detail in the testimony of Clarence Johnson.

Q. IN ADDITION TO THE LACK OF INFORMATION SHOWING AN ADVERSE IMPACT ON BUSINESS, IS THERE INFORMATION AFFIRMATIVELY DEMONSTRATING THE LACK OF ANY ADVERSE IMPACT?

A. Yes. The Table below shows the difference between the 2019 Quarter 4 and the 2020 Quarter 3 Gross Domestic Product by state for the nine states having universal service programs such as the Pennsylvania CAP.[28] In this Table, only Pennsylvania allocates universal service costs exclusively to the residential class. As can be seen in this Table, whatever drives economic performance in a state, it is not the allocation of utility universal service costs amongst customer classes. Even during the COVID-19 pandemic, Pennsylvania had the second largest decline in Gross Domestic Product from the Fourth Quarter of 2019 through the Third Quarter of 2020. Ohio and New Jersey, which have universal service programs most like Pennsylvania, and which each allocate the costs of

[28] Ettinger and Hennsley (January 13, 2021). COVID-19 Economic Crisis by State, Table A3, available at https://public.tableau.com/views/GreatRecessionandCOVIDRecessionGDPChange/Dashboard1?:language=en&:display_count=y&:origin=viz_share_link&:showVizHome=no (last accessed June 9, 2021).

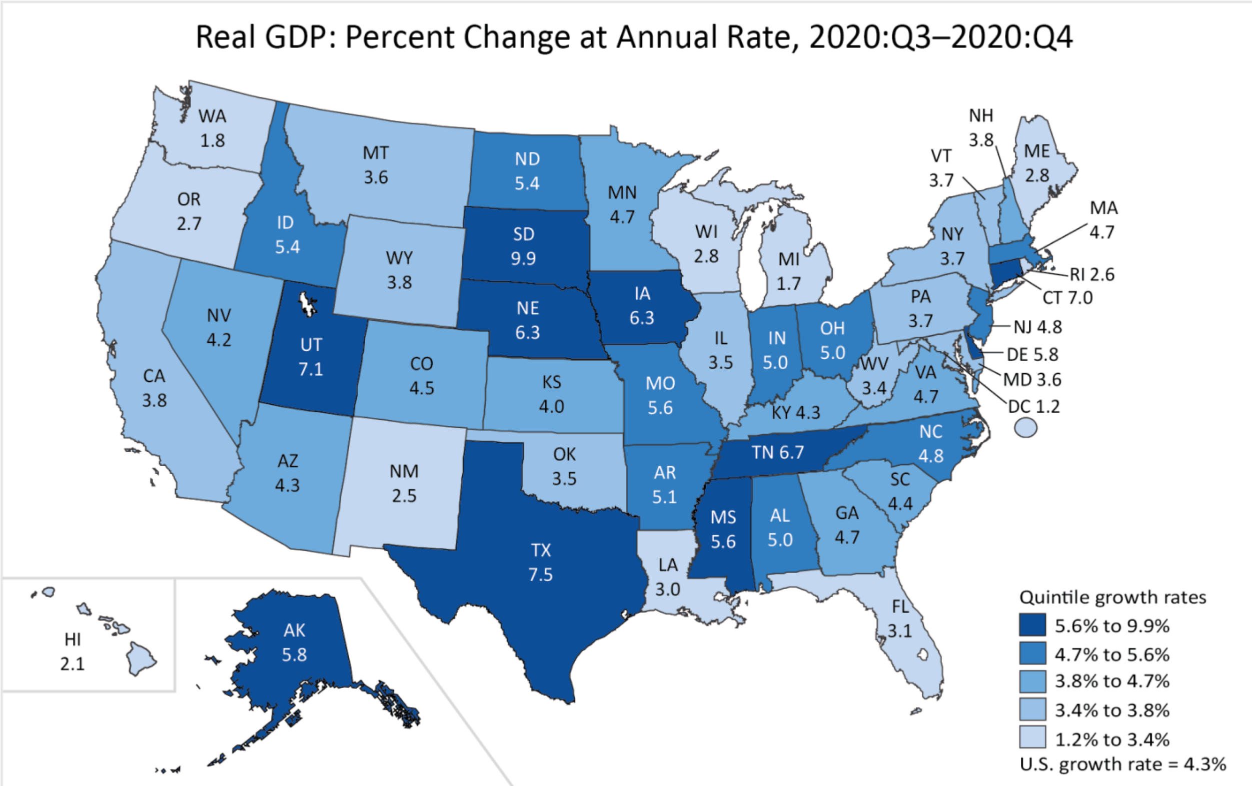
those programs over all customer classes, both had better economic performance than did Pennsylvania (which did not allocate universal costs to other than residential customers).

Table 16. Difference Between 2019 Q4 and 2020 Q3 Gross Domestic Product (GDP) By State	
Nevada	-4.3%
Pennsylvania	-4.2%
Maine	-4.2%
New Jersey	-3.9%
Ohio	-3.5%
New Hampshire	-3.4%
Illinois	-3.0%
Maryland	-2.6%
Colorado	-2.0%

As can be seen in the Table above, the allocation of universal service costs is not a factor that affects economic performance in a state. States that allocate universal service costs over all customer classes have businesses that perform better than the Pennsylvania, the only state that does not make that multi-class allocation.

Q. IS THERE ADDITIONAL DATA BEYOND THE IMPACTS YOU CONSIDER ABOVE?

A. Yes. The U.S. Bureau of Economic Analysis tracks the GDP by states on a quarterly basis (reporting annual data each quarter). The Figure below presents the GDP change from the Third Quarter of 2020 to the Fourth Quarter of 2020.



U.S. Bureau of Economic Analysis

Again, it is possible to compare the states which allocate universal service costs to all customer classes to Pennsylvania. The two most comparable programs, Ohio and New Jersey, both have better economic performance than does the Pennsylvania. Colorado, New Hampshire, and Nevada, which allocate universal service costs over all customer classes, also have better economic performance than does Pennsylvania. Maryland and Illinois have economic performance nearly identical to Pennsylvania. The decision of state utility regulators to share costs amongst all customer classes is not the factor that drives economic performance.

Q. WHY IS IT LIKELY THAT ALLOCATING UNIVERSAL SERVICE COSTS OVER ALL CUSTOMER CLASSES IS GOOD FOR THE ECONOMY?

A. The fact that states which allocate universal service costs over all customer classes also have strong economies is not surprising. A percentage of income program (such as those that exist in states such as New Hampshire, New Jersey, Ohio, Colorado and Nevada, all of which have strong economies) is a program that supports employment. In this fashion, the program is like the Federal Supplemental Nutrition Assistance Program (SNAP) (previously known as Food Stamps). With Food Stamps, as the Center on Budget and Policy Priorities (CBPP) notes, "SNAP benefits are. . .designed to support work. The SNAP benefit formula targets benefits based on a household's income and expenses, phases out benefits slowly as earnings rise, and includes a 20 percent deduction for earned income to reflect the cost of work-related expenses and encourage work."[29]

Similar conclusions could be reached regarding CAP. As households improve their working situation, and increase wages, their CAP benefits phase out. Given that CAP benefits are based on a percentage of income, a participant with a $20,000 income would receive fewer benefits than a participant with a $10,000 income (all other things equal).

Q. WHAT DO YOU CONCLUDE?

A. The allocation of universal service costs over all customer classes, including small business and industry, is not merely common throughout the United States, it is the norm throughout the country. In those states which allocate universal service costs over all customer classes, no harm has arisen to business. The available data not only fails to

[29] Jennings and Palacios (2017). SNAP Helps Millions of Low-Wage Workers, Crucial Financial Support Assists Workers in Jobs with Low Wages, Volatile Income, and Few Benefits, Center on Budget an Policy Priorities: Washington D.C., available at https://www.cbpp.org/research/food-assistance/snap-helps-millions-of-low-wage-workers (last accessed June 8, 2021).

support the conclusion that harms to business will arise, the available data specifically demonstrates the contrary conclusion.

B. The Commission-Identified Factors.

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In its 2019 Final Order quoted above, the Pennsylvania PUC identified several factors that "contribute to households struggling to afford utility service" and indicated that such factors "are not just residential class problems." Amongst those factors which the PUC identified were "poverty, poor housing stock, and other factors." Having addressed the impact on business above, in this section of my testimony, I address those specifically-identified factors more generally.

Q. HOW DO YOU RESPOND TO THE FACTORS SPECIFICALLY DISCUSSED IN THE PUC REVISED CAP POLICY STATEMENT REGARDING THE ALLOCATION OF UNIVERSAL SERVICE COSTS?

A. For all the reasons set forth below, I agree that the PUC was correct when it found in its 2019 final Order quoted above that:

- poverty is "not just [a] residential class problem."
- several factors "contribute to households struggling to afford utility service" and that, amongst those factors are "poverty, poor housing stock, and other factors."
- Poverty is a broad-based social problem not associated with any particular customer class, including specifically not being associated with the residential class exclusively.
- "helping low-income families maintain utility service and remain in their homes is also a benefit to the economic climate of a community."

- “clearly, there is a persuasive argument to be made that home heating and energy assistance for low-income households serves a public good whose responsibility is not merely other residential ratepayers.”

- “while there are strong arguments to be made that non-residential classes do benefit from universal services, there are also strong arguments to be made in favor of multi-class allocation even if one discounts any non-residential benefits.”

- “in approving PGW’s practice of recovering such costs across all ratepayer classes, we noted that ‘all firm customers, including commercial and industrial customers, benefit indirectly from PGW’s extensive low-income assistance programs.’” (internal note omitted).

My testimony below provides a factual basis for reaching the same conclusions in this proceeding that have been previously reached by the Commission.

Q. PLEASE RESPOND TO THE PUC’S FINDING THAT THE ALLOCATION OF UNIVERSAL SERVICE COSTS WILL AFFECT THE POPULATION OF CUSTOMERS WHOSE INCOMES ARE ABOVE CAP ELIGIBILITY BUT BELOW THAT LEVEL TO SUSTAIN A HOUSEHOLD.

A. Yes. In its 2019 Final Order, the Commission discussed the impact of allocating universal service costs exclusively to the residential class on customers with income from 150% to 200% of Poverty. According to the Commission:

> Given the significant past increase in EDC universal service spending – and the anticipated increases in both EDC and NGDC universal spending through 2021 – the Commission is concerned that recovering CAP costs (as well as other universal service costs) from only residential ratepayers will continue to make electric and/or natural gas bills increasingly unaffordable for non-CAP customers, <u>*especially those with incomes between 151-200% of the FPIG*</u>.

(Final Order, at 95). (emphasis added). Given this expressed concern by the PUC, I examine the impacts on this specific population. In my discussion below, I examine customers who have income above the maximum income-eligibility established by the PUC for CAP (150% of Poverty), but whose income is sufficiently low that they can reasonably be expected to face difficulties paying their utility bills. I define this population of customers with income above the maximum CAP eligibility but below an income level sufficient to sustain payments to include households who have income higher than 150% of Poverty, but lower than 200% of Poverty. In total, 7.3% of PECO's customers are estimated to live with income of greater than 150% of Poverty, but less than 200%.

Q. IN THERE A SECOND POPULATION TO BE CONCERNED ABOUT?

A. Yes. For purposes of the PUC's consideration of whether to allocate universal service costs over all customer classes, it is also important to remember that nearly 160,000 customers with income at or *below* 150% of Poverty (n=158,902) (274,966 estimated low-income – 116,064 CAP participants) do not participate in CAP notwithstanding their low-income status.

In addition, 111,204 *more* customers live with incomes that are above the income-eligibility maximum of 150% of Poverty, but less than 200% of Poverty (1,521,849 total customers x 7.3% with income between 150% and 200% of Poverty). Allocating universal service costs over all customer classes would help improve the affordability of PECO bills to these more than 270,000 residential customers (111,902 + 158,902 =

270,106) who are reasonably viewed as income-challenged but not participating in, or not eligible for, PECO's universal service programs.

C. Poverty is Not Just a Residential Class Problem.

Q. PLEASE ADDRESS THE STATEMENT BY THE PUC THAT POVERTY IS "NOT JUST [A] RESIDENTIAL CLASS PROBLEM."

A. I agree with the PUC's observation that poverty is "not just [a] residential class problem." In reaching this conclusion, I examine broad economic factors throughout the PECO service territory, not exclusively associated with the residential class, which contribute to the inability-to-pay of PECO low-income customers.

Q. DO LOW WAGES AFFECT THE PARTICIPATION OF CUSTOMERS IN THE UNIVERSAL SERVICE PROGRAMS OF PECO?

A. Yes. PECO provides the PUC's Bureau of Consumer Services the number of CAP participants by source of income each year. (OCA-I-21). The data is set forth in the Table immediately below.[30] The Table demonstrates that, according to PECO's own data, the Company's CAP participation includes a substantial proportion of participants who are eligible notwithstanding the fact that they receive "employment" income. In contrast, a very small proportion of PECO's CAP participants have income from public assistance. Only 4,500 CAP recipients receive public assistance income. In contrast, nearly 30,000 customers participate in CAP even though they receive employment income.

[30] This data has not been updated to account for Year 2020 given that the COVID-19 pandemic, and the economic crisis engendered by that pandemic, would seem to make the 2020 data not typical.

Table 17. CAP Participants by Source of Income for All or Part of their Income (OCA-I-21)				
	Employment	Disability	Public Assistance	Pension / Retirement
2019	29,938	34,277	4,519	25,327
2020	29,207	34,511	4,408	25,766

The prevalence of employment income has persisted over time. In the 2019 APPRISE evaluation of the PECO universal service programs, APPRISE stated that its data "displays the income source for the CAP participants. The Table shows that the most common specified income source for the CAP participants was employment, followed by SSI, and then retirement income." (2019 PECO USECP APPRISE Evaluation, at 85). In fact, according to the PECO's 2019 APPRISE Evaluation, as the Table below indicates, the prevalence of employment income amongst CAP participants was not substantially different from the prevalence of employment income amongst CAP non-participants.

Table 18. PECO (Electric Only): Source of Income[31]						
	2017 Enrollees	CAP Participants			CAP Non-Participants	
		2016	2017	2018	2016	2017
Employment	30%	23%	25%	24%	25%	28%

While the percentage of CAP participants receiving employment income ranged from 23% to 25% in 2016 through 2018, the percentage of CAP non-participants receiving employment income ranged from 25% to 28%. The "non-participants" was a group of

[31] APPRISE, Inc. (June 2019). PECO Energy Universal Services Program, Final Evaluation Report, at Table VII-3A and Table VII-3B, page 85, available at https://www.puc.pa.gov/pcdocs/1626073.pdf (last accessed June 11, 2021).

2017 LIHEAP recipients used for comparative purposes. (2019 PECO USECP APPRISE Evaluation, at vii).

Q. DO YOU HAVE AN OVER-ARCHING REASON TO CONCLUDE THAT IT IS NOT THE RESIDENTIAL CLASS THAT IS THE EXCLUSIVE "CAUSE" OF THE NEED TO INCUR UNIVERSAL SERVICE COSTS?

A. Yes. The need for utilities to incur universal service costs is largely caused by the receipt of low wages in Pennsylvania. The Figure below shows that Pennsylvania had the sixth (6th) largest rate of employees receiving wages at or below the minimum wage in the nation in 2020 (published February 2021).[32] As a result of these low wages, as described above, these low wage workers experience adverse impacts such as inability-to-pay utility bills, the stress accompanying the difficulties paying normal household expenses, and the health impacts associated with that stress.

[32]Available at https://www.statista.com/statistics/635009/us-minimum-wage-workers-by-state/ (last accessed June 11, 2021).

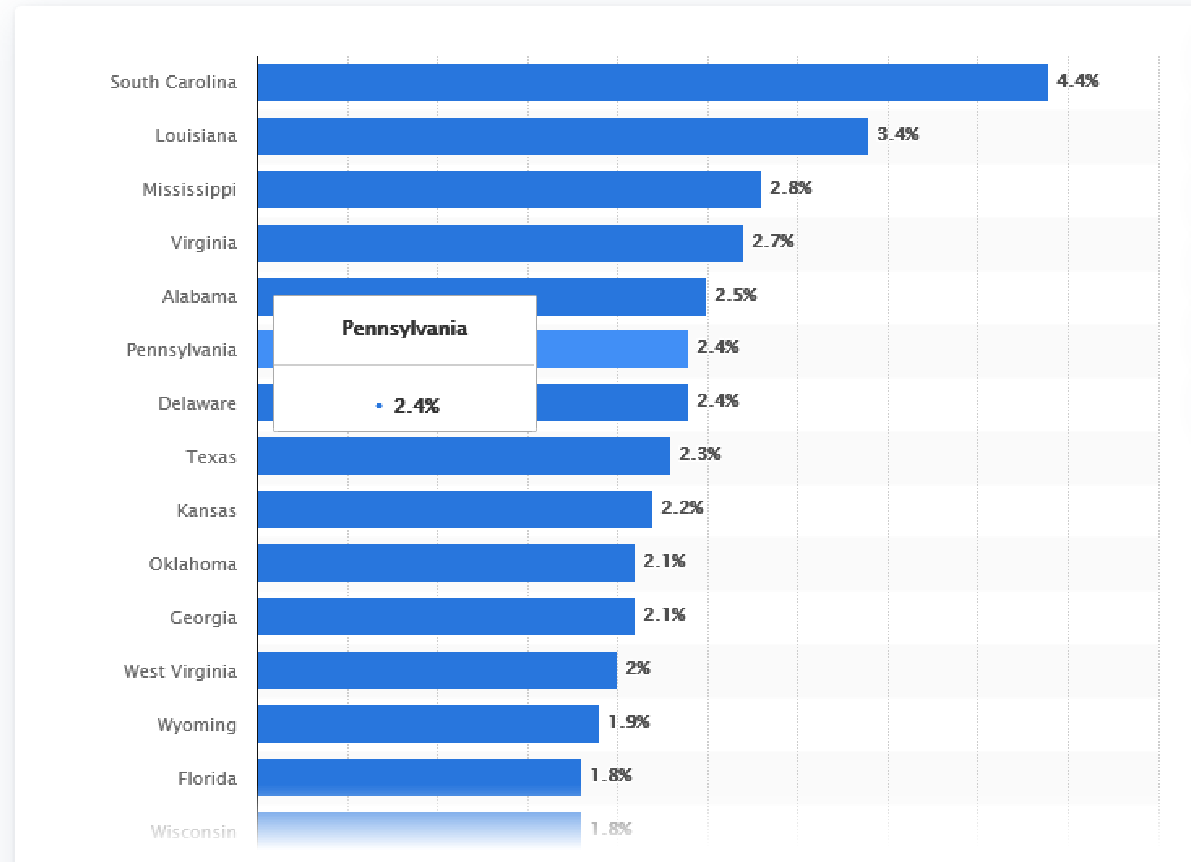


Figure 3. Share of Workers Paid Hourly Rates with Earnings at or Below the Minimum Wage in the United States, by State.

Q. HAVE YOU HAD OCCASION TO EXAMINE THE VARIOUS UNDERLYING ECONOMIES WITHIN THE PECO SERVICE TERRITORY IN PARTICULAR?

A. Yes. It is important to recognize that the employment and wage data I discuss below predates the COVID-19 health pandemic. I find that low wages are prevalent throughout the PECO service territory. Based on this local wage data, [33] I find that the inability-to-pay issues addressed by the universal service programs of PECO are not "caused" by the

[33] The reporting areas are defined by the U.S. Bureau of Labor Statistics (available at https://www.bls.gov/oes/current/oessrcma.htm#P (last accessed June 11, 2021).

residential customer class. They are instead broader societal issues that can be attributed to every customer class.

Q. UPON WHAT DO YOU BASE YOUR CONCLUSION THAT THESE LOW WAGES ARE PREVALENT THROUGHOUT THE PECO SERVICE TERRITORY?

A. The purpose of the discussion above is not to identify the particular communities as having particular problems, but rather to identify these communities as illustrative of the social issues underlying a universal service program. The Table below shows the data for the Philadelphia-Camden-Wilmington metropolitan area,[34] as well as for the York-Hanover metropolitan area. As is evident, low-wage jobs are prevalent throughout the PECO service territory. They are not unique to any particular metropolitan area, nor to any particular region of the area which PECO serves.

Table 19. Employment by Selected Median Hourly Wages and PECO Metropolitan Areas (May 2020)[35]

	$10.00 or less	>$10.00 - $11.00	>$11.00 - $12.00
Philadelphia-Camden-Wilmington[36]	900	20,780	209,262
York-Hanover[37]	6,910	8,250	7,050

[34] According to the Bureau of Labor Statistics, this metropolitan area encompasses Philadelphia, Delaware, Bucks, Montgomery, and Chester Counties.

[35] Occupations and Wages, MSA, May 2020, available at https://www.bls.gov/oes/tables.htm (last accessed June11, 2021).

[36] https://www.bls.gov/oes/current/oes_37980.htm (last accessed June 11, 2021).

[37] https://www.bls.gov/oes/current/oes_49620.htm (last accessed June 11, 2021).

The Table shows that thousands of workers in these areas served by PECO work for wages that would place them well below annual income that would qualify them for CAP.

Q. WHY DID YOU SELECT $12.00 AS THE TOP OF THE RANGE OF WORKER WAGES THAT YOU EXAMINED?

A. The most recent non-COVID-19 affected data reported by the Bureau of Labor Statistics for employee wages is for May 2020. Accordingly, I took the 2020 Federal Poverty Guidelines and, for each household size (up to 3 persons), converted those guidelines into an hourly wage. I performed this conversion at 150% of Poverty, which is the Commission's definition of low-income. The Table below sets out the results for households with one to three persons in the household. The Table shows that the Poverty Wage (at 150% of Poverty) is somewhat over $12.00 per hour for a 2-person household. The Poverty wage is somewhat above $15.00 per hour for a 3-person household. It is clear that my use of $12.00 as the top code for my inquiry is a conservative measure of workers who are working at Poverty wages (defining a "Poverty wage" as the wage at 150% of Poverty).

Table 20. 150% of Poverty Level as an Hourly Wage

	100% FPL	150% FPL	No. Annual Hours	Hourly Wage
1	$12,490	$18,735	2080	$9.01
2	$16,910	$25,365	2080	$12.19
3	$21,330	$31,995	2080	$15.38

Q. WHAT DO YOU CONCLUDE BASED ON THIS DATA?

A. I conclude that the Pennsylvania PUC was correct when it observed in its 2019 Final Order that Poverty is a broad-based social problem not associated with any particular customer class, including specifically not being associated with the residential class exclusively. I find that a substantial number of wage-earning customers participate in PECO's universal service programs. I find further that one reason that these customers income-qualify for PECO's universal service programs is because a substantial number of people throughout the PECO service territory are working at Poverty wages.

Q. HAVE OTHER RESEARCHERS FOUND A CAUSAL RELATIONSHIP BETWEEN THE NEED FOR ECONOMIC ASSISTANCE AND THE ACTIONS OF LARGE AND SMALL BUSINESSES?

A. Yes. Work by the Urban Institute, one of the nation's primary research institutions, reaches similar conclusions. According to the Urban Institute:

> data show that most people applying for assistance are low-wage workers who turn to assistance programs either when they are between jobs or to supplement wages while working. Understanding the nature of low-wage jobs, the reasons workers lose or leave work, and workers' strategies for getting by on low and fluctuating incomes is important for understanding how these factors shape worker's outcomes. . . The public debate around public assistance programs often focuses on how to move people off assistance programs and into work, but this ignores evidence that *most people applying for assistance are workers who turn to such programs to supplement income from wages*.[38]

(emphasis added). Similarly, the Economic Policy Institute (EPI) reports that:

[38] Coffey, Hahn and Park (2019). The Intersection of Low-Wage Work and Public Assistance, The Urban Institute: Washington D.C., available at https://www.urban.org/sites/default/files/publication/100628/the_intersection_of_low-wage_work_and_public_assistance.pdf (last accessed June 8, 2021)

> [G]iven rising costs of necessities such as child care, housing, and health care, many families' ability to achieve a modest but adequate standard of living requires resources earned on the job *and* assistance from government programs. (internal citation omitted).
>
> However, *for many workers in certain sectors, wages are so low that even those who work full time must rely heavily on government assistance to make ends meet*. This suggests that *low pay by many employers*. . .is placing unwarranted demands on public resources.[39]

(emphasis added). As this research finds, the cause of the public expenditures – Pennsylvania's Universal Service Program in the case at hand—is not the individual receiving the benefits. It is "caused," at least in part, by the economic entities providing the low wages which require a public subsidy.

Allocating the costs of such programs to all customer classes, as every other state other than Pennsylvania does, helps reduce what, in effect, is a wage subsidy paid by residential utility customers to these non-residential customers. It results in the inescapable conclusion that Universal Service Costs are not "caused" by the residential class any more than they are caused by the broader social and economic forces in play yielding low wages that cannot sustain a household. Low-wages have long been found to be not sustainable without the provision of the additional public resources provided to support the employee receiving such low wages. In the circumstances now facing the Pennsylvania PUC, the "public resources" that are required to survive are not only

[39] Cooper (2016). Balancing paychecks and public assistance: How higher wages would strengthen what government can do, Economic Policy institute: Washington D.C. , available at https://www.epi.org/publication/wages-and-transfers/ (last accessed June 8, 2021);

government-funded social assistance programs, but are additionally ratepayer-funded Universal Service Programs.

D. How Universal Service Benefits Business.

Q. OUTSIDE OF THE LACK OF HARM TO BUSINESS, HAVE YOU HAD OCCASION TO CONSIDER HOW PROVIDING UNIVERSAL SERVICE BENEFITS BUSINESS?

A. Yes. Any increase in electricity costs from payment of universal service costs would be offset by increases in employee productivity. Poverty produces ill-prepared workers whose lives are easily disrupted by small catastrophes. If the car breaks down, if a child gets sick, it suddenly becomes impossible to be a reliable worker. Poverty also generates poor health among workers, making them less reliable still and raising the cost of employing them. Paying a small increase in costs to help generate these offsetting benefits is a reasonable investment for a business to make.

In addition to generating economic development impacts on their own accord, programs such as Pennsylvania's CAP help contribute to the overall competitiveness of the Pennsylvania economy. This conclusion is not disputed by researchers that consider the impacts of assistance programs on private employers. One comprehensive study published in 2004 concluded:

> Why the under-use of public benefits is a problem. When most people hear about the idea of marketing public benefits through employers, their initial reaction is "why would a company want to get involved with a social service program?"

> In fact, employers have good reason to be concerned that large numbers of working people with low family incomes do not take advantage of the public benefits intended to help them and their families achieve economic sufficiency--benefits that also help employers by contributing to the economic stability of their workforces. These public benefits bolster the ability of low-income workers to meet their basic needs, in effect providing a wage supplement to employers.[40]

Note that these conclusions are made by business stakeholders: the U.S. Chamber of Commerce and the National Association of Manufacturers.

Q. HAS THE CONCLUSION THAT ADDRESSING UNIVERSAL SERVICE PROBLEMS BEEN REACHED THROUGH PENNSYLVANIA-SPECIFIC RESEARCH?

A. Yes. Addressing the problems of poverty is a critical element to restoring the competitiveness of Pennsylvania businesses. In its report *Back to Prosperity: A Competitive Agenda for Renewing Pennsylvania*,[41] the Brookings Institute Center on Urban and Metropolitan Policy consistently noted the need to address the factors contributing to the decline of communities, large and small, in the state. According to the report, funded by the Heinz Endowment and the William Penn Foundation, neighborhood decline "has become a contagious self-sustaining process in parts of older urban Pennsylvania." Such decline, the report found, triggers a slide in property values, brings

[40] Scott (2004). "Private Employers and Public Benefits," Workforce Innovation Networks (WINS): Boston (MA) and Washington D.C. WINS is a collaboration of Jobs for the Future, the Center for Workforce Preparation of the U.S. Chamber of Commerce, and the Center for Workforce Success, The Manufacturing Institute of the National Association of Manufacturers. Available at: https://www.jff.org/resources/private-employers-and-public-benefits/ (last accessed June 9, 2021).

[41] Available at: https://www.brookings.edu/research/back-to-prosperity-a-competitive-agenda-for-renewing-pennsylvania/ (last accessed June 9, 2021).

negative perceptions, and erodes public health and safety, all of which impede the competitiveness of the state's business and industry. According to this analysis of the competitiveness of Pennsylvania business, and how to "restore prosperity," "the widening social and economic gap between Pennsylvania's older communities and their suburbs has negative implications for the overall health of its regions."

Q. WILL PROGRAMS SUCH AS CAP HELP ADDRESS THESE PROBLEMS?

A. Programs such as CAP, while not a complete solution standing by themselves, are one *part* of the solution. In addition to addressing utility payment problems, home energy affordability programs can help address trends toward housing abandonment, reductions in educational attainment,[42] and adverse health outcomes for payment-troubled utility customers.[43]

Q. HAVE YOU HAD OCCASION TO REVIEW RESEARCH ON THE RELATIONSHIP BETWEEN INABILITY-TO-PAY AND THE MITIGATION OF ANY INCREASE IN UTILITY COSTS TO BUSINESS THAT MIGHT ARISE AS A RESULT OF THE ASSOCIATED UNIVERSAL SERVICE PROGRAMS?

[42] Colton (1996). "The Road Oft Taken: Unaffordable Home Energy Bills, Forced Mobility And Childhood Education in Missouri," 2 Journal on Children and Poverty 23.Available at: https://www.tandfonline.com/doi/abs/10.1080/10796129608414757 (last accessed June 9, 2021).

[43] See generally, Apprise, Inc. (2018). National Energy Assistance Survey: Final Report, National Energy Assistance Directors' Association: Washington D.C. Available at: http://www.appriseinc.org/resource-library/selected-reports/energy-survey-research-and-policy-analysis/ (last accessed June 9, 2021).

A. Yes. A 2014 study by the Consumer Financial Protection Bureau[44] (CFPB) reports that "even when the economy was booming, financial stress was sapping the productivity and hurting the health of millions of American workers."[45] According to the CFPB:

> Multiple surveys offer ample evidence of the impact of financial stress at work. For example, in 2012, roughly one in five employees admitted they had skipped work in the past year to deal with a financial problem. Among workers now in their 30's and 40's – a critical cohort of the American workforce - stress levels are even higher. Many Generation X workers (29%) say their personal finances distract them at work, and a majority (53%) find it stressful to deal with their personal finances. This is a particularly salient finding given that Gen Xers – those born between 1964 and 1980 – are beginning to enter their peak-earning years. If they are financially stressed now, Gen Xers may have more difficulty than other generations finding security in the future. Across workers of all generations, 24% admit their personal finances have been a distraction at work. And, of those workers who are concerned about their finances, 39% spend at least three hours each week either thinking about or dealing with financial problems at work.[46]

According to the CFPB:

> It's not just employees who want help managing financial stress at work. Managers confront this stress every day. In a recent survey, 61% of human resources professionals say financial stress is having some impact on

[44] CFPB (August 2014). Financial wellness at work: A review of promising practices and policies. https://www.consumerfinance.gov/data-research/research-reports/financial-wellness-at-work/ (last accessed June 9, 2021).

[45] Financial wellness at work, at 6, citing E. Thomas Garman et al., Financial Stress Among American Workers: Final report: 30 Million Workers in America –One in Four—Are Seriously Financially Distressed and Dissatisfied Causing Negative Impacts on Individuals, Families, and Employers, 17 2005).

[46] Id., citing MetLife, Inc., 10th Annual Study of Employee Benefits Trends: Seeing Opportunity in Shifting Tides 51 (2012), available at http://www.winonaagency.com/img/~www.winonaagency.com/10th annual met life study of benefits trends.pdf (last accessed June 9, 2021). ("22% of employees admit that they have taken unexpected time off in the past 12 months to deal with a financial issue and/or spent more time than they think they should at work on personal financial issues . . . ."). 15% of Gen Y respondents, 10% of Gen X respondents, 5% of Younger Boomer respondents, and 1% of Older Boomer respondents admitted to the same; PricewaterhouseCoopers, LLC, Employee Financial Wellness Survey 10,11 (2014), available at http://www.pwc.com/en_US/us/private-company-services/publications/assets/pwc-employee-financial-wellness-survey-2014-results.pdf (last accessed June 9, 2021).

> employee work performance. Twenty-two percent say worries over personal finances have a "large impact" on employee engagement.[47]

Q. HOW SUBSTANTIAL ARE THE EMPLOYER COSTS THAT UNIVERSAL SERVICE PROGRAMS HELP THOSE EMPLOYERS TO AVOID?

A. The costs to employers can be substantial, and engaging in activities to reduce these costs can be helpful to employers. One white paper presented "an overview of the research literature related to financial stress, how it can affect employee productivity, and real world data regarding the estimated costs to businesses when financially stressed employees are left to struggle on their own."[48]

Indeed, an increase in health care costs is one of the most cited costs imposed on employers due to financial stress. As CFPB reported:

> there is reason to consider whether financial stress may also raise employer health care costs, specifically, the documented link between psychological stress and physical health and well-being. . . researchers have attempted to quantify the overall cost to employers from all forms of stress, and they have found those costs are not trivial. . . researchers at Ohio State surveyed 9,200 people between 2005 and 2011 to learn more about their stress levels. The findings of the Consumer Finance Monthly surveys indicate one in five people report debt stress has had a high negative impact on their health. Judging from the available survey evidence, a large share of the American population reports they suffer from chronic financial stress, and they blame that stress for hurting their health.

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[47] Id., citing Society for Human Resource Management, SHRM Research Spotlight: Financial Education Initiatives in the Workplace 2 (2012), available at https://www.shrm.org/hr-today/trends-and-forecasting/research-and-surveys/Documents/Financial_Education_Flier_FINAL.pdf (last accessed June 9, 2021).

[48] Brown and Menard (June 2017). Improving Employees' Financial Wellness: Why it Matters and What Employers Can Do About It." https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3011461 (last accessed June 9, 2021).

> A recent report in Health Affairs analyzed the health risks and medical expenses of more than 92,000 employees over a three-year period. Those reporting high stress were $413 more costly per year on average than workers who were not at risk from stress. By comparison, smoking – a common health risk targeted by corporate wellness programs – was found to raise health care costs by $587 dollars on average. Since financial problems are an important stress factor, it appears employers may be paying a high cost for employee financial stress, but they do not recognize it because a large portion of that expense shows up indirectly as a health care expense.[49]

Moreover, financial stress adversely affects employers both through absenteeism and presenteeism.[50] According to Menard:

> Academic researchers have studied the costs of absenteeism, presenteeism, and employee turnover specifically associated with employee financial stress, and have estimated these costs based on real world data. Absenteeism from work resulting from worrying about personal finances and employee turnover in particular represents a problem that has been well documented in the literature, and higher levels of financial stress are associated with higher levels of absenteeism, particularly among blue-collar workers. A recent survey of over 5,000 US workers by the company Willis Towers Watson found that employees who are worried about their finances are absent on average for 3.5 days annually.[51]

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[49] CFPB Financial Wellness at Work, supra, citing, Dunn & Mirzaie, Working Paper, Determinants of Consumer Debt Stress: Differences by Debt Type and Gender (2012), available at http://www.chrr.org/content/surveys/cfm/doc/DSI-Working-Paper-07-19-12.pdf (last accessed June 9, 20210); Goetzel, et al.,Ten Modifiable Health Risk Factors Are Linked To More Than One-Fifth Of Employer-Employee Health Care Spending, 31 Health Affairs 2474 (2012).; Ron Z. Goetzel, et al., The relationship between modifiable health risks and health care expenditures, 40 J. Occup. Environ. Med. 843 (1998) (showing an analysis of the multi-employer HERO health risk and cost database). https://journals.lww.com/joem/Abstract/1998/10000/The_Relationship_Between_Modifiable_Health_Risks.3.aspx (last accessed June 9, 2021). https://www.healthaffairs.org/doi/pdf/10.1377/hlthaff.2011.0819 (last accessed June 9, 2021); Health Poll, AP-AOL/ABT SRBI (2008), http://surveys.associatedpress.com/data/SRBI/AP-AOL%20Health%20Poll%20Topline%20040808_FINAL_debt%20stress.pdf (last accessed June 9, 2021).

[50] "Presenteeism" has long been recognized in both the industry and academic literature. See, e.g., Hemp (October 2004). Presenteeism: At Work but Out of It, Harvard Business Review https://hbr.org/2004/10/presenteeism-at-work-but-out-of-it (last accessed June 9, 2021).

[51] Menard, supra, at 6 (internal notes omitted).

According to Menard, “financially troubled employees bring [their] concerns to work.” Dr. Menard reports:

> The previously mentioned Mercer survey found that 16% of employees reported spending more than 20 working hours each month worrying about money. The average across those surveyed was 13 hours per month. For an individual employee, that is equal to 7.8% of their annual work time spent being distracted as a result of their financial situation. Other estimates are even higher. Garman and colleagues peg financial presenteeism and absenteeism costs at 15-20% of total compensation paid to all employees in the businesses studied. . .The Mercer survey also found that 22 percent of employees report missing at least one day of work to handle financial problems, and a full 20 percent have had to resign from jobs due to financial stress.[52]

The fact that employee financial problems affect the employer is recognized widely within industry circles.[53]

Q. IN ADDITION TO REDUCING THE COSTS OF REDUCED PRODUCTIVITY ATTRIBUTABLE TO EMPLOYEE STRESS (“PRESENTEEISM”), DOES A REDUCTION IN EMPLOYEE STRESS THROUGH UNIVERSAL SERVICE PROGRAMS GENERATE OTHER FINANCIAL BENEFITS TO THE BUSINESS COMMUNITY SERVED BY THE COMPANY?

A. Yes. Affordable home energy can be analogized to child care because of the direct benefits that have has been found to arise for business. The Committee on Economic Development has quantified the beneficial impacts to business from reducing the causes

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[52] Menard, supra, at 7 (internal notes omitted).

[53] Bonner (Nov./Dec. 2016). The Impact of Financial Stress on Your Employees, Plans and Trusts, Vol. 34:6: 18-24. https://www.ifebp.org/inforequest/ifebp/0200354.pdf (last accessed June 9, 2021).

of employee absenteeism and employee turnover associated with unaffordable child care. According to CED:[54]

> Many businesses also find that helping parents meet their child care needs can potentially reduce absenteeism and employee turnover. The 1990 *National Child Care Survey* (NCCS) found that 15 percent of the mothers in its sample who worked outside the home reported losing some time from work (including arriving late, leaving early, or having to take a full day off) during the previous month because of a failure in their regular child care arrangement. Studies have found that employee turnover produces disruption and inefficiency in the work environment and that the cost of replacing employees is high. For example, Merck & Co., Inc. found that it costs. . . about 75 percent of salary to replace a clerical or technical employee. It also found that it may take considerable time to fill a vacant position and an average of 12.5 months for a new employee to become adjusted to the job.[55]

Other people have found comparable costs associated with turnover. For example, the Society for Human Resource Management (SHRM), who I have previously referenced, estimates the average replacement cost of a salaried employee to be six to nine months' salary.[56] Factors that must be considered include the cost of hiring (advertising, interviewing, screening, hiring); "on-boarding" (training, management time); lost productivity; lost engagement (employees faced with high turnover disengage); customer

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[54] CED is a national business-academic partnership. One objective of CED is "to unite business judgment and experience with scholarship in analyzing the issues and develop recommendations to resolve the economic problems that constantly arise in a dynamic and democratic society." Objectives of the Committee for Economic Development. The Research and Policy Committee of the CED is directed under the organization's bylaws to "initiate studies into the principles of business policy and of public policy which will foster the full contribution by industry and commerce to the attainment and maintenance" of the objectives of the organization.

[55] Research and Policy Committee (1993). Why Child Care Matters: Preparing Young Children for a More Productive America, A Statement by the Research and Policy Committee of the Committee for Economic Development, at 1, Committee for Economic Development: New York: NY. Available at: https://www.ced.org/pdf/Why_Child_Care_Matters_1993.pdf (last accessed June 9, 2021).

[56] USI Insurance (April 2019). The Cost of Employee Turnover (available at https://mnwi.usi.com/Resources/Resource-Library/Resource-Library-Article/ArtMID/666/ArticleID/782/Cost-of-employee-turnover, last accessed June 8, 2021).

service errors; and training (as much as 10 – 20% of an employee's salary). This doesn't even include the indirect costs of needing to "cover" the time of the lost employee pending a new hire. These high costs are not associated exclusively with higher cost employees. It has been suggested that the replacement cost of an employee who is paid $8 an hour can range upwards of $4,000.[57] There can be little question but that the relatively minor investment in employee retention through the allocation of universal service costs over all customer classes results in a quick, and generous, payback to Pennsylvania businesses.

Q. DOES THIS REASONING APPLY TO PENNSYLVANIA AND TO PECO?

A. Yes. There is a direct relationship between the offer of a universal service program such as CAP and economic benefits to local commercial and industrial customers. For example:

- Turnover costs business money. We know that unaffordable home energy bills lead to the frequent mobility of households.[58]

- Time missed due to family care provision costs business money. We know that unaffordable home energy leads to more frequent childhood illnesses.[59]

- Time missed due to lack of employee productivity and employee illness costs business money. We know that the inability to stay warm due to unaffordable home

[57] Paiement (2009). It will $4,000 to replace just one $8 per hour, full-time employee (available at https://charityvillage.com/it_will_cost_you_4_000_to_replace_just_one_8_per_hour_full_time_employee/, last accessed June 8, 2021).

[58] Colton. "A Road Oft Taken: Unaffordable Home Energy Bills, Forced Mobility, and Childhood Education in Missouri," 2 Journal of Children and Poverty 23 (1996). Available at: https://www.tandfonline.com/doi/abs/10.1080/10796129608414757 (last accessed June 9, 2021).

[59] Bhattacharya et al. (June 2002). Heat or Eat? Cold Weather Shocks and Nutrition in Poor American Families, National Bureau of Economic Research: Cambridge (MA). Available at: https://ajph.aphapublications.org/doi/10.2105/AJPH.93.7.1149 (last accessed June 9, 2021).

> energy bills leads to increased illnesses, including pneumonia, influenza, and other infectious diseases.[60]

In sum, increasing employee productivity directly contributes to the increased profitability of firms. With low-wage employees, in particular, unaffordable home energy directly contributes to lowered productivity. Increased personal illness, increased employee turnover, and increased family care responsibilities are but three of the factors contributing to lower employee productivity. The provision of affordable energy through universal service programs such as CAP positively affects each of these productivity factors.

Q. DO UNIVERSAL SERVICE COSTS BENEFIT LOCAL BUSINESSES IN ANY OTHER FASHION?

A. Yes. Offering affordable rates to low-income customers can be expected to have long-term positive impacts for businesses who comprise the local economy. The provision of a strong social safety-net so that individuals and households do not face the deprivation of basic household necessities is a strong and growing factor in businesses making locational decisions. These locational factors are particularly important for high technology firms, which represent a particularly strong future growth potential for the economy. Research for Ontario's Ministry of Enterprise, Opportunity and Innovation, in collaboration with the Institute for Competitiveness and Prosperity, reports that sound economic development

[60] Apprise, Inc. (December 2018). 2018 National Energy Assistance Survey: Final Report, National Energy Assistance Directors' Association (NEADA): Washington D.C. Available at: http://www.appriseinc.org/wp-content/uploads/2019/02/NEADA-2018-LIHEAP-Survey.pdf (last accessed June 9, 2021).

policy includes ensuring that "the right social investments are made to ensure social harmony."[61]

The observation here is being increasingly recognized as relevant to various services. "It should be noted that businesses focus on quality of life considerations when making location decisions because they are relevant for attracting a high quality workforce."[62] Quality of life has been deemed particularly influential for companies involved in research and development and high technology, and in enterprises employing highly skilled workers in information or knowledge-based services and production. Evidence of this observation is a study conducted by Love and Crompton in which they surveyed 174 decision makers of businesses that had initiated, expanded or relocated to Colorado. "In the previous five years. . .quality of life was considered the second most important factor for prompting the business move and not selecting a specific community, as well as the third most important factor in the final selection of a specific community."[63] The

[61] Gertler (2002). Competing on Creativity: Placing Ontario's Cities in North American Context, report produced for the Ontario Ministry of Enterprise, Opportunity and Innovation and the Institute for Competitiveness and Prosperity (available at http://webarchive.urban.org/UploadedPDF/410889_Competing_on_Creativity.pdf, last accessed June 8, 2021). In this sense, affordable home energy can be viewed in the same way that health and education are viewed. "There are numerous empirical studies that demonstrate the links between education, health and competitiveness. In particular, both health and education are correlated with superior economic outcomes such as higher productivity, higher per capita incomes, and faster growth." Burstein (2004). Developing the Business Case for Multiculturalism, at 8, Multiculturalism and Human Rights Branch, Department of Canadian Heritage (available at http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.132.7196&rep=rep1&type=pdf,, last accessed June 8, 2021). .

[62] Taylor, *et al.* (2006). A Cost-Benefit Analysis of Universally-Accessible Pre-Kindergarten Education in Texas, Bush School of Government and Public Service, Texas A&M University: College Station (TX) (available at https://oaktrust.library.tamu.edu/handle/1969.1/97006, last accessed June 8, 2021).

[63] Id. (citations omitted).

connection between assuring access to basic household necessities and maintaining the competitiveness of the local economy has been recognized.[64]

E. Summary and Recommendation.

Q. WHAT DO YOU CONCLUDE?

A. Based on the data and discussion above, I find that programs such as the Pennsylvania universal service programs, directed toward preserving basic home energy service and relieving financial stress about a household's capacity to meet its fundamental household needs on a month-to-month basis, address a societal-wide problem that is not limited to the residential customer class. The problems that are related to unaffordable home energy are not "caused" by the residential class. Nor does the PECO universal service program deliver benefits that are limited to the residential class.

Accordingly, the costs of those programs should be allocated and spread over all of PECO's customer classes. No reason exists for the residential class to be charged with paying the entire cost of programs that have the effect of improving business profitability by reducing business costs, including reducing absenteeism and turnover, and increasing employee productivity.

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[64] Improving the Competitiveness and Standard of Living of Canadians: Common Position of Provincial and Territorial Finance Ministers (December 1999); *see also*, Human Resources and Skills Development Canada, Social and Economic Impact of Labor Standards (March 2008, available at https://www.fin.gov.on.ca/en/publications/1999/99compe.html, last accessed June 8, 2021; Pindus, *et al.* (2007). Place Matters: Employers, Low-Income Workers and Regional Economic Development, The Urban Institute: Washington D.C. ("racial inclusion and income equality can enhance regional economic growth") (citations omitted) (available at https://www.urban.org/sites/default/files/publication/46666/411534-place-matters.pdf), last accessed June 8, 2021).

Q. WHAT DO YOU RECOMMEND?

A. I recommend that universal service charges be allocated among customer classes on a competitively neutral basis. The allocation of universal service costs among customer classes should be based on the percentage of revenue provided by each customer class at base rates.

Q. WHAT IS THE COST IMPACT ON EACH CUSTOMER CLASS OF YOUR PROPOSED ALLOCATION OF UNIVERSAL SERVICE COSTS?

A. The impact of allocating universal service costs over all customer classes is presented in the Direct Testimony of Clarence Johnson (OCA St. 3, Schedule CJ-4).

Part 5. Equity Adder for Management Efficiency.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I review the proposal by PECO to attach an addition to its equity return of "0.25% in recognition of the exemplary performance of the Company's management." (PECO St. 5, at 2). My review of this proposal is limited to the following elements of management performance: (1) credit and collection; (2) customer satisfaction; and (3) community involvement through staff volunteerism. My review supports the conclusions of OCA witness David Garrett regarding the requested management adder. I do not examine universal service performance due to the fact that PECO has made major changes to its universal service programs in recent years (with which changes OCA has agreed) in an effort to improve universal service performance.

Accordingly, it is not clear that universal service data affected by those change between years would be comparable. My review of PECO is based on data provided by the BCS annual report on Universal Service Programs and Collections Performance (previously cited) (hereafter, "BCS Report"). My comparisons below are limited to other Pennsylvania electric distribution utilities.

Q. WHAT IS YOUR FIRST OBSERVATION ABOUT PECO'S CREDIT AND COLLECTION PERFORMANCE?

A. One important element to credit and collections performance is for a utility to identify its low-income population. Only if PECO identifies its low-income population can it make its universal service programming and low-income specific customer service protections available to those who are eligible for such programs and protections. This metric is not affected by PECO's recent changes to its CAP program design. PECO identifies one of the lowest rates of Confirmed Low-Income customers amongst Pennsylvania electric utilities. In 2019, PECO's Confirmed Low-Income customer rate of 9.4% is lower than all electric utilities except Duquesne (at 9.0%). (2019 BCS Report, at 5). This low rate of Confirmed Low-Income customers cannot be attributed to a low rate of low-income customers throughout its service territory. According to BCS, only Penelec has a higher rate of estimated low-income customers (31.0%) than PECO has (26.4%). (2019 BCS Report, at 6).[65]

[65] While PECO has 138,014 Confirmed Low-Income customers, it has 274,966 estimated low-income customers. While Penelec has 91,350 Confirmed Low-Income customers, it has 155,072 estimated low-income customers.

Not only does PECO identify a low *percentage* of its customers as Confirmed Low-Income, but the *number* of customers it has confirmed the low-income status of has been declining as well. While in 2017, PECO had 155,803 Confirmed Low-Income customers, in 2018, that number declined to 146,100, while in 2019, it declined further to 139,655. (2019 BCS Report, at 6). Indeed, PECO's 2019 number of Confirmed Low-Income customers (139,655) is a full 30,000 fewer Confirmed low-Income customers than it had identified in 2015 (169,370). (2016 BCS Report, at 7). That decline occurred even though the number of estimated low-income customers in that time period increased by nearly 12,000 (from 381,799 to 393,662). (2016 BCS Report, at 7l; 2019 BCS Report, at 6).

Q. HAVE YOU REVIEWED DATA ON PECO'S PERFORMANCE REGARDING COLLECTIONS?

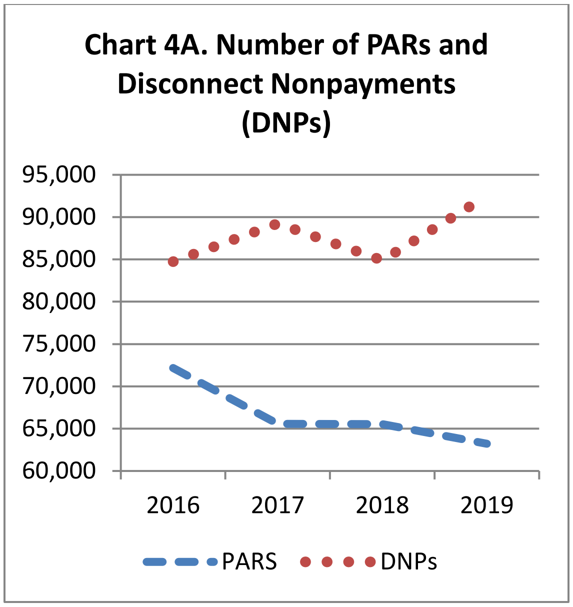
A. Yes. PECO is entering into fewer and fewer Payment Arrangements (PARs) with its residential customers. According to data reported to BCS,[66] from 2017 through 2019, PECO entered into nearly four percent fewer PARs with its residential customers. The number of PARs declined from 65,563 in 2017 to 63,217 (2019). (2019 BCS Report, at 10). Indeed, the 2019 number of PARs (63,217) was a decline of nearly 10,000 since 2016 (71,169). (2016 BCS Report, at 9).

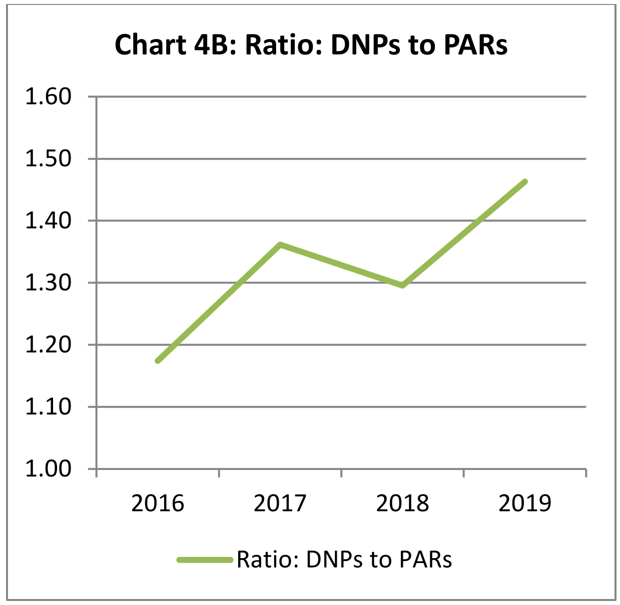
The decline in the number of payment agreements is significant, in part, because PECO experienced a significant increase in the number of residential nonpayment service disconnections. The 92,497 residential disconnections in 2019 was a nearly four percent

[66] The BCS annual report is based on data reported by each individual utility.

increase over the 89,257 disconnections in 2017. (2019 BCS Report, at 11). In fact, the number of 2019 service disconnections was the highest number of disconnections PECO has performed since at least 2014 (88,802). (2016 BCS Report, at 10). The 92,497 2019 residential service disconnections was nearly 8,000 more than PECO performed in 2016 (84,736). (2016 BCS Report, at 10). In percentage terms, while PECO had a residential termination rate of 4.4% in 2016 (2016 BCS Report, at 12), it had a 6.2% residential termination rate in 2019. (2019 BCS Report, at 13).

It is clear that PECO now relies much more heavily on the disconnection of service as a response to nonpayment than it relies on the negotiation of a PAR. Chart 4A below shows the number of Payment Agreements (PARs) along with the number of Nonpayment Disconnections (DNPs) by year for 2016 through the most recent (2019). Chart 4B shows the ratio of DNPs to PARs. The charts show the increasing number of residential nonpayment disconnections PECO has performed while, at the same time, it has entered into a decreasing number of payment agreements. While in 2016, PECO performed 1.17 disconnections for every payment agreement it entered into, by 2019, that ratio had increased to 1.46 (an increase of 25%).





The extent to which PECO is reducing its reliance on payment agreements as a response to residential nonpayment is evident, as well, in the percentage of accounts in debt, along with the percentage of revenue in debt, that the Company is making subject to payment agreements. As the Table immediately below documents, both the number and the percentage of residential accounts in debt not on an agreement has increased for PECO since 2016. In 2019, PECO's 83.1% of accounts in arrears not on agreement was higher than every other Pennsylvania electric utility's. The next closest was Duquesne Light (72.4%), with a performance 10% better than PECO.

Table 21. Number and Percent of Residential Accounts in Debt, and Residential Accounts in Debt on Payment Agreements (2016, 2019) (BCS Annual Report: 2016, 2019)

	Accts in Debt	On Agreement	Not on Agreement	Pct Not on Agreement
2016	96,065	20,654	75,411	78.5%
2019	102,667	17,310	85,357	83.1%

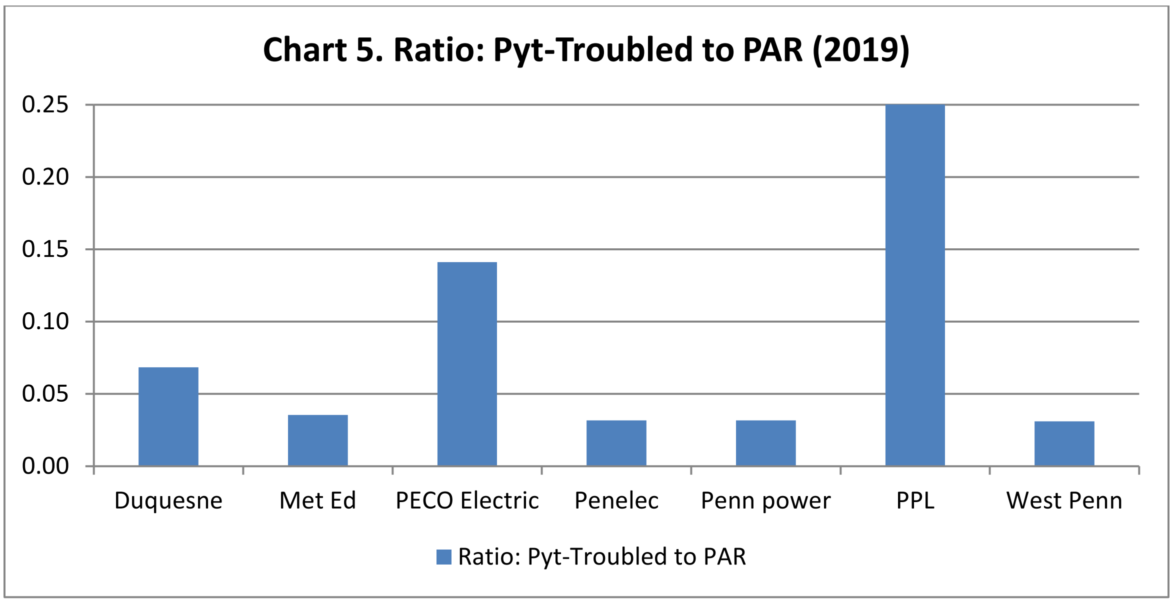
It is not the case that PECO is enrolling high arrearage residential accounts in payment agreements, while not making small dollar amounts subject to agreement. The Table immediately below shows that PECO also has an extremely high percentage of *dollars* that are in arrears but not on an agreement. The percentage of dollars in arrears but not on agreement has increased in recent years, reaching nearly 70% in 2019 (up from 63.9% in 2016). In 2019, the percentage of PECO residential dollars in debt but not on agreement (68.6%) was higher than every other Pennsylvania electric utility. (2019 BCS Report, at 26). The next highest utility was PPL (58.8%), a full ten percent better than PECO. The PECO figure (68.6%) was nearly 20% worse than the total electric industry average in Pennsylvania (49.7%). (2019 BCS Report, at 26).

Table 22. Percent of Residential Dollars in Debt on Payment Agreements and Not on Agreements (2016, 2019)
(BCS Annual Report, 2016, 2019)

	On Agreement	Not on Agreement	Total
2016	36.1%	63.9%	100%
2019	31.4%	68.6%	100%

Not only does PECO rely on residential payment agreements to a lesser extent than other Pennsylvania electric utilities, but the payment agreements (PARs) PECO does enter into are less likely to be successful. BCS tracks a metric called "payment troubled customer." According to BCS, "a payment troubled customer is a customer who has failed one or more payment arrangements in a 1-year period." (2019 BCS Report, at 8, citing 52 Pa. Code sec. 54.72 or sec. 62.2).

Setting aside the PPL data as aberrational (i.e., PPL reports having more customers default on payment arrangements than customer entering into payment arrangements), PECO has a rate of "payment troubled customers" (i.e., customers who failed to maintain one or more payment arrangement) that is far higher than any other Pennsylvania electric utility. The data (2019 BCS Report, at 8) is set forth in Chart 5 below (PPL is limited by the top-code at 0.25). Chart 5 sets forth the ratio of the number of residential customers who "fail to maintain" a payment arrangement to the number of residential customers who entered into a payment arrangement. The ratio of customers who "fail to maintain" their payment arrangements is two times higher for PECO (0.14) than it is for the next highest utility (Duquesne: 0.07) and three times higher than other Pennsylvania electric utilities (ranging from 0.03 to 0.04) (setting aside PPL).



Q. WHAT DO YOU CONCLUDE BASED ON THE ABOVE DATA?

A. Based on my review of the credit and collections performance data presented above, I conclude that PECO has no claim for "exemplary management" in the area of collections performance. I conclude further that the area of collections performance is a critical area of management performance to review given that the PUC chooses to publish an annual report devoted to that topic. I finally conclude that the metrics I have examined above are each important metrics to review given that the PUC's Bureau of Consumer Services chooses to collect and publish data on these metrics.

Q. HAVE YOU EXAMINED THE PECO CLAIMS OF EXEMPLARY MANAGEMENT FROM THE PERSPECTIVE OF CUSTOMER SATISFACTION?

A. Rather than looking at a single amalgamated number for customer satisfaction, I have examined some of the more detailed results for PECO Energy. The customer satisfaction results are for PECO Energy as a whole, not for PECO specifically. When a customer contacts the PECO call center, for example, that customer is not seeking the PECO representative to be "somewhat courteous." When a customer contacts PECO with a problem, that customer is not seeking a representative who is only "somewhat knowledgeable." To combine those two scores ("somewhat," "very") is to present a skewed picture of customer satisfaction.

According to the PUC's data,[67] PECO was tied for the second lowest percentage of customers who were "very satisfied" with the Company representative's handling of the call. (Customer Service Report, at 22). One-of-four customers (23%) were less than "very satisfied" with PECO's handling of their contact.

Indeed, one of the most fundamental aspects of customer contact would be treating customers with courtesy. PECO Energy was tied (with West Penn Power) for the lowest percentage among Pennsylvania electric utilities for customers who responded that the

[67] Customer Service Performance Report: 2019 (hereafter "Customer Service Report") (published October 2020), available at https://www.puc.pa.gov/filing-resources/reports/customer-service-performance-reports/ (last accessed June 22, 2021).

Company's representative was "very courteous." Nearly one-of-five customers (18%) who contacted the Company reported that they felt the Company representative was less than "very courteous." PECO Energy was also tied (again with West Penn Power) for the lowest percentage among Pennsylvania electric utilities who responded that the Company's representative was "very knowledgeable." Nearly one-of-four customers contacting PECO reported that they felt the representative with which they interacted was less than "very knowledgeable." (Customer Service Report, at 23).

Overall, when limited to customers who had experienced a recent contact with PECO Energy, the Commission's own data reports that PECO had the third lowest score among the state's electric utilities with respect to being "very satisfied" with PECO's "overall quality of service during recent contact." (Customer Service report, at 26). Nearly three-of-ten customers (28%) who had made a recent contact with PECO said that they were less than "very satisfied" with PECO's overall quality of service related to that contact. (Id.)

The problem of PECO's amalgamation of "customer satisfaction" into a single score carries over to Witness McDonald's testimony regarding the Company's J.D. Power ranking (PECO St. 1, at 23). Witness McDonald reports a single score from J.D. Power. As is evident from the data above from the PUC's own reports, however, the "overall score" does not tell the entire story. In order to truly examine a utility's performance, an examination of the detailed data is needed. We know from the J.D. Power website that the purchase of a "study subscription" provides "access to a competitive industry data set allowing you to see how your utility stacks up against your peers, the industry, and the highest performers across six factors and 36 attributes at both the national and regional levels."[68] To be presented with only a single summary statistic rather than the greater detail on "six factors and 36 attributes" does not provide a sound basis for decision-making. The J.D. Power discussion in the Direct Testimony of PECO witness McDonald should not be relied upon in this proceeding.

Q. IS THERE OTHER REASON FOR THE COMMISSION NOT TO RELY ON THE J.D. POWER SCORES?

A. Yes. Rather than relying on internal PECO data regarding customer satisfaction, I instead rely on data generated by the PUC for use by the PUC. The PUC has stated that "in order to establish a means to monitor customer service, the Commission promulgated regulations that specify the information that will be reported to and analyzed by the PUC. Regulations require the EDCs and NGDCs to report on important components of customer service, including. . .the level of customer satisfaction with the company's handling of recent interactions with its customers." (2019 Customer Service Performance Report, at 1). For PECO to instead use its own internally-generated data would inappropriately involve substituting PECO's decision-making on what data to collect, and how to collect it, for the PUC's decisions to "specify the information that will be reported to and analyzed by the PUC." (Id.) The PUC explicitly states that its information collection, specified by regulation, was developed "in order to establish a means to

[68] Available at . https://www.jdpower.com/sites/default/files/file/2020-11/JDP_US_2020_ResidentialElectric_Brochure_FINAL_103020.pdf (last accessed June 17, 2021).

monitor customer service." Accordingly, I rely upon the information specified by PUC regulation for the purpose for which it was intended.[69]

Q. HAVE YOU EXAMINED THE PECO CLAIMS OF EXEMPLARY MANAGEMENT FROM THE PERSPECTIVE OF "COMMUNITY INVOLVEMENT"?

A. Yes. PECO witness McDonald references the "volunteer" efforts of PECO employees as one example of "a strong and continuing tradition of community involvement." (PECO St. 1, at 34). As the Company acknowledges, however, this "volunteer" time is not uncompensated time to the employee. PECO instead permits employees to engage in "volunteering during work hours for Company-sponsored events, team-building opportunities, and other activities." (OCA-XI-17). The employee's supervisor must be notified and must approve the request. (Id.) The "volunteer" time is recorded on the employee's timesheet. (Id.) PECO concedes that "the dollar amount of employee time related to volunteer work is not tracked separately from normal business work." (Id.)

As can be seen, the "volunteer" time cited by PECO witness McDonald is not volunteer time at all. It is paid work time, done only with the approval of an employee's supervisor. It is paid work time that is tracked the same as any other work time and is paid through ratepayer dollars.

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[69] By internal notes in this quotation from the Commission publication, the PUC cites to (1) "Rulemaking on EDC Reporting Requirements for Quality of Service Benchmarks and Standards final on Apr. 24, 1998, at Docket No. L-00970131. Reporting began in 1999"; (2) "Rulemaking on NGDC Reporting Requirements for Quality of Service Benchmarks and Standards Order entered Jan. 14, 2000 at Docket No. L-00000147 final on Jan. 12, 2000. Reporting began in 2001"; and (3) "52 Pa Code §§ 54.151-54.156 for EDCs and 52 Pa Code §§ 62.31-62.37 for NGDCs."

Q. WHAT DO YOU RECOMMEND?

A. Based on the data and discussion I present above, I recommend that the equity adder requested by PECO be disapproved as recommended by OCA witness David Garrett.

Part 6. Fraud/Theft Investigation Charge.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to PECO's proposal to impose a "fraud/theft investigation charge." (proposed Tariff Section 18.8). The new tariff language would read:

> If the Company's meters or other Company equipment on the customer's premises have been tampered or interfered with by any means whatsoever, the customer being supplied through such equipment whether an applicant or a customer as defined at Pa. C.S. § 1403 shall pay a theft investigation charge in addition to any amount that the Company estimates is due for service used, but not registered on the Company's meter. These theft investigation charges listed below include allocated overheads, all investigative costs and administrative cost deemed necessary by the Company to correct any and all unauthorized conditions at the premise. The Company reserves the right to assess theft investigation charges as a precedent to reconnection of service as well as the right to assess a separate reconnection charge as described in Rule 18.7.

The charge is proposed to be $460.00. (Id.)

Q. IS THE PROPOSED PECO TARIFF LANGUAGE REASONABLE?

A. No. The proposed tariff language provides the Company with authority to determine the extent to which, if at all, the "Company's meters or other Company equipment" has been "tampered or interfered with." No definition has been provided for either term. No process has been established to determine whether an ***allegation*** that the Company's equipment has been "tampered or interfered with" has a basis in fact. I note that allegations of meter tampering (or "interference" with Company equipment) have a higher standard of proof that must be met than most allegations.[70] There is, with respect to any allegation of fraud, a presumption that the customer acted honestly in good faith. That allegation must be overcome by clear and convincing evidence. The fact the PECO considers an allegation of meter tampering (or interference with other Company equipment) to be a type of "fraud" is evident in the tariff itself (i.e., "The Company reserves the right to assess theft/fraud investigation charges. . ."). Indeed, the Company's own label for its proposed tariff section is "Theft/Fraud Investigation." The PECO tariff does not provide for any process to determine the legitimacy of an allegation that the Company's meters "or other Company equipment" have been "tampered or interfered with," it does not provide a process by which the Company must sustain its allegations by application of the appropriate burden of proof.

Q. IS THERE A SECOND PROBLEM WITH THE COMPANY'S PROPOSED TARIFF CHANGE?

A. Yes. The proposed tariff is irremediably excessively broad. Rather than proposing a specific charge applicable to specifically prescribed actions on the part of a customer, PECO proposes a charge applicable if the Company alleges that its equipment has been interfered with "by any means whatsoever." Not only is there no limit on what PECO

[70] Colton (1990). "Heightening the Burden of Proof in Utility Shutoff Cases Involving Allegations of Fraud." 33 Howard L. Review 137.

might deem to be “interference,” but there is no limit on what activities PECO deems to be covered by the charge. Moreover, while the proposed tariff references meter tampering, the charge is not limited to meter tampering. The proposed PECO language covers all allegations of “theft/fraud.”

The problem with the over-reach of the tariff, for example, can be seen in a hypothetical applicable to a landlord/tenant situation. “Tenant A” moves into a rental unit, believing the landlord has provided natural gas service. The landlord allows Tenant A to move in, believing that the Tenant understands his/her obligation to transfer service into the Tenant’s name. PECO alleges that the Tenant, who is not a customer of PECO, has committed “fraud,” asserting that taking service without applying for service falls within the language of “interfering with equipment by any means whatsoever.”

In this (and similar) situations –this hypothetical is not intended to be exclusive, but rather illustrative—what PECO alleges to be “fraud” is seen to be a “mistake” by others. Nonetheless, PECO imposes a fee pursuant to this tariff of $460 for costs, including “all investigative costs,” “allocated overheads,” and “administrative costs deemed necessary by the Company. . .”

The over-reach of the tariff can be seen in the tariff language further when PECO, in the four corners of its tariff, expands its charges from being applicable to meter tampering (or interference by any means whatsoever), to “theft/fraud,” to circumstances which PECO merely alleges involves “unauthorized conditions at the premise.”[71] The hypothetical illustration above, in other words, even if not representing meter tampering, may well be alleged to be an “unauthorized condition.”

Q. IS IT APPROPRIATE TO APPROVE A CHARGE THAT INCLUDES “ALLOCATED OVERHEADS. . .AND ADMINISTRATIVE COSTS”?

A. No. Overhead costs and administrative costs have already been included in base rates. To include these costs in the proposed charge would be allow PECO to recover them twice: once in base rates and again through the proposed new tariffed charge.

Q. IS THE PROPOSED TARIFF LANGUAGE INAPPROPRIATE IN ITS APPLICABILITY?

A. Yes. PECO proposes a tariff charge to be applied even if a household is not a PECO customer. PECO’s tariff proposal is to assess the proposed charge to “an applicant” as well as to a customer. The $460 charge may be assessed by PECO whether or not the person had any involvement with, or any responsibility for, whatever objectionable behavior PECO is alleging (whether it be meter tampering, “interference with other equipment by any means whatsoever,” “theft/fraud,” or “unauthorized conditions”).

Whatever the intended breadth of the tariff, the language in the four corners of the tariff language as proposed by PECO is excessive and over-reaching to the extreme. The

[71] PECO proposes to delete its prior language stating that “in the case of fraud, the reconnection charge will also include allocated overheads, all investigative costs and administrative costs as determined by the Company.” PECO Exh. JAB-2, page 29 of 83. That deletion should occur notwithstanding a denial of the proposed “Theft/Fraud Investigation Charge.”

language within the four corners of the proposed tariff is certainly not limited to meter tampering.

Q. WHAT ARE THE CONSEQUENCES OF IMPOSING THE PROPOSED "THEFT/FRAUD INVESTIGATION CHARGE"?

A. When PECO states that it will apply this charge to "applicants," it seems clear that the Company will refuse to connect service to a new customer unless/until the proposed charge has been paid. In addition, PECO explicitly states that it "reserves the right to assess theft/fraud investigation charges as precedent to reconnection of service." Inherent with reserving that "right," in other words, is the presumed action by PECO to disconnect service, and to leave a premises without service, pending payment of the fee.

Q. WILL LOW-INCOME CUSTOMERS/APPLICANTS LIKELY BE DISPROPORTIONATELY ADVERSELY AFFECTED BY THE PROPOSED CHARGE?

A. Yes. My testimony above documents that low-income customers in the PECO service territory are disproportionately tenants, the housing situation where allegations that usage is "unauthorized" are more likely to occur. In addition, Census data clearly demonstrates that tenants move far more frequently than do homeowners,[72] giving rise to more frequent possibilities that there may be allegations of "unauthorized use."

[72] See, e.g., Tenure by Year Households Moved into Unit (ACS Table B25038, Table B25039) (ACS 2019 5YR), available at https://data.census.gov/cedsci/all?q=moved-in (last accessed June 22, 2021); see also, Median Year Householder Moved into Unit by Tenure, (ACS Table B25039) (ACS 2019 5YR), available at https://data.census.gov/cedsci/all?q=moved-in (last accessed June 22, 2021).

Q. WHAT DO YOU CONCLUDE?

A. The PECO proposed tariff charge is fatally flawed. PECO Gas proposed an identical charge in its most recent rate case. That proposal was denied by the Commission.[73] I recommend that the proposed charge should not be approved in this proceeding either.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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[73] In the Recommended Decision (Docket No. R-2020-3018929, April 9, 2021) the ALJ "agree(s) with the OCA that the language of proposed Rule 17.7 is vague and overbroad." (Id., at 317). The ALJ continued to state that he was "equally concerned with the $90 increase over the existing $370 fee. While PECO indicated that the $460 fee "is consistent with the average cost that PECO incurs to investigate and remediate theft or fraud," nothing was offered to substantiate that claim." (Id.) The Commission found the ALJ decision to be reasonable. (Opinion and Order, at 300, June 22, 2021).

Appendix A:

Abbreviated Colton Vitae

Roger Colton
Fisher, Sheehan & Colton
Public Finance and General Economics
Belmont, MA

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EDUCATION:

J.D. (Order of the Coif), University of Florida (1981)

M.A. (Regulatory Economics), McGregor School, Antioch University (1993)

B.A. Iowa State University (1975) (journalism, political science, speech)

PROFESSIONAL EXPERIENCE:

Fisher, Sheehan and Colton, Public Finance and General Economics: 1985 - present.

As a co-founder of this economics consulting partnership, Colton provides services in a variety of areas, including: regulatory economics, poverty law and economics, public benefits, fair housing, community development, energy efficiency, utility law and economics (energy, telecommunications, water/sewer), government budgeting, and planning and zoning.

Colton has testified in state and federal courts in the United States and Canada, as well as before regulatory and legislative bodies in more than three dozen states. He is particularly noted for creative program design and implementation within tight budget constraints.

PROFESSIONAL AFFILIATIONS:

Past Chair:	Belmont Zoning By-law Review Working Committee (climate change)
Member:	Board of Directors, Massachusetts Rivers Alliance
Columnist:	Belmont Citizen-Herald
Producer:	Belmont Media Center: BMC Podcast Network
Host:	Belmont Media Center: Belmont Journal
Member:	Belmont Town Meeting
Vice-chair:	Belmont Light General Manager Screening Committee
Past Chair:	Belmont Goes Solar
Coordinator:	BelmontBudget.org (Belmont's Community Budget Forum)
Coordinator:	Belmont Affordable Shelter Fund (BASF)
Past Chair:	Belmont Solar Initiative Oversight Committee
Past Member:	City of Detroit Blue Ribbon Panel on Water Affordability
Past Chair:	Belmont Energy Committee
Member:	Massachusetts Municipal Energy Group (Mass Municipal Association)

Past Chair:	Housing Work Group, Belmont (MA) Comprehensive Planning Process
Past Member:	Board of Directors, Belmont Housing Trust, Inc.
Past Chair:	Waverley Square Fire Station Re-use Study Committee (Belmont MA)
Past Member:	Belmont (MA) Energy and Facilities Work Group
Past Member:	Belmont (MA) Uplands Advisory Committee
Past Member:	Advisory Board: Fair Housing Center of Greater Boston.
Past Chair:	Fair Housing Committee, Town of Belmont (MA)
Past Member:	Aggregation Advisory Committee, New York State Energy Research and Development Authority.
Past Member:	Board of Directors, Vermont Energy Investment Corporation.
Past Member:	Board of Directors, National Fuel Funds Network
Past Member:	Board of Directors, Affordable Comfort, Inc. (ACI)
Past Member:	National Advisory Committee, U.S. Department of Health and Human Services, Administration for Children and Families, Performance Goals for Low-Income Home Energy Assistance.
Past Member:	Editorial Advisory Board, International Library, *Public Utility Law Anthology*.
Past Member:	ASHRAE Guidelines Committee, GPC-8, *Energy Cost Allocation of Comfort HVAC Systems for Multiple Occupancy Buildings*
Past Member:	National Advisory Committee, U.S. Department of Housing and Urban Development, Calculation of Utility Allowances for Public Housing.
Past Member:	National Advisory Board: Energy Financing Alternatives for Subsidized Housing, New York State Energy Research and Development Authority.

PROFESSIONAL ASSOCIATIONS:

National Association of Housing and Redevelopment Officials (NAHRO)
National Society of Newspaper Columnists (NSNC)
Association for Enterprise Opportunity (AEO)
Iowa State Bar Association
Energy Bar Association
Association for Institutional Thought (AFIT)
Association for Evolutionary Economics (AEE)
Society for the Study of Social Problems (SSSO)
Association for Social Economics

BOOKS

Colton, *et al.*, ***Access to Utility Service***, National Consumer Law Center: Boston (4th edition 2008).

Colton, *et al.*, ***Tenants' Rights to Utility Service***, National Consumer Law Center: Boston (1994).

Colton, ***The Regulation of Rural Electric Cooperatives***, National Consumer Law Center: Boston (1992).

BOOK CHAPTERS

Colton (2018). The equities of efficiency: distributing energy usage reduction dollars, Chapter in Energy Justice: US and International Perspectives (Edited by Raya Salter, Carmen Gonzalez and Elizabeth Ann Kronk Warner), Edward Elgar Publishing (London, England).

JOURNAL PUBLICATIONS

65 publications in industry and academic journals, primarily involving utility regulation and affordable housing. (list available upon request)

TECHNICAL REPORTS

200 technical reports for public-sector and private-sector clients (list available upon request)

JURISDICTIONS IN WHICH EXPERT WITNESS PROVIDED

1. Maine
2. New Hampshire
3. Vermont
4. Massachusetts
5. Massachusetts
6. Rhode Island
7. Connecticut
8. New Jersey
9. Maryland
10. Pennsylvania
11. Washington D.C.
12. Virginia
13. North Carolina
14. South Carolina
15. Florida (Federal Court)
16. Alabama
17. Mississippi
18. Tennessee
19. Kentucky
20. Ohio
21. Indiana
22. Michigan
23. Wisconsin
24. Illinois
25. Minnesota
26. Iowa
27. Missouri
28. Arkansas
29. Texas (Federal Court)
30. South Dakota
31. North Dakota
32. Montana
33. Colorado
34. New Mexico
35. Arizona
36. Utah
37. Idaho
38. Nevada
39. Washington
40. Oregon
41. California
42. Hawaii

Canadian Provinces

1. Nova Scotia
2. Ontario
3. Manitoba
4. British Columbia

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024601
	:	
PECO Energy Company – Electric Division	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts set forth in my Direct Testimony, OCA Statement 4, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: June 28, 2021
*311947

Signature: ______________________
Roger D. Colton

Consultant Address: Fisher, Sheehan, & Colton
34 Warwick Road
Belmont, MA 02478

OCA Statement No. 5

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission v. PECO Energy Company – Electric Division	Docket No. R-2021-3024601

DIRECT TESTIMONY

OF

NOAH D. EASTMAN

ON BEHALF OF

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

June 28, 2021

<u>Introduction</u>

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

A. My name is Noah D. Eastman. My business address is 555 Walnut Street, Forum Place, 5th Floor, Harrisburg, Pennsylvania 17101. I am currently employed as a Regulatory Analyst by the Pennsylvania Office of Consumer Advocate (OCA).

Q. Please describe your educational background and qualifications to provide testimony in this case.

A. I have a bachelor's degree in Economics with a Business Concentration from Shippensburg University. My educational background and qualifications are described in Appendix A.

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

A. I am testifying on behalf of the Office of Consumer Advocate.

<u>Purpose of Direct Testimony:</u>

Q. Please describe the purpose of your Direct Testimony.

A. The purpose of my Direct Testimony is to identify the impacts the COVID-19 pandemic has had on the ratepayers of Pennsylvania. I will present information and analysis that details the effects of the pandemic and resulting economic disruption on different groups. With that, I will also discuss the effects on small businesses in Pennsylvania and the measure known as the coincident index, a single summary statistic used by the Federal Reserve banks to measure economic conditions. The facts being presented should be considered by the Public Utility Commission (PUC) when deciding on any revenue increase in this matter.

<u>Impacts of the Pandemic on People in Pennsylvania</u>

Q. What changes have occurred to the unemployment rate in Pennsylvania as a result of the COVID-19 Pandemic?

A. The pandemic led to economic shocks so unique that they have no historical equivalent. In January 2020, the unemployment rate in Pennsylvania was 4.8%. In less than 3 months, the unemployment rate more than tripled to 16.2%.[1] The most recently recorded monthly unemployment rate of Pennsylvania in May 2021 was 6.9%, still 43% above the January 2020 rate.[2] Along with this, the unemployment rate has been relatively unchanged since September 2020.

Q. What counties are found in the service territory of PECO Energy Company – Electric Division (PECO)?

A. PECO – Electric serves 1.6 million customers in Philadelphia, Bucks, Delaware, Montgomery, Chester, and York counties.[3]

Q. What unemployment rates have been observed in the counties that make up PECO's service territory?

A. Unemployment rates in all counties have not returned to their pre-pandemic levels. Philadelphia County, the county with the most customers in the PECO service territory, is still elevated 50% over its January 2020 levels. Delaware County is 42% over January 2020 unemployment, and the suburban areas served by PECO (Montgomery, Bucks, Chester)

[1] Unemployment Rate in Pennsylvania. Federal Reserve Bank of St. Louis. https://fred.stlouisfed.org/series/PAUR
[2] $\frac{(6.9\%-4.8\%)}{4.8\%}$
[3] Regional Demographics. PECO Energy. https://www.peco.com/DoingBusinessWithUs/Pages/RegionalDemographics.aspx

are all close to or greater than 20% over their January 2020 levels. As can be seen in Figure 1 below and Exhibit NDE-1, the progression of unemployment is characterized by a large reemployment from summer 2020 through the fall of 2020, followed by relative stability in employment levels since September 2020.

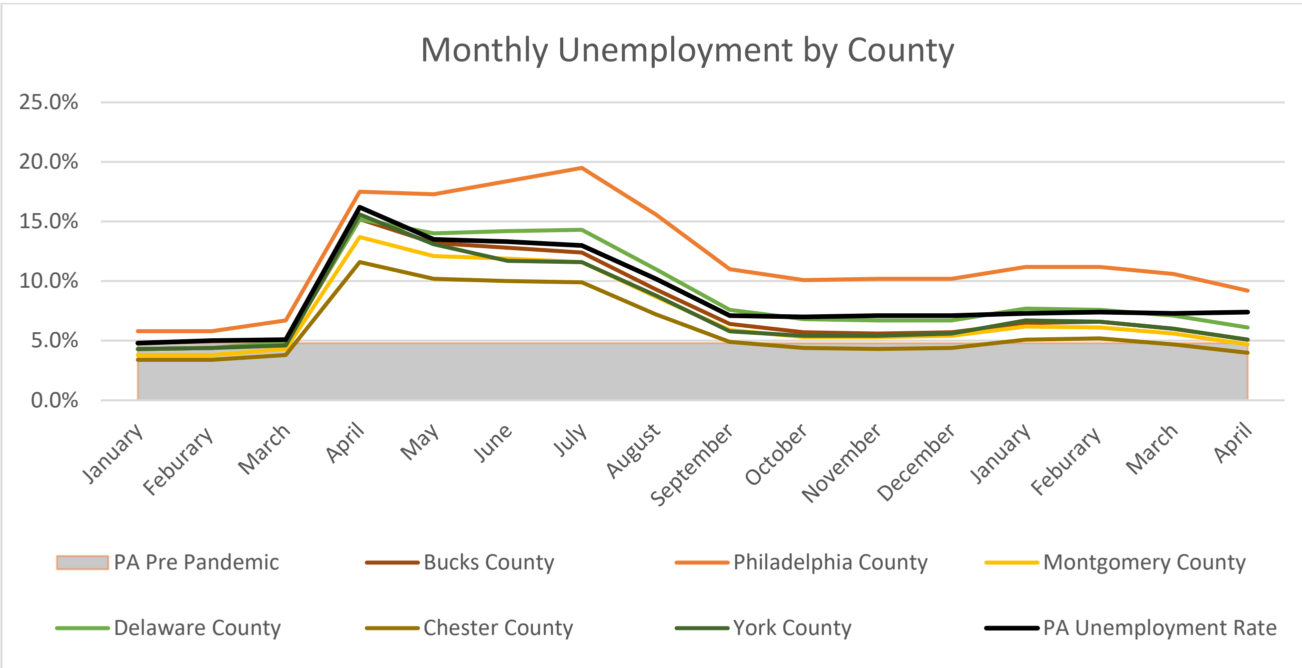

Figure 1[4]

Q. What is the Household Pulse Survey (Pulse Survey)?

A. The Pulse Survey is a data product compiled by the United States Census Bureau. It was designed to deploy data collected on how the coronavirus pandemic has impacted people's lives. The data is available disaggregated by state and metropolitan area, with the effect of the pandemic observed based on factors such as income, household size, employment status, and other socioeconomic factors. The data has been collected in three phases, with Phase 1 beginning in April 2020. The phases were collected from (1) April

[4] U.S. Bureau of Labor Statistics, Unemployment Rate in Pennsylvania Counties, retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/categories/29613. June 23, 2021.

23, 2020 – July 21, 2020, (2) August 19, 2020 – October 26, 2020, (3) October 28, 2020 – March 29, 2021, and (3.1) April 14, 2021 - Present.

Q. What trends have been identified in the Pulse Survey during the pandemic?

A. There have been noticeable trends in responses by Pennsylvania Residents to both "experienced loss in employment income" and "expected loss in employment income".

Q. What portion of Pennsylvania respondents stated that they experienced a loss in employment income?

Originally, the survey asked if respondents have experienced a loss in employment income since March 13, 2020. This led to mostly consistent responses showing between 40% and 50% having experienced a reduction in employment income since March 13, 2020. Beginning in Phase 3.1, the question was revised to whether respondents have experienced a reduction in employment income *in the last four weeks.* This gives a more immediate view of the lingering effects of the pandemic, and the entirety of the Pulse Survey results are below in Figure 2.

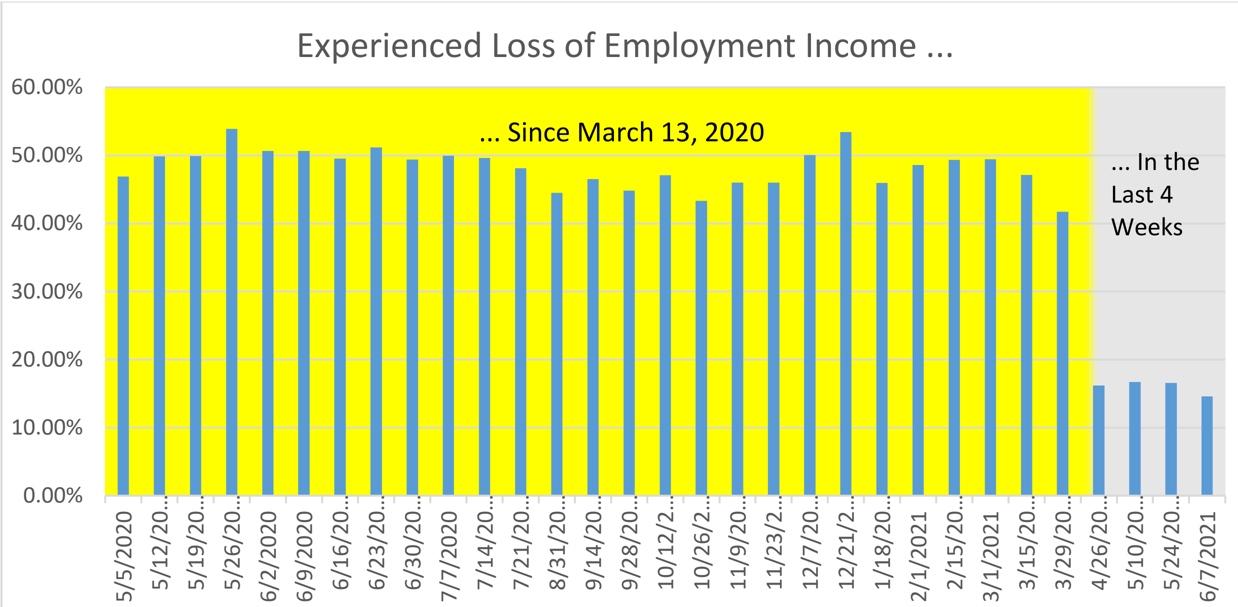

Figure 2[5]

Q. What portion of Pennsylvania respondents expect to lose income in the next four weeks?

A. The most recent responses to Phase 3.1 of the Pulse Survey were collected from 5/26/2021 through 6/7/2021. During this period, 10.13% of respondents stated that they expected to experience a loss in employment income in the next four weeks.

Q. How does this compare to other points in the pandemic?

A. The multiple waves of infections, economic stimulus, and estimations of the end of the pandemic led to fluctuations in expectations of employment income. At the beginning of the pandemic when layoffs were at unprecedented highs, expected loss in employment income peaked at nearly 40%. Peaks occurred again in June 2020 and December 2020, coinciding with two more waves of infections. The current rate of 10.13% is much lower

[5] U.S. Census Bureau. (2021). Household Pulse Survey. https://www.census.gov/data/tables/2021/demo/hhp/hhp31.html

than any point in the pandemic up to this point.

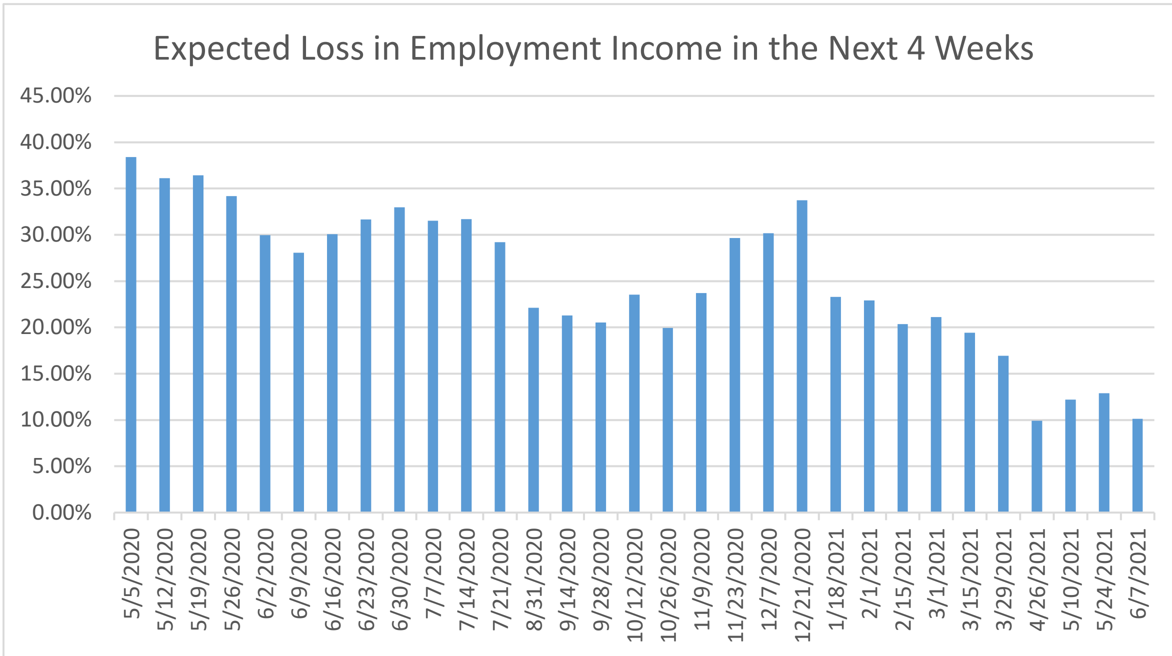

Figure 3[6]

Q. Should this reduction in expected loss in employment income be taken as a sign that the pandemic, and its effects, will soon be over?

A. No. 1 in 10 people expecting a loss in income in the next 4 weeks is still a strong sign of uncertainty for the short term. While the steady reduction is a good sign that the economy and people's lives are beginning to reach a new normal, it would be ill-advised to assume that life will return to the pre-pandemic normal soon.

Q. How are those who have experienced and/or are expecting a reduction in employment income paying their bills?

[6] U.S. Census Bureau. (2021). Household Pulse Survey. https://www.census.gov/data/tables/2021/demo/hhp/hhp31.html

A. Currently, about 986,594 Pennsylvanians expect a reduction in employment income in the next four weeks. Of those, 32% are working, 29% are paying bills using credit or loans, 38% are selling possessions to pay their bills, and another 34% are using unemployment insurance (which expires in September). This is set out further in the table below.

Used in the last 7 days to meet spending needs*	Experienced Loss in Employment Income	Expect Loss in Employment Income
Regular income sources like those received before the pandemic	27.9%	32.1%
Credit cards or loans	25.2%	28.8%
Money from savings or selling assets or possessions	32.8%	37.8%
Borrowing from friends or family	16.9%	12.9%
Unemployment insurance (UI) benefit payments	23.2%	34.1%
Stimulus (economic impact) payment	21.5%	29.9%
Money saved from deferred or forgiven payments (to meet spending needs)	3.5%	4.6%
Supplemental Nutrition Assistance Program (SNAP)	10.5%	9.8%
Other	2.4%	2.2%
Did not report	28.1%	22.8%

Table 1[7]

Q. Are there any other factors that seem to be correlated with experienced/expected reductions in employment income?

A. Yes. Those with lower incomes have been disproportionally affected and are also facing much more uncertainty. Households that have reported their income, and that report measures them as making less than $25,000, have experienced reductions in employment income at a rate of 21% in the last 4 weeks. With that, 19% expect to experience a reduction in employment income in the next 4 weeks.

[7] U.S. Census Bureau. (2021). Household Pulse Survey. https://www.census.gov/data/tables/2021/demo/hhp/hhp31.html

	Experienced Loss in Employment Income	Expect Loss in Employment Income
Total Reported	791,538	604,442
Less than $25,000	21.2%	19.4%
$25,000 - $34,999	18.1%	16.6%
$35,000 - $49,999	8.0%	10.6%
$50,000 - $74,999	18.0%	21.7%
$75,000 - $99,999	11.1%	10.4%
$100,000 - $149,999	13.1%	11.7%
$150,000 - $199,999	8.0%	8.1%
$200,000 and above	2.5%	1.5%

Table 2[8]

<u>Impacts on PECO - Electric Division Customers</u>

Q. Are more customers having trouble paying their bills now compared to pre-pandemic?

A. This would be difficult to conclude without speaking directly to every PECO customer. However, the arrears data provided by the company in response to OCA Set I-11(a) and OCA Set I-13(a) indicates that the number of customers in arrears was elevated during the pandemic, and that the amount owed by each customer in arrears is almost double what it was before the pandemic. What this means, and is visualized below, is that the number of customers in arrears is elevated slightly over pre-pandemic levels, and the amount of arrears per customer is much larger. For those customers in arrears, it is apparent that they are having more trouble paying their bills now than before the pandemic.

[8] U.S. Census Bureau. (2021). Household Pulse Survey. https://www.census.gov/data/tables/2021/demo/hhp/hhp31.html

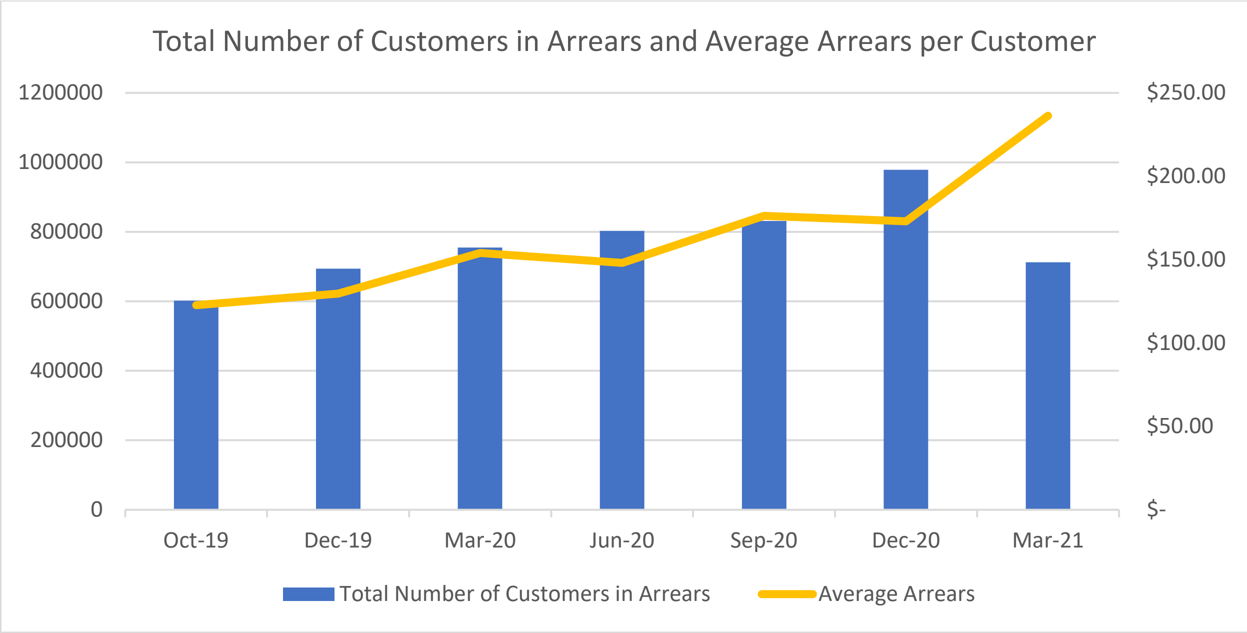

Figure 4[9]

<u>The Pandemic's Impact on Small Businesses</u>

Q. How has the pandemic impacted small businesses in Pennsylvania?

A. The Census Bureau has also conducted surveys similar to the Pulse Survey, but with a focus on the changes experienced by small businesses during the pandemic and expectations for the future. The most recent survey results were collected from June 7, 2021 – June 13, 2021. When asked how their business has been affected by the COVID-19 Pandemic, 28.3% stated they had a faced a large negative impact, and another 44% faced at least a moderate negative impact.[10]

Q. What expectations do small businesses have for a return to normal?

A. When asked how long the business expects to return to normal operations, the share of business replying with greater than 6 months or never was 40.7%. The breakdown of

[9] OCA Set I-11 and OCA Set I-13
[10] U.S. Census Bureau. (2021). Small Business Pulse Survey. https://portal.census.gov/pulse/data/

responses is shown in Figure 4 below. While businesses are expecting a shorter-term return to normal, many are expecting a long-term recovery of their operations, or no recovery at all.

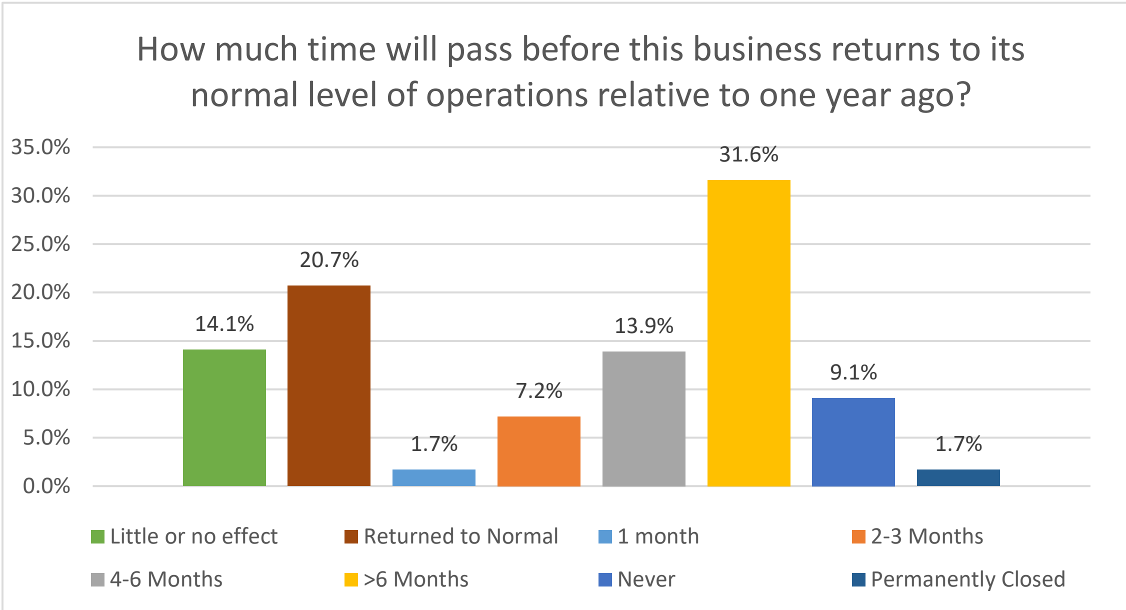

Figure 5[11]

<u>Employment Projections</u>

Q. What are the employment expectations as we leave the Pandemic economic environment?

A. The Brookings Institution utilized publications from the Congressional Budget Office and Federal Reserve to calculate their projection of when the economy will return to pre-pandemic employment levels. This was published in March 2021, using GDP growth to estimate coinciding employment growth. While the United States as a whole is the

[11] U.S. Census Bureau. (2021). Small Business Pulse Survey. https://portal.census.gov/pulse/data/

subject of their research, it is reasonable to assume that Pennsylvania, and specifically the PECO – Electric Division territory, will follow a similar pattern of employment growth. In their published paper, they set out multiple scenarios for the rate of job growth in the economic recovery. The authors' estimate that the ten-month period from March 2021 through March 2022 would bring with it average job growth of 700,000 to 1 million per month.[12] This estimation is much faster than other forecasters' estimates, with other less optimistic forecasts believing growth to be around 460,000 jobs per month. The Brookings Institution also put together an analysis of the job growth forecasts of an

[12] Sheiner, L., & Milesi-Ferretti, G. M. (2021, March 24). How many jobs is the US likely to add this year? Brookings. https://www.brookings.edu/blog/up-front/2021/03/22/how-many-jobs-is-the-u-s-likely-to-add-this-year/.

economic survey by the Wall Street Journal, which is seen below in figure 6.

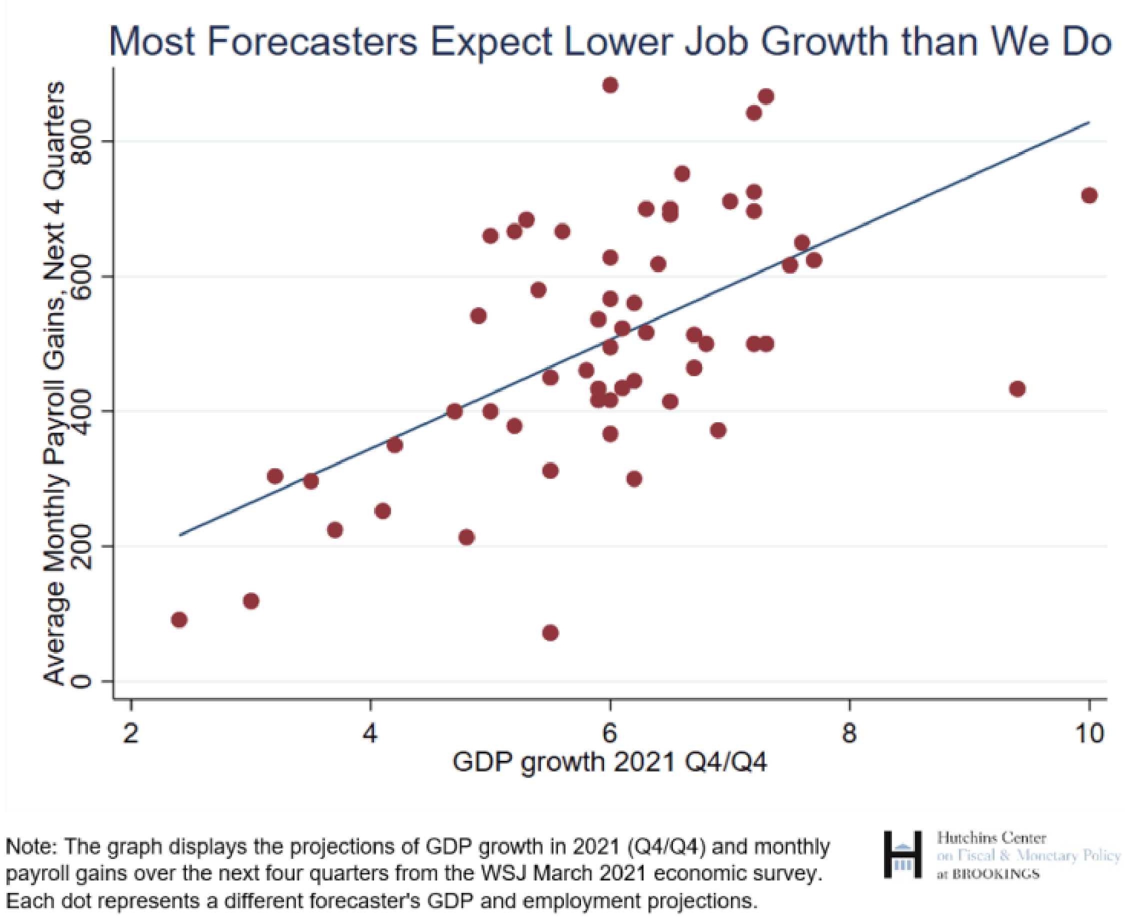

Figure 6[13]

Q. What employment growth has been realized thus far?

A. Employment growth by month since January 2021 has averaged below the expectations of The Brookings Institution. Only one month has seen job growth in the range of averages that they projected, and the current average job growth for 2021 is 478,000, around the range of the less optimistic estimate mentioned above. It is difficult to make a

[13] Sheiner, L., & Milesi-Ferretti, G. M. (2021, March 24). How many jobs is the US likely to add this year? Brookings. https://www.brookings.edu/blog/up-front/2021/03/22/how-many-jobs-is-the-u-s-likely-to-add-this-year/.

perfectly accurate estimate, but at the current pace it is very unlikely that the 9 million jobs lost during the pandemic will be recovered within the next twelve months.

	Total Non-Farm Employment	Change in Employment
Jan-21	142,736,000	233,000
Feb-21	143,272,000	536,000
Mar-21	144,057,000	785,000
Apr-21	144,335,000	278,000
May-21	144,894,000	559,000
Average 2021		478,200

Table 3[14]

<u>Pennsylvania State Coincident Index</u>

Q. What is the State Coincident Index?

A. The State Coincident Index is an index that uses four state-level variables to help summarize current economic conditions in one single statistic. "The four state-level variables in each coincident index are (1) nonfarm payroll employment, (2) average hours worked in manufacturing by production workers, (3) the unemployment rate, and (4) wage and salary disbursements deflated by the consumer price index (U.S. city average). The trend for each state's index is set to the trend of its gross domestic product (GDP), so long-term growth in the state's index matches long-term growth in its GDP."[15] A rise in the index indicates expanding economic activity, while a decline indicates a contraction.

[14] Federal Reserve Bank of St. Louis. *All Employees, Total Nonfarm, Thousands of Persons, Monthly, Seasonally Adjusted.* https://fred.stlouisfed.org/series/PAYEMS
[15] https://www.philadelphiafed.org/surveys-and-data/regional-economic-analysis/state-coincident-indexes

Q. What conclusions can be drawn from the activity in the State Coincident Index?

A. The April 2021 Coincident index for Pennsylvania was 114.61 and the US Coincident Index was 126.27. The coincident index of both Pennsylvania and the US in February 2020 were 122.76 and 130.81, respectively. The coincident index is indexed to 100 based on the 2007 measure. So, 36% of the index growth since 2007 that was seen in February 2020 is still yet to be recovered.[16] The economy is beginning to recover, but there is still a large amount to be done before we can declare normality.

<u>Conclusion:</u>

Q. Does this conclude your testimony?

A. Yes. However, I reserve the right to modify or supplement my testimony if necessary.

311975

[16] $= \frac{(114.61-100)-(122.76-100)}{(122.76-100)}$

OCA Exhibit NDE-1
PECO Energy Company - Electric
Docket No. R-2021-3024601
Unemployment Rate by County

Month	Philadelphia County	Montgomery County	Delaware County	Bucks County	Chester County	York County
January	5.80%	3.80%	4.30%	4.30%	3.40%	4.30%
February	5.80%	3.80%	4.40%	4.40%	3.40%	4.40%
March	6.70%	4.30%	4.90%	4.80%	3.80%	4.60%
April	17.50%	13.70%	15.20%	15.20%	11.60%	15.60%
May	17.30%	12.10%	14.00%	13.20%	10.20%	13.10%
June	18.40%	11.90%	14.20%	12.80%	10.00%	11.70%
July	19.50%	11.60%	14.30%	12.40%	9.90%	11.60%
August	15.60%	8.70%	11.00%	9.30%	7.20%	8.80%
September	11.00%	5.90%	7.60%	6.40%	4.90%	5.80%
October	10.10%	5.30%	6.80%	5.70%	4.40%	5.40%
November	10.20%	5.30%	6.70%	5.60%	4.30%	5.40%
December	10.20%	5.40%	6.70%	5.70%	4.40%	5.60%
January	11.20%	6.20%	7.70%	6.50%	5.10%	6.70%
February	11.20%	6.10%	7.60%	6.60%	5.20%	6.60%
March	10.60%	5.60%	7.10%	6.00%	4.70%	6.00%
April	9.20%	4.70%	6.10%	5.10%	4.00%	5.10%

APPENDIX A

QUALIFICATIONS OF

NOAH D. EASTMAN

Education

2019 B.S. Economics, Shippensburg University

Currently Pursuing: M.B.A., Shippensburg University

Positions

Jan. 2020 – Present Regulatory Analyst, Pennsylvania Office of Consumer Advocate

Experience

I am currently employed by the Pennsylvania Office of Attorney General, Office of Consumer Advocate (OCA) as a Regulatory Analyst. My responsibilities include financial and economic analysis, rate of return determination, and other business operations analysis in the review of utility filings with the Pennsylvania Public Utility Commission. Additional responsibilities with the OCA include formulating recommendations for utility filings and preparing testimony.

Relevant Training

IPU Accounting and Ratemaking Course, April 2020

IPU Intermediate Course, August 2020

Previous Cases wherein testimony was submitted

McCloskey v. Hidden Valley Utility Service - C-2014-2447138, C-2014-2447169

Application of Pennsylvania American Water Company - A-2020-3019634

Previous cases worked; no testimony submitted

PaPUC v. Reynolds Disposal Company - R-2020-3019612

Application of Pennsylvania American Water Company - A-2020-3021460

PaPUC v. Pike County Light and Power Company – R-2020-3022135, R-2020-3022134

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024601
	:	
PECO Energy Company – Electric Division	:	

VERIFICATION

I, Noah D. Eastman, hereby state that the facts set forth in my Direct Testimony, OCA Statement 5, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: June 28, 2021
*311951

Signature: ______________________
Noah D. Eastman

Consultant Address: Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923

OCA STATEMENT NO. 6

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
V.	:	DOCKET NO. R-2021-3024601
PECO ENERGY COMPANY – ELECTRIC DIVISION	:	

DIRECT TESTIMONY

OF

RON NELSON
DIRECTOR
STRATEGEN CONSULTING

ON BEHALF OF
THE OFFICE OF CONSUMER ADVOCATE

June 28, 2021

Table of Contents

I. INTRODUCTION

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

A. My name is Ron Nelson. I am a Director with Strategen Consulting. My business address is Suite 400, 2150 Allston Way, Berkeley, California 94704.

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

A. I am testifying on behalf of the Office of the Consumer Advocate.

Q. Please describe your formal education and professional experience.

A. Currently, I am a Director at Strategen Consulting. The Strategen team is nationally recognized for its thought leadership and deep expertise in rate design, renewable program development, grid modernization, and new grid technologies including distributed and centralized renewable energy, energy storage, smart grid technologies, and electric vehicles. During my time at Strategen, I have worked with numerous consumer advocates on issues related to cost of service modeling, rate design, grid modernization, distributed energy resource ("DER") valuation and integration, and performance-based regulation ("PBR").

Before joining Strategen in early 2018, I worked for the Minnesota Attorney General's Office for almost five years, where I led the Office's work on cost of service, rate design, renewable energy program design, and performance-based regulation. Before that, I worked for two universities and the United States Geological Survey as an economic researcher. I have a Master of Science from Colorado State University in

Agriculture and Resource Economics, and a Bachelor of Arts in Environmental Economics and a Minor in Mathematics from Western Washington University.

Q. Have you testified in similar regulatory proceedings previously?

A. Yes. I have testified in 19 proceedings in Minnesota, Pennsylvania, Oklahoma, Illinois, New Hampshire, Utah and Ohio. The issues covered in these proceedings include marginal and embedded cost of service studies, revenue apportionment, rate design, renewable program design, fuel clause adjustments, formula rates, decoupling, performance-based regulation, multi-year rate plans, performance metrics, distributed energy resource ("DER") interconnection, DER compensation, DER integration, pilot frameworks, automated metering infrastructure, and smart inverter specifications.

I have also assisted with testimonies and regulatory analysis in Hawai'i, Washington D.C., Maryland, Minnesota, Massachusetts, California, North Carolina, South Carolina, Kentucky, and the Federal Energy Regulatory Commission ("FERC").

Regarding specific EV-related proceedings, I serve as the technical expert to the Hawaii PUC on advanced rate design, including EV rates, and DER compensation within Docket No. 2019-0323. I also work as stakeholders experts in advanced rate design proceedings in Minnesota and Utah. The Minnesota PUC recently adopted my proposed time-of-use (TOU) with critical peak pricing (CPP) rate design for large C&I customers, including large EV charging facilities, for piloting and consideration as a default rate in Docket No. 20-86. I have also assisted or been the lead analyst on EV rate design and infrastructure proposals in Massachusetts and Washington DC.[1]

A summary of my resume is attached as Schedule REN-1.

Q. Have you previously provided testimony before the Pennsylvania Public Utility Commission ("Commission")?

A. Yes. I submitted testimony on behalf of the OCA regarding PPL Electric Utilities' DER Management Plan in Docket No. P-2019-3010128.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to evaluate and review PECO Energy Company – Electric Division's ("PECO" or the "Company") Electric Vehicle ("EV") Charging Pilot and to make recommendations on EV load management strategies.

Q. What portions of the Company's filing will you be responding to?

A. I will be responding to the Direct Testimonies of Richard A. Schlesinger (Statement No. 8) and Jacqueline F. Golden (Statement No. 9).

Q. How is your testimony organized?

A. My testimony is organized into several additional sections: Section II provides an overview of PECO's proposed Transportation Electrification ("TE") programs; Section

[1] *See* DPU Docket No. 18-150, testimonies of Edward Burgess. *See Also* DC PSC Formal Case No. 1130, comments filed December 12, 2018.

III addresses PECO's proposed pilots; and Section IV summarizes my recommendations and concludes my testimony.

II. OVERVIEW OF THE COMPANY'S PROPOSALS

Q. What transportation-related pilots is the Company proposing in this proceeding?

A. The Company is seeking approval of its EV Charging Pilot, which consists of the Transit Charging Program, the Commercial and Industrial Level 2 Charging Program ("L2 Program"), and the EV Education and Outreach Program. A description of each program and its cost is provided in the table below:

PROGRAM	DESCRIPTION	COSTS
Transit Charging Program	PECO will offer transit authorities an incentive to offset public transit charging station development costs. The incentive will be paid in installments over a three-year period as the customer meets charging station development milestones.	$1,000,000
L2 Program	PECO will provide make-ready incentives for 200-250 non-residential charging stations such as multi-unit dwellings ("MUDs"), workplaces, and other public locations. The incentive amount is the lesser of $3,000 per port or 75% of make-ready costs for sites in an Environmental Justice ("EJ") Area, and the lesser of $2,000 per port of 50% of make-ready costs for sites in other locations.	$575,000
EV Education and Outreach Program	PECO will conduct proactive EV education and outreach to increase customer knowledge of the Company's EV offerings.	$50,000

Q. What other transportation-related offerings is the Company proposing in this proceeding?

A. The Company is also proposing to expand the availability of the EV-FC Pilot Rider to public transit DC Fast Charging ("DCFC") stations. Under the EV-FC Pilot Rider, PECO applies a demand (kW) credit initially equal to 50% of a public DCFC station's nameplate capacity for a period of three years.

Q. How is the Company treating the costs of the pilots for ratemaking purposes?

A. The Company is treating EV Charging Pilot costs as expenses, not rate based capital investments. However, it is unclear how the Company is treating the costs associated with the EV-FC Rider. I request that the Company explain how the costs of the EV-RC Rider are being treated (i.e., expensed or rate based, per-customer rebate limits, and how the costs will be allocated between rate classes).

Q. Please explain the purpose of TE Pilots.

A. TE is accelerating rapidly. It will lead to significant changes within the power system and provide unique opportunities that could greatly benefit customers or create significant costs for customers. Whether ratepayers see benefits or costs from TE will largely be determined by how utilities integrate EVs. TE pilots provide insights into how the utilities are thinking about TE. For example, are utilities seeing TE as a way to justify more infrastructure spending or are they viewing TE as a flexible load that can be managed thoughtfully to control rate pressure on their customers?

III. ASSESSMENT OF THE COMPANY'S PROPOSED EV CHARGING PILOT

Q. How is this section of your testimony organized?

A. In Section IV.A I discuss the objectives of the Company's EV Charging Pilot and high-level structural components. I also provide an analysis of the proposed rebates and incentives of the Company's pilot proposals. In Section IV.B, I discuss the importance of load management and provide an analysis of PECO's load management efforts within the pilots. In Section IV.C, I provide my recommendations to the Commission.

A. Objectives and Structure

Q. What features should a pilot have?

A. First, pilots should seek to answer important questions that provide tangible benefits to ratepayers. Such questions may be related to new technologies, business models, or pricing constructs that have the potential to deliver value to electric customers. This step seems to be straightforward, but utilities frequently fail to clearly articulate clear objectives associated with pilots.

Second, pilots should be designed to ensure transparency, enabling comprehensive and efficient review of utility proposals and pilot implementation. Transparency requires clear communication of the goals and objectives for proposed projects, project economics, and measurement and evaluation criteria.

Third, pilots should strive for scalability since the delivery of meaningful system and customer benefits can only be achieved at scale. There should be a clear path towards scaling the project beyond the demonstration phase if the pilot is deemed successful and beneficial to ratepayers.

Overall, pilots should be infrequent as to answer only questions that are important and can generate customer benefits. If the importance of a question warrants a pilot, the pilot should be designed with enough rigor to clearly articulate the question and provide a clear answer, including, at a minimum, a basic evaluation and assessment plan.

Q. What are the Company's objectives for the EV Charging Pilot?

A. According to the Company's response to discovery OCA-VII-3, the objectives of the Pilot are to incentivize the development of EV charging sites and to gather EV charging data to inform the Company's distribution system planning and potential load management programs. The Company identified the tangible outcome related to these objectives to be to obtain charging session transactional data for 3 years for the Transit Charging Program and 2 years for the L2 Program.[2]

Q. What is your assessment of the Company's objectives?

A. The Company's inclusion of both building infrastructure and load management in its pilot objectives is appropriate and necessary. EV load management, such as ensuring EVs charge during off-peak hours, is critical in order for ratepayers to realize benefits from TE efforts. However, the Company has not identified specific metrics to

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[2] Company response to OCA-VII-3.

effectively evaluate whether these objectives will be met. For example, the tangible outcome the Company is seeking to accomplish through the pilot is stated broadly as "to obtain charging session transactional data." There are many types of data associated with EV charging, and specific pieces of data are necessary to sufficiently inform the development of load management and other TE programs. The Company should clarify explicit data collection and reporting metrics to a higher level of detail. For example, the costs caused by charging are primarily temporal and locational in nature. The Company, however, did not mention any locationally specific learnings they were trying to glean from the pilots including the charging data, but, because of the lack specificity, it is possible the Company does not plan for locational analysis. Either way, transparency is important for regulators and intervenors to be able to conduct a thorough analysis of the pilot proposals.

Along the same lines, the Company's objective to "inform the Company's future distribution system planning" is vague and uninformative. As a threshold matter, PECO does not file distribution system plans that have a strong focus on DER integration, as well as methods and strategies to avoid and/or justify distribution level investments, also referred to as integrated distribution system plans.[3] Pennsylvania's requirements for long-term infrastructure improvement plans and asset optimization plans appear to differ significantly from distribution system planning processes in other

[3] States that have active distribution system planning processes include, but are not limited to, Minnesota, Maryland, California and Connecticut.

states, especially due to the lack of filing requirements related to DER integration.[4] Without transparent distribution system planning processes, the Company's objective is to feed undefined charging metrics into a black box that only the utility can access. This is obviously problematic for many reasons but, simply put, the objective is overly vague and is unlikely to create any transparent lessons learned.

Q. Did PECO file anything that resembles an evaluation and assessment plan for its proposed pilots?

A. No. While the rigor and depth of an evaluation and assessment plan will vary based on the resources expended within a pilot, each pilot should be accompanied by an evaluation and assessment plan. This is essential for every pilot to ensure that the pilot is transparently and effectively evaluated and that useful lessons are generated to inform programs or rate designs that deliver ratepayer benefits. Given the small size of PECO's proposal, I recommend that the Commission require PECO to file a basic evaluation and assessment plan. This could include refining objectives to provide more clarity, determining outcomes that map to those objectives, and metrics for measuring outcomes.

B. Rebates and Incentives

Q. What is your assessment of the Company's proposal to provide incentives for charger installation?

[4] *See* Chapter 121 of the Commission's Regulations and 66 Pa. C.S. §1356.

A. As long as the Company provides the additional information discussed above, I would not object to the Company providing customers with incentives for charger installation at this time. The market for EV chargers is already mature and highly competitive, with many market providers offering a diversity of products that serve a variety of customer needs. Electric panels are also part of an emerging competitive market, with smart panels beginning to offer load control options for DERs, including EVs.[5] Utility ownership of such equipment not only would stifle competition, but also is unnecessary to address a need that can already be met by the market. Thus, providing customers with incentives and leaving ownership of the infrastructure to customers can help alleviate cost barriers while requiring a lower level of ratepayer funds than if PECO were to own the charger or other EV-related infrastructure. Additionally, rebates aid in market development for EVs and associated services, which can benefit all ratepayers if EVs are integrated thoughtfully.

Q. What is your assessment of the Company's proposal to focus investments on non-residential EV charging sites and provide higher incentive levels for customers in Environmental Justice ("EJ") Areas?

A. Overall, the Company's identification of non-residential EV infrastructure for investment and proposals to provide higher incentive levels for customers in EJ Areas

[5] Smart electric panels enable a customer to optimize backup energy to certain house appliances, such as a refrigerator, while not supplying other equipment. For additional information see: https://electrek.co/2021/05/20/egeb-100-homes-in-vermont-to-get-free-gen-2-span-smart-panel-in-pilot-program/

are reasonable for a pilot program. Publicly accessible or shared charging stations at sites such as MUDs, workplaces, or other public locations expands access to EV charging to a greater degree than do charging stations at private homes. Moreover, low-income households tend to be renters and/or live in MUDs, and thus usually have to rely on public charging for their EV charging needs. Therefore, such prioritization ensures that ratepayer dollars facilitate EV charging access for those who are the least likely to afford it.

Q. Do you have any concerns about the Company's proposed level of incentives under the Transit Charging Program?

A. Yes. I am concerned about the lack of a cap on the amount of incentive per charging port or per customer under the Transit Charging Program. PECO provides a justification in its response to discovery IE-RE-44-D, arguing that its proposal is appropriate because the actual costs of DCFC installations are complex and dependent on many factors. This justification is insufficient for the Commission to allow PECO complete discretion on how to use the $1 million budget. Such a lack of limitation could result in a scenario where a single customer installing a single charging station can take up most of the program budget, regardless of whether the program incentives are necessary for the customer's decision to install the charging infrastructure or not.

As an alternative, I recommend an upper limit of 33% of make-ready costs on each installation under the Transit Charging Program, in line with the Company's proposed limit under the L2 Program for customers and 50% within an EJ Area. The intent of capping the incentive is to ensure that ratepayers in more locations benefit from the program by ensuring that funding for more than one project is available.

C. Load Management

Q. Why is load management so important for EVs?

A. EVs are more flexible than many other traditional loads. This means in most cases EVs can control the timing of energy charged from the grid and technologies are available to control how fast EVs take power from the grid (i.e., throttling demand). If customers are sufficiently educated and provided useful load management services, the flexibility of EV load could help reduce rate pressure by spreading rates over more sales units.

However, the load growth and magnitude that EVs could, and likely will, represent over coming years should not be underestimated. Swift and focused attention is required by regulators and utilities to ensure EV loads are managed through various approaches. If unmanaged, the majority of EV load can occur during peak periods and create considerable rate pressure, not only necessitating significant infrastructure buildout to accommodate the higher peak load but also consuming energy when prices are the highest. A study conducted in 2020 by the Lawrence Berkeley National Laboratory suggests that California can save between $90 to $690 million, or up to 10%, of grid operating costs by 2025 with managed charging compared to a scenario with only unmanaged charging.[6] While these figures may not be directly applicable to Pennsylvania, they are illustrative of the potential impacts of unmanaged EV load. Load management is crucial in limiting rate increases associated with TE.

Figure 1, below, provides an example of the peak load requirements associated with different EV types.

Figure 1[7]

6 Julia K. Szinai, Colin J.R. Sheppard, Nikit Abhyankar, Anand R. Gopal. 2020. Reduced grid operating costs and renewable energy curtailment with electric vehicle charge management. *Energy Policy*, Volume 136. https://doi.org/10.1016/j.enpol.2019.111051.

[7] *See* Commercial Vehicles and the Global Electricity Landscape. Presented by Calstart. September 19, 2019.

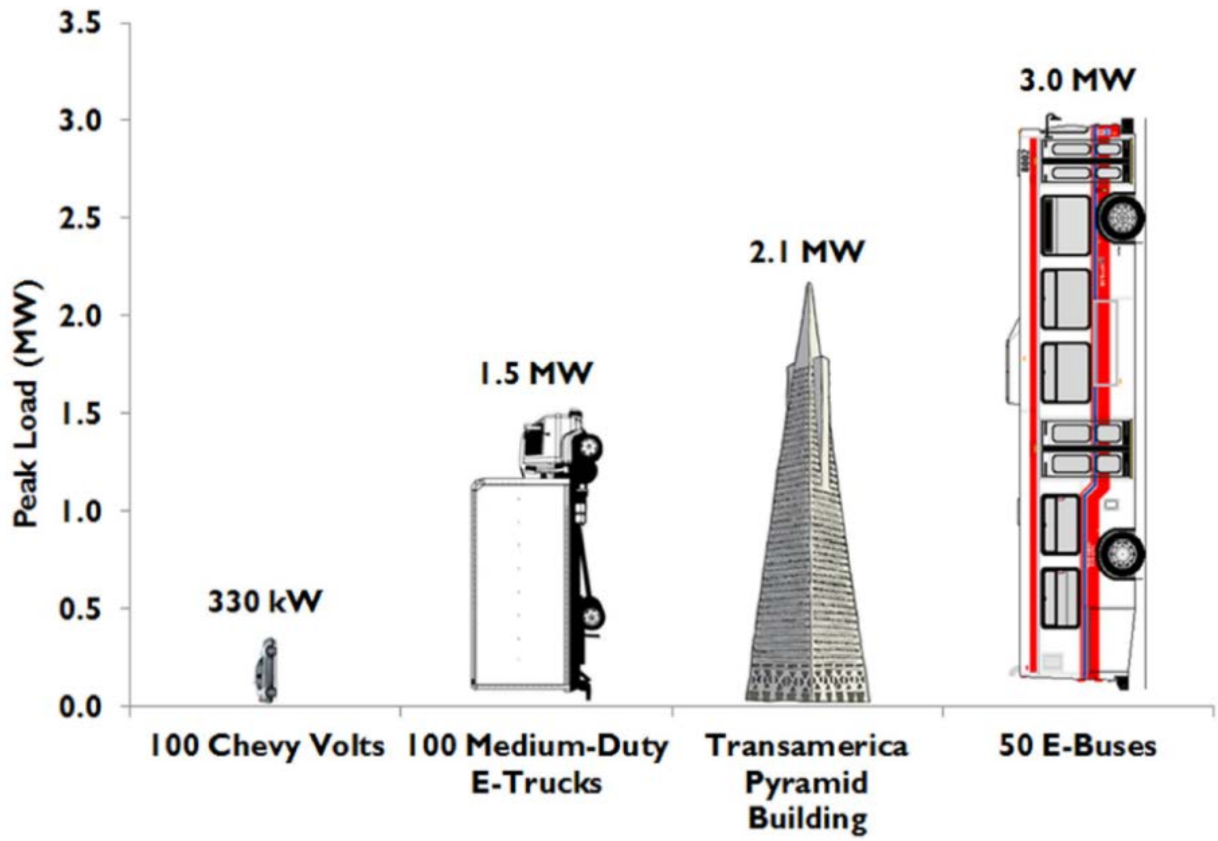


Figure 1 demonstrates that electrifying approximately 50 buses can create about 150% the peak load requirement of a modern (non-electrified) sky-scraper.[8] Additionally, even a small EV, such as a Chevy Volt, can create a significant spike in a resident's peak demand. For example, a maximum non-coincident peak for a residential customer could be approximately 6 kW. In this case, charging a Chevy Volt would increase residential non-coincident peak demand by over 50%, which could create local distribution capacity constraints. As EV penetrations increase, the need to avoid

[8] *See* https://chptap.lbl.gov/profile/239/pyramid-building.pdf

charging during coincident system peaks is necessary to avoid significant costs for ratepayers.

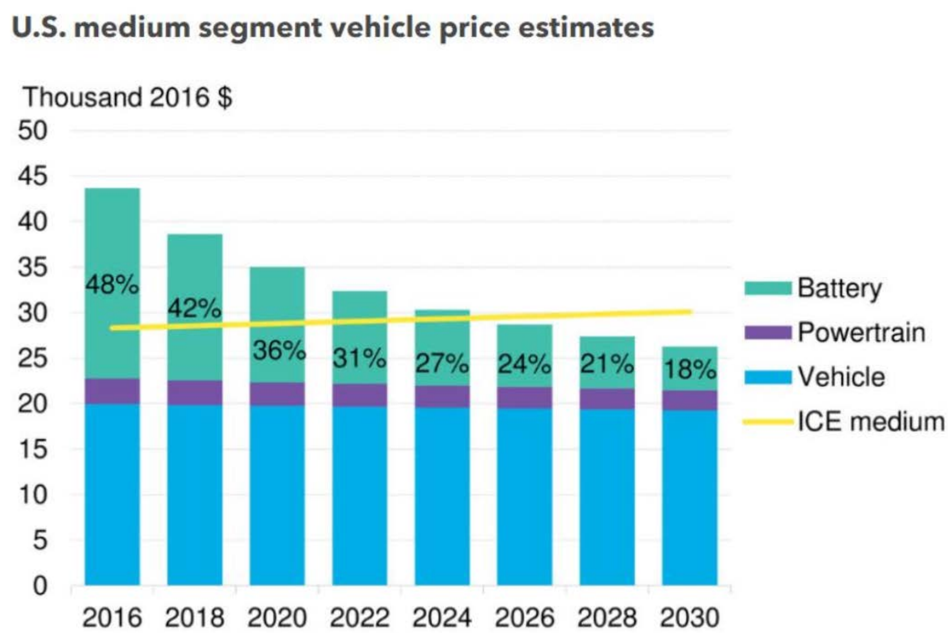
Q. Are there any current trends in EVs that are particularly relevant to the importance of load management?

A. Yes. A key factor for customers' purchasing decisions is the sticker price of a good, including cars. For an equivalent EV model, EVs have always required a premium for purchase.

While EV growth in the Company's territory has been modest, a key threshold for EV uptake is the sticker price. Once equivalent EVs have lower sticker prices than comparable internal combustion models, adoption will likely accelerate faster. The sticker price threshold forecast is shown in Figure 2, below.[9]

Figure 2

9 Bloomberg NEF. 2017. "Electric Cars to Reach Price Parity by 2025." https://about.bnef.com/blog/electric-cars-reach-price-parity-2025/



Source: Bloomberg New Energy Finance

While Figure 2 is based on a somewhat dated estimate, the trend is similar for more recent estimates in other countries and demonstrates that sticker price parity is possible within the next 5 years.[10]

Furthermore, automakers are increasingly turning their focus to EVs. Honda has a goal for 40% of sales to be EVs by 2030, 80% by 2035, and 100% by 2040; GM aspires to have 40% of its models to be EVs by 2025, and 100% by 2035; and other automakers such as BMW and Ford have also announced plans to introduce several EV models in

[10] *See https://bnef.turtl.co/story/evo-2021/?teaser=yes*

the coming years.[11] IHS Markit has projected that approximately 130 EV models will be available in the US in 2026.[12]

Q. What should be the utility's central role in transportation electrification?

A. Given the significant ratepayer impacts of unmanaged EV charging, it is incumbent on the utility to address load management concerns. Building infrastructure to support TE is permissible and necessary, but load management is critical. Large transportation electrification efforts by a utility should not be authorized until a comprehensive load management plan has been developed and implemented. Frontloading utility investment on EV infrastructure, without a comprehensive load management plan, will lead to overbuilding because the utility will not likely have an accurate understanding of how load management options can reduce the need for infrastructure, nor will the utility be capable of integrating the impacts of load management into their distribution system plans.

Q. What load management offerings is the Company currently considering?

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11 Consumer Reports. 2021. "Here Are Automakers' Plans for Adding More Electric Vehicles to Their Lineups." https://www.consumerreports.org/hybrids-evs/why-electric-cars-may-soon-flood-the-us-market/

12 Reuters. 2019. "Outside of Tesla, future EV sales in U.S. may be thin for most brands: study." https://www.reuters.com/article/us-autos-electric-forecast/outside-of-tesla-future-ev-sales-in-u-s-may-be-thin-for-most-brands-study-idUSKCN1SZ20I

A. According to the Company's response to discovery OCA-VII-5, the Company is currently in the initial stages of considering an EV Time-of-Use ("TOU") rate and an active managed charging program.

Q. What load management programs should the Company consider?

A. In addition to the offerings identified by the Company above, the Company should consider additional passive and active managed charging offerings, as well as offerings for Automated Load Management ("ALM").

1. Passive Managed Charging

Q. What is passive managed charging?

A. Passive managed charging focuses on altering customer behavior to affect charging times.[13] This can be accomplished through rate design or other financial incentives for off-peak charging and for avoiding on-peak charging.

Q. How could the Company's passive managed charging offerings in development be improved?

A. The Company currently has one passive managed charging offering under consideration: an EV TOU rate. While an EV TOU rate with time-varying energy charges is an important first step, more advanced rate designs are necessary to expand options for customers and ensure EV load is shifted away from peak periods to off-peak

[13] Smart Electric Power Alliance. 2019. "EV Managed Charging: Lessons from Utility Pilot Programs." https://sepapower.org/knowledge/ev-managed-charging-lessons-from-utility-pilot-programs/

periods. For example, Xcel Energy Colorado and Minnesota currently offers commercial and industrial customers an EV Critical Peak Pricing ("CPP") Rate, under which energy costs are considerably higher during utility-called critical peak events, on top of on-peak and off-peak pricing during non-event periods.[14] San Diego Gas & Electric currently offers the EV Grid Integration Pilot Program, a dynamic rate schedule that reflects day-ahead wholesale electricity prices.[15] Providing a variety of rate designs can help accommodate a diversity of customer needs and sophistication, thus creating more grid flexibility and lower costs to ratepayers.

Additionally, the Company should also evaluate passive managed charging efforts that go beyond rate design going forward. Many utilities have implemented programs that provide customers with a per kWh incentive for off-peak charging and/or monthly incentive for avoiding on-peak charging. For instance, National Grid in Massachusetts provide residential customers with an Off-Peak Charging Rebate of 3-5 cents per kWh (depending on the season) for all off-peak charging.[16] In New York, Con Edison offers the SmartCharge NY Program, which provides residential customers with a 10 cents per kWh incentive for off-peak charging, a $20 per month incentive for

[14] Xcel Energy Colorado. 2021. *EV Critical Peak Pricing Information Sheet.* https://www.xcelenergy.com/staticfiles/xe-responsive/Programs%20and%20Rebates/Business/EV-CPP-Info-Sheet.pdf
[15] San Diego Gas & Electric. 2017. *Schedule VGI*. https://www.sdge.com/sites/default/files/elec_elec-scheds_vgi.pdf
[16] Massachusetts Department of Public Utilities. 2019. *September 30 Order*, pg. 340-341, 387-392. Proceeding 18-150. https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/11262053

avoiding summer peak charging, as well as ongoing participation incentives.[17] Fleet customers are also able to participate in SmarCharge NY, earning 2.21 cents per KWh for off-peak charging and $250 per month for avoiding charging during demand response periods. Central Hudson,[18] NYSEG, RG&E,[19] and Orange & Rockland[20] have also proposed similar programs as per Commission directive. This program structure can achieve similar objectives as an EV TOU rate, but could allow billing determinants to be measured via the charger or the vehicle's onboard telematics.[21] This type of program would be more affordable for customers, particularly low-income households.

2. Active Managed Charging

Q. What is active managed charging?

A. Active managed charging programs utilize direct load control via the charger, vehicle telematics, or smart circuit breaker or panel, to allow the utility or a third party

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[17] Con Edison. 2020. "ConEdison EV Managed Charging Filing." Case 18-E-0138. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F8F2D2E1-B190-4DB4-B3F3-2BDC127568F5}

[18] Central Hudson. 2020. "Central Hudson Electric Vehicle Managed Charging Proposal." Case 18-E-0138. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={CE9F89CB-B8FF-43FB-9BEF-B63D6E62638C}

[19] NYSEG & RG&E. 2020. "Mass Market Managed Charging Program Proposal." Case 18-E-0138. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={DB610147-8910-4D1C-9BCF-C1E689129617}

[20] Orange & Rockland. 2020. "Managed Charging Program for Mass Market Customers." Case 18-E-0138. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={AF86B4E0-861F-4AE1-BBD4-0EF3E4C561EB}

[21] Telematics describes the vehicle's onboard communication services and applications that enables communication between a vehicle and an established network. Telematics can be used for energy and charge reporting, GPS vehicle tracking, route management, battery health monitoring, direct load control, and more.

(e.g., aggregator, EV service providers) to determine and/or control the charging time, level, and location.[22]

Q. Why is active managed charging important?

A. Active managed charging allows for a greater degree of flexibility and control of EV load than passive managed charging. Passive managed charging, which relies on rate designs or program incentives to encourage off-peak charging, can oftentimes lead to a load peak at the start of the off-peak period. Active managed charging allows the utility or a third party to "smooth" the EV demand curve by scheduling charging sessions. The Static Optimization program offered by Xcel Energy Colorado follows this approach.[23] Active managed charging can also be used to ensure EVs are charged during periods with the lowest energy costs or highest renewable energy penetration. For example, the Charge Smart Program offered by Central Hudson and Orange & Rockland in New York leverages networked chargers to shift EV charging to periods when greenhouse gas emissions from power generation are the lowest, using forecast and real-time emissions data.[24] Xcel Energy Colorado is also working with automakers

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[22] Smart Electric Power Alliance. 2019. "EV Managed Charging: Lessons from Utility Pilot Programs." https://sepapower.org/knowledge/ev-managed-charging-lessons-from-utility-pilot-programs/

23 Xcel Energy Colorado. 2021. "2021/2022 Demand-Side Management Plan," pg.262-263. https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/CO-DSM/CO_2021-22_DSM_Plan_Final.pdf

24 Orange & Rockland Store. 2020. "Charge Smart Program." https://myorustore.com/s/ORU/content_charge_smart_program.html

to implement the Charging Perks Pilot, which uses vehicle telematics to shift charging to hours with the lowest day-ahead power production costs.[25] Under Xcel Energy Colorado's TE Plan, all residential customers and certain MUD customers receiving rebates for EV chargers and infrastructure are required to enroll in a managed charging program.[26] Finally, active management can allow EVs to participate in demand response ("DR") programs, like the Active Demand Reduction programs implemented by National Grid and Eversource in Massachusetts.[27]

3. Automated Load Management

Q. What is Automated Load Management?

A. Automated Load Management (ALM), also known as Dynamic Load Management or EV Management Systems, strategically distributes charging capacity among multiple charging ports at the same charging site.

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25 Xcel Energy Colorado. 2021. "2021/2022 Demand-Side Management Plan," pg. 263-265. https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/CO-DSM/CO_2021-22_DSM_Plan_Final.pdf

26 Colorado Public Utilities Commission. 2021. *Decision No. C21-0117*, pg. 9-11. Proceeding No. 20A-0204E. https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=941065

27 Massachusetts Joint Statewide Electric and Gas. 2018. "Three-Year Energy Efficiency Plan 2019-2021." Appendix K. https://ma-eeac.org/wp-content/uploads/Exh.-1-Final-Plan-10-31-18-With-Appendices-no-bulk.pdf

Q. Why is Automated Load Management important?

A. ALM can help safely connect multiple charging ports whose total nameplate load would otherwise exceed the rated capacity of the customer connection. This in turn can avoid or defer the need to upgrade certain customer-side and utility-side infrastructure to accommodate the new EV charging load. For example, if a MUD seeks to deploy a charging station with 5 ports, each with a 10-kW capacity, the distribution upgrades would normally be sized to accommodate 50 kW of incremental coincidental charging demand, equal to all 5 ports charging at full capacity. However, ALM can lower the coincident charging demand to 30 kW, or 6 kW per port on average, when all 5 ports are occupied, thus reducing distribution system upgrades to what is required for only 3 ports. In this scenario, when only 3 or fewer ports are occupied, the EVs can still charge at full speed. Having ALM available to customers as an option can lead to significant savings for ratepayers and ensure that investments in TE are used efficiently. Pacific Gas & Electric has worked with EV service providers to implement ALM solutions at 20 MUD and workplace host sites as of Q4 2020 and saved between $30,000 and $200,000 per project.[28]

4. EV-FC Rider

Q. Do you have any concerns with the Company's proposal to extend the eligibility for the EV-FC Rider to public transit customers?

28 Pacific Gas & Electric. 2021. Presentation at CPUC ALM/EV EMS Workshop, Panel 2.

A. Since the Company is not requesting any additional funding in order to provide the demand credit under the EV-FC Rider to public transit customers, I am not opposed to the Company's proposal. However, the EV-FC Rider is not conducive to load management. The demand charges under the three rate schedules (GS, PD, and HT) that qualify customers for the Rider are based on the customer's non-coincident peak demand, rather than demand during system peaks or through a heavily weighted, time-varying volumetric rate. Thus, these rates do not fully or efficiently reflect the full costs, including generation and transmission costs, of DCFCs to the entire system and does not incentivize customers to manage load during system peaks. The availability of the EV-FC Rider does not change this dynamic. A TOU rate with CPP would help limit charging during periods with high system stress and therefore would be a more appropriate price signal to ensure DCFCs align with system needs. A non-coincident demand charge could still be a part of this rate structure to limit distribution system impacts.

IV. RECOMMENDATIONS AND CONCLUSION

Q. Should the Commission approve the Company's proposed pilots?

A. Load management should be prioritized in any utility-led TE efforts. Even though PECO's proposals are lacking in this respect, given their limited nature, the Commission could reasonably move forward with the Company's proposed pilots with the modification of requiring a cap on the incentive for public transit customers and additional filing requirements, discussed in Section IV.B.

If the Commission approves PECO's proposed pilots, it should require the following:

- Within 90 days of approval the Company should file the following:
    - An evaluation and assessment plan tied to more clearly defined objectives, which will inform annual filing requirements for the approved pilots.
    - A detailed description of what exactly it plans to learn from "charging session transactional data," the additional metrics that will be filed with any pilot reports, and a detailed explanation how PECO will integrate charging data into its distribution planning process. The explanation should, at a minimum, include a discussion on DER forecasting, and mitigation approaches for addressing locationally specific peak demand requirements caused by EVs.
- Within 18 months of approval, PECO should file a comprehensive EV load management proposal that includes a description of the Company's future offerings, investments required to offer each type of load management offering, an estimated timeline to implement the offerings, to what customers segments the offerings may be made available, a proposed implementation plan for ALM to mitigate customer and utility side infrastructure requirements, and how it's

potential investment in a Distribution Energy Resource Management System (DERMS) will be leveraged to reduce EV and DER related costs across all levels of the power system.[29]

- Regarding the information provided on offerings, the Company should discuss opt-out offerings for passive managed charging and opt-in offerings for active managed charging for all customer types.
- Six months prior to this filing, the Commission should require the Companies to provide a presentation to stakeholders that provides an overview of what will be in the comprehensive load management proposal, allow for Q&A at the meeting, and allow stakeholders to file comments on impressions and improvements that could be made to the scope of the proposal.

After the 18 month filing, the Commission should require one stakeholder meeting with the purpose of allowing stakeholders to ask questions of the Company, a round of formal comments from stakeholders on how to improve the Company's filings, and a reply round for the Company to respond to and incorporate feedback from stakeholders.

Q. Does this conclude your direct testimony?

A. Yes.

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[29] *See* The Company's response to OCA-VII-9 for a discussion of its potential DERMS investment. The question asked about a constraint management system, which is distinct from DERMS. Constraint management systems monitor substations and can allow for locationally specific demand response. A DERMS is not necessarily capable of providing such functionality.

PROFESSIONAL BACKGROUND AND EDUCATION

EDUCATION

M.S. **Agricultural and Resource Economics**
Colorado State University, Fort Collins, CO, 2013

Minor **Mathematics**
Western Washington University, Bellingham, WA, 2011

B.A. **Environmental Economics**
Western Washington University, Bellingham, WA, 2006

EMPLOYMENT

2018 - Present	Director, Strategen Consulting
2013 – 2017	Utilities Economist, Antitrust and Utilities Division, Office of the Minnesota Attorney General
2012 – 2013	Consulting Economist, United States Geological Survey
2011 – 2013	Economic Research Assistant, Colorado State University

PREVIOUS TESTIMONY

Company	**Docket No.**	**Subject**
Rocky Mountain Power	20-035-04	ECOSS, Rate Design, Pilot Frameworks, AMI
Minnesota Power*	E-002/GR-19-442	ECOSS and low-income rate design
Pennsylvania Power and Light	P-2019-3010128	DER integration and management
Eversource	DE 19-057	ECOSS, MCOSS, Rate Design, Decoupling, and Performance-Based Regulation
Liberty Utilities	DE 19-064	MCOSS, Rate Design, and Performance-Based Regulation
Oklahoma Gas and Electric	201800140	CCOSS and Rate Design
Public Service Company of Oklahoma	201800096	Rate Design, Grid Modernization, and Performance-Based Regulation
Vectren Energy Delivery of Ohio	18-0298-GA-AIR	CCOSS and Rate Design
Commonwealth Edison	18-0753	Distributed Generation Rebates
Ameren Illinois Company	18-0537	Distributed Generation Rebates
Oklahoma Gas and Electric	201700496	CCOSS and Revenue Apportionment
Minnesota Power	E-002/GR-16-664	CCOSS, Rate Design, and the Utility Business Model
Otter Tail Power	E-002/GR-15-1033	Marginal and Embedded CCOSS and Rate Design
Xcel Energy	E-002/GR-15-826	CCOSS, Rate Design, and Performance-Based Regulation
Minnesota Energy Resources Corp.	G-011/GR-15-736	CCOSS and Rate Design

CenterPoint Energy	E-002/GR-15-424	CCOSS and Rate Design
Dakota Energy Association	E-002/GR-14-482	CCOSS and Rate Design
Xcel Energy	E-002/GR-13-868	CCOSS and Rate Design
Minnesota Energy Resources Corp.	G-011/GR-13-617	CCOSS
CenterPoint Energy	G-008/GR-13-316	CCOSS

*Settled before direct was filed

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024601
	:	
PECO Energy Company – Electric Division	:	

VERIFICATION

I, Ron Nelson, hereby state that the facts set forth in my Direct Testimony, OCA Statement 6, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: June 28, 2021
*311950

Signature: Ron Nelson
Ron Nelson

Consultant Address: Strategen Consulting
2150 Allston Way
Suite 400
Berkeley, CA 94704

OCA STATEMENT NO. 3-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket Number R-2021-3024601**
	:	
PECO Energy Company—Electric Division	:	

REBUTTAL TESTIMONY OF

CLARENCE L. JOHNSON

ON BEHALF OF

OFFICE OF CONSUMER ADVOCATE

July 22, 2021

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Table of Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Clarence L. Johnson. My business address is 3707 Robinson Ave, Austin, Texas 78722.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am presenting testimony on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS YOUR CURRENT EMPLOYMENT?

A. I am self-employed as a consultant providing technical analysis, advice, and testimony regarding energy and utility regulatory issues.

Q. ARE YOU THE SAME CLARENCE JOHNSON WHO PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. Yes. I presented my initial testimony and schedules in OCA Statement No. 3. In addition, I would note that upon further review of my Direct Testimony I identified a minor error. My recommended class revenue allocation is shown in correct form on OCA Statement No.3, Schedule CJ-1. However, the table summarizing the recommendation on page 25 of the testimony contains a minor typographical error. The proposed allocation for Residential should be shown as $151,430 instead of $151,480.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS CASE?

A. My testimony will rebut testimony presented by other parties on cost allocation and rate design issues pertaining to PECO's ("Company") base rate increase requested in this docket. In particular, I will rebut the testimony of Pennsylvania Industrial Energy Users Group (PAIEUG) witness Pollock,[1] Office of Small Business Advocate (OSBA) witness Kalcic,[2] and Walmart witness Kronauer[3] To the extent that my rebuttal testimony does not address the positions of a witness, that should not be construed as agreement with the witness' testimony on that subject.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. My conclusions are as follows:

- I disagree with PAIEUG witness Pollock's and OSBA witness Kalcic's proposal to increase the residential share of PECO's rate increase substantially higher than the amount proposed by the Company.
- The principal source of the difference between OCA's revenue allocation and the OSBA and PAIEUG revenue increase proposals is the underlying class cost of service study ("CCOSS"). Mr. Pollock and Mr. Kalcic used the Company's CCOSS without any changes, but my testimony relied upon the OCA CCOSS that included several modifications. The most significant modification is classifying secondary facilities as demand-related. Based upon OCA's CCOSS, my recommended revenue allocation moves

[1] PAIEUG Statement No. 2.
[2] OSBA Statement No. 1.
[3] Walmart Statement No. 1.

the residential class in the direction of cost. In the interest of gradualism, my recommendation did not move the residential class fully to cost.

- The class revenue allocation method suggested by Walmart witness Kronauer is similarly flawed because it does not reflect appropriate changes to the CCOSS, as presented in my testimony.
- Mr. Pollock opines that rate classes will not suffer rate shock if class revenues are set at cost as determined by the PECO's CCOSS. I disagree with his approach to evaluating rate shock and the need for rate moderation. In particular, an evaluation should consider that residential customers have experienced extraordinary adverse economic conditions and unemployment.
- Contrary to the positions taken by Mr. Pollock and Mr. Kalcic, equalizing class rates of returns is not always an appropriate target.
- PAIEUG witness Pollock contends that distribution costs allocated to the High Tension (HT) class should be reduced based on his view that industrial customers taking service at 69 kV or higher should be excluded from the allocation of Primary facilities. Mr. Pollock recommends that the Commission direct PECO to reduce the allocation to the HT class in the next rate case. I disagree with Mr. Pollock's contention that the CCOSS over-allocates distribution costs to the HT class, and recommend rejection of his proposal.

II. ALLOCATION OF CLASS REVENUE INCREASE

Q. WHAT IS THE POSITION OF PAIEUG WITNESS POLLOCK AND OSBA WITNESS KALCIC REGARDING CLASS REVENUE INCREASES?

A. The positions of Mr. Kalcic and Mr. Pollock are similar. PAIEUG witness Mr. Pollock recommends a revenue increase based on placing all customer classes at equalized rates of return using the Company's CCOSS.[4] OSBA witness Mr. Kalcic recommends the same revenue allocation, with the exception of the Lighting class, which he limits to no change in revenues.[5] These recommendations produce a substantial revenue increase--over and above the Company's proposed increase--to residential customers. The Company proposes a $157.7 million rate increase to Rates R and RH, and OSBA and PAIEUG recommend, respectively, additional increases of $38.4 and $39.2 million for residential customers.[6]

Q. MR. POLLOCK AND MR. KALCIC RECOMMEND LARGE REVENUE INCREASES FOR RESIDENTIAL CUSTOMERS BECAUSE THEY CONTEND RESIDENTIAL RATES ARE BELOW COST. DOES THIS CRITICISM APPLY TO YOUR RESIDENTIAL REVENUE RECOMMENDATION?

A. No. The principal difference between the OSBA and PAIEUG positions and my position is that Mr. Pollock and Mr. Kalcic accept the Company's CCOSS in order to define "cost."

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4 See, PAIEUG Statement No. 2 at 20-23.

5 See, OSBA Statement No. 1 at 10-11.

6 See, OSBA Statement No. 1, Schedule BK-1 through BK-3 and PAIEUG Statement No. 2, Ex. JP-4.

My testimony presents several proposed changes to the Company's CCOSS, and, as a result, residential rates are above costs in the revised CCOSS. The most significant revision is my recommendation to classify all secondary facilities, except for meters and services, on a demand basis. In contrast, the Company's CCOSS allocates secondary distribution lines, poles, and underground facilities on a 100% customer basis. In addition, my recommended CCOSS includes revisions in the allocation of other revenues and the treatment of Rate R and Rate RH as a consolidated class for cost allocation purposes.

Q. DOES YOUR RECOMMENDATION MOVE RESIDENTIAL CUSTOMER REVENUES IN THE DIRECTION OF COST AS DEFINED BY YOUR PROPOSED CCOSS?

A. Yes. However, in the interest of gradualism, my recommendation does not move residential rates fully to cost.[7] My revenue increase recommendation for the consolidated residential class is $6.3 million less than the Company's residential proposal and represents 62.8% of the total proposed increase ($251 million). My recommendation is $44 - $45 million less than the residential class revenue increases recommended by Mr. Kalcic and Mr. Pollock.[8] The PAIEUG and OSBA proposals shift residential revenues too far above

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7 If the combined Residential class is moved immediately to cost, as measured by my CCOSS, the revenue increase for aggregate Residential class would be $19 million less than proposed by my revenue allocation recommendation.

8 Note that my recommendation is to treat Rate R and Rate RH as sub-classes of the consolidated Residential class. Therefore, any potential cross subsidy between Rate R and Rate RH is confined within the class.

a cost-based rate as indicated by my CCOSS result. Consequently, the Kalcic and Pollock revenue allocations would increase residential revenues more than $60 million above cost. For comparison, the parties' revenue allocation recommendation for the residential class is shown as a percentage of the system average percentage increase (18.3%):

TIMES SYSTEM AVERAGE
PECO 92.5%
OCA 88.8%
PAIEUG 115.4%
OSBA 115.0%

Q. DOES THE TABLE ABOVE INCLUDE THE RECOMMENDATION OF WALMART WITNESS KRONAUER?

A. No. Walmart witness Mr. Kronauer did not provide the results of his recommended class revenue allocation. But his testimony describes his approach to developing class revenue increases.[9] His proposed method would set the EP class at cost, maintain the current revenues for Lighting and apply an equal percentage revenue increase to the remaining classes. His approach would not produce as large a percentage increase to the Residential class as the PAIEUG and OSBA proposals. However, his method does not recognize the impact of CCOSS modifications such as those discussed in my testimony. In particular,

[9] See, Walmart Statement No. 1 at 15-16.

my recommended CCOSS indicates that the Residential class should receive a below average percentage revenue increase relative to the system average increase.

Q. WHY DOES PAIEUG'S WITNESS POLLOCK OPPOSE THE APPLICATION OF GRADUALISM LIMITS ON THE RESIDENTIAL CLASS' REVENUE INCREASE?

A. According to Mr. Pollock, moderating movement toward equalized rates of return is justified only if a class will suffer rate shock, which he defines as "1.5 – 2 times system average."[10] I disagree that the 1.5 times or 2 times system average is an absolute threshold for evaluating rate shock or determining whether rate moderation is justified. An evaluation of rate shock involves consideration of a number of factors, such as the rate class size and number of customers affected, ability to pay, customer complaints, and the current economic conditions affecting the customers. For example, OCA witness Eastman describes the unusual economic conditions affecting the Philadelphia area, marked by historic unemployment rates during the pandemic, current elevated unemployment levels, and significant uncertainty regarding future loss of income among households.[11] The extraordinarily sensitive economic conditions provide a reasonable basis for applying rate moderation to residential revenue increases.

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[10] PAIEUG Statement 2 at 20. The chart on this page shows a recommended 21.7% increase in Rate R revenues, with a times system average of 119%.

[11] OCA Statement 5 at 2 – 7.

Q. PLEASE RESPOND TO MR. POLLOCK'S AND MR. KALCIC'S ASSUMPTION THAT ALL CLASSES SHOULD PAY THE SAME EQUALIZED RATE OF RETURN?

A. Rate of return is a cost component of the utility's cost of service. The electric utility's required return reflects its perceived risk. However, not all customer classes impose the same risk on electric utilities' operations—a fact that, in addition to principles of gradualism, can justify different target rates of return for each class. For example, industrial and manufacturing customers are generally considered as conferring greater business risk upon the public utility than residential customers. A greater capital investment is required to serve each industrial customer, and thus the loss of each customer has a greater revenue impact. Dr. Bonbright states in *Principles of Public Utility Rates*:

> [T]he rates of charge for service rendered to a gigantic user of power, regardless of the formula used in the determination of his annual demand charges, may well result in less than barely compensatory rates when measured in the light of hindsight. If based on advance estimates of "cost of service" these rates should therefore incorporate an appropriate allowance for the risk factor—for a risk factor well in excess of that which would be appropriate in an estimate of the cost of supplying the more stable, residential service.

> The unpredictability of future demands for certain types of utility services presents another problem alike for cost analysis and for rate determination: namely, the problem of an unpredictable change in the system load curve.[12]

Rate design features can mitigate but not eliminate the risk—particularly if the large customer's change in consumption is long term in nature.[13]

Similarly, the Company's cost of capital witness, Mr. Moul, points out that industrial customers represent 21% of sales, and as a result, "the energy needs of just 0.2% of all customers can have a significant impact on the Company's operations."[14] He previously discussed "the reality that service furnished to industrial customers entails higher risk to electric utilities than service to residential customers," which he said is "intuitively obvious."[15] If the composition of sales by customer class has the effect of producing differing business risks to the utility, this undermines the CCOSS's premise that all customer classes should be targeted to produce equal rates of return. In that situation, it is no more reasonable to expect equal relative contributions to return than it would be to expect all stocks in a portfolio to make equal contributions to the overall rate of return of the portfolio.

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12 *Principals of Public Utility Rates*, Columbia UniversityPress, James Bonbright (1961) at 365.

13 Bonbright's discussion supports this point: "*Moreover, except under some special contracts between the industrial user and the utility company, the obligation of the customer to continue the payment of <u>any</u> charges will cease, or will have only limited duration, if it is ready to abandon the taking of service altogether.*" *(Ibidem.)*

14 PECO Statement No. 5 at 3.

15 PECO Response to OCA II-7 (May 4, 2018), Docket No. R-2018-3000164.

Strict adherence to equalized class rates of return may result in a false sense of security about the precision of the CCOSS. In theory, the more stable classes, such as residential, should be expected to produce a lower relative rate of return, and classes with higher risk, such as industrial customers, a higher relative rate of return. Since the revenue targets produced by a CCOSS presume uniform class rates of return, this is an inherent weakness in the practice of strictly moving classes toward the class revenue requirements in the CCOSS. For this reason, some utilities and analysts may target class revenues within a reasonable band around equalized rates of return.

III. CCOSS ALLOCATION TO HIGH TENSION CLASS

Q. DOES PAIEUG WITNESS MR. POLLOCK DISAGREE WITH THE DISTRIBUTION COSTS ALLOCATED TO THE HIGH TENSION (HT) CLASS?

A. Yes. Mr. Pollock focuses on high voltage customers who take service at voltages higher than 69 kV, and argues that these loads should be excluded from the demand allocator applied to the HT primary function investment. Therefore, he posits that the HT class allocation should be reduced, shifting costs from the HT class to all other customer classes. Mr. Pollock's direct testimony asserts that he cannot quantify the revenue requirements which would be shifted to other classes as a result of this recommendation. Therefore, he proposes that the Commission direct PECO to conduct a study consistent with his position before the next PECO rate case and require a reduction of the HT class allocation in the Company's next CCOSS. Notably, customers who take service at 69 kV or higher in the

HT class already receive a credit to compensate them for lower distribution facility costs. Despite this credit, the objective of his proposal is reduce the costs allocated to the overall HT class.

Q. DO YOU AGREE WITH MR. POLLOCK'S PROPOSAL?

A. No. Although Mr. Pollock's proposal would not be implemented until the next rate case, the impact of his proposal on all other rate classes will be detrimental. PECO's allocation of HT primary distribution facilities to all loads is consistent with average cost rate making principles. Mr. Pollock complains that some of his clients do not use all of the HT primary facilities, but that is not unusual. Classes of customers receiving allocations of distribution cost may not "use" every distribution facility on the PECO system. This is inherent in average cost ratemaking, and increased granularity may overlook system or network benefits. For example, most electric utilities design substations so that the facilities can provide redundancy and handle additional power flows in the event of an emergency or contingency event elsewhere on the system. Moreover, Mr. Pollock's position is contradictory, in that it ignores situations that would result in a reduced allocation to low voltage classes.

Q. WHY IS MR. POLLOCK'S POSITION INCONSISTENT?

A. Mr. Pollock proposes to eliminate above-69 kV loads from the allocation of facilities with a lower rated voltage. However, he does not propose to eliminate other customer classes' loads from the allocation of any above-69 KV facilities. A substantial part of the above-69 kV distribution facilities consists of radial lines, which solely or primarily serve high voltage industrial customers. Currently these facilities are allocated to all customer classes in the same way as other HT primary facilities. If his proposal was consistent, Mr. Pollock should also recommend a reduction in the allocation of these radial line costs to lower voltage customer classes.

Q. DO THIS CONCLUDE YOUR REBUTTAL TESTIMONY AT THIS TIME?

A. Yes.

#313858

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024601
	:	
PECO Energy Company – Electric Division	:	

VERIFICATION

I, Clarence L. Johnson, hereby state that the facts set forth in my Rebuttal Testimony, OCA Statement 3-R, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 22, 2021
*313689

Signature: ______________________________
Clarence L. Johnson

Consultant Address: CJ Energy Consulting
3707 Robinson Avenue
Austin, TX 78722

OCA Statement No. 4R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2021-3024601
PECO Energy Company – Electric Division	:	

Rebuttal Testimony of
Roger D. Colton

On Behalf of:
Office of Consumer Advocate
Statement No. 4R

July 22, 2021

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, MA 02478.

Q. ARE YOU THE SAME ROGER COLTON WHO HAS PREVIOUSLY PREPARED DIRECT TESTIMONY ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. In my Rebuttal Testimony, I respond to the Direct Testimony of Harry Geller regarding CAP energy burdens and the In-Program Arrearage Forgiveness program. Mr. Geller makes recommendations to which I respond:

- First, Mr. Geller states that "while I recognize that there is a pending proceeding where PECO's CAP design is under consideration, the fact remains that CAP rats are unjust, unreasonable, and unaffordable <u>*now.*</u> (emphasis in original). In the short term, PECO should be required to implement the Commission's CAP energy burden standards for the period that it continues to operate its CAP FCO." (TURN/CAUSE-PA St. 1, at 27 – 28). Mr. Geller's reference to "CAP Rates" is a reference to the percentage of income burdens that underlie CAP bills.

- Second, Mr. Geller recommends that "PECO adopt an [In-Program Arrearage Forgiveness] program for CAP customers comparable to –and in tandem with—its pro-program arrearage (PPA) forgiveness program for first time CAP participants." (TURN/CAUSE-PA St. 1, at 32).

I will address each of these recommendations in turn below.

PART 1. Recommended Changes in CAP Burdens.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE PROPOSAL TO IMMEDIATELY CHANGE PECO'S CAP BURDENS?

A. I recommend that this proposal be deferred to PECO Energy's Universal Service and Energy Conservation Program (USECP) proceeding now pending before the Commission. (Docket Nos. P-2020-3020727, et al.).

Q. HAS A SIMILAR RECOMMENDATION BEEN CONSIDERED BY THE PUC IN ANY OTHER RECENT RATE PROCEEDING?

A. Yes. This was the decision of the PUC in the Columbia Gas 2020 base rate decision (R-2020-3018835, Decision and Order, at 161 ["we find that issues related to Columbia's energy burden levels are more properly considered in the context of the Company's next USECP filing. We agree with Columbia and the OCA that the energy burdens of customers on PIP Plans should not be considered separately from other parts of the Company's CAP and universal service programs but should be considered as part of the Company's entire universal service plan, including the need for changes and associated costs."]).

The Commission reached a similar conclusion in the recent PECO (gas) base rate decision (R-2020-3018929, Opinion and Order, Non-Proprietary Version). In that PECO decision, the Commission stated:

> [W]e will not consider CAUSE-PA's proposals relating to PECO's energy burdens, PECO's CAP, and other universal service program issues within the context of this base rate proceeding. We agree with the ALJ that CAUSE-PA's proposals are more properly considered in the ongoing 2019-2024

> USECP proceeding. This determination is consistent with the language in the *Final CAP Policy Statement Order*, at 60, 106, and the *February 2020 Reconsideration Order* at 10-11, which provide that energy burden levels and CAP credit issues should be addressed in a public utility's USECP proceeding. . .
>
> We addressed similar issues in *Columbia Gas*, finding that issues related to Columbia Gas's energy burden levels were more properly considered in the context of the Company's next USECP filing. We concluded that energy burdens should not be considered separately from other parts of the Company's CAP and universal service programs but should be considered as part of the Company's entire universal service plan, including the need for changes and associated costs.

(Id., at 195).

Q. ARE THERE PRACTICAL IMPLICATIONS ASSOCIATED WITH DEFERRING THE PROPOSED REDUCTION IN CAP BURDENS TO PECO'S PENDING USECP PROCEEDING?

A. Yes. Having deferred any modification of the natural gas burdens to the pending PECO USECP proceeding, it is not clear how, or why, the Commission could or would modify the associated electric burdens in a separate proceeding. The same issues would present themselves, not only involving a determination of what the increased costs to non-participating ratepayers might be, but also involving a determination of what cost-control measures, if any, should be adopted in response to those increased CAP costs. The changes (if any) to electric and natural gas burdens, and the responses thereto, should be considered in the same USECP proceeding.

Q. IS THERE A SECOND REASON TO DEFER THIS ISSUE TO PECO'S PENDING USECP PROCEEDING?

A. While Mr. Geller's testimony focuses on the impact of the revised energy burdens on CAP participants, his testimony does not address the impact of the revised energy burdens on other ratepayers not participating in CAP who may have difficulty paying their home energy bills.

The costs of universal service are borne by all non-participating residential customers. Many of those residential customers are low-income, as defined by the Commission, who are eligible for, but do not participate in, the Company's CAP. One reason an income-eligible customer may not participate in PECO's CAP, for example, would be that the Company has simply not identified that customer as being income-eligible. According to the most recent (2019) Bureau of Consumer Services (BCS) annual report on Universal Service Programs and Collections Performance,[1] for example, while PECO had 112,157 CAP participants in 2019 (page 51), it had 393,662 estimated low-income customers (page 7). Those low-income customers (i.e., customers with income less than 150% of Poverty) who do not participate in CAP pay for the cost of providing benefits to those low-income customers who do participate in CAP.

In addition to these customers who are eligible for, but who do not participate in CAP, there are those customers whose income is higher than 150% of Poverty but lower than a self-sufficiency standard. Customers in this group are those customers who do not have

[1] BCS (annual). Universal Service Programs and Collections Performance. Available at: http://www.puc.state.pa.us/filing_resources/universal_service_reports.aspx (last accessed July 5, 2021).

income sufficiently low to be eligible for CAP, but who also do not have income sufficiently high to meet their day-to-day needs. The group of customers having income in this range can be considered in light of Pennsylvania's Self-Sufficiency Standard.

The data on Pennsylvania's self-sufficiency standard in the PECO counties[2] demonstrates that customers may not be "low-income" as per the PUC's definition, but still may have insufficient household resources to consistently pay their daily expenses. I consider the six (6) counties which PECO lists in its Tariff as comprising (in whole or part) its service territory (Philadelphia, Delaware, Buck, Montgomery, Chester, York).

In this assessment, I consider the self-sufficiency incomes, limited to three-person households, for these PECO counties. There are fifteen different potential family configurations for a three-person household. For example, there could be a single parent with two infants, or a single parent with an infant and a teenager, or two parents with a teenager. Each family configuration needs a different income to meet self-sufficiency. In the PECO service territory, of the 90 possible incomes for three-person households (6 counties x 15 configurations for a 3-person household), 13 exceed 150% of income (100% of income for three-person household = $21,960 x 150% = $32,940) but are less than 250% of Poverty ($21,960 x 250% = $54,900). Of the remaining, 14 exceed 250% of Poverty, but are less than 300% ($21,960 x 300% = $65,880). As can be seen, a significant number of 3-person self-sufficiency incomes in the PECO counties fall between 150% and 300% of Poverty (27 of 90). As I discuss above, therefore, there is a

[2] http://www.selfsufficiencystandard.org/pennsylvania (last accessed July 5, 2021).

substantial population who falls within this group of concern (i.e., those who are below a Self-Sufficient income but above the CAP income eligibility line).

In sum, I conclude that there is no single population of income-challenged customers served by PECO. As always, the provision of assistance by PECO to CAP participants must simply be balanced against the obligation of income-eligible non-participants, as well as the obligation of those whose income exceeds CAP eligibility but are below a standard of self-sufficiency, to pay the costs of such assistance.

Q. WHAT ARE PECO'S COSTS?

A. If the Commission approves a decrease to the energy burdens, it would be necessary to examine other aspects of the program to ensure that costs are controlled and that the program remains as cost-effective as possible. The costs of PECO's CAP will increase given a reduction in CAP burdens. PECO projects its CAP PIPP will increase anticipated program costs by approximately $20 million to $23 million per year compared to its current CAP FCO.

Projected CAP Costs 2022-2024: CAP FCO vs. Proposed CAP PIPP						
CAP Costs	**2022**		**2023**		**2024**	
	CAP FCO	*Proposed PIPP*	*CAP FCO*	*Proposed PIPP*	*CAP FCO*	*Proposed PIPP*
Admin	$3,126,621	$3,126,621	$3,204,786	$3,204,786	$3,284,906	$3,284,906
PPA Forgiveness	$7,600,000	$7,600,000	$7,900,000	$7,900,000	$8,200,000	$8,200,000
CAP Credits	$62,206,000	$82,500,000	$61,818,060	$84,562,500	$62,436,241	$85,408,125
Total	**$72,932,621**	**$93,226,621**	**$72,922,846**	**$95,667,286**	**$73,921,147**	**$96,893,031**

Source: January 16, 2020 2019 USECP filing at 26 and Amended Proposed 2019 USECP (filed on September 25, 2020) at 23.

As I explain in more detail in my Direct Testimony regarding the historic allocation of universal service costs exclusively to the residential class, I remain concerned with CAP cost increases that are flowed through automatically exclusively to residential customers through the universal service charge.

For the reasons set forth below, the Commission should not approve the proposed changes to the energy burdens in this proceeding, particularly in light of the current financial impact of COVID-19 on residential customers who must bear the increased costs of these changes. Asking residential customers to assume even greater costs during this difficult economic time would further strain affordability for the many residential customers who do not qualify for CAP or who do not participate in CAP.

Q. PLEASE DESCRIBE YOUR AFFORDABILITY CONCERNS ASSOCIATED WITH COVID-19.

A. In my Direct Testimony, I outlined in detail the basis for concluding that the economic and financial circumstances of residential customers remains tenuous and likely will be for some time to come. I appreciate the need for CAP at this critical time. As I outline in my Direct Testimony, the focus of PECO should be on enrolling customers who are income-eligible. A particular focus should be on enrollment of customers whose income is less than 50% of Poverty Level. That focus was identified in the Commission's Revised CAP Policy Statement.

Q. IS THERE A THIRD REASON THE ISSUE OF CAP BURDENS SHOULD BE DEFERRED TO PECO'S USECP PROCEEDING?

A. Yes. If the Commission determines that the energy burdens proposed by Mr. Geller should be approved, the Company should be required to implement additional cost control measures as discussed below. Examples of cost control measures that perhaps should be considered include (but may not be limited to):

- limiting the annual increases in CAP costs flowed through the universal service charge;

- increasing the minimum payment;

- extending the length of time for arrearage forgiveness; capping the amount of arrearage forgiveness charged to ratepayers; decreasing overall administrative costs;

- revisiting and adjusting maximum CAP credits;

- allocating Low Income Usage Reduction Program resources (LIURP) to reduce high user bills; and

- re-examining the CAP participation of the Department of Housing and Urban Development (HUD) tenants who receive federal dollars designed to pay their *entire* utility bills (in the absence of CAP).

The reasonableness of each such possible cost control measure would depend on the particular facts presented in a USECP proceeding.

Q. WHAT DO YOU CONCLUDE?

A. Based on the discussion above, I conclude that a base rate case is not the appropriate proceeding in which to determine whether CAP burdens should be revised. This base rate case does not provide the evidentiary record upon which to formulate the entire range of decisions that should accompany a decision on whether or not to reduce CAP burdens. The decision to reduce CAP burdens is not a decision that can stand alone. To the extent that CAP burdens are reduced, a whole host of corollary decisions regarding CAP structure and operation are also presented.

Q. WHAT DO YOU RECOMMEND?

A. Note that in amending its CAP Policy Statement, the PUC explicitly "urged" utilities to incorporate the CAP Policy Statement amendments, including the revised energy burdens, "in their USECPs." The importance of this is that there is a specific process established for revised USECPs. That process does not involve base rate proceedings.

Based on this discussion, I recommend that whether, and to what extent, PECO reduces its CAP burdens, as well as whether, and to what extent, PECO adopts other CAP cost control mechanisms at the same time it considers a reduction in CAP burdens, should be deferred to the Commission's consideration of PECO's revised USECP.

Part 2. The Recommended In-Program Arrearage Forgiveness.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to Mr. Geller's proposal to implement a new In-Program Arrearage Forgiveness (IPAF) program to customers who have been participating in the PECO Fixed Credit Option (FCO) CAP.

Q. WHAT DO YOU RECOMMEND?

A. As with changes in the CAP energy burdens, the issue of whether there should be an additional IPAF program offered by PECO should be addressed in the PECO USECP proceeding. Whether there should be an IPAF, for whom, and under what circumstances and conditions, are fundamentally part of the Company's USECP proceeding.

Q. DOES AN IN-PROGRAM ARREARAGE FORGIVENESS PROGRAM ADDRESS THE ARREARS ARISING AS A RESULT OF COVID-19?

A. By definition, an IPAF would address the arrearages only of CAP participants. IPAF, as proposed by Mr. Geller, is directed toward CAP bills that have not been paid during COVID-19 notwithstanding the CAP discount.

Q. DOES MR. GELLER MIS-CHARACTERIZE THE IMPACT OF THE PECO FIXED-CREDIT OPTION (FCO) CAP ON AFFORDABILITY?

A. Yes. Mr. Geller states that "PECO has conceded that its CAP FCO program has not improved affordability for its CAP customers, particularly for CAP customers with income between 0-50% of the poverty level." (TURN/CAUSE-PA St. 1, at 29). That's not an entirely complete statement. For example, when PECO filed its evaluation of the FCO on June 28, 2019, it noted what Mr. Geller notes, that "in the first two operational years of the FCO program (calendar years 2017 and 2018), unaffordability in the 50% group remained high." (June 28, 2019 conveyance letter of six-year evaluation, at 2). What PECO went *on* to state, however, was that "PECO has been working with its external evaluator to obtain a deeper understanding of the drivers that caused this level of unaffordability in 2017 and 2018. *Unfavorable weather* during those years appears to be one dominant driver of the outcome." (Id.) (emphasis added). In addition, a disproportionate number of customers with income at or below 50% of Poverty do not pay the PUC-prescribed maximum burdens. Instead, customers in this income bracket frequently, if not generally, end up being charged the minimum payment, which (by definition) will exceed the PUC burdens.[3]

Mr. Geller's comment that the FCO did not improve affordability, "particularly for CAP customers with income between 0-50% of the poverty level" does not fully capture the nuances of what occurred with the FCO. According to PECO's six-year evaluation of its universal service programs, the evaluation in which PECO considered the impacts of the

[3] If payment at the PUC burden exceeded the minimum bill, the customer would be charged that payment, not the minimum payment.

FCO, for example, PECO found any number of factors contributing to unaffordability outside of the burdens which were being charged. The Table below, for example, presents data for both 2016 (pre-FCO) and 2018 (during FCO). While it might appear that the FCO resulted in more CAP participants having burdens exceeding the PUC target burdens under the FCO (31%) than before the FCO (24%), the Table demonstrates some of the nuances which I mentioned. The percentage of customers exceeding the PUC target burden because they reached the maximum CAP credit limit, for example, increased from 48% to 57%; the percentage of participants exceeding the PUC target burden because they paid the minimum bill increased from 26% to 53%. It was, in other words, not the target burdens (which Mr. Geller proposes to change in this proceeding), but other aspects of the program which were in play.

Table 1. Energy Burden Relative to PUC Target After Enrollment CAP (2016 vs. 2018)
(2016: Pre-FCO, 2018: FCO) (PECO Evaluation, at 129)

		2016 CAP Participants				2018 CAP Participants			
		Obs.	Below	Within	Above	Obs.	Below	Within	Above
Electric Heating	All	11,631	6%	15%	24%	11,940	45%	24%	31%
	>=Max CAP Credit	418	40%	12%	48%	315	29%	14%	57%
	Min Bill	164	74%	12%	14%	641	31%	13%	57%
Electric only (electric baseload)	All	89,674	41%	24%	35%	86,062	19%	37%	44%
	>=Max CAP Credit	6,415	13%	13%	74%	3,768	8%	14%	79%
	Min Bill	2,677	50%	24%	26%	3,277	20%	27%	53%

In addition, the PECO evaluation explicitly stated that "Most of the CAP participants who were above the target burden were at or below 50 percent of the poverty level."

(PECO Evaluation, at 149). One reason that CAP participants with income at or below 50% of Poverty tend to have burdens that exceed the PUC targets is because of mandatory minimum payments. Minimum payments are required when a CAP participant's income is sufficiently low the participant would make no payment, or a de minimis payment, toward the utility bill. Without a minimum payment, for example, in a percentage of income program, a customer would make *no* payment toward their bill. In all circumstances, the Commission has held, customers are to make a minimum payment determined in proceedings reviewing each utility's USECP. A move from the FCO to a percentage of income program does not mean that minimum payments will be eliminated.

Particularly if the in-program arrears of CAP participants are not exclusively (or primarily) related to the operation of the FCO, but are instead related to other aspects of the operation of CAP (e.g., maximum CAP credits, minimum payments), it would be particularly inappropriate to adopt an IPAF program within this rate case without also considering what other changes should be made, if any, to address any issues with those other CAP design features. Moreover, if the unaffordability of the FCO lies, as the PECO evaluation found, primarily with customers with income at or below 50% of Poverty, it would seem to be inappropriate to adopt an IPAF for customers at all income ranges.

Q. DO YOU HAVE ANY FINAL OBSERVATION ABOUT MR. GELLER'S PROPOSED IPAF?

A. Mr. Geller appears to assert as an article of faith that any in-program arrearages of CAP participants are associated with an unaffordable bill. He asserts, for example, without documentation, that "PECO CAP customers are carrying significant in-program arrears, which are much higher than the average residential arrears. This is caused by two primary factors: the failure of PECO's FCO to deliver an affordable bill, and (2) the unprecedented and disproportionate economic devastation caused by the pandemic within low-income communities." (TURN/CAUSE-PA St. 1, at 28 – 29). I agree with the impact that the COVID-19 pandemic has had on the low-income community. Those problems can and should be addressed through the COVID-19 relief program that both PECO and I addressed in Direct Testimony, not through an IPAF.

There has been no documentation, however, that in-program arrears are caused by "the failure of PECO's FCO to deliver an unaffordable bill." It may well be the case that nonpayment of bills is occurring by CAP customers who were receiving an affordable bill under PECO's FCO. Mr. Geller does not demonstrate that the unpaid CAP bills are associated with CAP participants who received bills that exceeded the PUC's target energy burdens. If CAP payments are not being made despite the CAP participant receiving an affordable bill, it would be inappropriate to make any arrears from such nonpayment subject to an IPAF.

Neither has Mr. Geller demonstrated that the increase in in-program arrears flows primarily from the population of CAP participants with income below 50% of Poverty. It should be remembered, again, that PECO's evaluation found that it was that income level which had “most of the CAP participants who were above the target burden. . .” (PECO Evaluation, at 149).

More than concluding that Mr. Geller’s recommendation is reasonable or unreasonable, however, I conclude simply that the factual basis for Mr. Geller’s recommended IPAF program is more nuanced that has been presented in this proceeding. The proceeding in which the PECO evaluation of the FCO is part of the record is the pending PECO USECP review. The proceeding in which stakeholders are addressing not only the move from the FCO to a PIP, but also the impacts of other CAP design features (e.g., minimum payments, maximum CAP credit ceilings), is the pending PECO USECP review. The proceeding in which the impact of PECO’s CAP not only on CAP participants as a whole, but on CAP participants disaggregated by income levels is the pending PECO USECP review. I conclude that the proceeding in which Mr. Geller’s IPAF recommendation should be addressed is also the PECO USECP review.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

313939

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024601
	:	
PECO Energy Company – Electric Division	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts set forth in my Rebuttal Testimony, OCA Statement 4-R, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 22, 2021
*313688

Signature: ______________________
Roger D. Colton

Consultant Address: Fisher, Sheehan, & Colton
34 Warwick Road
Belmont, MA 02478

OCA Statement No. 1-SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
v.	**)**	**Docket No. R-2021-3024601**
PECO Energy Company – Electric Division	**)**	

SURREBUTTAL TESTIMONY OF

DANTE MUGRACE

ON BEHALF OF THE

COMMONWEALTH OF PENNSYLVANIA

OFFICE OF CONSUMER ADVOCATE

August 5, 2021

TABLE OF CONTENTS

I. PURPOSE OF SURREBUTTAL TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dante Mugrace. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS DOCKET?

A. Yes. I submitted Direct Testimony on June 28, 2021, which was marked as OCA Statement No. 1. My qualifications and experience are attached to my Direct Testimony.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony is to address the Rebuttal Testimonies of Company witnesses Mr. Trzaska (Statement No. 3-R), Mr. Stefani (Statement No. 2-R) and Ms. Feldhake (Statement No. 10-R). I am also making certain adjustments to proposals in my testimony and a revised calculation of the Company's revenue requirement that incorporates the effects of my adjustments. I've also updated the Company's adjustments to certain of its revenue requirement schedules, (Interest on Customer Deposits and Salary and Wages). To the extent that I do not respond to or address a particular issue or argument, I defer to my Direct Testimony on those issues.

Q. WITH YOUR ADJUSTMENTS TO YOUR DIRECT TESTIMONY, WHAT IS YOUR REVISED COMPANY REVENUE REQUIREMENT?

A. With my revised adjustments, I have calculated a revenue requirement increase of $28,881,459. This includes OCA Witness Mr. Garrett's overall rate of return of 6.215%, which includes a common equity cost rate component of 8.50%.

II. REVENUE REQUIREMENT ISSUES

A. Rate Base Issues – Utility Plant In Service (UPIS)

Q. WHAT IS THE COMPANY'S POSITION REGARDING YOUR ADJUSTMENTS TO ITS UTILITY PLANT IN SERVICE?

A. Mr. Stefani did not agree with my adjustments to the Company FPFTY plant in service. He identified four reasons for his argument. His first argument relates to my removal of capital projects identified in response to OCA-VI-6 Attachment that I have stated might likely be delayed beyond the FPFTY ($69,764,261). Mr. Stefani's second argument relates to my removal of capital projects that have been rescheduled for completion in 2022 due to delays ($22,502,364). Mr. Stefani's third argument related to my removal of projects that no longer have an in-service date in the FTY or the FPFTY periods ($11,629,965). Mr. Stefani's final argument relates to my normalizing the baseline capital additions between the projected balances for the FTY and FPFTY periods. ($109,633,073). (Statement No. 2-R at 3-4). Mr. Stefani stated that my argument for removing these capital projects from the Company's UPIS balance did not provide any evidence that these projects would not meet the deadline and expected completion dates in the month of December 2022. (Statement No. 2-R at 3). Mr. Stefani stated that I hypothesized that since projects had experience delays in the past it is unclear whether the Company will place these projects into service in 2022. (Statement No. 2-R at 3). Mr. Stefani stated that my adjustments are inappropriate because of the fact that plant will be placed into service in the month of December in the FPFTY. (Statement No. 2-R at 4). Mr. Stefani stated that the month of December represents the largest proportion of projects of capital additions being placed into service in prior years (Statement No. 2-R at 5).

Q. WHAT DID MR. STEFANI STATE REGARDING YOUR NORMALIZATION OF BASELINE CAPITAL ADDITIONS?

A. Mr. Stefani stated that removing these baseline capital additions would be deleterious in the Company's ability to maintain its distribution system. He states that the Company regularly schedules routine maintenance work that is short in duration and capitalized monthly or quarterly and is not budgeted into individual projects. (Statement No. 2-R at 6). Mr. Stefani stated that baseline spend includes projects to fulfill the Commission-approved Long-Term Infrastructure Improvement Plan (LTIIP) commitments, including $105 million in the FTY and almost $300 million in the FPFTY. (Statement No. 2-R at 6).

Q. WHAT DID MR. STEFANI STATE REGARDING YOUR REMOVAL OF CAPITAL PROJECTS THAT THE COMPANY INDICATED WILL BE DELAYED BEYOND THE FPFTY PERIOD?

A. Mr. Stefani stated that I failed to include $9,752,323 in projects that are identified as New on OCA Exhibit DM-1 pp. 2-8 for both the FTY and FPFTY. The $1.87 million between my recommended $11.62 million disallowance and the addition of $9.75 million New projects will be offset by additional plant in service during the FPFTY that well exceed this amount in response to major storms. (Statement No. 2-R at 6).

Q. WHAT IS YOUR RESPONSE TO MR. STEFANI'S ARGUMENTS?

A. With respect to the baseline capital additions of $109,633,073 and given that certain of these baseline capital additions includes commitments to fulfill the Commission approved LTIIP, I am accepting the Company's reasoning. Mr. Stefani has stated that these baseline additions provide the Company with the ability to properly maintain its distribution system and includes regularly scheduled routine maintenance work. I have added back the baseline capital additions of $109,633,073 and is shown on my Schedule SR-DM-5.

Q. WHAT IS YOUR RESPONSE RELATED TO MR. STAFANI'S ARGUMENTS ON THE ABANDONED PROJECTS, DELAYED PROJECTS AND DELAYED PROJECTS THAT HAVE BEEN PUSHED BACK?

A. I am not inclined to adjust my recommended $11,629,965 related to abandoned projects. The Company has claimed to have added $9,752,323 of new projects which Mr. Stefani stated offsets the difference by $1.87 million, and that the Company forecasted that it will be adding additional plant in service during the

FPFTY that will well exceed the amount in response to major storms. (Statement No. 2-R at 6). The Company has not specifically identified these projects and has stated that these expenditures are not included in the Company's capital expenditures budget but will be added due to major storms. (Statement No. 2-R at 6). With respect to the Delayed Projects that have been pushed back totaling $22,502,364, most of these projects have been delayed by up to nine-months from their original in-service dates. [1] The Company has stated in response to OCA-VI-6 (a) that these delays related to in part, parallel building demolition, underground obstructions, site-construction issues, permitting requirements, scope commitments, and reprioritizing other critical and emergent projects. The Company should update this response to show beginning construction dates and updating as needed. The Company should indicate whether these delays have been resolved and the projects are moving forward and expected to be in service by the end of the FPFTY period. I am still recommending that these projects be removed from the Company's UPIS balance. Finally with respect to Delayed Projects totaling $69,784,261 [2] the Company has not provided any specific delays in these project but for the reasonings outlined in the Commentary section of Attachment OCA-VI-6 (a). Mr. Stefani stated that removing these costs simply because they are delayed until the last month of the FPFTY period is contrary to the basic tenets of cost recovery in connection with a FPFTY. (Statement No. 2-R at 4). Again, the Company should indicate the beginning construction dates and update as needed with respect to stages of completion.

Q. WHAT IS YOUR SURREBUTTAL RECOMMENDATION ON THE DELAYED PROJECTS TOTALING $69,784,261?

A. I am recommending that all but one project be removed from the Company's UPIS balance. This project is related to the Company's LTIIP (URD Mainstem -Byberry 131 in the amount of $339,628- Attachment OCA-VI-6 (a) page 2 of 7). As I indicated previously in my testimony, the Company has a commitment to fulfill

[1] In my direct testimony I identified these projects as highlighted in green, they are highlighted in blue.
[2] These capital projects are highlighted in green, not blue.

these projects. This adjustment reduces my recommended reduction balance from $69,784,261 to $69,444,633.

Q. WHAT DID MR. STEFANI STATE REGARDING YOUR ADJUSTMENT RELATED TO THE COMPANY'S ACCUMULATED DEFERRED INCOME TAXES (ADIT)?

A. Mr. Stefani stated that I incorrectly calculated the rate base effect of ADIT, in that I only adjusted for the effects of the change in book depreciation without considering the associated reduction to accelerated tax deduction including accelerated tax depreciation. Mr. Stefani stated that I understated rate base by $1,843,937 (Statement No. 2-R at 7).

Q. WHAT IS YOUR RESPONSE?

A. I made the adjustment related to my disallowed plant additions, utilizing the Company's deferred income tax rate of 28.89% (Schedule SR-DM-9). In other words, my adjustment computes the effect of my recommended Accumulated Depreciation Expense deduction of $3,003,732 times the deferred income tax rate of 28.89% to compute an Accumulated Deferred Income Tax adjustment of $867,778. I believe this is the appropriate way to calculate the dollar effect of my adjustment. I am not sure what Mr. Stefani is addressing. Mr. Stefani should specifically identify my mistake in the calculation of my ADIT; I will correct my mistake at that time.

Q. WHAT DID MR. TRZASKA STATE REGARDING YOUR CAPITAL ADJUSTMENTS ASSOCIATED WITH THE REPAIRS DEDUCTION?

A. Mr. Trzaska stated that I failed to propose an adjustment to the Company's repairs deduction that would be needed if my proposal was adopted. (Statement No. 3-R at 6). Mr. Trzaska stated that the Company has used a repairs deduction of $128 million to reflect plant additions to be placed in service during the FPFTY that qualify for the repairs deduction (Statement No. 3-R at 6). Mr. Trzaska stated that if my adjustments to plant in service were adopted, a portion of the repairs deductions that would be generated by FPFTY plant additions should be eliminated in calculating the Company's income tax expense allowance in this case. (Statement No. 3-R at 6).

Q. WHAT IS YOUR RESPONSE?

A. I am assuming that Mr. Trzaska is referring to my disallowance of the Baseline Capital Additions that I recommended disallowance in the amount of $109,633,073. Given that I added back this amount, I did not make any adjustment to the Company's baseline capital additions, which won't affect the repairs deduction balance of $128,000,000. If I am incorrect, the Company should identify where my mistakes are and provide the adjustment. (Statement No. 3-R at 8-9). My adjustments are shown on my Schedule SR-DM-5.

1. Pension Asset

Q. WHAT HAS MR. TRZASKA STATED REGARDING YOUR DISALLOWANCE TO THE PENSION ASSET OF $128,977,000?

A. Mr. Trzaska disagrees with my adjustment removing the Pension Asset from rate base. (Statement 3-R at 12-13). Mr. Trzaska stated, among other things, that I inappropriately relied on the Commission's decision in PECO's recent Gas Division base rate case for support (Statement No. 3-R at 13).

Q. WHAT IS YOUR RESPONSE?

A. I am relying on the Commission's decision in the PECO Gas Division base rate case, there are no further arguments to be made regarding this issue. The Commission denied this Pension Asset balance proposal in the PECO Gas Division base rate case. In that Order, the Commission reasonably addressed all of the concerns that were raised by PECO Gas Company's witness Mr. Trzaska. The Company has stated that it has requested reconsideration of the Commission's decision (Statement No. 3-R at 17). Until such time as the Commission rules on the Company's reconsideration, I will abide by the Commission ruling. My adjustment is shown on my Schedule SR-DM-3.

B. OPERATING INCOME

1. Operating Revenues

Q. WHAT HAS THE COMPANY STATED REGARDING YOUR ADJUSTMENT TO OTHER REVENUE – FORFEITED DISCOUNTS?

A. Mr. Trzaska stated that my incremental Forfeited Discount adjustment is incorrect. (Statement No. 3-R at 27). He stated that since I did not disagree with the Company's budgeted Forfeited Discounts revenue of $12,795,000 at present rates, my Forfeited Discount balance should be the same. Mr. Trzaska stated that the Forfeited Discount at Present Rates should not include the incremental Forfeited Discounts related to the requested rate increase of $246 million, which I did not adjust. (Statement No. 3-R at 27).

Q. WHAT IS YOUR RESPONSE?

A. Given that the Company has adjusted its Forfeited Discounts to included additional dollars related to its proposed $246 million revenue requirement increase, I believe an adjustment should be made to account for my recommended revenue requirement increase accordingly. The $924,000 of additional Forfeited Discounts should be pared down to account for my recommended revenue requirement adjustment. There is no other way to account for this adjustment but to include it as part of the calculation in my revenue requirement recommendation. As shown on my Schedule SR-DM-1 and in more detail on my Schedule SR-DM-4, I included the incremental Forfeited Discount of $77,073, in the same fashion as the Company included its incremental Forfeited Discount balance of $924,000 related to the Company's proposed increase. My adjustment is shown on my Schedule SR-DM-4.

Q. WHAT DID MR. STEFANI STATE REGARDING YOUR ADJUSTMENTS TO MISCELLANEOUS SERVICE REVENUES, RENT FOR ELECTRIC PROPERTY AND OTHER ELECTRIC REVENUES?

A. Mr. Stefani stated that my adjustments to the above income items are related to historical figures instead of the Commission approved FPFTY methodology. He does not agree with my methodology in that I incorrectly determined the averaging method because I should have calculated a decrease in these adjustments, specifically because I include Mutual Assistance costs in my three-year normalization. (Statement No. 2-R at 49).

Q. WHAT IS YOUR RESPONSE?

A. I did review Mr. Stefani's RJS-10, and accept his methodology related to the exclusion of Mutual Assistance to develop the three – year normalization balance. My adjustment is shown on my Schedule SR-DM-4.

2. OPERATION AND MAINTENANCE EXPENSES

a. Payroll Expense/Payroll Taxes/Vacancy Rate

Q. WHAT DID MR. STEFANI STATE REGARDING YOUR USE OF THE COMPANY'S PAYROLL EXPENSE AND PAYROLL TAX ADJUSTMENTS?

A. Mr. Stefani did not agree with my adjustments related to the (1) Company's annualized adjustment for pay increases in 2023; (2) Vacancy adjustment of 1.83%; (3) removal of the Company's one-time union contract ratification bonus; (4) the Company's labor cost adjustment and; (5) disallowance of the Company's cash-based incentive compensation. With respect to Item (1), Mr. Stefani stated that the 2023 wage increases are known and measurable and will be incurred shortly after the end of the FPFTY period (Statement No 2-R at 10). Mr. Stefani stated that the annual wage increase of 2.5% is committed by the Company through 2026 (Statement No. 2-R at 10). With respect to Item (2) my Vacancy adjustment of 1.83%, Mr. Stefani stated that the application of a Vacancy rate is unwarranted because the Company's payroll expense claim reflects a total net increase of 212 FTE's by the end of the FPFTY period. Mr. Stefani stated that the Company has historically filled nearly all of the positions it sought to hire with a success rate in the range of 80-90%. (Statement No. 2-R at 12). With respect to

Item (3), Mr. Stefani stated that this one-time union bonus is a prudent expense which is necessary to retain the Company's talented labor pool and ensure the Company has access to skilled union workers. (Statement No. 2-R at 14). With respect to Item (4), Mr. Stefani stated that the labor cost adjustment of $4.5 million is a union ratification bonus to reflect the final numbers resulting from the union contract which should be approved. (Statement No. 2-R at 14).

Q. WHAT IS YOUR RESPONSE?

A. With respect to Item (1), (Annualized adjustment for 2023 pay increase), these costs are beyond the Company's FPFTY period of December 31, 2022), and should not be included in the Company's revenue requirement. Mr. Stefani's argument that these costs will be incurred shortly after the end of the FPFPY does not support the fact that the Company's FPFTY period ends on December 31, 2022. The fact the Company's wage increase that will occur on March 1, 2023, does not change the timing of the FPFTY period. Any adjustments beyond the test year should be disallowed. With respect to Item (2), (Vacancy Adjustment), the Company typically has a level of vacancies at any given year and does not have a full complement of employees at any given time. Employees get hired, leave the Company, get fired, laid off or retire. The Company does not know when these events will occur, so Mr. Stefani's argument that all of the Company's vacancies will be filled by the end of the FPFTY is not accurate. With respect to Item (3), (One-time bonus), and (Item 4) (One-time payment) Mr. Stefani stated that the one-time bonus will be paid upon ratification of the new union agreement (Statement No. 2-R at 14) and is needed to retain a talented labor pool. (Statement No. 2-R at 14). Regarding the Item 4 – the one-time payment, Mr. Stefani stated that the Company finalized a new union contract which has been ratified and recovery of the bonus should be approved. (Statement No. 2-R at 14). As I stated in my direct testimony, I believe that these payments are akin to bonuses, which are linked to certain goals and targets required to be achieved or earned in order to receive these bonuses. It is my opinion that these bonus type payments do not provide any benefit to ratepayers regarding safe and reliable service. These on-time bonuses are not linked to any performance criteria that are required to be met to receive the bonuses. These payments are simply costs needed for the parties to sign up and agree to a new union contract agreement.

b. Incentive and Stock Compensation

Q. WHAT DID COMPANY WITNESS MR. STEFANI STATE REGARDING YOUR ADJUSTMENTS TO INCENTIVE COMPENSATION AND STOCK COMPENSATION?

A. Mr. Stefani stated that my removal of incentive compensation is unreasonable, in that incentive compensation has been approved by the Commission and is common among the Company's utility peers. (Statement No. 2-R at 18). Mr. Stefani stated that my removal of stock compensation is unjust and unreasonable (Statement No. 2-R at 19). Mr. Stefani stated that the Company made a deliberate decision to ensure that the incentive plans of all employees have safety, customer satisfaction and reliability as key requirements to achieve maximum availability compensation, so that all employees are focused on maximizing Company performance in serving customers (Statement No. 2-R at 19).

Q. WHAT IS YOUR RESPONSE?

A. I would accept the recovery of incentive compensation related to union workers that provide benefits to ratepayers in the form of safety, customer satisfaction and reliability. However, in response to OCA-III-39, the Company stated that it does not have the capability to provide a breakdown into the requested employee groupings. In response to IE-RE-27-D, the Company was asked to provide a breakdown of incentive / bonus expense under various incentive plans and calculates the incentive expense in the aggregate based upon total payout and not by individual performance criteria. The Company has projected total Incentive Compensation of $13.545 million (OCA-III-36 (a)). The Company should provide a breakdown of incentive compensation that has been allocated to the union employees, I will review the information and update my recommendation related to incentive compensation.

Q. WHAT IS YOUR RESPONSE RELATED TO MR. STEFANI'S CLAIM THAT YOUR REMOVAL OF STOCK COMPENSATION IS UNJUST AND UNREASONABLE?

A. I believe these stock compensation costs are geared toward executive, vice-presidents and managers of the Company, (non-union) and not geared toward union employees or front-line workers. As I stated in my direct testimony (OCA-Statement No. 1 at 25) the Company has not identified who are the recipients of the stock compensation nor provided the development of these stock compensation costs. Without this information it is difficult to determine whether these costs benefit ratepayers. My recommendation is the same, to disallow stock compensation costs of $4,427,000 (OCA-VI-4 (a).

c. Employee Benefits

Q. WHAT HAS THE COMPANY STATED IN REGARD TO YOUR EMPLOYEE BENEFITS ADJUSTMENT?

A. Mr. Stefani stated that my removal of the 3% cost of living inflation adjustment is not correct in that the 3% adjustment is related to the annual stipend that participants may use to purchase insurance on an exchange as a result of the Company' 2014 retirement plan design modification. (Statement No. 2-R at 20).

Q. WHAT IS YOUR RESPONSE?

A. In response to OCA-III-20, the Company specifically identifies that the 3% is a discretionary cost of living adjustment and developed by taking into account inflation information current at the time of the adoption of the plan modification. I continue to believe that the 3% adjustment is an inflation adjustment and should be removed from the Company's Employee Expense adjustment. My adjustment is shown on my Schedule SR-DM-18.

d. Other Post-Employment Benefits (OPEB) Expense

Q. WHAT DID MR. STEFANI STATE REGARDING YOUR ADJUSTMENT TO THE COMPANY'S OPEB EXPENSE?

A. Mr. Stefani stated that I opposed the Company's independent third-party actuarial report as the basis for the forecasted OPEB expense. (Statement No. 2-R at 24). He stated that my proposed five-year normalization is not indicative of future expense in the FPFTY since the prior service adjustments will be fully amortized prior to 2022. (Statement No. 2-R at 25). Mr. Stefani stated that my adjustment to the Company's OPEB expense was due to the Company's absence of additional information needed to review the Company's proposal (Statement No. 2-R at 25).

Q. WHAT IS YOUR RESPONSE?

A. Mr. Stefani is correct that my adjustments were due to the absence of the Company's additional information needed to review the Company's adjustments. In Mr. Stefani's rebuttal, he stated that the Company now has readily available information that was not included in the standard report provided by Willis Towers Watson (the Company's actuarial company). I reviewed Mr. Stefani's Exhibit RJS-9. I am now accepting the Company's adjustment to its OPEB expense. This is shown on my Schedule SR-DM-18.

e. Exelon Business Service Company (EBSC) Expense

Q. WHAT HAS MR. STEFANI STATED WITH REGARD TO YOUR ADJUSTMENT TO ITS EXELON BUSINESS SERVICE COMPANY EXPENSES?

A. Mr. Stefani stated that my adjustment disallowing $8.3 million of incentive compensation was based upon the Company not providing support for whether EBSC incentive compensation benefits customers. (Statement No. 2-R at 34). Mr. Stefani stated that these costs are needed to retain and attract top talent for the provision of service to the Company and its customers. He further noted that the Commission has expressly approved recovery of incentive compensation.

Q. WHAT IS YOUR RESPONSE?

A. I do not believe ratepayers should be paying for costs in order for the Company to retain and attract top talent. The Company has not specifically identified what benefits these expenses provide to ratepayers but to retain top talent. The only information the Company provided was in response to OCA-III-21 which shows the total incentive compensation billed by EBSC to the Company was $8.3 million, a further breakdown is not available due to ESBC cost allocations. In my opinion, without a further breakdown of these costs, it is nearly impossible to determine whether any of these costs benefits ratepayers. The Company's assertions that the Commission has expressly approved recovery of these costs is without merit. There should be some type of information breakdown that shows the benefit to ratepayers. Without this breakdown, I am recommending disallowance of these costs. My recommendation is shown on my Schedules SR-DM-14, 15 and 18.

f. Employee Activity Costs

Q. WHAT HAS MR. STEFANI STATED WITH REGARD TO YOUR ADJUSTMENTS TO EMPLOYEE ACTIVITY COSTS?

A. Mr. Stefani stated that my disallowance to allow recovery of Employee Activity Costs that are relatively modest expenditures is contrary to what the Commission has recognized with respect to the importance of general employee events in contributing to a utility's workplace environment. (Statement No. 2-R at 35-36). Mr. Stefani stated that these types of costs are a means to increase employee engagement and benefits employee morale and productivity (Statement No. 2-R at 36).

Q. WHAT IS YOUR RESPONSE?

A. Ratepayers should not be responsible for employee morale or productivity, but rather the Company should be wholly responsible for providing a safe, healthy and productive workplace. As I stated in my direct testimony (OCA Statement No.1 at 43), I do not see a nexus between Company celebrations, activities, picnics and other in-hour celebratory gatherings with safe, adequate and reliable service to customers. If the Company believe that these types of costs are beneficial to ratepayers, the Company should pay for these costs and not ratepayers. Providing for celebratory events for employees is not the only thing that keeps and retains employees.

g. Vegetation Management

Q. WHAT HAS MR. STEFANI STATED WITH REGARD TO YOUR ADJUTMENT TO VEGETATION MANAGEMENT COSTS?

A. Mr. Stefani stated that the Company' Vegetation Management costs do vary from year-to-year due to a variety of operational factors that impact the timing of vegetation management spend. (Statement No 2-R at 39). Mr. Stefani stated that in using a five-year average a resultant adjustment would produce a reduction of $3,554,451 and not my recommended reduction of $3,668,841, an adjustment of $114,390. (Statement No 2-R at 28). Mr. Stefani stated that a reduction in the Company's proposed vegetation management spend will decrease the scope of preventive maintenance programs, adverse impacts to reliability and customer satisfaction. (Statement No. 2-R at 40).

Q. WHAT IS YOUR RESPONSE?

A. My Stefani adjusted my five-year average by adding in the Company's 2022 budget for vegetation management and using a five-year average. Mr. Stefani stated that the increase in vegetative management is due to the Commission – approved Emerald Ash Borer program which began in 2018 and will continue through the FPFTY. (Statement No. 2-R at 39). Mr. Stefani didn't specifically object to the use of a five-year average of vegetation management. Given this, I am accepting the Company's adjustment of $3,554,451 with respect to the five-year normalization. My recommendation is shown on my Schedule SR-DM-14.

h. Economic Development and Employee Volunteer

Q. WHAT HAS MR. STEFANI STATED IN RESPONSE TO YOUR ADJUSTMENT REGARDING ECONOMIC DEVELOPMENT AND EMPLOYEE VOLUNTEER?

A. Mr. Stefani stated that such costs provide for the Company to locate and expand its services in its territory for prospective new customers. Mr. Stefani stated that these costs provide for retaining and adding companies and has an impact on employment in the region. (Statement No. 2-R at 41). Mr. Stefani stated that volunteering events are an opportunity for the Company to directly interact with and serve customers in the community, to purchase supplies, and provide for giveaway items that customers receives (fans, hand sanitizers, hygiene wipes, soap, etc.). It also benefits to recruiting and maintaining employees. (Statement No. 2-R at 41-42).

Q. WHAT IS YOUR RESPONSE?

A. I believe that none of the above costs provide benefits to ratepayers, but rather provide benefits to the Company. As I stated in my direct testimony, these types of costs should be absorbed by the Company and not passed onto ratepayers through rates. Ratepayers should not be required to pay for volunteering activities or for the promotion of retaining and maintaining employees or for employment in the region. These costs should be wholly borne by the Company or through a collaboration with local, state and municipal entities. The Company is in their right to be good corporate citizens, and I commend them for this approach, but for ratemaking purposes these costs should not be borne by ratepayers.

i. Experimental / General Expense

Q. WHAT HAS MR. STEFANI STATED REGARDING YOUR ADJUSTMENT TO THE COMPANY'S EXPERIMENTAL/GENERAL EXPENSE?

A. Mr. Stefani that these costs are necessary and beneficial to customers given the number of successful programs and the impact. He stated that while not all experimental costs leads to technology or other improvements implemented for customers, these costs do provide benefits. Mr. Stefani stated that leveraged research related to the implementation of Unmanned Aircraft (drones) improves the ability to identify distribution and maintenance defects during routine inspection and provides for enhanced storm response during damage assessment, improved worker and public safety and provides for night flights that expedite job planning. (Statement No. 2-R at 42-43).

Q. WHAT IS YOUR RESPONSE?

A. I am still inclined to disallow these costs for ratemaking purposes. However, given the new information that Mr. Stefani has testified to in his rebuttal testimony, I am accepting his description of what these costs are related to and what they entail. Given this small dollar amount ($47,000) and the information Mr. Stefani stated this cost provides (worker safety, damage assessment and expedited job planning), I believe these types of costs do benefit ratepayers in the provision of safe, adequate and reliable utility service, while protecting workers in fulfilling their duties. My recommendation is shown on my Schedule SR-DM-18.

j. Membership Dues

Q. WHAT HAS MR. STEFANI STATED REGARDING YOUR ADJUSTMENT MEMBERSHIP DUES?

A. Mr. Stefani stated that the Commission has generally permitted utilities to recover membership expenses that are not precluded from recovery under Section 1316.1 of the Public Utility Code. He stated that none of these costs are fraternal, social or sports clubs or organization. (Statement No. 2-R at 45).

Q. WHAT IS YOUR RESPONSE?

A. I believe these costs are social club type costs, that do not benefit ratepayers. Ratepayers do not have a say as to which entities these costs are paid to**,** nor do they provide any customer utility service benefit. As I stated in my direct testimony page 48, and in 66 Pa. C.S. Section 1316.1, no public utility may charge to its customers as a permissible operating expense for ratemaking purposes, costs related to fraternal, social or sports clubs or organization. While I do not see any sports or social type fees in response to OCA-VI-2 (a), I do note that most of these costs are related to chambers of commerce, business alliances, the arts, visitors' bureaus and natural science. I believe that the Legislature did not envision these types of costs are to be properly recovered from ratepayers. Therefore, I am continuing to recommend disallowance of these costs in rates. My recommendation is shown on my Schedule SR-DM-18.

k. Additional Uncollectible Accounts Expense

Q. WHAT DID MR. TRZASKA STATED REGARDING YOUR ADDITIONAL UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. Mr. Trzaska stated that he partially agreed with my adjustment to eliminate incremental Uncollectible Accounts expenses related to the requested rate increase, as this is the incremental amount at proposed rates. (Statement No. 3-R at 28-29). However, Mr. Trzaska stated that my direct testimony adjustment of Uncollectible Accounts should not be included at present rates as it relates to the proposed change that I recommended. (Statement No. 3-R at 29). Mr. Trzaska stated that my Uncollectible Accounts expenses should be the same as the Company's claim. (Statement No. 3-R at 29).

Q. WHAT IS YOUR RESPONSE?

A. In order to properly account for my recommended revenue requirement adjustment (now an increase in rates), I would need to account for the additional adjustment related to Uncollectible Accounts. I utilized the Company's Present Rate Revenues, along with my adjustments to determine the overall revenue requirement increase at present rates to calculate my additional revenue requirement increase proposal. If I utilized only the Company's present

Uncollectible Accounts balance, the Company would be out of additional Uncollectible Account dollars related to its Proposed Rate Revenues. My recommendation provides the Company with an additional $138,268 of costs to be included in the revenue requirement equation. (Schedule SR-DM-15). I used the same methodology as the Company used to compute the additional or incremental Uncollectible Accounts expense related to the proposed $246 million increase. It is a proper adjustment.

l. Additional PUC/OCA/OSBA Assessment

Q. WHAT DID MR. TRZASKA STATE REGARDING MY ADJUSTMENTS TO THE PUC/OCA/OSBA ASSESSMENT?

A. In the same manner as Mr. Trzaska testified to regarding my adjustment to the Company's Uncollectible Accounts expense. Mr. Trzaska stated that my adjustment should not be included at present rates as it relates to the proposed rate change. (Statement No. 3-R at 30). Mr. Trzaska stated that my PUC/OCA/OSBA assessment expense at present rates should be the same.

Q. WHAT IS YOUR RESPONSE?

A. As I testified to under item (k), above, I utilized the Company's Present Rate Revenues along with my adjustments to calculate my recommended revenue requirement increase. This provides the Company with additional dollars for this expense. It is a proper adjustment.

m. Gross Receipts Tax (GRT)

Q. WHAT DID MR. TRZASKA STATE REGARDING YOUR ADJUSTMENT TO GROSS RECEIPTS TAX?

A. Mr. Trzaska partially agrees with my adjustment to calculate the Company's GRT. However, he stated that my adjustment related to my proposed reduction of the

Company's distribution revenue should not be included at present rates, as it relates to the proposed change. (Statement No. 3-R at 31).

Q. WHAT IS YOUR RESPONSE?

A. As I testified to under item (k) and (l) above, I utilized the Company's Present Rate Revenues along with my adjustments to calculate my recommended revenue requirement increase. This provides the Company with additional dollars for this expense. It is a proper adjustment.

n. Transmission Expense

Q. WHAT DID MR. TRZASKA STATE REGARDING YOUR REMOVAL OF STOCK COMPENSATION OF $457,000?

A. Mr. Trzaska stated the $457,000 of Stock Compensation was never allocated to FERC Accounts 561.4 and 561.8 as it was entirely within the accounts under FERC jurisdiction for which the Company is not seeking recovery. Mr. Trzaska stated that I failed to reduce the Company's corresponding TSC and NBT revenues for the expenses in accounts 561.4 and 561.8.

Q. WHAT IS YOUR RESPONSE?

A. Upon review of the response to OCA-VI-4 (a), I am accepting Mr. Trzaska's statement related to the Stock Compensation not being allocated to the Company's distribution expenses. My adjustment is shown on my Schedule SR-DM-13.

o. Pension Expense

Q. WHAT DID MR. TRZASKA STATE REGARDING YOUR ADJUSTMENT TO THE COMPANY'S PENSION EXPENSE?

A. Mr. Trzaska stated that I did not dispute the Company's claimed pension expense recovery of $8.904 million, and that my adjustment only resulted in a pension expense recovery of $3.102 million (Company budget credit of $2.795 million plus the $5.897 million), instead of the $8.904 million based upon a five-year average contribution. (Statement 3-R at 35). Mr. Trzaska stated that if I adjusted the Company's pension expense in Schedule D-4 accordingly, the pension expense recovery would be exactly the same as the amount of $8.904 million based upon a five-year average contribution that is claimed by the Company. Mr. Trzaska stated that my adjustment to the Company's pension expense recovery claim based upon a five-year average contribution should not have any impact at all. (Statement No. 3-R at 35).

Q. WHAT IS YOUR RESPONSE?

A. The Company's pension contribution to be expensed is $8.904 million as shown on Company's Schedule D-9. The Company then adds a credit of $2.795 million to arrive at a balance of $11.699 million, in which the Company claims should be the additional Pension Expense. My question is the Company's budget credit of $2.795 million as an addition to the Company's $8.904 million pension expense. I am willing to accept the Company's $8.904 million balance as the FPFTY adjustment of ($2.795 million) may change and is uncertain. Given that the FPFTY period is December 31, 2022, the Company's independent third-party actuarial may change subsequent to the Commission setting rates in this proceeding. My adjustment is shown on my Schedule SR-DM-18.

p. Storm Expense

Q. WHAT DID MR. TRZASKA STATE REGARDING YOUR ADJUSTMENT TO STORM EXPENSE?

A. Mr. Trzaska did not agree with my removal of inflation factors from the Company's adjustment. Mr. Trzaska stated that I did not dispute the fact that average of costs of both labor and non-labor has been increasing in the past five-years and it will continue to increase during the FTY and the FPFTY. Mr. Trzaska stated that the Company will have to spend more money in the future to restore the same amount of storm damage than in the past. (Statement No. 3-R at 36). Mr. Trzaska stated that the Consumer Price Index (CPI) is one of the most frequently used statistics for identifying periods of inflation and deflation. It is known and measurable. (Statement No. 3-R at 36).

Q. WHAT IS YOUR RESPONSE?

A. Inflation factors do not represent the cost increases specific to the Company; it is simply an overall blanket-type adjustments that are applied to *all* goods and services that may or may not be directly related to the Company's utility operations. It is simply of forecast or prediction of cost adjustments. While inflation adjustments are used to develop economic data adjustments, it should not be used to set rates for ratemaking purposes, as it is *not* a known and measurable adjustment. The Company has not provided any evidence that all of its costs related to storm expense has increased, nor provided any proof from its vendors or outside contractors or updated service agreements that specifically addresses annual increases or annual adjustments to the storm expense. Basic ratemaking principles require that in order for costs to be included in the revenue requirement, these costs must be just and reasonable, prudently incurred and known and measurable. The Company has the opportunity to recover all of its costs in rates, it is not a guarantee. My recommendation is the same, that is, to remove all inflation cost adjustments from the Company's storm expense balance. My adjustment is shown on my Schedule SR-DM-14.

q. Rate Case Expense

Q. WHAT DID MR. TRZASKA STATE REGARDING YOUR ADJUSTMENTS TO THE COMPANY'S RATE CASE EXPENSE?

A. Mr. Trzaska stated that he did not agree with my proposed adjustment for rate case expenses and using the average of rate case expenses in the Company's last three rate cases, all of which were settled before evidentiary hearings and briefing. Mr. Trzaska projected rate case expenses assuming a fully litigated case and based upon the complexity of issues presented in this case, including the impact of the COVID-19 emergency, low-income customer issues and new incentives for electric vehicle charging. (Statement No. 3-R at 37). Mr. Trzaska also did not agree with my extending the amortization period, stating that the Company will file another base rate case in 2024 and every three years thereafter in the near term. (Statement No. 3-R at 38).

Q. WHAT IS YOUR RESPONSE?

A. I am normalizing rate case expenses based upon actual prior rate case expense filings. The fact that the Company has included rate case expenses based upon a fully litigated proceeding, does not change my position, as my recommendation is based upon prior rate case filings, and the frequency of historic rate case filings, and not based upon this instant proceeding, which the Company has claimed rate case expenses of $2.4 million. (Company Schedule D-7). With respect to my recommended normalization period, the Commission looks to the historical filing frequency to determine the proper normalization period, which in this case, is 3.5 years. My recommendations are the same as that in my direct testimony and is shown on my Schedule SR-DM-18.

r. Covid – 19 Incremental Bad Debt

Q. WHAT DID MR. TRZASKA STATE REGARDING YOUR ADJUSTMENT TO THE COMPANY'S PROPOSED ADJUSTMENT TO ITS COVID-19 INCREMENTAL BAD DEBT?

A. Mr. Trzaska stated that I accepted the Company's incremental bad debt expense of $48,250,000 but did not accept the Company's amortization period of 3-years. (Statement No. 3-R at 38). Mr. Trzaska stated that I did not provide any basis whatsoever for an amortization period longer than three years. Mr. Trzaska stated that my recommended five-year amortization period is not supportable or more appropriate than a three-year amortization period. (Statement No. 3-R at 39).

Q. WHAT IS YOUR RESPONSE?

A. I believe a longer amortization period is appropriate because it better balances sharing between ratepayers and shareholders. Given that the COVID-19 pandemic is still present, and the variant is spreading, I am still inclined to recommend an amortization period of five-years for recovery of this expense. It is my opinion that this cost should be recovered beyond the Company's proposed three-year period. This will minimize the impact of recovery from ratepayers. My recommendation is shown on my Schedule SR-DM-15.

s. Administrative & General Expenses (A&G)

Q. WHAT HAS MR. TRZASKA STATED REGARDING YOUR ADJUSTMENTS TO CERTAIN OF YOU'RE A&G EXPENSES?

A. Mr. Trzaska stated that he is unable to determine how I arrived at my proposed adjustment of $234,453. (Statement No. 3-R at 40).

Q. WHAT IS YOUR RESPONSE?

A. Mr. Trzaska's reference is to my adjustment related to Salaries and Wages. (Schedule SR-DM-18). I adjusted this balance downward from my direct testimony adjustment of $234,453 to $58,680. My adjustment corrects an error in the calculation of A&G Salary and Wages and incorporates the Company's updated revenue requirement that Mr. Trzaska testified to beginning on page 2 of his rebuttal testimony. My recommendation is shown on my Schedule SR-DM-18.

t. Incremental COVID-19 Related Cash Working Capital (CWC)

Q. WHAT DID MR. TRZASKA STATE REGARDING YOUR REMOVAL OF THE COMPANY'S INCREMENTAL COVID-19 RELATED CWC OF $5,778,000?

A. Mr. Trzaska stated that these costs are in compliance with Commission directives and is a direct result of the impacts of COVID-19, and the termination moratorium. He cites the Commission's March 18, 2021 Order as the reason he included the Incremental COVID-19 CWC. (Statement No. 3-R at 42). Mr. Trzaska stated that the Commission Order caused accounts receivable balances in 2020 to increase significantly and are not expected to return to normal levels until after the FPFTY, which in turn, will require the Company to incur an estimated incremental $17.3 million cost for the increase in CWC between 2020-2022. Mr. Trzaska stated that this is the exact type of direct, incremental COVID-related expense that fits within the construct that the Commission created in its March 18, 2021 Order for tracking expenses, and the Company should be permitted to recover, and earn a return on, these incremental expenses incurred in furtherance of the Commission's COVID-19 related initiatives. (Statement No. 3-R at 43).

Q. WHAT IS YOUR RESPONSE?

A. I am continuing to recommend disallowance of the Company's Incremental COVID-19 CWC. It is my opinion that the Company's recovery of these costs should not be afforded rate recovery because CWC should be allowed for the day to day cash activities between the revenues billed and the submission of payments throughout the year. In response to OCA-III-51, I asked for a detailed breakdown and development of the Company's CWC incremental costs. The Company referred me to the response to IE-RE-41-D. The attachment does not show the detail, only annual balances from 2019 through 2022, by AR account. I do not see this as the detail needed to support the Company's request. The Commission Order dated March 18, 2021, does not specify recovery of CWC, only non-recurring incremental COVID-19 related expenses and shall maintain detailed accounting records of such expenses. (Statement No. 3-R at 42). My recommendation is the same, to disallow these costs in rates, and is shown on my Schedule SR-DM-18.

u. Small Business Recovery Program

Q. WHAT DID MR. TRZASKA STATE REGARDING YOUR ADJUSTMENTS TO THE COMPANY'S SMALL BUSINESS RECOVERY PROGRAM?

A. Mr. Trzaska stated that I accepted the Company's proposed budget of $900,000 but recommended amortizing these balance over ten years. (Statement No. 3-R at 45). Mr. Trzaska stated that I did not justify the ten-year amortization. Mr. Trzaska believes the three-year amortization is consistent with both the Commission practice and policy.

Q. WHAT IS YOUR RESPONSE?

A. I believe these costs should be recovered over a longer period of time and not be fully recovered between rate case filings (three-years). These types of costs will benefit ratepayers over a longer period of time. Certain ratepayers will always be in a position where they will be struggling to pay their utility bills and extending this program beyond the three-year period will allow ratepayers to apply for assistance and not fret over the fact that these program costs will be recovered over a three-year period. My recommendation remains the same and is shown on my Schedule SR-DM-21.

v. Annual Residential Convenience Fee

Q. WHAT DID MS. FELDHAKE STATE REGARDING YOUR DISALLOWANCE OF THE COMPANY'S ANNUAL RESIDENTIAL CONVENIENCE FEE?

A. Ms. Feldhake stated that my removal of the Company's Annual Residential Convenience Fee is not applicable because the Customer Solutions Center in the Main Office Building will be open when the Company's proposed rates become effective. (Statement No. 10-R at 18).

Q. WHAT IS YOUR RESPONSE?

A. I am still inclined to remove these costs from the revenue requirement calculation. Given the most recent rise in the COVID-19 pandemic outbreaks, there is no certainty that the Company's Customer Solutions Center will open as proposed, or when new rates will become effective. Government emergency orders may still be in effect and until such time as the COVID-19 outbreaks is contained, I believe the Company should not be recovering these costs in rates.

3. Income Taxes

Q. WHAT DID MR. MR. TRZASKA STATE IN REGARD TO YOUR ADJUSTMENT TO THE COMPANY'S INCOME TAXES?

A. Mr. Trzaska stated that I erred in making the changes to the Company's Income Tax calculation in that I utilized a positive number instead of a negative number in the DIT on Timing - Federal (Schedule SR-DM-21). My error would have resulted in an increase of the revenue requirement by $13.2 million.

Q. WHAT IS YOUR RESPONSE?

A. I corrected my error, and my adjustment is shown on my Schedule SR-DM-21.

D. Act-40 Requirements (Act 40 of 2016)

Q. WHAT DID MR. TRZASKA STATE REGARDING YOUR ADJUSTMENTS TO THE COMPANY'S CONSOLIDATED TAX ADJUSTMENT (CTA) AND ACT 40 OF 2016?

A. Mr. Trzaska stated that I interpreted "general corporate use" to mean public utility purposes having some identifiable and quantifiable benefit to Pennsylvania and PECO ratepayers. Mr. Trzaska did not agree with my adjustment to reduce the Company's Rate Base by $7.202 million because he stated that I treated the 50% differential for general corporate purposes as ratepayer supplied funds, which they are not. (Statement No. 3-R at 26-27). Mr. Trzaska stated that Subsection (b) says nothing about deducting any part of the differential from Rate Base. Mr. Trzaska stated that that Subsection (b) deals with the uses of the differential and embodies the Legislature's directive that 50% of those funds be invested in vital infrastructure and reliability while the other 50% has no limitations. (Statement No. 3-R at 27).

Q. WHAT IS YOUR RESPONSE?

A. The Company should not benefit from the use of the compliance with Act 40 without any specific use related to general corporate purposes. While Mr. Trzaska stated that 50% of the of the CTA is related to “rate base eligible” infrastructure and has demonstrated that the Company has utilized these dollars for such, the Company simple omits how the other 50% of the differential is to be used for general corporate purposes. Ratepayers are already supporting the Company’s infrastructure and reliability investments through rates; more information is needed to show that the additional revenues now being provided by ratepayers is actually being used and not simply going to shareholders. The Company should provide evidence of actual applications of its differential related to general corporate purposes in a manner that reduces ratepayer obligations.

Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

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REVENUE REQUIREMENT SUMMARY

		(1) Company Proposed	Adjustment	OCA	References
1	Rate Base	$ 6,385,897,000	$ (237,390,099)	$ 6,148,506,901	
2	Rate of Return	7.68%		6.22%	
3	Operating Income	$ 490,436,890	$ (108,307,186)	$ 382,129,704	
4	Operating Income - Present Rates	$ 326,829,000	$ 36,084,766	$ 362,913,766	
5	Additional Income Requirement	$ 163,607,890	$ (144,391,952)	$ 19,215,938	
6	Gross Revenue Conversion Factor	1.502995		1.502995	
7	Base Revenue Requirement Increase	$ 245,901,840	$ (217,020,381)	$ 28,881,459	
8	Other Operating Revenue	$ 924,000	$ (815,550)	$ 108,450	
9	Total Revenue Requirement Increase	$ 246,825,840	$ (217,835,932)	$ 28,989,908	
10	Present Rate Revenues	$ 2,333,680,000		$ 2,334,623,531	
11	% Increase	10.577%		1.242%	

(1) Company Exhibit MJT-1
Schedule A-1
Differences due to rounding

RATE OF RETURN

		Capitalization Ratio	Embedded Cost	Return %
(1)	Company Proposed			
1	Long - Term Debt	46.590%	3.930%	1.83%
2	Common Equity	53.410%	10.950%	5.85%
3	**Total**	100.000%		7.68%
	OCA (2)			
4	Long - Term Debt	50.000%	3.930%	1.965%
5	Common Equity	50.000%	8.500%	4.250%
6	**Total**	100.000%		6.215%

(1) Company Exhibit MJT-1
Schedule B-7
(2) Testimony of David Garrett

	MEASURE OF VALUE - RATE BASE (Jurisdictional)	(1) Company Proposed	Adjustments	OCA	References
1	Utility Plant in Service	$ 8,915,180,000	$ (103,576,962)	$ 8,811,603,038	
2	Accumulated Depreciation	$ (2,251,728,000)	$ (3,003,732)	$ (2,248,725,268)	DM-6
3	Common Plant	$ 424,369,000	$ -	$ 424,369,003	DM-5
4	**Net Plant In Service**	$ 7,087,821,000	$ (100,574,227)	$ 6,987,246,773	
5	Working Capital	$ 155,548,000	$ (1,506,562)	$ 154,041,438	DM-7
6	Pension Assets / (Liabilities)	$ 128,977,000	$ (128,977,000)	$ -	DM-8
7	Accumulated Deferred Income Taxes	$ (658,825,000)	$ 868,690	$ (657,956,310)	DM-9
8	Customer Deposits	$ (49,195,000)	$ -	$ (49,195,000)	
9	Customer Advances	$ (1,707,000)	$ -	$ (1,707,000)	
10	Materials and Supplies	$ 19,944,000	$ -	$ 19,944,000	
11	Accumulated Deferred Income Taxes - Regulatory Liabilities	$ (296,666,000)	$ -	$ (296,665,000)	DM-10
	CTA	$ -	$ (7,202,000)	$ (7,202,000)	OCA VI-5
12	**Total Measure of Value - Rate Base**	$ 6,385,897,000	$ (237,390,099)	$ 6,148,506,901	

(1) Company Exhibit MJT-1
Schedule C-1

	INCOME STATEMENT	(1) Company Present Rates	Company Rate Increase	Company Proposed Rates	Adjustments	OCA Present Rates	References
	Operating Revenues						
1	Residential / Residential House Heating	$ 1,515,162,000	$ -	$ 1,515,162,000	$ -	$ 1,515,162,000	
2	C& I Small / Large	$ 567,253,000	$ -	$ 567,253,000	$ -	$ 567,253,000	
3	Railroads & Railways	$ 8,118,000	$ -	$ 8,118,000	$ -	$ 8,118,000	
4	Street Lighting	$ 21,305,000	$ -	$ 21,305,000	$ -	$ 21,305,000	
5	InterCompany	$ 1,283,000	$ -	$ 1,283,000	$ -	$ 1,283,000	
6	Transmission - All Classes	$ 172,082,000	$ -	$ 172,082,000	$ -	$ 172,082,000	
7	Forfeited Discounts	$ 12,795,000	$ 924,000	$ 13,719,000	$ 108,450	$ 12,903,450	
8	Miscellaneous Service Revenue	$ 3,829,000	$ -	$ 3,829,000	$ (389,000)	$ 3,440,000	OCA-III-35
9	Rent for Electric Property	$ 19,219,000	$ -	$ 19,219,000	$ (353,333)	$ 18,865,667	OCA-III-35
10	Other Electric Revenues	$ 12,633,000	$ -	$ 12,633,000	$ (1,613,667)	$ 11,019,333	OCA-III-35
11	Revenue Increase	$ -	$ 245,985,000	$ 245,985,000			
12	Total Operating Revenues	$ 2,333,679,000	$ 246,909,000	$ 2,580,588,000	$ (2,247,550)	$ 2,331,431,450	
	Operating Expenses						
13	Power Supply	$ 689,927,000	$ -	$ 689,927,000	$ -	$ 689,927,000	DM-12
14	Transmission Expense	$ 161,192,000	$ -	$ 161,192,000	$ (1,000)	$ 161,191,000	DM-13
15	Distribution Expense	$ 379,976,000	$ -	$ 379,976,000	$ (15,348,325)	$ 364,627,675	DM-14
16	Customer Accounts Expense	$ 126,529,000	$ 1,383,000	$ 127,912,000	$ (13,689,505)	$ 114,222,495	DM-15
17	Customer Service & Info. Expense	$ 11,747,000	$ -	$ 11,747,000	$ (861,330)	$ 10,885,670	DM-16
18	Sales Expense	$ 1,743,000	$ -	$ 1,743,000	$ (246,911)	$ 1,496,089	DM-17
19	Administrative & General Expense	$ 184,876,000	$ 851,000	$ 185,727,000	$ (19,305,221)	$ 166,421,779	DM-18
20	Vacancy Rate	$ -	$ -	$ -	$ (2,679,945)	$ (2,679,945)	OCA-III-38
21	Sub-Total	$ 1,555,990,000	$ 2,234,000	$ 1,558,224,000	$ (52,132,238)	$ 1,506,091,762	
22	Depreciation & Amortization Expense	$ 271,915,000	$ -	$ 271,915,000	$ (3,002,732)	$ 268,912,268	DM-19
23	Amortization of Regulatory Expense	$ 923,000	$ -	$ 923,000	$ -	$ 923,000	DM-19
24	Taxes Other Than Income	$ 158,556,000	$ 14,513,000	$ 173,069,000	$ (13,535,415)	$ 159,533,585	DM-20
25	Total Operating Expenses	$ 1,987,384,000	$ 16,747,000	$ 2,004,131,000	$ (68,670,385)	$ 1,935,460,615	
26	Net Operating Income Before Income Taxes	$ 346,295,000	$ 230,162,000	$ 576,457,000	$ (180,486,165)	$ 395,970,835	
27	State Income Taxes	$ 6,912,000	$ 22,993,000	$ 29,905,000	$ (18,420,029)	$ 11,484,971	DM-21
28	Federal Income Taxes	$ 12,554,000	$ 43,506,000	$ 56,060,000	$ (34,469,478)	$ 21,590,522	DM-21
28	Net Operating Income	$ 326,829,000	$ 163,663,000	$ 490,492,000	$ (127,596,658)	$ 362,895,342	
	Net Operating Income Present Rates					$ 382,129,704	
	Rate Base			$ 6,385,897,000		$ 6,148,506,901	
	Rate of Return			7.681%		6.215%	

(1) Company Exhibit MJT-1 Schedule A-1
Schedule D-18

ELECTRIC PLANT IN SERVICE COMMON PLANT IN SERVICE

		(1) Company Proposed	Adjustments	OCA	References
1	Intangible Plant	$ 232,753,000	$ -	$ 232,753,000	
2	Transmission Plant	$ -	$ -	$ -	
3	Distribution Plant	$ 8,405,217,000	$ (103,576,962)	$ 8,301,640,038	OCA VI-6
4	General Plant	$ 277,210,000		$ 277,210,000	
5	**Total Electric Plant In Service Balance**	**$ 8,915,180,000**	**$ (103,576,962)**	**$ 8,811,603,038**	
6	Land	$ 6,783,000	$ -	$ 6,783,000	
7	Organization	$ 677,000	$ -	$ 677,000	
8	Software	$ 373,618,000	$ -	$ 373,618,000	
9	General Plant	$ 751,017,000	$ -	$ 751,017,000	
10	Other	$ -	$ -	$ -	
11	**Total Common Plant In Service Balance**	**$ 1,132,095,000**	**$ -**	**$ 1,132,095,000**	OCA-III-12 OCA-III-24
	Accumulated Depreciation				
12	Land	$ -	$ -	$ -	
13	Organization	$ -	$ -	$ -	
14	Software	$ 295,102,000		$ 295,102,000	
15	General Plant	$ 228,116,000		$ 228,116,000	
16	Other	$ -	$ -	$ -	
17	**Total Accumulated Depreciation**	**$ 523,218,000**	**$ -**	**$ 523,218,000**	
18	Net Common Plant in Service	$ 608,877,000	$ -	$ 608,877,000	
19	Allocation Factor	69.697%		69.697%	OCA-III-24
20	**Net Common Plant to Utility**	**$ 424,369,003**	**$ -**	**$ 424,369,003**	

(1) Company Exhibit MJT-1 Schedule C-2
Schedule C-8
See Set VI 6

	ACCUMULATED DEPRECIATION	(1) Company Proposed	Adjustments	OCA	References
1	Intangible Plant	$ 165,969,000	$ -	$ 165,969,000	
2	Transmission Plant	$ -	$ -	$ -	
3	Distribution Plant	$ 1,977,526,000	$ (3,003,732)	$ 1,974,522,268	OCA-VI-6
4	General Plant	$ 108,234,000	$ -	$ 108,234,000	
5	Total Accumulated Depreciation	$ 2,251,729,000	$ (3,003,732)	$ 2,248,725,268	OCA-III-27

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(1) Company Exhibit MJT-1 Schedule C-3

WORKING CAPITAL ALLOWANCE

		(1) Expenses	Company Proposed Lead/Lag Days	Dollar Days	Adjustments	OCA	References
1	Revenue Lag Days		48.3000				
	Expense Lag Days						
2	Payroll (Distribution Only)	$ 171,625,000	13.4375	$ 2,306,210,938		$ 2,011,204,665	
3	Pension Expense	$ 8,904,000	-167.0044	$ (1,487,007,178)		$ (1,487,007,178)	
4	Commodity Purchased	$ 689,927,000	35.4411	$ 24,451,785,000		$ 24,451,785,000	
5	PJM Transmission Purchased	$ 161,192,000	12.5000	$ 2,014,895,000		$ 2,014,882,500	
6	Other Expenses	$ 501,496,000	40.0439	$ 20,081,861,000		$ 19,594,495,374	OCA-III-28
7	Sub-Total	$ 1,533,144,000		$ 47,367,744,760		$ 46,585,360,361	
8	Payment to Suppliers	$ 1,017,444,000	38.1645	$ 38,830,239,000		$ 38,830,239,000	OCA-III-28
9	Total O&M and POR Payments	$ 2,550,588,000		$ 86,197,983,760		$ 85,415,599,361	
10	O&M Expense/POR Payment Expense Lag Days		33.8000				
11	Net Lead/Lag Days		14.5000				
12	Days in Current Year		365.0000				
13	Operating Expenses Per Day	$ 6,987,912				$ 6,884,927	
14	Working Capital for O&M Expenses	$ 101,337,992				$ 99,831,438	
15	Average Prepayments	$ 5,442,000				$ 5,442,000	
16	Accrued Taxes	$ 62,517,000				$ 62,517,000	
17	Interest Payments	$ (13,749,000)				$ (13,749,000)	
18	Total Working Capital Requirements	$ 155,547,992				$ 154,041,438	
19	Proforma O&M Expenses	$ 1,556,046,000				$ 1,506,091,762	
20	Uncollectible Expense	$ 22,902,000				$ 22,902,000	
21	Proforma Cash O&M Expense	$ 1,533,144,000				$ 1,528,993,762	

	PENSION ASSET	(1) Company Proposed	Adjustments	OCA	References
1	Balance at end of HTY - 2020	$ 375,428,000			
2	Activities in FTY - 2021	$ 11,656,000			
3	Activities in FPFTY - 2022	$ 18,428,000			
4	**Balance at end of FPFTY - 2022**	$ 405,512,000	$ (405,512,000)	$ -	
5	Allocation Factor to Utility	76.26%			
6	Utility Amount	$ 309,240,000	$ 309,240,000	$ -	
7	Allocation Factor to Distribution Capital	41.71%			
8	**Balance at end of FPFTY - Distribution Capital**	$ 128,977,000	$ (128,977,000)	$ -	OCA III-29/30/31

(1) Company Exhibit MJT-1 Schedule C-5

	ACCUMULATED DEFERRED INCOME TAXES	(1) Company Proposed	Adjustments	OCA	References
	HTY				
1	ADIT - CIAC - 100.00%	$ (26,543,000)	$ -	$ (26,543,000)	
2	ADIT - Common Plant - 62.34%	$ 17,815,525	$ -	$ 17,815,525	
3	ADIT - Electric Common Plant - 80.99%	$ 3,056,563	$ -	$ 3,056,563	
4	ADIT - Electric Distribution - 100%	$ 631,703,000	$ -	$ 631,703,000	
5	Sub-Total	$ 626,032,088	$ -	$ 626,032,088	
	FTY				
6	DIT - CIAC - 100%	$ (4,407,000)	$ -	$ (4,407,000)	
7	DIT - Common Plant - 62.34%	$ -	$ -	$ -	
8	DIT - Electric Common Plant - 80.99%	$ -	$ -	$ -	
9	DIT - Electric Distribution - 100.00%	$ 26,066,000	$ -	$ 26,066,000	
10	Sub-Total	$ 21,659,000	$ -	$ 21,659,000	
	FPFTY				
11	DIT - CIAC - 100.00%	$ (4,566,000)	$ -	$ (4,566,000)	
12	DIT - Common Plant - 62.34%	$ -	$ -	$ -	
13	DIT - Electric Common Plant - 80.99%	$ -			
14	DIT Electric Distribution - 100.00%	$ 15,699,000	$ (867,778)	$ 14,831,222	OCA-III-23/VI-6
15	Sub-Total	$ 11,133,000	$ (867,778)	$ 10,265,222	
16	Total	$ 658,824,088	$ (867,778)	$ 657,956,310	OCA-III-32

(1) Company Exhibit MJT-1 Schedule C-6

	ACCUMULATED DEFERRED INCOME TAXES - REGULATORY LIABILITY	(1) Company Proposed	Adjustments	OCA	References
	HTY				
1	ADIT - Distribution	$ 330,796,000	$ -	$ 330,796,000	
2	ADIT - CIAC	$ (6,753,000)	$ -	$ (6,753,000)	
3	**Sub-Total**	$ 324,043,000	$ -	$ 324,043,000	
	FTY				
4	DIT - Distribution	$ (11,804,000)	$ -	$ (11,804,000)	
5	DIT - CIAC	$ (2,251,000)	$ -	$ (2,251,000)	
6	**Sub-Total**	$ (14,055,000)	$ -	$ (14,055,000)	
	FPFTY				
7	DIT - Distribution	$ (11,072,000)	$ -	$ (11,072,000)	
8	DIT - CIAC	$ (2,251,000)	$ -	$ (2,251,000)	
9	**Sub-Total**	$ (13,323,000)	$ -	$ (13,323,000)	
10	**Total**	$ 296,665,000	$ -	$ 296,665,000	OCA III-33

(1) Company Exhibit MJT-1 Schedule C-12

	POWER SUPPLY EXPENSE	(1) Company Proposed	Adjustments	OCA	References
1	Purchased Power	$ 689,927,000	$ -	$ 689,927,000	OCA-III-36

(1) Company Exhibit MJT-1 Schedule 4

	TRANSMISSION EXPENSE	(1) Company Proposed	Adjustments	OCA	References
1	Scheduling, System Control & Dispatch	$ 78,643,000	$ -	$ 78,643,000	OCA-VI-4
2	Reliability, Planning & Standard Develop.	$ 82,548,000	$ -	$ 82,548,000	
3	**Total**	$ 161,191,000	$ -	$ 161,191,000	OCA-III-36

(1) Company Exhibit MJT-1 Schedule 4

SALARY AND WAGES (1)

	Company Proposed				Adjustments	OCA	References
	Union	Non-Union	Union	Non-Union			
	Number of Employees		Salary Allocation				
	960	1,054	$ 76,096,000	$ 83,547,000			
Total		2,014		$ 159,643,000		$ 159,643,000	
Distribution - OP	112	122	$ 8,843,262	$ 9,707,738	$ (1,519,000)		OCA-III-36
Distribution - MN	362	397	$ 28,661,588	$ 31,463,413	$ (4,087,000)		
Customer Accounts	218	239	$ 17,261,784	$ 18,949,216	$ (3,493,000)		
Customer Service	10	11	$ 781,788	$ 858,212	$ (159,000)		
Sales	5	6	$ 405,672	$ 445,328	$ (84,000)		
Admin & General	254	279	$ 20,147,249	$ 22,116,751	$ (4,203,000)		
	960	1054	$ 76,101,341	$ 83,540,659	$ (13,545,000)		
Total		2014		$ 159,642,000	$ (13,545,000)	$ 146,097,000	
Annualize 3/1/2022 Wage Increase 2.5%			$ -	$ 348,086	$ -	$ 348,086	
Annualize 1/1-3/1/2023 2.5%			$ 1,902,534	$ 2,097,219	$ (3,999,752)	$ -	
Annualized Salary and Wages	960	1054	$ 78,003,875	$ 85,985,963			
		2014		$ 163,989,838	$ (17,544,752)	$ 146,445,086	OCA-III-7
One Time Contract Payment				$ 165,611	$ (165,611)	$ -	OCA-III-42
Labor Cost Increase				$ 4,347,000	$ (4,347,000)	$ -	OCA-III-43
Adjusted Salary & Wages				$ 168,502,450	$ (22,057,363)	$ 146,445,086	
Additional Employees				48		48	OCA-III-39
Annual Salary & Wages per Employee				$ 77,330	$ (10,123)	$ 67,207	
Annualization of New Employees				$ 3,703,542	$ (477,584)	$ 3,225,959	
Total Proforma Salary & Wages				$ 172,205,992	$ (22,534,947)	$ 149,671,045	
Total Proposed Increase				$ 12,563,992	$ (8,989,947)	$ 3,574,045	
Distribution - OP				$ 1,459,936	$ (1,044,632)	$ 415,304	
Distribution - MN				$ 4,732,856	$ (3,386,513)	$ 1,346,343	
Customer Accounts				$ 2,849,513	$ (2,038,920)	$ 810,593	
Customer Service				$ 128,907	$ (92,237)	$ 36,670	
Sales				$ 67,104	$ (48,015)	$ 19,089	
Admin & General				$ 3,325,689	$ (2,379,639)	$ 946,050	
				$ 12,564,004	$ (8,989,956)	$ 3,574,048	OCA-III-39
							OCA-III-36

Review I&E responses on incentive compensation - confidential documents
Review vacancy rates I&E-RE-26-D
Review capitalization ratios OCA-III-40

	DISTRIBUTION EXPENSE	(1) Company Present Rates	Adjustments	Company Proposed Rates	Adjustments	OCA	References
1	Proposed Balance at 12/31/2022	$ 370,979,000	$ 8,712,000	$ 379,691,000	$ (15,063,325)	$ 364,627,675	
	Distribution Operations						
2	Operation & Supervision - salaries	$ 1,056,000	$ 67,000	$ 1,123,000	$ (47,938)	$ 1,075,062	
3	Load Dispatching	$ -	$ -	$ -			
4	Station Expense	$ 640,000	$ -	$ 640,000	$ -	$ 640,000	
5	Overhead Line Expense - salaries	$ 17,030,000	$ 182,000	$ 17,212,000	$ (130,087)	$ 17,081,913	
6	Underground Line Expense - salaries	$ 11,313,000	$ 181,000	$ 11,494,000	$ (129,378)	$ 11,364,622	
7	Meter Expense - salaries	$ 5,199,000	$ 163,000	$ 5,362,000	$ (116,860)	$ 5,245,140	
8	Customer Installation Expense - salaries	$ 9,499,000	$ 375,000	$ 9,874,000	$ (268,184)	$ 9,605,816	
9	Miscellaneous Expense - salaries	$ 67,803,000	$ 492,000	$ 68,295,000	$ (352,084)	$ 67,942,916	
	Incentive Compensation - EBSC charges				$ (2,636,910)	$ (2,636,910)	OCA-III-9/21
	Total Distribution Operations - Salaries				$ -	$ -	DM-14A
	Stock Compensation				$ (440,000)	$ (440,000)	OCA VI-4
10	Rents	$ 3,139,000	$ -	$ 3,139,000	$ -	$ 3,139,000	
11	Total	$ 115,679,000	$ 1,460,000	$ 117,139,000	$ (4,121,440)	$ 113,017,560	
	Distribution Maintenance						
12	Maint. of Structures - salaries	$ 1,891,000	$ 86,000	$ 1,977,000	$ (61,631)	$ 1,915,369	
13	Maint. of Station Equipment - salaries	$ 15,973,000	$ 584,000	$ 16,557,000	$ (417,861)	$ 16,139,139	
14	Maint. of Overhead Lines - salaries	$ 192,828,000	$ 2,768,000	$ 195,596,000	$ (1,980,524)	$ 193,615,476	
	Vegetative Management		$ -	$ -	$ (3,554,451)	$ (3,554,451)	OCA-III-14/VI-7
	Storm Expense Normalization	$ -	$ 2,807,000	$ 2,807,000	$ (3,155,400)	$ (348,400)	OCA-III-7/50
15	Maint. of Underground Lines - salaries	$ 28,017,000	$ 1,044,000	$ 29,061,000	$ (746,997)	$ 28,314,003	
16	Maint. of Line Transformers - salaries	$ 1,476,000	$ 25,000	$ 1,501,000	$ (17,851)	$ 1,483,149	
17	Maint. of Street Lighting & Signal Systems - salaries	$ 1,014,000	$ 10,000	$ 1,024,000	$ (7,025)	$ 1,016,975	
18	Maint. of Misc. Distribution - salaries	$ 14,100,000	$ 214,000	$ 14,314,000	$ (153,145)	$ 14,160,855	
	Stock Compensation				$ (1,132,000)	$ (1,132,000)	OCA VI-4
	Total Distribution Maintenance Salaries				$ -	$ -	DM-14A
19	Total	$ 255,299,000	$ 7,538,000	$ 262,837,000	$ (11,226,885)	$ 251,610,115	
20	Total Distribution Expense	$ 370,978,000	$ 8,998,000	$ 379,976,000	$ (15,348,325)	$ 364,627,675	OCA-III-36

(1) Company Exhibit MJT-1 Schedule D-4
Pages 56-59
Differences due to rounding
Storm - MJT-1 D-13

	CUSTOMER ACCOUNTS EXPENSE	(1) Company Present Rates	Adjustments	Company Proposed Rates	Adjustments	OCA	References
1	Proposed Balance at 12/31/2022	$ 119,238,000	$ 7,795,000	$ 127,033,000	$ (12,972,877)	$ 114,060,123	
2	Supervision	$ -	$ -	$ -			
3	Meter Reading	$ 338,000	$ -	$ 338,000	$ -	$ 338,000	OCA-III-36
4	Customer Records & Collection	$ 79,174,000		$ 81,921,000			
	Customer Accounts Salaries		$ 2,747,000		$ (1,965,669)	$ 79,955,331	DM-14A
	Incentive Compensation - EBSC charges	$ -		$ -	$ (3,078,470)	$ (3,078,470)	OCA-III-21
5	Uncollectible Accounts	$ 35,551,000	$ (12,649,000)	$ 22,902,000	$ -	$ 22,902,000	
	COVID-19 Bad Debt Reg. Asset	$ -	$ 16,083,000	$ 16,083,000	$ (6,433,000)	$ 9,650,000	OCA-III-49
6	Misc. Customer Accounts Expense - Int Dep.	$ 4,175,000	$ 1,012,000	$ 5,187,000	$ -	$ 5,187,000	Update Schedule D-12
	Stock Compensation			$ -	$ (923,000)	$ (923,000)	OCA VI-4
	Customer Accounts Salaries		$ 103,000	$ 98,000	$ (68,738)	$ 29,262	DM-14A
7	Total	$ 119,238,000	$ 7,296,000	$ 126,529,000	$ (12,468,877)	$ 114,060,123	OCA-III-36 OCA-III-47/48
(2)	Additional Uncollectible Accounts			$ 1,382,928	$ (1,220,556)	$ 162,372	

(2) Revenue Requirement increase times 3 year average of Uncollectible Accounts of .5622%

(1) Company Exhibit MJT-1 Schedule D-4 D-11 Pages 56-59
Differences due to rounding

	CUSTOMER SERVICE & INFORMATION	(1) Company Present Rates	Adjustments	Company Proposed Rates	Adjustments	OCA	References
1	Proposed Balance at 12/31/2022	$ 102,672,000	$ (90,932,000)	$ 11,740,000	$ (854,330)	$ 10,885,670	
2	Customer Assistance - EEP	$ 101,187,000	$ (91,055,000)	$ 10,132,000	$ -	$ 10,132,000	
	Salaries & Wages		$ 129,000	$ 129,000	$ (92,330)	$ 36,670	
	Stock Compensation			$ -	$ (42,000)	$ (42,000)	OCA VI-4
	Economic Development - Labor/Ben.			$ -	$ (727,000)	$ (727,000)	OCA-III-18
3	Informational & Instructional	$ 1,351,000	$ -	$ 1,351,000	$ -	$ 1,351,000	
4	Miscellaneous Customer & Informational	$ 135,000	$ -	$ 135,000	$ -	$ 135,000	
5	Total	$ 102,673,000	$ (90,926,000)	$ 11,747,000	$ (861,330)	$ 10,885,670	OCA-III-36

(1) Company Exhibit MJT-1 Schedule D-4
Pages 56-59
Differences due to rounding

	SALES EXPENSE	(1) Company Present Rates	Adjustments	Company Proposed Rates	Adjustments	OCA	References
1	Proposed Balance at 12/31/2022	$ 1,676,000	$ 64,000	$ 1,740,000	$ (243,911)	$ 1,496,089	
2	Demonstrating and Selling	$ 1,676,000		$ 1,676,000	$ -	$ 1,676,000	
	Demonstrating and Selling Salaries		$ 67,000	$ 67,000	$ (47,911)	$ 19,089	DM-14A
	Stock Compensation			$ -	$ (20,000)	$ (20,000)	OCA VI-4
	Economic Development			$ -	$ (179,000)	$ (179,000)	OCA-III-18
3	Miscellaneous Sales	$ -	$ -	$ -			
4	Total	$ 1,676,000	$ 67,000	$ 1,743,000	$ (246,911)	$ 1,496,089	OCA-III-36

(1) Company Exhibit MJT-1 Schedule D-4
Pages 56-59
Differences due to rounding

	ADMINISTRATIVE & GENERAL EXPENSE	(1) Company Present Rates	Adjustments	Company Proposed Rates	Adjustments	OCA	References
1	Proposed Balance at 12/31/2022	$ 160,384,000	$ 24,339,000	$ 184,723,000	$ (18,401,122)	$ 166,321,878	
2	Administrative & General Salaries	$ 40,954,000	$ 3,116,000	$ 44,070,000	$ (2,229,930)	$ 41,840,070	DM-14A
3	Office Supplies & Expenses (salaries)	$ 6,998,000	$ 7,000	$ 7,005,000	$ (4,913)	$ 7,000,087	
4	Employee Volunteer Events - off. Supp.				$ (54,000)	$ (54,000)	OCA-III-18
5	Administrative Expenses - Trans/Credit	$ -	$ -	$ -	$ -	$ -	
6	Outside Services Employed - (salaries)	$ 66,466,000	$ (5,000)	$ 66,461,000	$ 3,510	$ 66,464,510	DM-14A
7	Incentive Compensation - EBSC charges			$ -	$ (2,584,620)	$ (2,584,620)	OCA-III-21
	Stock Compensation			$ -	$ (1,413,000)	$ (1,413,000)	OCA VI-4
8	Property Insurance	$ 499,000	$ -	$ 499,000	$ -	$ 499,000	
9	Injuries and Damages - (salaries)	$ 9,851,000	$ 117,000	$ 9,968,000	$ (83,614)	$ 9,884,386	DM-14A
10	Employee Pension & Benefits - (salaries)	$ 20,334,000	$ 9,000	$ 20,343,000	$ (6,616)	$ 20,336,384	DM-14A
11	Medicare Advantage 3% cost of living			$ -	$ (466,230)	$ (466,230)	OCA-III-45/20/46
12	Employee Benefits - add'l employees		$ 462,000	$ 462,000	$ (199,713)	$ 262,287	OCA-III-45
13	Pension		$ 11,699,000	$ 11,699,000	$ (2,795,000)	$ 8,904,000	OCA-III-19/29
14	OPEB		$ -	$ -	$ -	$ -	OCA-III-19
15	Economic Development - M&S			$ -	$ (54,000)	$ (54,000)	OCA-III-18
16	Employee Activities			$ -	$ (757,031)	$ (757,031)	OCA-III-10
17	Regulatory Commission Expense	$ 7,576,000	$ 800,000	$ 8,376,000	$ (396,286)	$ 7,979,714	OCA-III-44
18	Duplicate Charges - Credit	$ (675,000)	$ -	$ (675,000)	$ -	$ (675,000)	
19	Miscellaneous General Expenses-COVID	$ 1,931,000	$ 5,778,000	$ 7,709,000	$ (5,778,000)	$ 1,931,000	OCA-III-51
20	Experimental / General			$ -	$ -	$ -	OCA-III-8
	Corporate Dues			$ -	$ (169,000)	$ (169,000)	OCA-VI-2
21	Emergency Relief /Grant/Other	$ -	$ 2,427,000	$ 2,427,000	$ (1,507,000)	$ 920,000	OCA-III-57/58/59/60/61/62
22	A&G Maintenance of General Expenses	$ 6,450,000	$ 82,000	$ 6,532,000	$ (58,680)	$ 6,473,320	DM-14A
23	Total	$ 160,384,000	$ 24,492,000	$ 184,876,000	$ (18,554,122)	$ 166,321,878	OCA-III-36
24	Additional PUC/OCA/SBA Assessment Revenue Requirement Increase times the Assessment Rate of .03459%			$ 850,862	$ (750,961)	$ 99,901	OCA-III-34
	check				$ (18,554,122)		

(1) Company Exhibit MJT-1 Schedule D-4
Pages 56-59
Differences due to rounding
Company Schedule D-19

	DEPRECIATION & AMORTIZATION	(1) Company Present Rates	Adjustments	Company Proposed Rates	Adjustments	OCA	References
1	Proposed Balance at 12/31/2022	$ 258,833,333					
2	Distribution Plant	$ 179,462,000	$ 8,450,000	$ 187,912,000	$ (3,003,732)	$ 184,908,268	OCA VI-6
3	Common Plant	$ 16,763,000	$ 1,021,000	$ 17,784,000	$ -	$ 17,784,000	
4	General Plant	$ 19,569,000	$ 358,000	$ 19,927,000	$ -	$ 19,927,000	
5	Transmission Plant	$ -	$ -	$ -	$ -	$ -	
6	Sub-Total	$ 215,794,000	$ 9,829,000	$ 225,623,000	$ (3,003,732)	$ 222,619,268	
7	Intangible Plant	$ 44,040,000	$ 2,253,000	$ 46,293,000	$ -	$ 46,293,000	OCA-III-54
8	Total	$ 259,834,000	$ 12,082,000	$ 271,916,000	$ (3,003,732)	$ 268,912,268	OCA-III-22
9	Amortization of Regulatory Expense	$ 923,000		$ 923,000	$ -	$ 923,000	OCA-III-34/VI-3

(1) Company Exhibit MJT-1 Schedule D-17
Company Exhibit MJT-1 Schedule D-4
Page 57 and 59
Differences due to rounding

	TAXES OTHER THAN INCOME	(1) Company Proposed	Adjustments	OCA	References
1	Public Utility Real Tax (PURTA)	$ 6,273,000	$ (72,892)	$ 6,200,108	
2	Use Tax Accrued	$ 460,000	$ -	$ 460,000	
3	Real Estate Tax Accrued	$ 5,200,000	$ -	$ 5,200,000	
4	Miscellaneous TOTI	$ -			
5	Payroll Tax Accrued	$ 13,341,001	$ (653,298)	$ 12,687,704	
6	**Sub-Total**	$ 25,274,001	$ (726,190)	$ 24,547,812	
7	Gross Receipts Tax	$ 133,281,767	$ -	$ 133,281,767	OCA-III-52
8	**Total**	$ 158,555,768	$ (726,190)	$ 157,829,579	
9	Additional Gross Receipts Tax	$ 14,513,115	$ (12,809,109)	$ 1,704,006	
10	Revenue Requirement Increase times 5.90%				
11	**Total Taxes Other Than Income**	$ 173,068,883	$ (13,535,299)	$ 159,533,585	

(1) Company Exhibit MJT-1 Schedule D-16
Differences due to rounding

INCOME TAXES	(1) Company Proposed	Adjustments	OCA	References
Revenues	$ 2,580,588,000		$ 2,331,431,450	
Operating Expenses	$ 2,004,131,000		$ 1,935,460,615	
Operating Income Before Taxes	$ 576,457,000		$ 395,970,835	
Rate Base	$ 6,385,897,000		$ 6,148,506,901	
Weighted Cost of Debt	1.830970%		1.97%	
Synchronized Interest Expense	$ 116,860,858		$ 120,818,161	
Base Taxable Income	$ 459,596,142		$ 275,152,674	
State Accelerated Tax Depreciation	$ 272,228,000		$ 272,228,000	OCA-III-55
Pro-Forma Book Depreciation	$ 271,916,000		$ 271,916,000	
State Tax Depreciation (Over) Under Book	$ (313,000)		$ (313,000)	
Regulatory Asset Programs M-1 Pension / PBOP	$ (17,696,000)		$ (17,696,000)	
Other Property Basis Adjustments (CIAC/ICM)	$ (24,716,000)		$ (24,716,000)	
Removal Costs/Software	$ (20,433,000)		$ (20,433,000)	
AFUDC Equity	$ (15,645,000)		$ (15,645,000)	
Permanent Adjustments	$ 4,203,000		$ 4,203,000	
Repair Deductions	$ (128,000,000)		$ (128,000,000)	
State Taxable Income	$ 256,996,142		$ 72,552,674	
State Income Tax Rate	9.99%		9.990%	
State Income Tax Benefit / (Expense) before NOL	$ (25,673,915)	$ 18,425,902	$ (7,248,012)	
NOL Utilization %	40.00%		40.00%	
NOL Utilization	$ 10,269,566	$ (7,370,361)	$ 2,899,205	
State Income Tax Benefit (Expense)	$ (15,404,349)	$ 11,055,541	$ (4,348,807)	
Federal Accelerated Tax Depreciation	$ 247,075,000		$ 247,075,000	
Proforma Book Depreciation	$ 271,916,000		$ 271,916,000	
Federal Tax Deduct (Over) Under Book	$ 24,841,000	$ (867,778)	$ 23,973,222	
Regulatory Asset Program M-1	$ (17,696,000)		$ (17,696,000)	
Other Property Basis Adjustment (CIAC/ICM)	$ (24,716,000)		$ (24,716,000)	
Removal Costs/Software	$ (20,433,000)		$ (20,433,000)	
AFUDC Equity	$ (15,645,000)		$ (15,645,000)	
Permanent Adjustments	$ 4,203,000		$ 4,203,000	
Repair Deductions	$ (128,000,000)		$ (128,000,000)	
Federal NOL	$ -		$ -	
Federal Taxable Income	$ 266,745,793	$ (174,255,704)	$ 92,490,089	
Federal Income Tax Rate	21.00%		21.00%	
Federal Income Tax Benefit / Expense before Deferred and Adjustments	$ (56,016,617)	$ 36,593,698	$ (19,422,919)	
Total Tax Benefit (Expense) before DIT	$ (71,420,965)	$ 47,649,239	$ (23,771,726)	
DIT on Timing - Federal	$ (4,935,000)	$ (2,113,603)	$ (7,048,603)	
DIT on Timing - State	$ (4,236,959)	$ -	$ (4,236,959)	
Deferred State Tax on NOL	$ (10,269,566)	$ 7,370,361	$ (2,899,205)	
Excess Deferred Amortization	$ 9,742,000	$ -	$ 9,742,000	
Federal Income Tax on Flow-Through Adjust.	$ (4,881,000)	$ -	$ (4,881,000)	
Deferred Income Tax Benefit (Expense)	$ (14,580,525)		$ (9,323,767)	
Net Income Tax Benefit (Expense)	$ (86,001,490)		$ (33,095,493)	
Amortization of ITC	$ 20,000		$ 20,000	
Combined Income Tax Benefit (Expense)	$ (85,981,490)	$ 52,905,997	$ (33,075,493)	
Federal Income Tax Benefit (Expense)	$ (56,070,617)		$ (21,590,522)	
State Income Tax Benefit (Expense)	$ (29,910,873)		$ (11,484,971)	

(1) Company Exhibit MJT-1 Schedule D-18

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024601
	:	
PECO Energy Company – Electric Division	:	

VERIFICATION

I, Dante Mugrace, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 1-SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 5, 2021
*314837

Signature: Dante Mugrace
Dante Mugrace

Consultant Address: PCMG and Associates
90 Moonlight Court
Toms River, NJ 08753

OCA St. 2SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission v. PECO Energy Company – Electric Division	Docket No. R-2021-3024601

SURREBUTTAL TESTIMONY

OF

DAVID J. GARRETT

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

August 5, 2021

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David J. Garrett. My business address is 101 Park Avenue, Suite 1125, Oklahoma Company, Oklahoma 73102.

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

A. I am the managing member of Resolve Utility Consulting, LLC. I am an independent consultant specializing in public utility regulation.

Q. Have you previously filed testimony in this proceeding?

A. Yes. I filed direct testimony in OCA Statement 2 on June 28, 2021, on behalf of the Pennsylvania Office of Consumer Advocate ("OCA"). A summary of my qualifications is included in my direct testimony.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony responds to the rebuttal testimony of PECO Energy Company – Electric Division ("PECO" or the "Company") witness Paul Moul.

Q. Did any of the Company's rebuttal testimony you reviewed cause you to change your positions and recommendations as stated in your direct testimony?

A. No. To the extent I did not specifically address a statement made in the Company's rebuttal testimony filed in this case, it should not constitute my agreement with such testimony.

Q. In his rebuttal testimony, did Mr. Moul raise any new, significant issues related to your cost of equity and rate of return testimony and analysis?

A. No. In Mr. Moul's rebuttal testimony, it is clear that he disagrees with my opinions regarding PECO's cost of capital and my return on equity ("ROE") recommendation. However, I do not believe he raised any new, significant arguments or issues in addition to those provided in his direct testimony. Thus, in my surrebuttal testimony, I will not repeat all of the arguments and points raised in my direct testimony; rather, I will reiterate a few important points in my response to Mr. Moul's rebuttal testimony.

Q. Please describe the organization of your surrebuttal testimony.

A. In my surrebuttal, I respond to three pertinent issues discussed in Mr. Moul's rebuttal testimony, including (1) the growth rate input to the Discounted Cash Flow ("DCF") Model; (2) Mr. Moul's ROE comparisons; (3) the overall results of the Capital Asset Pricing Model ("CAPM"); (4) the leverage adjustment; and (5) the management performance premium.

I. <u>DCF GROWTH RATE</u>

Q. Please summarize Mr. Moul's rebuttal testimony regarding the growth rate input to the DCF Model.

A. Mr. Moul disagrees with my use of projected nominal GDP as a limiting factor for long-term growth projections of the proxy utility group. Mr. Moul relies instead on the growth rates published by various analysts.

Q. Please summarize the problems you have with the growth rates Mr. Moul used in his DCF Model.

A. The problems I have with Mr. Moul's growth rate inputs could be summarized into four key points: (1) analysts' growth rates cover short-term time periods; (2) it is not reasonable to assume that any company can outpace the growth rate of the aggregate economy in which it operates over the long run; (3) analysts' growth rates appear to ignore the qualitative aspects of utility operations and the fact they are very low-growth companies; and (4) Mr. Moul's growth rates result in a DCF Model that must be overstated given it exceeds a reasonable estimate for the market cost of equity. I will address each of these points below.

Q. Are the analyst growth rates used by Mr. Moul in his DCF Model long-term growth rates?

A. No. Growth rates published by various analysts typically cover a period of 3 – 10 years. However, the growth rate input in the constant growth DCF Model (or the terminal growth rate in a multi-stage DCF Model) contemplates a *long-term* period of time (technically, infinity). Regardless of the quantitative accuracy of the published growth rates Mr. Moul relies upon, the Commission should understand, that it is Mr. Moul, not the commercial analysts, who is suggesting to the Commission that the proxy companies will experience these annual rates of growth year after year for many years into the future.

Q. Is it reasonable to assume that a company's earnings or dividends will grow at an annual rate greater than that of the projected annual growth rate of the aggregate economy in which it operates?

A. No, I do not believe so. This is a fundamental concept in finance, but it also make sense intuitively. The growth rate of our economy is most widely measured by U.S. GDP. As discussed in my direct testimony, a reasonable projection of annual GDP growth going forward is about 3.8%. We could think of GDP as an "average" of sorts, which means there are relatively high-growth companies (that have not yet reached their mature stage of the lifecycle) that are bringing the average up, and likewise, there are relatively low-growth companies that are bringing the average down. Some companies would even have negative growth rates (i.e., decreasing earnings and/or dividends). The growth rates of all the companies in the U.S. market are constantly changing over time, but GDP growth is relatively consistent. Mathematically, if a company were to consistently outpace GDP growth year after year, then it would eventually have earnings that exceeded U.S. GDP, regardless of its starting point. An appropriate metaphor might be two runners in an infinite race. If Runner A runs at a faster pace than Runner B, Runner A will eventually surpass Runner B no matter the head-start distance Runner B was given. It is simply not reasonable to assume that the earnings of any one company, especially a low-growth utility, would ever surpass U.S. GDP, which is currently about $21 trillion.

Q. Do analysts' growth rates adequately consider the qualitative aspects of utility operations and the fact they are intrinsically very low-growth companies?

A. No, not in my opinion. Proxy groups of utilities are useful for estimating cost of equity in that they provide the requisite data to conduct the financial models we use to estimate utility cost of equity. However, it is important to keep in mind that the primary purpose of this exercise to estimate a cost of equity for PECO itself. With that in mind, it is useful to consider some intrinsic, qualitative growth indicators for PECO, such as total load growth and customer growth. As discussed in my direct testimony, PECO's own estimates for total customers and total load are less than 1.0%.[1] This figure is notably lower than the average growth rate of 5.15% used by Mr. Moul in his DCF analysis. Clearly, the quantitative growth projections of the proxy companies do not comport with the qualitative growth indicators of PECO.

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[1] *See* Exhibit DJG-5; *see also* response to OCA-IV-10.

Q. Do the results of Mr. Moul's DCF analysis appear unreasonable in light of the strong likelihood that they exceed a reasonable estimate for the current market cost of equity?

A. Yes. Regardless of the differing opinions regarding technical aspects of long-term growth indicators in the DCF Model, we should nonetheless check the results for reasonableness. Since the growth rate input in the DCF Model is the primary driver of the end results (given the fact that stock prices and dividends much less subjective), then an unreasonably high DCF result based on market indicators could be primarily attributable to an unreasonably high growth rate input. Mr. Moul's DCF Model produced a base cost of equity result of 9.23% (before adding other adjustments).[2] Since the average beta of the proxy group is less than 1.0, then the market cost of equity (which is based on a beta equal to 1.0) acts as a "ceiling" on PECO's cost of equity. The market cost of equity is estimated by adding the risk-free rate (as estimated by the current yield on 30-year U.S. Treasury bonds) to the equity risk premium ("ERP"). Although the ERP will be discussed in more detail below in relation to the CAPM, it is instructive here as part of our cost of equity "ceiling" estimate. As discussed in my direct testimony, the current risk-free rate is about 2%.[3] A reasonable estimate for the ERP is about 5.5%.[4] Thus a reasonable estimate for the market cost of equity is about 7.5%. Any cost of equity estimate for PECO above 7.5% is arguably high, especially one as high as Mr. Moul's 9.23% DCF result.

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[2] Direct Testimony of Paul R. Moul, p. 22, lines 18-20.

[3] *See* Exhibit DJG-7.

[4] *See* Exhibit DJG-10.

II. <u>Comparison to Pennsylvania Allowed ROEs</u>

Q. Please comment on Mr. Moul's comparison to "utility returns recently authorized by the Commission."

A. Mr. Moul cites to a variety of ROEs allowed by the Public Utility Commission since 2018. They include ROEs for small and large gas utilities, a small electric utility, and a large water utility. Several were determined based on market information before the impact of the COVID-19 pandemic. The PUC allowed PECO Gas a 10.24% ROE based upon a time frame which included the COVID-19 pandemic shut-down and re-opening. It should be noted, however, that none of the allowed rates of return incorporated his particular approach to estimating a cost of equity, such as his leverage adjustment to the DCF and CAPM.

Q. Mr. Moul also references an ROE identified by the Commission for use in electric utility Distribution System Improvement Charges (DSICs). Should the Commission use that DSIC ROE as a limit in this proceeding?

A. No, I disagree with Mr. Moul's suggestion. I have been advised that the DSIC allows PECO to impose a surcharge to recover certain eligible investments in electric infrastructure replacements between base rate cases. As such, the DSIC amounts to an automatic rate recovery mechanism for PECO that, in turn, lowers its risk.

Commission regulations allow PECO to implement a DSIC surcharge to further public policy which favors replacement of certain electric infrastructure, subject to consumer protections. Consumers are protected by a 5% cap on the amount of eligible investment in plant which PECO may recover through the DSIC surcharge. PECO's calculated achieved return on its DSIC eligible plant investment is compared to one of two benchmarks. The first benchmark is the utility's allowed ROE in a base rate case within two years. In the absence of a specific allowed ROE, the Commission's Quarterly Earnings Report identifies an industry ROE for use in the DSIC. The benchmark ROE serves as a guard against over-earnings. If PECO's calculated achieved return on its DSIC investment exceeds the applicable benchmark ROE, then PECO cannot collect the DSIC surcharge for the next quarter.

An ROE that is calculated by Commission staff, for use in a single quarter test of whether an electric utility without a recent allowed cost of equity may be over-earning through its DSIC surcharge, is not suited to identification of the cost of common equity which PECO should be allowed the opportunity to earn as of the end of the FPFTY.

III. <u>Credibility of CAPM Results</u>

Q. Please summarize Mr. Moul's surrebuttal testimony regarding your CAPM results.

A. Mr. Moul claims that the results of my CAPM are "on their face simply not credible."[5]

Q. Please summarize the inputs and results of your CAPM.

A. The CAPM is a Nobel-prize-winning financial model that has three inputs: (1) risk-free rate; (2) beta; and (3) the ERP. I will summarize and contrast the sources of these inputs between my CAPM and Mr. Moul's CAPM.

1. <u>Risk-free rate</u>

Financial analysts use the yield on Treasury securities as a proxy for the risk-free rate. I used a recent 30-day average on the daily yields on 30-year Treasury bonds as a proxy for the risk-free rate in my CAPM. This is a very reasonable approach. In contrast, Mr. Moul

[5] Rebuttal Testimony of Paul R. Moul p. 33, line 14.

relies on projected bond yields. I have reviewed dozens of utility ROE testimony dating back more than 20 years. In nearly every one of those cases, the witness representing the utility will rely on a forward-looking or projected Treasury bond yield for the risk-free rate, instead of relying on the current, *known* Treasury bond yield. In every single one of those cases, I cannot recall a single instance in which the utility's projected bond yield was *lower* than the current bond yield. In other words, I cannot recall a single case in which a utility witness's prediction of the future did not, all else held constant, result in a higher cost of equity estimate in the present. After observing this tactic numerous times over many years without exception, it reinforces my opinion that it is preferable use known (current) bond yields rather than unknown (future) bond yields.

2. Beta

For the beta input in my CAPM, I relied on the betas published by Value Line. In my experience, the vast majority of ROE witness in utility rate proceedings (representing both utilities and customers) rely on Value Line betas without further adjustment. In contrast, Mr. Moul takes the unusual approach of adjusting Value Line's published betas. It is not surprising that this adjustment is in the upward direction.

2. ERP

Mr. Moul criticized me for looking back over 30 days to get an average yield on T-bonds for my risk-free rate and described it as "backward-looking."[6] Curiously, Mr. Moul relies on data that predates the invention of color televisions in his ERP estimate. Relying on

[6] Rebuttal Testimony of Paul R. Moul, p. 33, lines 17-18.

data dating back to 1940 is not a reasonable approach in estimating the ERP.[7] As discussed in my direct testimony, there is substantial evidence showing that the current and forward-looking ERP is notably lower than the historical ERP (especially if one begins their historical ERP analyses just after the end of the Great Depression). In contrast to Mr. Moul's approach, I relied on a survey of thousands of unbiased experts in helping develop a reasonable estimate for the ERP. I also looked at the estimate published by Duff & Phelps (a respected, international corporate advising firm) and the estimate published by one of the world's leading experts on the ERP – Dr. Aswath Damodaran. The *highest* ERP from these sources is 5.6% (notably lower than Mr. Moul's 8.77% estimate). That is the ERP I used in my CAPM.

Q. Based on this summary, what do you conclude about the results on your CAPM analyses as compared with Mr. Moul's results?

A. I used reasonable figures for each of the three CAPM inputs. My inputs are not affected by biases. Indeed, there is very little, if any of my own personal judgement injected into the CAPM results. The current risk-free rate is known. It does not require a subjective estimate or adjustment. The betas I used are published by Value Line. To my knowledge, Value Line does not have any conflict of interest with either utilities or ratepayers that might affect their judgment. The ERP I used comes from a survey of thousands of unbiased experts. Based on these inputs, the results of my CAPM are quite reasonable.

[7] *See* Exhibit PRM-1, Sch. 12.

Q. Mr. Moul insists that a proper CAPM analysis for PECO should include a 1.02% adjustment for size. Do you agree?

A. No, I do not. A size adjustment is not appropriate in conducting a cost of equity estimate for the Company. The "size effect" phenomenon arose from a 1981 study conducted by Banz, which found that "in the 1936 – 1975 period, the common stock of small firms had, on average, higher risk-adjusted returns than the common stock of large firms."[8] According to Ibbotson, Banz's size effect study was "[o]ne of the most remarkable discoveries of modern finance."[9] Perhaps there was some merit to this idea at the time, but the size effect phenomenon was short lived. Banz's 1981 publication generated much interest in the size effect and spurred the launch of significant new small cap investment funds. However, this "honeymoon period lasted for approximately two years. . . ."[10] After 1983, U.S. small-cap stocks actually underperformed relative to large cap stocks. In other words, the size effect essentially reversed. In *Triumph of the Optimists*, the authors conducted an extensive empirical study of the size effect phenomenon around the world. They found that after the size effect phenomenon was discovered in 1981, it disappeared within a few years:

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[8] Rolf W. Banz, *The Relationship Between Return and Market Value of Common Stocks* 3-18 (Journal of Financial Economics 9 (1981)).

[9] 2015 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook 99 (Morningstar 2015).

[10] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 131 (Princeton University Press 2002).

> It is clear . . . that there was a global reversal of the size effect in virtually every country, with the size premium not just disappearing but going into reverse. Researchers around the world universally fell victim to Murphy's Law, with the very effect they were documenting – and inventing explanations for – promptly reversing itself shortly after their studies were published.[11]

In other words, the authors assert that the very discovery of the size effect phenomenon likely caused its own demise. The authors ultimately concluded that it is "inappropriate to use the term 'size effect' to imply that we should automatically expect there to be a small-cap premium," yet, this is exactly what utility witnesses often do in attempting to artificially inflate the cost of equity with a size premium. Other prominent sources have agreed that the size premium is a dead phenomenon. According to Ibbotson:

> The unpredictability of small-cap returns has given rise to another argument against the existence of a size premium: that markets have changed so that the size premium no longer exists. As evidence, one might observe the last 20 years of market data to see that the performance of large-cap stocks was basically equal to that of small cap stocks. In fact, large-cap stocks have outperformed small-cap stocks in five of the last 10 years.[12]

In addition to the studies discussed above, other scholars have concluded similar results. According to Kalesnik and Beck:

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[11] *Id*. at 133.

[12] 2015 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook 112 (Morningstar 2015).

> Today, more than 30 years after the initial publication of Banz's paper, the empirical evidence is extremely weak even before adjusting for possible biases. . . . The U.S. long-term size premium is driven by the extreme outliers, which occurred three-quarters of a century ago. . . . Finally, adjusting for biases . . . makes the size premium vanish. If the size premium were discovered today, rather than in the 1980s, it would be challenging to even publish a paper documenting that small stocks outperform large ones.[13]

For all of these reasons, the Commission should reject the arbitrary size premium proposed by the Company.

Q. Mr. Moul suggests that your CAPM result should be tested against a CAPM result from a Commission Quarterly Earnings Report. Please comment.

A. As I discussed above regarding Mr. Moul's criticism of my DCF results, Mr. Moul has picked out an ROE result from a Commission Quarterly Earnings Report which the Commission considered in setting an ROE to apply as a test for over-earnings, within the limited context of the DSIC. The purpose of this rate proceeding is different, as the ROE allowed by the Commission will provide the Company with an opportunity to earn an overall return, without any express cap on those earnings. My CAPM analysis is soundly based and provides a check on the reasonableness of my DCF results.

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[13] Vitali Kalesnik and Noah Beck, *Busting the Myth About Size* (Research Affiliates 2014), available at https://www.researchaffiliates.com/Our%20Ideas/Insights/Fundamentals/Pages/284_Busting_the_Myth_About_Size.aspx (emphasis added).

IV. <u>Leverage Adjustment</u>

Q. Please summarize Mr. Moul's rebuttal testimony regarding his leverage adjustment.

A. Mr. Moul claims that I "never really refute" his leverage adjustment and that I employ his leverage adjustment approach through the use of a similar mathematical technique as part of my capital structure analysis.[14]

Q. What is your response to Mr. Moul's rebuttal testimony regarding the leverage adjustment?

A. First, Mr. Moul's claim that I "never really refute" his leverage adjustment is inaccurate. In my direct testimony, I stated that "Mr. Moul's decision to add a leverage adjustment to his DCF result is inappropriate."[15] I also provided several reasons why I disagree with Mr. Moul's leverage adjustment, which is preceded by the sentence: "I disagree with Mr. Moul's leverage adjustment for several reasons."[16] In case it was not very clear in my direct testimony, I definitely refute Mr. Moul's leverage adjustment. Mr. Moul also states: "[Mr. Garrett] employs my leverage adjustment approach through the use of the Hamada formula to unlever betas as part of his capital structure analysis, thereby validating my approach."[17] This statement is misleading at best. First, I definitely do *not* "employ [Mr. Moul's leverage adjustment." As stated in my direct testimony, Mr. Moul is the only witness I have ever seen use a leverage adjustment in the manner that he has. To be clear, Mr. Moul is applying the leverage adjustment to his cost of equity estimate (making his

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[14] Rebuttal Testimony of Paul R. Moul, p. 30, lines 11-19.

[15] Direct Testimony of David J. Garrett, p. 45, lines 11-12.

[16] *Id*. at p. 47, line 12.

[17] Rebuttal Testimony of Paul R. Moul, p. 30, lines 18-19 through p. 31, lines 1-2.

results higher). It is true that I use the Hamada mathematical technique in my capital structure analysis. I do this for the purpose of assessing estimated costs of debt and equity at various debt ratios. To be clear, my use of the Hamada formula has no impact at all on my cost of equity estimate or proposed ROE. I do not use the Hamada formula to increase the betas published by Value Line as Mr. Moul has. Thus, my use of the Hamada formula as part of a comprehensive capital structure analysis does *not* "validate" Mr. Moul's leverage adjustment as a device for increasing his cost of equity estimate.

V. Management Performance Premium

Q. Please summarize Mr. Moul's rebuttal testimony regarding his premium for management performance.

A. Mr. Moul reaffirms his belief that 25 basis points should be added to the cost of equity estimate as additional compensation to shareholders for management performance.

Q. Please comment on Company witness John E. McDonald's rebuttal testimony regarding PECO's requested premium for management performance.

A. Mr. McDonald acknowledges that the Company seeks to be rewarded for past and projected activities, spanning 2010 through 2022 and beyond. This ranges from transformers replaced starting in 2010 through the Company's planned replacement of 26,000 poles in the 2023-2025 period. (OCA-XI-3, OCA-XI-9). Even the Company's claim of managed O&M expense and "savings" includes projected performance.

Mr. McDonald also emphasizes the Company's commitment to community and economic development. However, OCA witness Dante Mugrace has opposed the Company's inclusion of related O&M expense. OCA witness Roger Colton has stated that the Company's allowance of paid volunteer work does not support PECO's management performance claim. Further, the Company uses staff and executive time so the Company can donate shareholder funds to charities. (OCA-XI-18)

Q. What is your response to the Company's rebuttal testimony regarding the management performance premium?

A. Mr. Moul states the premium should be 25 basis points. Mr. McDonald states that it should be at the high end of Mr. Moul's recommended range. Regardless, I maintain the opinion stated in my direct testimony that the Commission should affirmatively reject any premium to either a cost of equity estimate or authorized ROE that is related to managerial performance. The market would have already accounted for the Company's past performance. Imposing additional costs on consumers, to reward PECO for giving away shareholder dollars or managing O&M expense since the last rate case, does not benefit consumers who will have to pay the higher rates. I recommend that the Commission deny the Company's request.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024601
	:	
PECO Energy Company – Electric Division	:	

<u>VERIFICATION</u>

I, David J. Garrett, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 2-SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 5, 2021
*314838

Signature: ______________________
David J. Garrett

Consultant Address: Resolve Utility Consulting, PLLC
101 Park Avenue
Suite 1125
Oklahoma City, OK 73102

OCA STATEMENT NO. 3-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket Number R-2021-3024601
v.	:	
	:	
PECO Energy Company—Electric Division	:	

SURREBUTTAL TESTIMONY OF

CLARENCE L. JOHNSON

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

August 5, 2021

OCA STATEMENT NO. 3-SR

SURREBUTTAL TESTIMONY OF CLARENCE JOHNSON

Table of Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Clarence L. Johnson. My business address is 3707 Robinson Ave, Austin, Texas 78722.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am presenting testimony on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS YOUR CURRENT EMPLOYMENT?

A. I am self-employed as a consultant providing technical analysis, advice, and testimony regarding energy and utility regulatory issues.

Q. ARE YOU THE SAME CLARENCE JOHNSON WHO PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A. My testimony will respond to rebuttal testimony presented by other parties on cost allocation and rate design issues pertaining to PECO's ("Company") base rate increase requested in this docket. In particular, I will rebut PECO witnesses Jamison, Bisti, and Feldhake, Pennsylvania Industrial Energy Users Group (PAIEUG) witness Pollock, Amtrak witness Faryniarz, and Office of Small Business Advocate (OSBA) witness Kalcic.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. This Surrebuttal Testimony encompasses the following recommendations:

- Secondary lines, poles, and underground facilities should be classified as demand-related in the CCOSS.
- Rate R and Rate RH should be treated as a single customer class for cost allocation purposes.
- My adjustment to Other Revenues in the CCOSS was accepted by the Company and should be adopted.
- The Company’s residential customer charge should be set at level between $8.37 and the current rate, $9.99
- The economic impact of the pandemic may have resulted in a temporary increase in the residential demand allocation. As a result, the amount of revenue increase to the residential class should be tempered.
- The rebuttal testimony of PECO witness Feldhake related to the allocation of universal service program costs should not be adopted.

II. OVERVIEW OF CLASS REVENUE INCREASE

Q. DO OTHER PARTIES OPPOSE YOUR ALLOCATION OF CLASS REVENUES?

A. Yes. PAIEUG and OSBA Rebuttal Testimony opposes my recommendation for allocating the system revenue increase among customer classes.[1] Their position is that the residential increase should be substantially higher than proposed in my Direct Testimony. My Rebuttal Testimony (OCA Ex. 3-R) discusses my disagreement with the PAIEUG and OSBA revenue allocation recommendations. In particular, their position that the residential classes should be set exactly at cost leads to an excessive impact on households in the Philadelphia area, without recognizing the exceptional economic distress which affected residential customers.

In addition, the Company's Rebuttal Testimony changed PECO's recommendation in order to increase the share of increase assigned to the residential class and decrease the share of increase assigned to other classes.[2] The Rebuttal Testimony of PECO witness Bisti revises the Company's proposal by changing the regular residential class' share of the total increase from 50.5% in PECO's initial filing to 60.5% in PECO's rebuttal recommendation.[3] Combining the two residential classes (RS and RH); this revision to PECO's proposal adds $40 million to the Company's initially filed residential increase, results in the combined residential share of the increase growing from 62.8% to 76.0%. Mr. Bisti rationalizes this substantial change in the Company's proposal as an effort to bring both RS and RH closer to cost. However, this revision depends on accepting PECO's class cost of service study (CCOSS). If my proposed CCOSS is

1 See, PAIEUG St. 2-R at 7-9.

2 PECO St. 7-R at 3.

3 Id.

adopted, the appropriate residential share of the total increase should be *decreased* from the Company's initial proposal. In my view, the Company's revision should have reduced the combined residential increase by $6 million, instead of adding $40 million to the increase.

Q. GIVEN YOUR RECOMMENDED CHANGES TO THE COMPANY'S CCOSS, SHOULD THE COMMISSION DISREGARD THE REBUTTAL OF YOUR REVENUE ALLOCATION RECOMMENDATION?

A. Yes. Other parties' opposition to my recommended revenue allocation is premised on adopting the Company's CCOSS. Therefore, Sec. III - V of my Surrebuttal Testimony will address the Rebuttal Testimony opposing the changes I made to the Company's CCOSS.

Q. PLEASE RESPOND TO COMPANY WITNESS BISTI'S REBUTTAL CONCERNING SCALE BACK METHODS.

A. "Scale back method" refers to the procedure for applying reductions in the total revenue requirement to class revenue increase allocation proposals. I agree with Mr. Bisti that a proportionate scale back of the proposed class revenue increases is appropriate. However, I disagree with his position that the scale back should not be applied to residential and general service customer charge rates.[4] Mr. Bisti's Rebuttal Testimony asserts that the Company supports proportionate scale back at the customer class level to ensure that all customer classes are provided some relief from the full request.[5] However, the Company's proposal does not carry through this goal to individual customers. If the customer charge is not scaled back for a reduced revenue increase, low

[4] PECO St. 7-R at 10.

[5] Id. at 11.

usage customers will not meaningfully share in the relief from the full request. Furthermore, the unstated assumption for this approach is that the reduced revenue requirement did not reduce the amount of customer costs. The Company has no basis for that assumption. Therefore, any scale back method should be applied to both fixed customer charges and volumetric rates.

III. CLASSIFICATION OF SECONDARY LINES & POLES

Q. PLEASE SUMMARIZE YOUR POSITION REGARDING THE COMPANY'S CLASSIFICATION OF SECONDARY DISTRIBUTION LINES, POLES, AND UNDERGROUND FACILITIES.

A. I disagree with the Company's classification of secondary distribution facilities (other than transformers) as 100% customer-related. These facilities are designed to meet maximum demand in the localized area, and should be classified as demand-related. As a result of the customer classification, the smallest apartment dweller is allocated the same amount of cost for secondary lines as a secondary voltage large commercial customer who uses large quantities of power.

Q. DO ANY WITNESSES PRESENT REBUTTAL TESTIMONY OPPOSING YOUR DEMAND CLASSIFICATION RECOMMENDATION?

A. Yes. PECO witness, Ms. Jamison, OSBA witness, Mr. Kalcic, and PAIEUG witness, Mr. Pollock, oppose my recommendation and support the Company's 100% customer classification of secondary voltage delivery facilities.

Q. ON PAGES 3-4 OF HER REBUTTAL TESTIMONY, MS. JAMISON STATES THAT OTHER PENNSYLVANIA ELECTRIC UTILITIES CLASSIFY 46% -

83% OF SECONDARY DISTRIBUTION FACILITIES ON A CUSTOMER BASIS, WHICH IS REPRESENTATIVE OF PRACTICE IN THE REGION. DOES THIS JUSTIFY PECO'S PRACTICE OF CLASSIFYING 100% OF SECONDARY DISTRIBUTION FACILITIES AS CUSTOMER-RELATED?

A. No. First, numerous cost factors affect differences in secondary distribution costs among Pennsylvania electric utilities, including customer density, length of conductors and number of poles per customer, electric space heating penetration, usage per customer, and land values.[6] Without a more rigorous comparison of PECO's cost characteristics to these electric utilities, those other companies' classification percentages have limited relevance. This is particularly true, given the fact that PECO did not perform an analysis to support its 100% customer classification for secondary lines and poles. Second, with respect to regional practice, Ms. Jamison does not acknowledge that PECO's sister company in Maryland, Baltimore Gas & Electric Co., applies 100% demand classification to electric secondary facilities, as stated in my interrogatory response.[7]

Q. PECO'S REBUTTAL TESTIMONY, PECO ST. 6-R AT 4, CLAIMS THAT YOU IGNORE COST DRIVERS LIKE LABOR INSTALLATION COSTS WHICH ARE MORE CLOSELY ALIGNED WITH CONDUCTOR CUSTOMER COSTS. DOES THIS ARGUMENT SUPPORT PECO'S SECONDARY CLASSIFICATION?

A. No. Ms. Jamison's testimony does not demonstrate that labor installation costs for secondary conductors justify a *100% customer classification*. Even if one accepts the

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[6] Later in the Rebuttal Testimony, Ms. Jamison states, "Costs are not the same in densely populated and less densely populated areas." PECO St. 6-R at 5.

[7] See, PECO Exhibit TJJ-10 (OCA Response REVISED PECO-OCA-II-52).

argument that labor installation rates can define the customer component of secondary plant, the implication is that a significant percentage of PECO's lines, poles, and underground plant *should* have been classified as demand-related. During discovery, PECO stated that it does not have records of labor installation costs for the FERC accounts associated with secondary facilities.[8] Based upon my experience in other utility rate cases, I would expect labor installation costs to comprise 20% - 50% of secondary delivery plant.[9] If PECO had classified 50% of the secondary delivery system on a demand basis, the allocated revenue requirement for the Residential class would decrease by more than $22 million.

Q. ON PAGES 4-5 OF HER REBUTTAL TESTIMONY, MS. JAMISON STATES THAT THE COMPANY MUST BUILD FACILITIES TO SERVE CUSTOMERS REGARDLESS OF SPATIAL DISTRIBUTION, AND BECAUSE THE FACILITIES CONNECT SECONDARY CUSTOMERS TOGETHER AND TO THE PRIMARY SYSTEM, THE COSTS ARE CUSTOMER-RELATED. DO YOU AGREE?

A. No. This argument attempts to attribute customer causation to causal factors that are not susceptible to classification or allocation. Distribution utilities are awarded a monopoly to provide distribution service within a defined geographic area. The shape, size, and population distribution of the geographic area obviously influences the design of the system and the costs of installing facilities. These are circumstances inherent in the

[8] PECO Response to OCA II-19.

[9] The FirstEnergy Companies, for instance, reported a labor installation rate of 49% for secondary lines, and Connecticut Light & Power Co. reported a 29% labor installation rate secondary lines. See, First Energy Companies Base Rate Case, Docket Nos. R-2016-2537349, et al., Direct Testimony of Clarence Johnson (July 22, 2016) at 23; Application of Connecticut Light & Power Co. to Amend Rate Schedules, Docket No. 14-05-06, Direct Testimony of Clarence Johnson (August 4, 2014) at 22.

franchise service area, which are not caused by customers. This is part of the "obligation to serve" which accompanies a monopoly franchise, not a customer cost. The notion that distribution facilities are built to serve customers, rather than customers' usage of the system, is a false premise. Customers who have no demand for electricity would have no need to be connected to the system. The presence of a customer creates a demand which must be carried by the distribution system. The obligations of a monopoly utility do not equate to customer-related costs.

Q. ON PAGES 5-6 OF PECO ST. 6-R, THE COMPANY'S REBUTTAL CLAIMS THAT YOU ARE "NIT-PICKING" THE LACK OF CUSTOMER CORRELATION WITH DISTRIBUTION PLANT, BUT THAT YOU DO NOT SHOW THAT A DEMAND CORRELATION EXISTS. IS THIS A VALID BASIS FOR REJECTING YOUR RECOMMENDATION?

A. No. The Company's planning guidelines for installing secondary distribution facilities provide a direct causal relationship between customer demand and distribution costs. As discussed on page 10 of my Direct Testimony, PECO's distribution planners rely on forecasts of localized demand in order "to estimate the peak demand *to size the secondary lines required to serve each customer*" and if load growth causes the need for replacement or additional secondary facilities, "actual load readings or meter data are used *to determine secondary wire size*."[10] Large loads on the secondary system may cause voltage drop which frequently limits conductor length or affects conductor sizing.[11]

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[10] OCA St. 3 at 10 (quoting PECO Response to OCA II-28 (emphasis added)). [Attached as Schedule CJ-SR-1]

[11] Ibidem.

The Company tracks distribution feeder demands annually, and takes action to relieve distribution feeders when demand exceeds 110% of the allowable rating.[12]

Q. ON PAGE 2 OF HIS REBUTTAL TESTIMONY, MR. POLLOCK STATES THAT SECONDARY LINES ARE NECESSARY FOR CUSTOMER ACCESS AND "INVESTMENTS THAT MUST BE MADE SOLELY TO ATTACH A CUSTOMER TO THE SYSTEM ARE CLEARLY CUSTOMER-RELATED." DOES THIS JUSTIFY A 100% CUSTOMER CLASSIFICATION FOR SECONDARY CONDUCTORS AND POLES?

A. No. Service lines, which are connected to the customer's premises, are the only investment made solely to attach a customer to the system, and my testimony does not dispute the customer classification of service lines. His argument that the presence of the customer causes secondary infrastructure investment is essentially the same "obligation to serve" argument which I responded to previously. Furthermore, I disagree with Mr. Pollock's position that voltage support is principally a customer function. Voltage support is necessary for reliability and avoiding outages, which are demand-related functions. The Company's conductor lengths must account for potential voltage drops in order to ensure that the lines are sized sufficiently to meet maximum demand. In planning for new secondary lines, PECO takes into account the amount of large loads with end use equipment requiring high starting currents.[13]

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12 PECO Response to OCA-II-26. [Attached as Schedule CJ-SR-2]

13 PECO Response to OCA II-28. [Attached as Schedule CJ-SR-1]

Q. MR. POLLOCK ATTACHES A SURVEY (PAIEUG STATEMENT 2-R, EXH. JP-5) WHICH SHOWS CUSTOMER PERCENTAGES FOR UTILITIES THAT CLASSIFY A PORTION OF THE DISTRIBUTION SYSTEM AS CUSTOMER-RELATED. HE CLAIMS THAT PECO'S OVERALL PERCENTAGE IS AT THE LOW END OF THE RANGE. PLEASE COMMENT ON THIS SURVEY AND HIS CONCLUSION.

A. First, Mr. Pollock has not stated the source of the survey or who conducted the survey. I do not know if this purports to be a survey of all electric utilities which utilize customer classification methods or just a sample of those utilities. Second, the PECO customer percentage appears to be relatively low because the survey excludes electric utilities which classify all underground facilities, conductors, poles, and transformers as 100% demand-related. For example, since Mr. Pollock testifies extensively before the Texas PUC, he must be aware that all nine investor-owned electric utilities in that state use a 100% demand classification. Third, the survey does not show how many other electric utilities classify secondary delivery facilities as 100% customer-related, as PECO has done. Mr. Pollock's 22% customer percentage for PECO is a composite average for Primary and Secondary facilities. I concur with PECO's position that its primary facilities are planned for maximum demand, but disagree with the Company's claim that secondary facilities are 100% customer-related. By focusing on a composite percentage, Mr. Pollock ignores the actual issue in dispute (classification of secondary facilities).

Q. AT PAGES 3-4 OF HIS REBUTTAL TESTIMONY, MR. POLLOCK REFERENCES THE NARUC ELECTRIC UTILITY COST ALLOCATION MANUAL TO SUPPORT HIS POSITION. DID PECO FOLLOW THE NARUC

MANUAL IN ITS DEVELOPMENT OF A 100% CUSTOMER CLASSIFICATION FOR SECONDARY FACILITIES?

A. No. The NARUC Manual discusses methodologies for splitting distribution facilities between customer and demand components. The discussion includes methods such as the minimum size system and zero intercept regression analyses. PECO has not used a methodology to quantify demand and customer components of the secondary delivery system.

Q. WHAT IS THE BASIS FOR MR. KALCIC'S OBJECTION TO YOUR RECOMMENDATION?

A. On page 7 of his Rebuttal Testimony, Mr. Kalcic cites the 2012 Pennsylvania Power & Light Co. (PPL) rate case[14] as the basis for his opinion. He states that he is advised that the PPL decision rejected 100% demand classification for Accounts 364-367. However, he does not indicate that the PPL decision supports a 100% customer classification for the secondary portion of Accounts 364-367. PECO has not attempted to quantify any demand percentage for the secondary Accounts 364-367. Notwithstanding the PPL decision, the Company has not provided an alternative to 100% customer classification of secondary delivery facilities. Under those circumstances, the Commission should adopt my recommendation.

IV. ALLOCATION OF OTHER REVENUES

Q. WHAT IS THE COMPANY RESPONSE TO YOUR PROPOSED CHANGE TO THE ALLOCATION OF TWO COMPONENTS OF OTHER REVENUES?

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[14] See, Pennsylvania Public Utility Commission v. PPL Electric Utilities Corporation, Docket No. R-2012-2290597, (Order entered December 28, 2012).

A. After reviewing my Direct Testimony, PECO witness Jamison agreed to change the Company CCOSS to allocate service connection revenue and returned check charge revenue on a customer basis, as recommended in my Direct Testimony. Ms. Jamison states that the impact of this change is to reduce residential and RH revenue requirement by $1 million.[15]

Q. WHAT IS YOUR RECOMMENDATION?

A. Ms. Jamison is correct that these two items in other revenue should be allocated based on customers because residential customers pay for almost all of the charges in this revenue category.

V. COMBINING RATES R AND RH IN THE CCOSS

Q. DID ANY REBUTTAL WITNESSES OPPOSE YOUR RECOMMENDATION TO COMBINE THE RESIDENTIAL AND RESIDENTIAL HEATING CLASSES FOR PURPOSES OF THE CLASS COST OF SERVICE STUDY?

A. Yes. PECO witness Ms. Jamison,[16] PAIEUG witness Mr. Pollock,[17] and OSBA witness Mr. Kalcic[18] filed rebuttal testimony opposing the recommendation.

Q. PLEASE DESCRIBE YOUR PROPOSAL.

A. Rate R and RH both consist of residential customers. The only difference between class eligibility is that RH customers use electric space heating appliances. Because residential

[15] PECO St. 7-R at 7.

[16] PECO St. 7-R at 8-10.

[17] PAIEUG St. 2-R at 5-6.

[18] OSBA St. 1-R at 8-9.

customers compose both rate groups, my recommendation is to treat both rates as sub-classes of the residential class. The CCOSS effect is to allocate embedded costs to a single residential class based upon combined billing determinants for R and RH. As a result of this treatment, the combined residential non-coincident peak (NCP) demand is lower than the RS and RH classes individually. For revenue allocation purposes, my recommendation assigns a combined revenue increase to the residential class, with the increase split between the R and RH sub-classes. This permits any cross-subsidies between RS and RH to be confined to the residential class. My recommendation does not alter the winter discount that applies to the RH class.

Q. MR. KALCIC AND MR. POLLOCK OBJECT TO THIS TREATMENT BECAUSE YOU DID NOT COMBINE THE RS AND RH CLASSES FOR RATE DESIGN. IS THIS A REASON TO REJECT YOUR PROPOSAL?

A. No. Mr. Kalcic and Mr. Pollock apparently object to a single residential class if customers in the class do not pay the same rates. As noted above, RH customers pay a lower winter rate due to their electric space heating. This is a vestige of PECO's previous history as a fully bundled electric utility. However, in my view, eliminating the winter discount would produce unreasonable rate impacts on RH customers. The customers in the two sub-classes consist of domestic households, with the winter space heating appliance as the only difference. Functionally, the sub-class treatment of R and RH is the same as a single residential class with a space heating rider for the customers with electric space heating appliances. Riders are utilized in other rate classes' tariffs which permit a specific sub-set of customers within the class to pay a different rate. For example, HV and EP class customers with voltage higher than 69 kV receive a rate discount applied to the HV and EP rates. The Night Service Riders apply to commercial and industrial customers with off-peak demand in excess of on-peak demand. The Economic Development Rider provides a rate discount to commercial and industrial customers that meet eligibility requirements. PECO has a number of other riders. The point is that the existence of a discount in the RH winter rate does not preclude the treatment of RH customers as a sub-class of the residential class

Q. ON PAGE 9 OF HER REBUTTAL TESTIMONY, MS. JAMISON ASSERTS THAT YOUR PROPOSAL RESULTS IN A SUBSIDY TO RATE RH. IS THIS A VALID OBJECTION?

A. No. As a practical matter, the extent of any "subsidy" of the RH sub-class will be determined by the proportion of the residential revenue increase split between Rate R and RH. Essentially, Ms. Jamison's complaint is that my recommendation accepted the RH revenue increase proposed in PECO's initial filing. To the extent this is a subsidy, it was contained in PECO original request. Although PECO's rebuttal testimony subsequently revised the Company's RH revenue allocation, I continue to support rate moderation for the RH rate. Treating R and RH as sub-classes will allow the rate moderation determination for Rate RH to be evaluated as an intra-class decision. Consequently, rate moderation for heating customers can be developed without affecting other classes. The impact of the combined class is analogous to the discount for higher voltage HT customers, which is also contained within the HT class and treated as an intra-class issue. Based on my CCOSS, Rate R produces revenues substantially above cost, and can receive a below system average revenue increase while also permitting a moderation of the Rate RH revenue increase. In addition, by combining the R and RH classes, the demand allocator can reflect the reduction in demand costs associated with a larger class, which in turn reduces revenue requirements for both R and RH customers.

Q. IS IT REASONABLE THAT COMBINING THE R AND RH CLASSES REDUCES THE TOTAL RESIDENTIAL DEMAND USED TO ALLOCATE COST?

A. Yes. Maximum demand for the single class is less than the total maximum demand for two classes. As the number of customers in the class increase, the probability that the customers will all peak in the same hour decreases. For the R and RH customers, this characteristic is confirmed by the maximum diversified demand (MDD) data provided by the Company. Although Ms. Jamison argues that the diversity of heating loads should not be reflected in the combined residential class maximum demand, this is exactly how the MDD allocation method is supposed to work. General Service and Primary classes already receive the allocation benefit of diversity from space heating loads within their classes. A combined residential class should receive the same diversity benefit.

Q. MR. POLLOCK'S EXH. JP-6 COMPARES AVERAGE LOAD CHARACTERISTICS OF R AND RH CUSTOMERS IN AN ATTEMPT TO SHOW THAT THE CUSTOMERS SHOULD NOT BE IN THE SAME CUSTOMER CLASS. IS THAT A CORRECT CONCLUSION?

A. No. Most likely the same kind of load differences between space heating and non-space heating customers exist within commercial customer classes. Space heating customers are expected to have higher winter demands and higher electric consumption. The more relevant question is whether the combined residential class has relatively uniform demand characteristics. A measure of similar demands within a class is the diversity ratio.[19] The greater the diversity of demands within the class, the higher the ratio. After combining R and RH, the residential class is significantly less diverse (i.e., more uniform) than commercial and industrial customer classes (GS, Primary, HV). The diversity ratios are compared on Schedule CJ-SR-3. The customers within the combined residential class are more similar than the customers within the major commercial and industrial classes.

Q. DOES THE COMPANY'S REBUTTAL TESTIMONY CRITICIZE THE WAY THAT YOU APPLIED THE NCP DEMAND ADJUSTMENT IN YOUR CCOSS?

A. Yes. PECO witness Ms. Jamison contends that the residential NCP demand reduction should be 6.9% instead of 7.4%.[20] However, even if that calculation change is made, the impact on the CCOSS result is relatively small ($1.5 million). This change is too small to affect my class revenue allocation recommendation.

Q. WHAT IS YOUR RECOMMENDATION?

A. Rate R and RH customers should be combined into a single residential class for purposes of cost allocation.

[19] The diversity ratio is class NCP demand divided by CP demand. The diversity ratio is the reciprocal of coincidence factor.

[20] PECO St. 7-R at 9-10.

VI. PANDEMIC ECONOMIC EFFECT ON DEMAND ALLOCATORS

Q. DOES YOUR DIRECT TESTIMONY RAISE CONCERNS AS TO WHETHER THE PANDEMIC ECONOMIC IMPACT AFFECTED DEMAND ALLOCATION FACTORS?

A. Yes. The demand allocation factors in the Company's CCOSS are based in part on 2020 demand data. However, 2020 data is likely to be influenced by the extraordinary economic effect of dealing with COVID-19. My testimony compared class demand data in the 2018 CCOSS with the 2021 CCOSS. For those time periods, the demand data reflected a **significant increase** in residential NCP demand and **substantial declines** in commercial/industrial demand. The data is inadequate to develop an adjustment to the 2021 CCOSS. However, my testimony suggested that the pandemic impact is a subjective concern that should temper the revenue allocation to the residential class.

Q. DID THE COMPANY'S REBUTTAL TESTIMONY ADDRESS THIS ISSUE?

A. Yes. Ms. Jamison's testimony compared calendar year 2019 demands to the demand data in the 2021 and 2018 CCOSSs.[21] The calendar year 2019 data should exclude the impact of the pandemic. She concluded that the differences between calendar year 2019 demand data and the data in the 2018 CCOSS for several classes are directionally similar to differences between data in the 2018 and 2021 CCOSSs. As a result, Ms. Jamison does not agree with the concern raised in my Direct Testimony.

Q. HAS MS. JAMISON'S ANALYSIS RESOLVED THE CONCERN THAT YOU RAISED?

A. No. PECO Statement 6-R at Exh. TJJ-12 shows the class demand ratios based on 2019 data compared to the demand ratios in the 2021 CCOSS. Although the impact may not be as large as suggested by my testimony, this data does indicate a possible pandemic economic impact on the residential class allocation ratio. In particular, the residential class allocation factor based on calendar year 2019 is 40.9%--comparatively lower than the 43.2% allocation based on partial 2020 demand data. The result is a 14% reduction in the residential allocation factor based on calendar year 2019 data compared to Oct. 2019 - September 2020

Q. WHAT IS YOUR CONCLUSION?

A. The 2019 data does not allay my concerns that the pandemic economic impact adversely affected the residential class allocation factors. The Company asserts that the 2022 future test year revenues assume that the economy has been restored, without continuing COVID-19 impact. However, the class demand allocation factors are based on Oct. 2019

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21 PECO St. 7-R at 10-11.

– September 2020 data, which encompasses the COVID-19 shut down period. Therefore, the revenue allocation process should reflect caution in utilizing the CCOSS results.

VII. RESIDENTIAL CUSTOMER CHARGE

Q. DOES YOUR DIRECT TESTIMONY ADDRESS THE RESIDENTIAL CUSTOMER CHARGE?

A. Yes. In my opinion, the residential customer charge should not be increased above the current $9.99 fixed charge. In addition, my analysis of direct customer charge costs quantified a cost-based customer charge of $8.37.[22] Therefore, policy considerations would permit a reduction of the current customer charge.

Q. DO ANY REBUTTAL WITNESSES OBJECT TO YOUR CUSTOMER CHARGE RECOMMENDATION?

A. Yes. Ms. Jamison disagrees with my recommendation to use only costs which directly vary with the number of customers as a benchmark for evaluating the residential customer charge.[23]

Q. DOES MS. JAMISON SET OUT ANY SPECIFIC CRITICISMS OF YOUR COST ANALYSIS?

A. Yes. She objected to the removal of a portion of call center costs unrelated to billing, collection, and establishment of new customers or termination/transfer of existing

[22] OCA Statement No. 3, Schedule CJ-3.

[23] PECO St. 7-R at 14-16.

customers.[24] Her Rebuttal Testimony also opposed the exclusion of uncollectible expense and customer service and sales expense from the customer charge.[25]

Q. PLEASE RESPOND TO THE SPECIFIC CRITICISMS OF YOUR DIRECT CUSTOMER COST CALCULATION.

A. Ms. Jamison claims that the call center calls related to outages and emergencies are associated with the number of customers. However, this argument ignores the underlying functional cause for these calls. With respect to outages and emergency calls, these calls are related to the safety and reliability of the system. These costs are more appropriately viewed as demand-related instead of customer-related. Reliability ensures that the delivery system is capable of meeting current demand, and therefore is associated with the demand classification. Moreover, timely identification of outages and safety problems provides a system benefit that extends beyond the customer who reports the issue. The Company's rebuttal testimony also contends that administrative costs included in Accounts 908 – 915 are caused by the number of customers. In my opinion, this position ignores the underlying purpose of the activities recorded to these customer service and sales accounts. A major component of Account 908 – 915 relate to the Low Income Usage Reduction Program (LIURP) and marketing/information dissemination related to Act 129 Energy Efficiency programs.[26] LIURP and energy efficiency advertising are energy or demand related activities rather than customer costs properly

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24 Id.

25 Id.

26 See, PECO Response to OCA I-21, and Ex. TJJ-7, page 10.

includable in the customer charge. The benefit for participants in these programs will be proportionate to the reduction in energy charges. These usage-related activities are more appropriately recovered in the residential energy charge. Moreover, a portion of these accounts pertain to economic development and marketing activities, which are aimed at larger customers and clearly do not vary with the number of customers.

Q. DO YOU AGREE WITH MS. JAMISON'S CONTENTION THAT UNCOLLECTIBLE EXPENSE SHOULD BE RECOVERED THROUGH THE CUSTOMER CHARGE?

A. Ms. Jamison states that uncollectible expense varies with the number of customers without providing any evidence of such a correlation.[27] The amount of uncollectible expense is a function of the size of bills which are unpaid, and the amount of such bills is connected to the customer's kWh's of electricity usage. To the extent that high bills lead to non-payment, the energy charge is a more significant contributor to high bills than the fixed $9.99 customer charge. Even if uncollectible costs are recoverable through the customer charge, the amount should be limited to the fixed charge component of the residential bill, which is 10%[28] -- considerably lower than the proportion assigned by the Company's customer charge computation.[29] Furthermore, in response to an interrogatory regarding components of the residential customer charge analysis which are related to transmission and purchase power, the Company stated: "Uncollectible accounts expense… are related to all components of a customer's bill, including Retail

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[27] Id. at 16-17.

[28] PECO Response to OCA-X-8(a), which presents customer charge as percentage of residential bill.

[29] The Company's customer charge analysis for Rate R [Ex. PECO-OCA II-17(a)] includes $8 million of uncollectibles, which is 28% of the $28 million uncollectible expense allocated to Rate R.

Transmission and Energy components, and are recovered via distribution rates."[30] This confirms my position that uncollectible expense is inappropriately included in the customer charge.

Q. WHAT IS YOUR RECOMMENDATION?

A. I continue to support my recommendation that the residential customer charge should be set within the range of $8.37 and the current charge amount of $9.99.

[30] PECO Response to OCA-X-9. This interrogatory refers to the components in the customer charge analysis.

VIII. ALLOCATION OF UNIVERSAL SERVICE COSTS

Q. WILL YOU RESPOND TO REBUTTAL TESTIMONY REGARDING THE ALLOCATION OF UNIVERSAL SERVICE COSTS?

A. I will respond to specific points relevant to my Direct Testimony in this case. OCA witness Mr. Colton (OCA St. 4) is the principal witness sponsoring recommendations related to the universal service costs. Based on his recommended revenue allocation, I prepared Schedule CJ-4 in my Direct Testimony demonstrating the impact of the recommendation. The Company continues to oppose a change in the existing assignment of universal service program cost to the residential class, as stated in PECO witness Feldhake's rebuttal testimony.[31] I disagree with the Company's overall position, and will address other parties' specific rebuttal of my testimony below.

Q. DO YOU AGREE WITH REBUTTAL WITNESSES FOR AMTRAK AND PAIEUG THAT A CUSTOMER ALLOCATION IS PREFERABLE TO THE REVENUE ALLOCATION FOR UNIVERSAL SERVICE COST?

A. No. Amtrak witness Mr. Faryniarz justifies his position on the basis that the Company has classified universal service costs as customer-related.[32] However, these customer classified expenses are administrative costs for CAP and LIURP, which comprise only 13% of the universal service costs identified in my testimony. The primary cost of the CAP program is not included in the CCOSS, and is recovered through the proof of revenue process. These CAP discount costs are not recovered on a per customer basis within the residential class, as claimed by the Amtrak witness. Mr. Faryniarz also

[31] PECO Statement 10R at 11.

[32] Amtrak St. 1-R at 5-6 and 26-27.

contends that a customer allocation is appropriate because the size of the CAP program is dictated by the number of customers who access the program. [33] This "customer access" argument is not a reasonable approach to allocation. Taken to its logical conclusion, all distribution costs would be allocated on a customer basis. Moreover, Mr. Faryniarz ignores the role of the customer's bill and usage of electricity in creating the need for assistance. A revenue allocation more reasonably recognizes that the size of customers' bills affects ability to pay for electric service. Generally, a revenue allocator is relatively neutral because it reflects the impact of multiple allocation factors (energy, demand, customer) in the underlying CCOSS. Mr. Pollock has a more direct justification for supporting a customer allocation, namely to "minimize and cap" the amount allocated to the HV class.[34] This is an end-result approach to allocation which should be rejected.

Q. MR. KALCIC CONTENDS THAT THE UNIVERSAL SERVICE COST ALLOCATION SHOULD HAVE BEEN INCLUDED AS PART OF YOUR REVENUE INCREASE ALLOCATION [OCA STATEMENT NO. 3 SCHEDULE CJ-3]. IS THIS CORRECT?

A. No. The revenue allocation is based on the distribution revenue requirement included in the CCOSS. OCA's approach is to exclude universal service costs from the CCOSS, so that the allocation can be applied separately to all universal service program costs. In this case, the Company includes only CAP administrative expenses and LIURP expense in the CCOSS. The Company recovers the remaining CAP discount amount ($88 million) from residential classes through the proof of revenue procedure. The revenue allocation witnesses do not include this $88 million CAP discount as part of their revenue allocation

[33] Id. at 31.

[34] PAIEUG Statement 2-R at 11.

schedules. In the past, to the best of my knowledge, when the Company increased the total amount of CAP discount, the Company did not reflect it as part of a higher percentage revenue increase for the residential class. For this reason, the column "OCA with CAP" in Mr. Kalcic's Schedule BK-1R appears to be incorrect and inaccurate. My direct testimony Schedule CJ-3 sets out the universal service program allocation in a transparent manner which should adequately inform parties of the proposal's impact.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes.

315030

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Electric Division

Docket No. R-2021-3024601

Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set II

Response Date: 05/21/2021

OCA-II-28

Provide details regarding the methodologies used to estimate demand requirements before installing new secondary lines or replacing existing secondary lines.

RESPONSE:

When forecasting demand for a new customer (or group of customers), a number of items are considered in the engineering analysis performed to estimate the peak demand to size the secondary lines required to serve each customer. These items include:

- Intended use of customer's facility, such as, residence or commercial space and, if the latter, the use of the commercial space (store, warehouse, office, fast food restaurant, etc.).
- HVAC requirements including air conditioning and type heating (electric or non-electric) and similar factors.
- The customer's connected load
- Building size (square footage, number of floors, etc.)

Voltage drop, both steady state and instantaneous, from large loads with high starting currents, such as central air conditioners, are considered in determining secondary line sizes. Voltage drop frequently limits the length of secondary lines or requires the installation of larger secondary conductors.

Existing secondary lines may be replaced due to load growth from new or existing customers, material condition, or voltage issues. If the replacement is due to load-related issues, actual load readings or meter data are used to determine secondary wire size.

Responsible Witness: Tamara J. Jamison

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Electric Division

Docket No. R-2021-3024601

Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set II

Response Date: 05/21/2021

OCA-II-26

Please describe the Company's planning guidelines for installing new distribution feeders and for replacing, or adding devices to, existing distribution feeders. Explain how load diversity and reduction in losses is taken into account during this planning process.

RESPONSE:

Feeders are relieved when the forecasted load is projected to exceed 110% of the allowable feeder rating. Options to relieve overloaded feeders, such as by transferring load to surrounding feeders, are used before new feeders are installed. Feeders are typically installed and new devices, such as transformers, are added to supply a specific new business load.

The Company reviews and tracks actual peak distribution feeder demands annually. Because actual peak data are used, load diversity and loss reductions are automatically included. New business additions and load transfers per feeder are tracked and included in this review. Forecasted peak feeder loads are based on the actual peak feeder demands adjusted using a 1-in-10-year weather correction factor.

Responsible Witness: Tamara J. Jamison

Class Diversity Ratios

Combined Residential	**101%**
General Service	**118%**
Primary Distribution	**117%**
High Tension	**116%**
PECO System	**112%**

Source: Diversity Rate = Class NCP / Class CP.
NCP and CP data from Ex. TJJ-7, page 2.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024601
	:	
PECO Energy Company – Electric Division	:	

VERIFICATION

I, Clarence L. Johnson, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 3-SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 5, 2021
*314840

Signature: ______________________
Clarence L. Johnson

Consultant Address: CJ Energy Consulting
3707 Robinson Avenue
Austin, TX 78722

OCA Statement No. 4-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2021-3024601
PECO Energy Company – Electric Division	:	

Surrebuttal Testimony of
Roger D. Colton

On Behalf of:
Office of Consumer Advocate
Statement No. 4-SR

August 5, 2021

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, MA 02478.

Q. ARE YOU THE SAME ROGER COLTON WHO HAS PREVIOUSLY PREPARED DIRECT AND REBUTTAL TESTIMONY ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. In my Rebuttal Testimony, I respond to the Rebuttal Testimony of Brian Kalcic on behalf of the Office of Small Business Advocate (OSBA), Jeffrey Pollock on behalf of the Philadelphia Area Industrial Energy Users Group (PAIEUG), Stan Faryniarz on behalf of the National Railroad Passenger Corporation (AMTRAK), Laura Feldhake on behalf of PECO Energy, and John McDonald on behalf of PECO Energy. I finally respond to the Rebuttal Testimony of D.C. Patel on behalf of the Bureau of Investigation and Enforcement (I&E).

Part 1. Response to John McDonald.

Q. PLEASE EXPLAIN THE REBUTTAL TESTIMONY OF JOHN MCDONALD TO WHICH YOU RESPOND.

A. Mr. McDonald responds to my testimony regarding management performance. While he mentions payment arrangements and service disconnections in his Rebuttal Testimony, he references Ms. Feldhake's testimony on those issues (PECO St. 1R, at 6). I respond to those issues in my response to Ms. Feldhake.

Mr. McDonald does not dispute the facts presented in my Direct Testimony. The facts that he does not dispute are:

- According to the PUC's data,[1] PECO was tied for the second lowest percentage of customers who were "very satisfied" with the Company representative's handling of a customer service call. (Customer Service Report, at 22). (OCA St. 4, at 92).

- PECO Energy was tied (with West Penn Power) for the lowest percentage among Pennsylvania electric utilities for customers who responded that the Company's representative was "very courteous." Nearly one-of-five customers (18%) who contacted the Company reported that they felt the Company representative was less than "very courteous."

- PECO Energy was tied (again with West Penn Power) for the lowest percentage among Pennsylvania electric utilities who responded that the Company's representative was "very knowledgeable." Nearly one-of-four customers contacting PECO reported that they felt the representative with which they interacted was less than "very knowledgeable." (Customer Service Report, at 23).

- Overall, when limited to customers who had experienced a recent contact with PECO Energy, the Commission's own data reports that PECO had the third lowest score among the state's electric utilities with respect to being "very satisfied" with PECO's "overall quality of service during recent contact." (Customer Service report, at 26).

- Nearly three-of-ten customers (28%) who had made a recent contact with PECO said that they were less than "very satisfied" with PECO's overall quality of service related to that contact. (Id.)

[1] Customer Service Performance Report: 2019 (hereafter "Customer Service Report") (published October 2020), available at https://www.puc.pa.gov/filing-resources/reports/customer-service-performance-reports/ (last accessed June 22, 2021).

The above data does not support a finding of exemplary management when viewed from the perspective of customer satisfaction.

Moreover, Mr. McDonald does not seek to justify its use of a single J.D. Power summary statistic rather than the more detailed data that J.D. Power says it makes available. He does not dispute that J.D. Power states that it provides its clients with data on "six factors and 36 attributes at both the national and regional levels."[2] At no point did I dispute that J.D. Power scores are a "well-recognized industry standard for benchmarking utility call center performance." (PECO St. 1R, at 7). I simply pointed out that PECO does not choose to provide all the data generated by J.D. Power so that the Commission can make meaningful use of the J.D. Power data.

In sum, Mr. McDonald provides no reason to reject the findings and conclusions of my Direct Testimony regarding customer satisfaction.

Part 2. Response to Lauren Feldhake.

Q. PLEASE IDENTIFY THOSE PARTS OF THE REBUTTAL TESTIMONY OF PECO WITNESS LAUREN FELDHAKE TO WHICH YOU RESPOND.

A. The testimony of Ms. Feldhake (PECO St. 10R) addresses my recommended modifications to PECO's COVID-19 Residential Relief Program; my recommendations regarding CAP outreach; and my recommendation regarding the allocation of universal

[2] Available at . https://www.jdpower.com/sites/default/files/file/2020-11/JDP_US_2020_ResidentialElectric_Brochure_FINAL_103020.pdf (last accessed June 17, 2021).

service costs to all customer classes. Ms. Feldhake further responds to my testimony regarding management performance with respect to collection outcomes.

Q. PLEASE RESPOND TO MS. FELDHAKE'S REBUTTAL TESTIMONY REGARDING THE PECO RESIDENTIAL RELIEF PROGRAM.

A. It is important to first remember that I recommend approval of the PECO COVID-19 Residential Relief Program (RRP). (OCA St. 4, at 4, 22). Ms. Feldhake disagrees with the recommendations I advance with respect to the on-the-ground implementation of the RRP which PECO did not explain in its Direct Testimony. (OCA St. 4, at 22).

Ms. Feldhake states that "it is reasonable to offer bill credits to customers with any amount of arrears. Any reduction to an active arrearage could help prevent collection activities." (PECO St. 10R, at 4). My testimony demonstrates, however, that the economic crisis engendered by COVID-19 will substantially outlast the public health crisis. It is difficult to support the proposition advanced by Ms. Feldhake that someone who is in arrears by $100 represents the same risk of collection activity, and the same risk of the loss of service, that is represented by a customer who is in arrears by $350. My recommendation to limit the RRP to customers owing more than $200 would help target the RRP benefits to those most in need, and would help extend the time over which the RRP benefits would be available (since those benefits would not be available to customers with smaller arrears). My recommendation is reasonable and should be adopted.

Ms. Feldhake states that "the Company's requirement to provide proof of unemployment or a federal COVID-19 relief check is both consistent with other Commission-approved COVID-19 relief programs and is reasonable from an administrative perspective." (PECO St. 10R, at 4). In my Direct Testimony, I expressed concern about how PECO's requirement of "unemployment" will miss customers in economic crisis not because they lost their jobs completely, but rather because they lost employment income. (OCA St. 4, at 23).). "Lost income" may arise from a reduction in hours, which does not raise to the level of completely losing one's job. "Lost income" may also arise from an intermittent or sporadic layoff or furlough. Ms. Feldhake's concern about being "reasonable from an administrative perspective" is not well-founded. The same documentation can be required to establish "lost employment" and "lost income." For example, one need not lose employment altogether in order to receive "unemployment" in Pennsylvania. See, e.g., https://www.uc.pa.gov/faq/claimant/Pages/Reduced-Work-Hours-FAQS.aspx.

Finally, Ms. Feldhake asserts that PECO's "proposed Program budget of $3.0 million is appropriate and that the Program should terminate when funds are exhausted." (PECO St. 10-R, at 5). My recommendation, however, is simply to provide PECO some flexibility in responding to the exigencies of the COVID-19 economic emergency. Given the inherent regulatory lag of petitioning the Commission for approval of a program expansion, it would not necessarily be possible for PECO to react in a timely fashion to future exigencies. My recommendation was that PECO should only be required to seek additional PUC approval when a budget modification represents a material expansion of the program. What constitutes a "material" expansion of the program should be determined in consultation with the Bureau of Consumer Services and other stakeholders.

Q. PLEASE RESPOND TO MS. FELDHAKE'S RESPONSE TO YOUR DIRECT TESTIMONY REGARDING CAP OUTREACH.

A. Ms. Feldhake does not dispute the fact that PECO's own data shows that the utility "has experienced a continuing decline in CAP participation within the population with income less than 50% of Poverty."(OCA St. 4, at 46 – 47). Her Rebuttal Testimony again reveals that PECO does not target the population with income less than 50% of Poverty for CAP outreach, but rather engages in a more generic targeting of "low-income" customers. (PECO St. 10-R, at 8-9). This generalized outreach comes notwithstanding the Commission's specific, explicit directive that "while utilities have flexibility as to the contents of their plans. . .[i]*n particular, these plans should identify efforts to educate and enroll eligible and interested customers at or below 50% of the FPIG."* Final Order, at 79, Docket M-2019-3012599 (emphasis added).

Moreover, while PECO tracks the outreach activities in which it engages, it does not track the outcomes. Particularly in light of the specific directive the PUC provided with respect to the below 50% of Poverty population "in particular," my recommendation that PECO be directed to identify specific metrics by which to track the outcomes of its outreach with respect to this population is not unreasonable.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY "OUTCOMES."

A. Distinguishing between "activities" and "outcomes" is commonly accepted in program planning. An *activity* is defined as the work performed that directly produces products and/or services. The *outcome* of a program is the accomplishment of program objectives attributable to program outputs. Ms. Feldhake's Rebuttal Testimony focuses on activities. She speaks of the "number of events"; "counties covered" and "number of materials distributed." (PECO St. 10-R, at 8). She references "solicitation efforts"; "flyer distribution" and "emails to targeted zip codes"; "expanded social media"; "training social service staff"; and "Virtual Townhalls." (PECO St. 10-R, at 9). These are all activities, not outcomes. When she references metrics regarding "CAP Enrollment," there is no inclusion at all of any metrics regarding outcomes with respect to the below 50% of Poverty population. (PECO St. 10-R, at 9). My recommendation addresses this shortcoming. As I recommend, "PECO should be directed to provide a detailed plan addressing how it intends to expand its CAP outreach to expand CAP participation for customers with annual income less than 50% of Poverty. . .[T]hat Plan should include not only a discussion of the *activities that the Company intends to take*, it should *also* include *quantitative outcomes by which the success (or lack thereof) can be measured*." (OCA St. 4, at 4) (emphasis added). This is the same distinction the Commission made in its decision in the most recent Columbia Gas rate case.[3] It is not merely the activities that a utility is pursuing that should be the subject of review. It is the *results* of those activities. The PUC said in its Columbia Gas decision that "we expect Columbia will address these additional outreach efforts *and corresponding results*. . ." (emphasis added).

[3] Pennsylvania PUC v. Columbia Gas of Pennsylvania, Docket No. R-2020-3018835.

Q. PLEASE RESPOND TO MS. FELDHAKE'S REBUTTAL REGARDING THE ALLOCATION OF UNIVERSAL SERVICE COSTS.

A. Ms. Feldhake's Rebuttal Testimony regarding universal service cost allocations simply cited two recent PUC decisions. (PECO St. 10-R, at 11 – 12). I have previously addressed both of those decisions in my Direct Testimony. (OCA St. 4, at 50 – 51).[4]

Q. PLEASE RESPOND TO MS. FELDHAKE'S REBUTTAL REGARDING MANAGEMENT EFFICIENCY.

A. Ms. Feldhake states that she disagrees with my "contention that PECO is treating payment arrangements improperly." (PECO St. 10-R, at 12). She never cites to any testimony where I might have made that "contention." What she does *not* dispute is my observation that PECO is entering into fewer and fewer Payment Arrangements (PARs) with its residential customers. Indeed, the number of residential PARs declined by nearly 10,000 from 2016 through 2019. (OCA St. 4, at 87). Neither did she dispute the fact that PECO was entering into fewer PARs at the same time it was disconnecting service to more residential customers for nonpayment.

Nor does Ms. Feldhake dispute the facts that both the number and the percentage of residential accounts in debt not on an agreement has increased for PECO since 2016. She did not dispute my observation that in 2019, PECO's 83.1% of accounts in arrears not on agreement was higher than every other Pennsylvania electric utility. She did not dispute the fact that the percentage of *dollars* in arrears, but not on agreement, has increased in recent years, or that that percentage was also higher than every other Pennsylvania

[4] Other rebuttal witnesses raise these same decisions, to which rebuttal testimony my response would be the same.

electric utility. (OCA St. 4, at 90). She did not dispute the fact that the ratio of customers who "fail to maintain" their payment arrangements is two times higher for PECO (0.14) than it is for the next highest utility (Duquesne: 0.07) and three times higher than other Pennsylvania electric utilities (ranging from 0.03 to 0.04) (setting aside PPL). (OCA St. 4, at 91).

In sum, I conclude that Ms. Feldhake provides no factual basis for approving the Company's requested equity adder for exemplary Company management.

Part 2. Response to OSBA Witness Kalcic.

Q. PLEASE IDENTIFY THE ASPECTS OF MR. KALCIC'S REBUTTAL TESTIMONY TO WHICH YOU RESPOND.

A. I respond to the Rebuttal Testimony of Mr. Kalcic wherein he opposes the allocation of universal service costs to all customer classes. Mr. Kalcic's testimony is incomplete in many important places. In other places, he provides no basis for rejecting my recommendation that universal service costs be allocated to all customer classes.

Q. WHERE IS MR. KALCIC'S ANALYSIS INCOMPLETE?

A. In his Rebuttal Testimony, Mr. Kalcic states that he was advised by his Counsel that the only reason the Commission has decided to revisit its policy of allocating universal service costs exclusively to the residential class is because "the anticipated increases in universal spending (sic) on the part of electric and gas distribution companies would make electric and/or natural gas bills 'increasingly unaffordable' for non-CAP customers.

. ." (OSBA St. 1-R, at 2-3). Mr. Kalcic's statement that it is only the "anticipated *increases* in universal [service] spending" mis-states the Commission's decision. The Commission was clear when it observed that "[t]he *current* cost- recovery method for universal services, including CAP costs, is putting a significant burden on residential customer bills. . ." (Final Order, (Docket M-2019-30125, at 92) (emphasis added).

In addition, the burden on residential bills was only one of several factors the Commission said it was taking into consideration. As I explained in my Direct Testimony, the PUC was correct when it found in the same 2019 Order cited by Mr. Kalcic:

- poverty is "not just [a] residential class problem."
- several factors "contribute to households struggling to afford utility service" and that, amongst those factors are "poverty, poor housing stock, and other factors."
- Poverty is a broad-based social problem not associated with any particular customer class, including specifically not being associated with the residential class exclusively.
- "helping low-income families maintain utility service and remain in their homes is also a benefit to the economic climate of a community."
- "clearly, there is a persuasive argument to be made that home heating and energy assistance for low-income households serves a public good whose responsibility is not merely other residential ratepayers."
- "while there are strong arguments to be made that non-residential classes do benefit from universal services, there are also strong arguments to be made in favor of multi-class allocation even if one discounts any non-residential benefits."
- "in approving PGW's practice of recovering such costs across all ratepayer classes, we noted that 'all firm customers, including commercial and industrial customers,

> benefit indirectly from PGW's extensive low-income assistance programs.'" (internal note omitted).

(OCA St. 4, at 62 et seq.)

Q. DOES MR. KALCIC DOWNPLAY THE FINANCIAL BURDEN PLACED ON RESIDENTIAL CUSTOMERS BY PECO UNIVERSAL SERVICE SPENDING?

A. Yes. Mr. Kalcic asserts that universal service costs would be affordable because, "if all of PECO's claimed CAP-related costs were to continue to be recovered solely from Rates R and RH, the average monthly impact on residential bills *would be only $5.49 and $5.00*, respectively for Rate R and Rate RH customers." (OSBA St. 1-R, at 3). (emphasis added). Mr. Kalcic should not be so quick to dismiss the impact of an additional $60 ($5.00/month x 12 months = $60.00) to $66 ($5.49/month x 12 months = $66.88) on low-income customers.

PECO Electric is the electric utility serving the City of Philadelphia. PECO is unique amongst all Pennsylvania electric distribution companies in the number of estimated low-income customers it serves. According to the most recent (2019, published December 2020) BCS annual Report on Universal Service Programs and Collections Performance, PECO has more than 124,000 more estimated low-income customers than the next closest electric distribution utility (PECO: 393,662 vs. PPL: 269,535). Just as the Commission noted with respect to PGW as a gas utility, PECO is the electric equivalent to PGW in that it is a large electric utility situated within the City of Philadelphia and serves more low-income customers than any other jurisdiction electric utility.

Table 1. Number of Estimated Low-Income Customers (PA Electric Distribution Utilities) 2019 BCS Annual Report on Universal Service Programs and Collections Performance	
Duquesne	103,720
Met-Ed	116,570
PECO Electric	393,662
Penelec	155,072
Penn Power	35,872
PPL	269,535
West Penn	157,491

Just like the Commission noted with respect to PGW in 2017, PECO's CAP participation rate has substantially declined in the past five years. In approving the allocation of universal service costs over all PGW customer classes, the Commission noted that "participation in PGW's CRP program has declined by 24,262 customers from 2010 to 2015 even though the number of confirmed low-income customers served by PGW has increased by more than 22,000 customers." (2017 PGW Opinion and Order, at 74). Similarly, participation in PECO's CAP has declined by 28,362 (from 140,514 to 112,152) over a five year span (2014 – 2019), even though PECO's number of estimated low-income customers has increased by 14,915 (from 378,747 in 2014 to 393,662 in 2019).

Just like the Commission said in 2017 when it found that allocating universal service costs exclusively to the residential class would "exacerbate the problems PGW experiences with the low-income customer population's inability to pay issues," allocating universal service costs exclusively to PECO's residential class would exacerbate the problems PECO experiences with the low-income customer population's inability pay issues. Given the small percentage of PECO low-income customers that have had their low-income status confirmed, I examine residential customers. As Table 2 below shows, PECO Electric:

- Has 40,000 more disconnections for nonpayment (DNPs) than the next closest utility;
- Has the highest DNP Rate (i.e., percentage of residential accounts disconnected for nonpayment) amongst all Pennsylvania electric utilities;
- Has the second highest number of customers in debt;
- Has the highest percentage of dollars that are owed that are not on a Payment Arrangement (PAR).

Table 2. Residential Collection Statistics (2019)
PA Electric Distribution Utilities
2019 BCS Annual Report on Universal Service Programs and Collections Performance

	DNPs	DNP Rate	Customers in Debt	Dollars Owed Not on PAR
Duquesne	27,688	5.20%	42,078	39.20%
Met-Ed	26,076	6.20%	45,140	32.90%
PECO-Electric	92,497	4.20%	102,667	68.60%
Penelec	21,065	2.90%	50,830	31.90%
Penn Power	4,293	4.30%	12,173	32.80%
PPL	53,340	3.10%	196,086	58.80%
West Penn	19,743	4.90%	54,081	36.10%

Overall, I conclude that Mr. Kalcic errs when he downplays the affordability impacts of allocating PECO Electric universal service costs exclusively to the residential class, by saying that the impact of his recommendation "would be <u>*only $5.49 and $5.00*</u>. . ."

Instead, all of the findings that the Commission made with respect to the impacts on affordability for PGW, the natural gas utility serving Philadelphia, are equally applicable to PECO, the electric utility serving Philadelphia.

Q. PLEASE RESPOND TO MR. KALCIC'S COMMENTS ABOUT THE IMPACTS ON BUSINESS OF ALLOCATING UNIVERSAL SERVICE COSTS TO ALL CUSTOMER CLASSES.

A. Mr. Kalcic asserts that "the Commission need not concern itself at this time with how businesses may or may not have fared in other jurisdictions that allocate universal service costs to all rate classes." (OSBA St. 1-R, at 4). The Commission, however, has previously disagreed with that assertion. At this time, there is ample *experience* with the impacts of inter-class cost allocation on business and industry. And, as the Commission stated in 2019:

> OSBA and the Industrial Customers have argued that recovering costs of universal service programs from industrial and commercial customers may negatively impact businesses in the Commonwealth. However, we have not seen evidence that the economic climate in Philadelphia has been negatively impacted as a result of universal service costs charged by PGW. Further, as noted by multiple parties in the *Review* proceeding, many states recover the cost of utility low-income programs from all ratepayer classes, including New York, New Jersey, Ohio, Illinois, Maine, and New Hampshire.[5] We are not aware that this practice has negatively impacted the business climate of any OF these states.

[5] New York, for example, determines the specific distribution of this cost recovery in rate cases, where the total impacts of all revenue requirement changes can be considered. *See Order Adopting Low Income Program Modifications and Directing Utility Filings*, New York Public Service Commission, Case 14-M-0565 (Issued and Effective May 20, 2016), at 4.

(Final Order, at 98). Indeed, the Commission has previously explicitly found that "in approving PGW's practice of recovering such costs across all ratepayer classes, we noted that 'all firm customers, including commercial and industrial customers, benefit indirectly from PGW's extensive low-income assistance programs.'" PGW's universal service program helps keep people in their homes and contribute to local economic activity, as the Commission favorably noted in the 2017 PGW rate case proceeding approving the allocation of universal service costs to all customer classes. (Final CAP Policy Statement, at note 144, page 96, citing *Pa. PUC, et al. v. PGW* at 63),

What Mr. Kalcic has not explained is how, or why, allocating the natural gas universal service costs in Philadelphia would keep residents of Philadelphia in their homes and contribute to the well-being and economic vibrancy of the City's business community, but allocating the electric universal service costs to the same businesses in the same city would instead have the opposite effect. Mr. Kalcic has not explained why the allocation of a portion of natural gas universal service costs to non-residential customers is offset by the substantial positive economic impact in Philadelphia on those non-residential customers created by PGW's universal service programs, but the allocation of a portion of electric universal service costs would have the opposite impact, only harming business and industry.

In contrast, my Direct Testimony explains why what was true for PGW in Philadelphia is also true for PECO in Philadelphia. Mr. Kalcic does not even attempt to rebut my Direct Testimony in this regard.

Q. HOW DOES MR. KALCIC RESPOND TO THE BENEFITS TO BUSINESS?

A. Mr. Kalcic appears to accept the fact that businesses benefit from PECO's universal service programs. He argues, however, that that principle has not been applied to electric efficiency programs. He does not acknowledge, however, that OSBA has previously presented that identical argument to the Commission and had it rejected. The allocation of efficiency investments is done pursuant to specific statutory directive. The Commission previously rejected the OSBA argument, stating that "In fact, there is specific justification for the class restrictions in the Act 129 arena. Act 129 programs are evaluated using a benefit/cost ratio pursuant to the Commonwealth's Total Resource Cost (TRC) Test.[6] Also, societal benefits, specifically including universal service program costs, are expressly excluded from the TRC Test calculation. There are no such test requirements or exclusions for CAPs or other universal service benefits." (Final Order, at 97).

In fact, the Commission said, the Act 129 restrictions on cost allocation speak in favor of the authority of the Commission to allocate universal service costs over all customer classes. "The Act 129 restrictions clearly indicate that the General Assembly can and will mandate class restrictions when it determines that such restrictions are warranted." (Id., at 97) (internal notes omitted).

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[6] *See*, *e.g.*, *2016 TRC Test Order*, Docket No. M-2015-2468992 (order adopted on June 22, 2015). http://www.puc.pa.gov/pcdocs/1367195.docx.

Part 3. Response to PAIEUG Witness Pollock.

Q. PLEASE EXPLAIN THE ASPECT OF MR. POLLOCK'S REBUTTAL TESTIMONY TO WHICH YOU WILL RESPOND.

A. Mr. Pollock opposes the allocation of universal service costs to all customer classes. He provides no compelling reasons to support that recommendation.

First, Mr. Pollock states that universal service costs should be allocated exclusively to the residential customer class because "other customer classes do not receive the benefits of [universal service programs]." (PAIEUG St. 2R, at 9 – 10). I explained in detail in my Direct Testimony how all customer classes benefit from PECO's universal service programs. I further explain above in response to both Mr. Kalcic and Ms. Feldhake the benefits that appertain to non-residential customers. Finally, the Commission has previously rejected this argument. The Commission has previously stated: "Clearly, there is a persuasive argument to be made that home heating and energy assistance for low-income households serves a public good whose responsibility is not merely other residential ratepayers. While there are strong arguments to be made that non-residential classes do benefit from universal services, there are also strong arguments to be made in favor of multi-class allocation even if one discounts any non-residential benefits." (Final Order, at 96 – 97). Even if Mr. Pollock is correct, in other words, which he is not, his argument does not support his opposition to multi-class allocation of universal service costs.

Mr. Pollock argues further that "low-income issues are best addressed by the state legislature who can provide more meaningful assistance." (PAIEUG St. 2R, at 11). The question of whether universal service costs are "best addressed" by the legislature is not presented in this proceeding. Indeed, as the Commission has previously noted, "

> We note there is no statutory or appellate prohibition that limits the recovery of CAP costs, whether specifically calculated or as part of total universal service costs, to funding from the residential class.[7] Universal service funding from non-residential classes, while not mandatory, is permissible:
>
> > Thus, under *Lloyd*, there is no statutory requirement that the funding for special programs come only from those who benefit from the programs. However, the lack of such a requirement does not mean that funding for special programs must come from those who do not benefit.
>
> *MEIUG v. Pa. PUC*, 960 A.2d 189, 202 (2008), citing *Lloyd v. Pa. PUC*, 904 A.2d 1010 (Pa. Cmwlth. 2006).
>
> Consistent with the comments of the Low Income Advocates and OCA, the Commission concludes that the General Assembly clearly identified the public purpose of these programs in the Competition Acts by requiring that their costs be nonbypassable" when a customer switches energy providers.

(Final Order, at 98 – 99) (internal notes omitted).

Finally, Mr. Pollock recommends that if the Commission determines that universal service costs should be allocated to all customer classes, a charge "of no higher than $62.73 per customer" should be used. (PAIEUG St. 2R, at 12). He asserts that this allocation "places a reasonable limit on the amount paid by each customer." (Id., at 11). He explicitly defines "reasonable" as minimizing charges to industrial customers (Id., at 11), and capping industrial charges at no higher than the charge to residential customers.

[7] In PGW's 2017 rate case, the Commission noted that recovering universal service costs from all ratepayers does not appear to be a violation of Title 66 or Commission regulations. *Pa. PUC, et al. v. PGW* at 74.

(Id.) Mr. Pollock offers no data, no discussion, and no argument, about why the industrial charge should be equal to the residential charge. Nor does he offer any support as to why this particular dollar amount is reasonable. Lacking such support, and given the explanation above of why the dismissal of affordability concerns is in error, Mr. Pollock's recommendation should not be approved.

Moreover, Mr. Pollock's proposal treats universal service costs as though they are a static figure once established in a rate case. He fails to recognize that universal service cost recovery for PECO is reconcilable. While Mr. Pollock estimates universal service costs to be specific figure, PECO's estimated universal service costs (including CAP credits) are simply estimates. While my recommended cost allocation methodology has the advantage of being "administratively easy to apply," Mr. Pollock's proposal would involve extraordinary complexity. Reconciliation could involve changes in his recommended per customer charge of fractions of a cent on a monthly basis. Mr. Pollock does not explain how such a monthly charge could be imposed which would provide PECO full cost recovery.

Finally, Mr. Pollock's proposal treats the number of customers as though it is a static figure from month-to-month (or year-to-year). PECO's CAP participation, however, is not constant. The process of adjusting PECO universal service cost recovery based on changes in the number of customers would add yet another layer of complexity to Mr. Pollock's recommendation that he neither acknowledged nor considered. In contrast, the cost allocation recommended in my Direct Testimony would not generate such complexity.

In short, apart from its lack of a conceptual foundation, Mr. Pollock proposes to allocate universal service costs on a per-customer basis, even though neither the costs nor the number of customers is a known figure. His recommendation should not be approved.

Part 4. Response to AMTRAK Witness Faryniarz

Q. PLEASE EXPLAIN THE ASPECT OF MR. FARYNIARZ'S REBUTTAL TESTIMONY TO WHICH YOU RESPOND.

A. Mr. Faryniarz opposes the allocation of universal service costs to all customer classes. I examine each of his opposing arguments.

Q. PLEASE RESPOND TO MR. FARYNIARZ'S COMMENTS ABOUT THE BONBRIGHT RATEMAKING OBJECTIVES.

A. Mr. Faryniarz lists in summary fashion what he refers to as "the ratemaking conventions established by Bonbright, other experts and academics. . ." (AMTRAK St. 1-R, at 9 – 11). He asserts that "first and perhaps foremost, is that rates should be designed on the basis of *cost causation*." (Id., at 9). The argument that principles of cost causation do not support an allocation of universal service costs to all customer classes has been directly presented to the Commission before. In its Final Order regarding the PUC's Revised CAP Policy Statement, the PUC noted that:

> PSU, PPL, and the Industrial Customers separately maintain that recovering universal service costs from commercial and industrial customers is not

> consistent with the cost-causation principles established in *Lloyd v. Pa. PUC*, 904 A.2d 1010, 1019–21 (Pa. Cmwlth. 2006). These parties argue that residential customers are the "cost causers" of universal service programs because they are the only class who may benefit from these programs. PSU Comments at 5–6, PPL Comments at 11–12, and Joint Reply Comments of Industrial Customers at 11. PSU contends there is no support for OCA's argument that non-residential ratepayers contribute to the cost of CAPs. PSU Reply Comments at 8–9.

(Final Order, at 88 – 89). The Commission rejected that argument as a basis for allocating costs exclusively to residential customers. After citing the PUC's Bureau of Consumer Services conclusion that "BCS] does not find any logic to the argument that because the larger societal economic conditions are negatively affecting the ability of some [low-income] residential customers to pay their bills, that the problem is somehow caused by the residential class and should therefore be paid for by that class. *Final Report on The Investigation of Uncollectible Balances* at 157–158." The Commission specifically stated that it "agrees that poverty, poor housing stock, and other factors that contribute to households struggling to afford utility service are not just 'residential class' problems." (Final Order, at 96).

Q. PLEASE RESPOND TO MR. FARYNIARZ'S REBUTTAL TESTIMONY REGARDING THE IMPORTANCE OF SEPTA TO THE REGIONAL ECONOMY.

A. Mr. Faryniarz argues that universal service costs should not be allocated to SEPTA in part because SEPTA "is a major economic driver" and SEPTA's "transit service enables the efficient functioning of the regional economy and shapes development patterns."

(AMTRAK St. 1-R, at 14. He argues that SEPTA's "transit investments generate significant dividends in the form of jobs and economic activity. . ." (Id.)

I do not question the importance of SEPTA to Philadelphia's regional economy. However, what Mr. Faryniarz fails to acknowledge is not merely the benefits that PECO's universal service programs bring to the regional economy, but the extent to which PECO's universal service programs are essential to preserving the robust nature of Philadelphia's economy. The Commission has previously found with Philadelphia in particular that "in approving PGW's practice of recovering such costs across all ratepayer classes, we noted that 'all firm customers, including commercial and industrial customers, benefit indirectly from PGW's extensive low-income assistance programs.'" The Commission has acknowledged that PGW's universal service program helps keep people in their homes and contributes to the local economic activity, as the Commission favorably noted in the 2017 PGW rate case proceeding (Final CAP Policy Statement, at note 144, page 96, citing *Pa. PUC, et al. v. PGW* at 63).

The allocation of universal service costs to all customer classes helps to maintain the regional economy upon which SEPTA depends. The relationship between the economy and universal service programs is a reason to allocate universal service costs over all customer classes, not to allocate them only to residential customers.

Q. PLEASE RESPOND TO MR. FARYNIARZ'S REBUTTAL TESTIMONY REGARDING THE FINANCIAL CONDITION OF AMTRAK.

A. Mr. Faryniarz argues that AMTRAK is not in the financial condition to absorb the allocation of universal service costs to all customer classes. He argues that AMTRAK experienced a revenue decline of 31% due to COVID-19, an operating loss increase of 71%, and a decline in ridership of 47%. (AMTRAK St. 1-R, at 16). Mr. Faryniarz argues that allocating universal service costs to all customer classes would result in an additional cost of $499,000 annually (Id., at 15). He argues that bearing the $499,000 cost "must be recovered from Amtrak's and the Commuter Rail Agencies' ridership through either fare increases, reductions in service, or both, or an increase in subsidies from the federal and state governments." (Id., at 7). Given that that $499,000 would be spread over a total ridership of more than 32 million in a non-COVID-19 year (Id., at 16), assuming away any offsetting cost reductions, and assuming that the entire $499,000 would be collected in increased fares, Mr. Faryniarz appears to argue that the $0.015 increase per ride would impose an unreasonable burden, or in the absence of the 1.5 cents per rider, a "reduction in service." As discussed below, that claim is not supported.

Q. HAVE YOU HAD OCCASION TO REVIEW THE DATA WHICH MR. FARYNIARZ PRESENTS IN HIS TABLE 1?

A. Yes. Mr. Faryniarz presented ***selected*** Amtrak operating results from FY 2020 and FY 2019 in his Table 1 (AMTRAK St. 1-R, at 16). I have examined not only the source document he cites, but have examined other aspects of those "operating results" which he selected ***not*** to present for the years he presented, as well as the corresponding documents for prior years as well.

Several important observations flows from the Table immediately below.

Table 3. Selected AMTRAK Operating Results (2016 – 2020) ($000)

	2020	2019	2018	2017	2016
Total revenues	$2,430,701	$3,503,515	$3,386,733	$3,305,705	$3,240,558
Salaries, wages and benefits	$1,995,134	$2,174,302	$2,020,565	$2,084,564	$2,087,609
Fuel, power and utilities	$215,496	$206,208	$269,811	$239,742	$230,369
Total operating expenses	$4,154,935	$4,403,212	$4,238,951	$4,210,395	$4,261,268
Fuel power and utilities as pct of total operating expenses	5%	5%	6%	6%	5%
Salaries, wages and benefits as pct of total operating expenses	48%	49%	48%	50%	49%
Fuel power and utilities as pct of total revenues	9%	6%	8%	7%	7%
PA universal service costs	$499	$499	$499	$499	$499
PA universal service as pct of fuel, power and utilities	0.23%	0.24%	0.18%	0.21%	0.22%
PA universal service as pct of total operating expenses	0.012%	0.011%	0.012%	0.012%	0.012%

First, note the sharp decline in total “fuel power and utilities” expenses over the years. In 2020, AMTRAK spent $54.3 million less on fuel, power and utilities than it did in 2018. It spent $24.2 million less than it did in 2017. The allocation of $0.499 million in Pennsylvania universal service costs will not lead to the “fare increases, reductions in service, or both” as testified to by Mr. Faryniarz. Remember, PECO costs would be a fraction of the total “fuel, power and utilities” included in this expense line item.

Second, while total fuel, power and utilities represent from 6% to 8% of total expenditures in a non-COVID-19 year, salaries, wages and benefits represent nearly half of total operating expenses. To the extent that PECO’s universal service programs improve productivity as I documented they would, the potential for gain far outweighs any potential increase in costs.

Third, if AMTRAK would have borne Pennsylvania universal service costs in 2016 through 2020 at the rate projected by Mr. Faryniarz ($499,000), those costs would have increased AMTRAK total operating expenses by twelve one-thousandths of one percent. The expenditure identified by Mr. Faryniarz ($499,000) would have represented between 18 and 24 one-hundredths of one percent of total fuel, power and utilities costs. To argue that such an increase would lead to "fare increases, reductions in service, or both" lacks support.

Fourth, the variability in AMTRAK expenditures from year-to-year shows the lack of credibility that an increased cost of $499,000 would lead to "fare increases, reductions in service, or both." The variability simply in fuel, power and utilities from year-to-year is in the tens of millions of dollars. AMTRAK's fuel, power and utilities costs were more than $63 million *less* in 2019 than they were in 2018. Fuel, power and utilities costs were $54 million less in 2020 than they were in 2018. It was more than $24 million less in 2020 than they were in 2017.

Finally, from a revenue perspective, AMTRAK sees considerable variability as well. Even setting aside 2020 as the year affected by COVID-19, it is evident that total revenues increased from 2016 to 2017 by $65 million. Total revenues increased by $146 million from 2016 to 2018, and by nearly $263 million from 2016 to 2019. In contrast, at the same time, total operating expenses decreased by nearly $51 million from 2016 to 2017; and by nearly $142 million from 2016 to 2019.

The argument by Mr. Faryniarz that his projected fair share of universal service costs ($499,000) would result in "fare increases, reductions in service, or both" has no basis and should be rejected.

Q. PLEASE RESPOND TO MR. FARYNIARZ'S REBUTTAL TESTIMONY REGARDING THE IMPACT OF ALLOCATING UNIVERSAL SERVICE COSTS TO OTHER PECO COMMERCIAL AND INDUSTRIAL CUSTOMERS.

A. Mr. Faryniarz argues that "economic theory suggests that, all else being equal, just like with Amtrak and other Commuter Rail Agencies, PECO's commercial and industrial customers will face increased price pressure for goods and services as a consequence of the OCA proposal and possibly, for the most financially precarious ones, wage or hours reductions, job losses or business shutdowns." (AMTRAK St. 1-R, at 17).

This argument should not be relied upon in deciding not to allocate universal service costs to all customer classes. What Mr. Faryniarz does not acknowledge is that the Commission has previously agreed that allocating the universal service costs of a regulated utility serving Philadelphia would ***benefit***, not harm, Philadelphia businesses.

The Commission affirmatively noted that in the 2017 PGW rate case proceeding in which it again approved PGW's allocation of universal service costs to all customer classes, "PGW argued that all non-residential customers indirectly benefit from universal service programs by keeping low income customers in their homes and allowing them to contribute to Philadelphia's economic activity." (Final CAP Policy Statement, at note 144, page 96, citing *Pa. PUC, et al. v. PGW* at 63). The same is true for PECO. The Commission has long tracked the extent to which housing has been abandoned after the disconnection of service.[8] While in 2020 the number of vacant homes after a disconnection was dramatically lower (given that PECO was not disconnecting service for nonpayment), in 2019, there were 1,551 such vacant homes. The average number of vacant homes found after a service disconnection from 2015 to 2018 was 2,383. The same conclusion reached for PGW regarding "keeping low income customers in their homes and allowing them to contribute to Philadelphia's economic activity" applies to PECO as well to PGW.

These empirical results, found after 30 years of PGW cost allocation to all customer classes in Philadelphia, and based on more than 30 years of Commission tracking of the extent of "vacant" homes that arise subsequent to a PECO disconnection for nonpayment, provides a stronger case for allocating universal service costs to all customer classes than what Mr. Faryniarz states "economic theory suggests" might "possibly" happen if "all else is equal." (AMTRAK St. 1-R, at 17).

[8] PUC Cold Weather Survey (annual results 1999 – 2020). Available at https://www.puc.pa.gov/media/1497/cold_weather_survey_results_e-ng2020.pdf (last accessed July 28, 2021).

Q. PLEASE RESPOND TO MR. FARYNIARZ'S REBUTTAL TESTIMONY REGARDING HIS CLAIMS OF ADVERSE IMPACTS TO LOW AND MODERATE-INCOME HOUSEHOLDS.

A. Mr. Faryniarz states that allocating universal service costs to all customer classes would adversely, not beneficially, affect low- and moderate income (LMI) customers because it would "increase their cost of living due to increased prices for goods and services, including transit expenses, reduced transit offerings or both." (AMTRAK St. 1-R, at 17 – 18). He offers no data or analysis in support of this assertion. And, as demonstrated above, his assertion relative to increased transit prices and reduced services has no basis.

Q. PLEASE RESPOND TO MR. FARYNIARZ'S REBUTTAL TESTIMONY REGARDING LOW WAGES IN PENNSYLVANIA.

A. Mr. Faryniarz states that my Direct Testimony "argues that wages are low in Pennsylvania, and infers that that is the fault of commercial and industrial businesses." (AMTRAK St. 1-R, at 22). No such inference can be found in my Direct Testimony. My Direct Testimony is in support of the Commission's finding in its Revised CAP Policy Statement that "[t]he Commission agrees that poverty, poor housing stock, and other factors that contribute to households struggling to afford utility service are not just 'residential class' problems. " (Final Order, at 96). Rather than attributing "fault" (in the words of Mr. Faryniarz), my Direct Testimony supports the conclusion reached by the Commission's BCS that "[T]he problem of the inability of some low income [*sic*] customers to pay their entire home energy bills *<u>is caused primarily by societal economic conditions that are unrelated to any one rate class</u>*. . .[BCS] does not find any logic to the argument that because the larger societal economic conditions are negatively affecting the ability of some [low-income] residential customers to pay their bills, that the problem is somehow caused by the residential class and should therefore be paid for by that class." *Final Report on The Investigation of Uncollectible Balances* at 157–158.

Q. PLEASE RESPOND TO MR. FARYNIARZ'S REBUTTAL TESTIMONY REGARDING THE ECONOMIC CONDITIONS OF PENNSYLVANIA RELATIVE TO OTHER STATES.

A. Mr. Faryniarz testifies that my discussion of the economic strength of other states, all of which allocate utility universal service costs to all customer classes except Pennsylvania, "provides an empirically weak argument." (AMTRAK St. 1-R, at 23). Given that he does not indicate what it is an "empirically weak argument" in support of, his observation should not be relied upon for decision-making. Instead, he proceeds to make the same fundamental argument I make (with the difference being that he provides no data at all), stating that "there are complex economic factors underlying any particular state's GDP and economic performance, such as the mix of commercial and business sectors, the infrastructure in place that is necessary to support higher wage technology, manufacturing and transportation jobs, workforce education and training differences, the strength of labor unions and the cost of utility services, among other examples." (AMTRAK St. 1-R, at 23). Given those "complex economic factors underlying any particular state's GDP and economic performance," with which I agree, the arguments that allocating universal service costs to all customer classes, unto itself, will be the factor that results in "PECO's commercial and industrial customers [facing] increased price pressure for goods and services as a consequence of the OCA's proposal and possibly, for the most financially precarious ones, wage or hour reductions, job losses or business shutdowns" lacks any credibility. By Mr. Faryniarz's own testimony, there are too many "complex economic factors underlying any particular state's GDP and economic performance" for his argument that the allocation of PECO's universal service costs would be the tipping point to lower wages, lost jobs, and business shutdowns to be accepted.

Q. PLEASE RESPOND TO MR. FARYNIARZ'S REBUTTAL TESTIMONY ABOUT THE LACK OF A STATISTICAL ANALYSIS IN YOUR DIRECT TESTIMONY.

A. Mr. Faryniarz asserts that the substantial academic research provided in my Direct Testimony should be rejected as a basis for decision-making because it does not present "a rigorous economic analysis providing statistically significant findings that spreading USP costs to all customers is either not harming, or is actually beneficial to Pennsylvania businesses." (AMTRAK St. 1-R, at 24). This testimony is simply a red herring. Compare what Mr. Faryniarz asserts is lacking in my Direct Testimony with the support that he provides for his assertion that business will be harmed. "*Economic theory suggests* that, all else being equal, just like with Amtrak and other Commuter Rail Agencies, PECO's commercial and industrial customers will face increased price pressure for goods and services as a consequence of the OCA proposal and possibly, for the most financially precarious ones, wage or hours reductions, job losses or business shutdowns." That single sentence represents the entirety of his presentation regarding the impact of multi-class allocation on business and industry.

Rather than providing any data at all, Mr. Faryniarz relies on what he claims "economic theory suggests." Rather than demonstrating an adverse impact on Philadelphia businesses, he posits that harms will arise "all else being equal" (without demonstrating that all else is equal or even identifying what factors need to be equal to what other factors). Rather than demonstrating harms to Philadelphia business, he claims (without data) that "possibly" harms might arise (without identifying what that possibility is). Even then, those "possible" harms would not arise for everyone, but only for "the most financially precarious ones" (without defining what represents a "financially precarious" business, or how many such businesses there are).

Mr. Faryniarz's comments about his willingness to accept only "a rigorous economic analysis providing statistically significant findings" in lieu of his "economic theory" which he believes (without explaining why or how) "suggests" might "possibly" happen, but only if "all else is equal," should be rejected.

Q. PLEASE RESPOND TO MY FARTNIARZ'S COMMENTS ABOUT WHAT HE TERMS THE CONSISTENCY OF THE OCA COST ALLOCATION PROPOSAL WITH RATEMAKING PRINCIPLES.

A. Mr. Faryniarz restates his prior arguments in reviewing "ratemaking principles." (AMTRAK St. 1-R, at 25 – 31). For example:

- He argues that an inter-cost allocation of universal service costs would violate cost causation principles because only low-income residential customers are eligible for the programs. (AMTRAK St. 1-R< at 25). That cost causation argument has been discussed in detail above.

- He argues that non-residential customers do not benefit from PECO's universal service programs. (AMTRAK St. 1-R, at 26 – 27). That argument has been discussed in detail above.
- He argues that an inter-class universal service cost allocation is not just and reasonable. (AMTRAK St. 1-R, at 27). This, however, is simply a restatement of his "cause" argument ("non-residential customers do not cause the need for USPs and, therefore, should not be allocated any USP costs." AMTRAK St. 1-R, at 27). That cost causation argument has been previously rebutted.
- He argues that inter-class universal service cost allocation is not "economically efficient." (AMTRAK St. 1-R at 27). This is, however, merely a restatement of his prior argument that businesses will be harmed. That argument was addressed in detail above.
- He argues that inter-class universal service cost allocation would violate the principle of gradualism. This, however, is simply a restatement of his prior argument that the dollar amount of PECO universal service costs that would need to be borne ($499,000) is burdensome. That argument was addressed in detail above.
- He argues that inter-class universal service cost allocation would not be equitable. (AMTRAK St. 1-R, at 28). This is, as even Mr. Faryniarz notes, simply a restatement of his arguments regarding cost causation and the

benefits to non-residential customer, both of which have been addressed above.

- He argues that inter-class universal service cost allocation would be inconsistent with sending appropriate price signals. (AMTRAK St. 1-R, at 28 – 29). Allocating the $499,000 in universal service costs he identifies over Amtrak's ridership of 32,000,000 is not sufficiently substantial to have any impact one way or the other on price signaling to Amtrak.
- Finally, he argues that inter-class universal service cost allocation would not be "competitively neutral." (AMTRAK St. 1-R, at 29 – 30). He acknowledges, however, that this is merely a restatement of his argument that businesses receive no benefit. "The approach cannot be deemed competitively neutral for those customers if they are forced to pay for a program from which they cannot directly benefit." (AMTRAK St. 1-R, at 30). Mr. Faryniarz's argument about "direct benefits" was discussed in detail above.

Q. PLEASE RESPOND TO MR. FARYNIARZ'S PROPOSAL THAT UNIVERSAL SERVICE COSTS, SHOULD THEY BE ALLOCATED TO ALL CUSTOMER CLASSES, SHOULD BE ALLOCATED BASED ON THE NUMBER OF CUSTOMERS.

A. Mr. Faryniarz's proposal that universal service costs, to the extent that they are allocated to all customer classes, should be allocated based on the number of customers has no basis. He argues that "The USP is directly caused by the number of customers accessing the program, and is therefore assignable based on the number of customers. . ." (AMTRAK St. 1-R, at 31). That argument presents a complete non-sequitur. There is no relationship between the universal service costs and the number of customers in *any* customer class. Allocating universal service costs as proposed in my Direct Testimony results in a fair apportionment of the costs of addressing universal service needs.

In addition to this shortcoming, the proposal advanced by Mr. Faryniarz suffers the same shortcomings I identify in my response to Mr. Pollock's corresponding proposal above.

Part 5. Response to I&E Witness D.C. Patel.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to the Rebuttal Testimony of I&E Witness D.C. Patel. Witness Patel opposes my recommendation that PECO's COVID-19 emergency relief program be approved.

While Witness Patel testifies that while he is "empathetic to the hardships many ratepayers are experiencing as a result of the pandemic" (I&E St. 1-R, at 3), he does not believe that additional resources are needed to address the needs of those ratepayers experiencing hardship. He asserts, "there has been speculation that workers have not been returning to their previous jobs or accepting available jobs. . ." (Id., at 4). Mr. Patel's concerns are now out-of-date. Beginning with the week of July 11 through July 17, 2021, the Pennsylvania Office of Unemployment Compensation has reinstated its work search requirements. Work search requires all Unemployment Compensation (UC), Pandemic Emergency Unemployment Compensation (PEUC), or Pandemic Unemployment Assistance (PUA) claimants to apply for two jobs and complete one work search activity every week.

Mr. Patel asserts that things are getting better, given that "more and more Pennsylvania's are becoming vaccinated and the economy is reopening. . ." (Id., at 3). While he notes that 6.9% of Pennsylvanians are still unemployed, well above the percent unemployed before the pandemic (Id., at 4), at least the unemployment rate is not as high as the 16.2% rate where it was "at the peak of the pandemic in April 2020." (Id., at 4).

Q. ARE THINGS GOING AS WELL AS MR. PATEL SUGGESTS IN HIS REBUTTAL TESTIMONY?

A. No. Consider the weekly COVID-19 impacts for the Week 28 (April 14 through April 26) (the first week of Phase 3.1 of the Census PULSE Surveys) through Week 33 (June 23 through July 5) (the most recent PULSE Survey available). The updated PULSE Survey data is presented in the Table below. In the Table, the income ranges where the percentage of Pennsylvania residents having no difficulty at all in paying usual household expenses is ***lower*** in Week 33 than it was in Week 28 is shaded in yellow. In contrast, in the Table, the income ranges where the percentage of Pennsylvania residents having a "somewhat" or "very" difficult time is ***higher*** in Week 33 than it was in Week 28 is shaded in blue.

Table 4. Difficulty in Paying Usual Household Expenses (by income) (Week 28 through Week 33 of Census COVI-19 PULSE Survey)								
	Not at All Difficult				Somewhat or Very Difficult			
Week	Below $25,000	$25,000 - $34,999	$35,000 - $49,999	$50,000 - $74,999	Below $25,000	$25,000 - $34,999	$35,000 - $49,999	$50,000 - $74,999
28	20.6%	33.6%	51.6%	52.1%	54.8%	45.8%	21.4%	18.6%
29	25.2%	25.5%	45.7%	55.7%	48.6%	54.6%	29.0%	19.0%
30	19.7%	26.5%	45.2%	56.6%	56.5%	47.1%	30.7%	19.7%
31	25.2%	28.7%	44.4%	47.9%	50.2%	53.9%	20.6%	26.3%
32	18.2%	30.6%	44.4%	59.1%	53.0%	45.8%	30.6%	24.9%
33	25.6%	26.2%	48.7%	58.7%	49.3%	57.2%	28.3%	19.5%

The Table demonstrates that in only two of the four income ranges have the lack of payment difficulties decreased. The Table further documents that in three of the four income ranges have the extent of “somewhat” or “very” difficult times in paying usual household expenses increased. The decrease in the number of residents having no payment difficulties, along with the increase in the number of residents having substantial difficulties, has occurred notwithstanding the presence of federal stimulus dollars.

Q. IS THERE ANY OTHER SIGNIFICANT OBSERVATION FLOWING FROM THE TABLE ABOVE?

A. Yes. The Table above shows that only one-of-four instances of persons with income below $35,000 are having no difficulty in paying their usual household expenses. Three-of-four Pennsylvanians at these income ranges are still having difficulties. Indeed, more than half of residents with income as high as $25,000 to $35,000 are having some difficulties in paying their usual household expenses. In fact, despite Mr. Patel’s testimony about how much better things are today, 50% to 60% of Pennsylvania's residents with income less than $35,000, as of the most recent week for which data is available, are having a "somewhat" or "very" difficult time in paying their usual household expenses. More than one-in-four households with income between $35,000 and $50,000 are having a somewhat or very difficult time, compared to nearly one-in-five residents with incomes of $50,000 to $75,000.

Q. PLEASE RESPOND TO MR. PATEL'S TESTIMONY REGARDING "NUMEROUS FEDERAL, STATE AND LOCAL PROGRAMS PROVIDING AID."

A. In addition to this generic reference to unidentified "federal, state and local programs, Mr. Patel references other "federal government aid including stimulus payments as well as extended and enhanced employment benefits." The basis for the extended unemployment benefits, however, is established in my Direct Testimony, which documents the ongoing loss of employment due to COVID-19.

References to "federal stimulus payments" tends to overstate the extent to which federal assistance is available to help pay for ***utility*** bills. I assume Mr. Patel's reference is to the stimulus program commonly referred to as the Federal Emergency Rental Assistance Program (ERAP). Mr. Patel does not mention important limitations on the federal ERAP funding he cites. For example, he does not mention that ERAP assistance is available only to renters.

While Mr. Patel notes the availability of "federal stimulus payments," he does not go on to disclose what percentage of the ERAP funding is devoted to "rental assistance" and what proportion is devoted to "utility" assistance. He does not report that, through May 31, 2021, nearly 60% of the households assisted through ERAP received rental assistance, not utility assistance. Even more substantially, households who receive rental assistance receive far more dollars of benefits than households who receive utility assistance. The funding devoted to rental assistance, compared to the funding devoted to utility assistance, is presented in the Table below.

Table 5. Pennsylvania Statewide ERAP Assistance by Type of Assistance by Month
(PA DHS ERAP Monthly Report to PA Legislature)

	A Rental Assistance	B Utility Assistance	C Total Assistance[9]	D Percent Devoted to Utilities (B / C)
March/April 2021	$11,924,104.10	$1,829,612.56	$15,488,966.50	11.8%
May 2021	$29,215,994.51	$2,732,285.66	$33,858,028.66	8.1%

One thing that Mr. Patel does not disclose is that, unlike LIHEAP, the "utility assistance" is available not merely for home heating and cooling, but for electricity and water/sewer service as well. Indeed, ERAP "utility assistance" can even be used to pay for trash removal and internet bills. In addition, the term "utility assistance" should not be misconstrued to provide assistance only to regulated utilities. ERAP assistance used to pay for "utility assistance" is divided not only between regulated energy utilities,

[9] A limited amount of the funding is devoted to "other expenses related to housing." Accordingly, the total is greater than the sum of rental and utility assistance.

water/sewer, trash removal, and internet bills. When this relatively small pie, in other words, is divided into multiple parts, the piece of the pie available for PECO customers as utility assistance is not necessarily very large.

I conclude that witness Patel provides no basis for disallowing PECO's proposed Residential Relief Program.

Q. PLEASE RESPOND TO MR. PATEL's PROPOSED MODIFICATIONS TO PECO'S PROPOSED RESIDENTIAL RELIEF PROGRAM.

A. Mr. Patel makes three recommendations regarding PECO's proposed Residential Relief Program in the event that the PUC approves the proposal. First, he recommends that a dollar ceiling be placed on program expenditures, which ceiling should be set at $3.0 million. (I&E St. 1-R, at 7). I do not object to this proposal.

Second, Mr. Patel recommends that the Commission "express a clear end date or termination date for the COVID-19 RRP such as June 30, 2022." (I&E St. 1-R, at 7). With the caveat that I recommended in my Direct Testimony (that such a date could be extended by motion of a stakeholder or on the Commission's own motion), I do not oppose that proposal (given my recommended caveat).

Finally, Mr. Patel recommends that the program be fully funded by PECO shareholders, arguing that "the financial burden of this program should not be placed on ratepayers who have been and intend to continue paying their electric bills in-full and on-time." (I&E St. 1-R, at 7). This recommendation should be disapproved.

The issue is not one of the extent to which some ratepayers "intend to continue paying their electric bills in-full and on-time." As my Direct Testimony establishes, and the data I discuss above further confirms, the economic crisis which arose from the COVID-19 health pandemic continues to adversely affect a certain portion of PECO customers. A customer's "intention to pay" is not at issue; the short-term "inability to pay," as created by the COVID-19 economic crisis, is what the Residential Relief Program is addressing. No-one is "at fault" for having been placed in the economic situation of being unable to pay their bills during the COVID-19 economic crisis. Adopting a continuing emergency relief program is the most effective, most efficient, way for PECO to respond to that continuing economic crisis. The economic crisis will not continue forever and PECO will not need to provide emergency relief on an ongoing basis. As Mr. Patel and I both agree upon, the relief is limited, both in terms of dollars and in terms of time.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

315055

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024601
	:	
PECO Energy Company – Electric Division	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 4-SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 5, 2021
*314841

Signature: ______________________
Roger D. Colton

Consultant Address: Fisher, Sheehan, & Colton
34 Warwick Road
Belmont, MA 02478

OCA Statement No. 5-SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission		
v.		Docket No. R-2021-3024601
PECO Energy Company – Electric Division		

SURREBUTTAL TESTIMONY

OF

NOAH D. EASTMAN

ON BEHALF OF

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

August 5, 2021

Introduction

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

A. My name is Noah D. Eastman. My business address is 555 Walnut Street, Forum Place, 5th Floor, Harrisburg, Pennsylvania 17101. I am currently employed as a Regulatory Analyst by the Pennsylvania Office of Consumer Advocate (OCA).

Q. Are you the same Noah D. Eastman who filed OCA Statement 5 in this proceeding?

A. Yes.

Purpose of Surrebuttal Testimony:

Q. Please describe the purpose of your Surrebuttal Testimony.

A. The purpose of my surrebuttal testimony is to present updated statistics regarding the economic and labor outlook with regard to the COVID-19 Pandemic and to respond to the Rebuttal Testimony of I&E Witness D.C. Patel (I&E Statement No. 1-R).

Q. What arguments did Witness Patel make in rebuttal testimony?

A. Witness Patel argues that OCA Witness Colton's recommendation for a Residential Relief Program (RRP) is unnecessary because there is improvement in the current pandemic climate. First, witness Patel states that the large push for vaccinations and subsequent reduction in mitigation efforts is proof that the economy is and will continue to improve (I&E Statement 1-R, pg. 3). Second, witness Patel argues that the unemployment rate which peaked at 16.2% last year, is now down to 6.9% (I&E Statement 1-R, pg. 4). Witness Patel states that this, combined with the return of work-search requirements and the reduction of unemployment benefits, is proof that the labor market is going to return to normal soon (I&E Statement 1-R, pg. 4). Mr. Patel also relies on the decision by the Commission to lift the moratorium on shut-offs and the generous arrearage collection policy (I&E Statement 1-R, pg. 4-5). Lastly, witness Patel argues that PECO has already implemented relief measures and expanded others (I&E Statement 1-R, pg. 5-6).

Based on these arguments, Witness Patel concludes that the RRP should be rejected because it is unnecessary.

<u>Updated Unemployment Statistics</u>

Q. Before responding to I&E witness Patel, what is the updated unemployment rate for the PECO Electric counties and Pennsylvania?

A. There has been a slight uptick in the Pennsylvania unemployment rate in June, which can be seen separated by county below in Figure 1 and in Exhibit NDE-1. The unemployment rate in Pennsylvania is still at 6.9% as of June 2021.

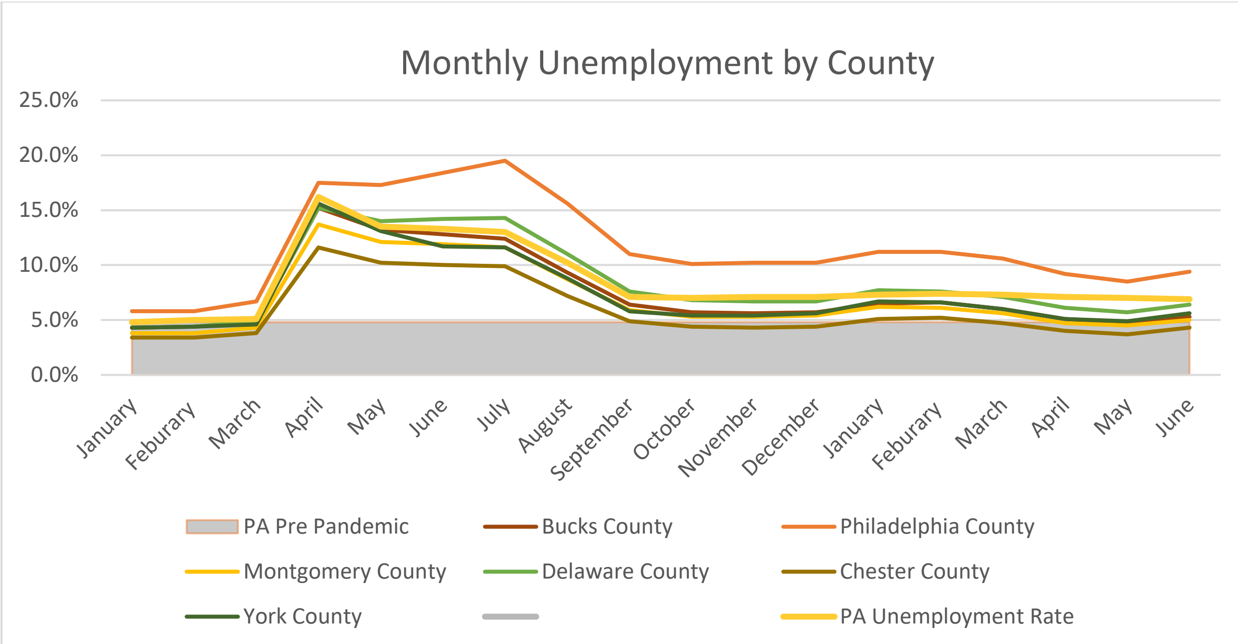

Figure 1[1]

Updates to the Household Pulse Survey

Q. Has there been any updates to the Household Pulse Survey mentioned in your Direct Testimony (OCA Statement 5)?

A. There have been two more releases of data covering the period from June 9 – June 21 and June 23 – July 5. Those expecting income loss in the next four weeks is still over 10% and those having experienced a loss in income is slightly higher than the June 7th release at 14.77%.

[1] U.S. Bureau of Labor Statistics, Unemployment Rate in Pennsylvania Counties, retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/categories/29613. August 4, 2021.

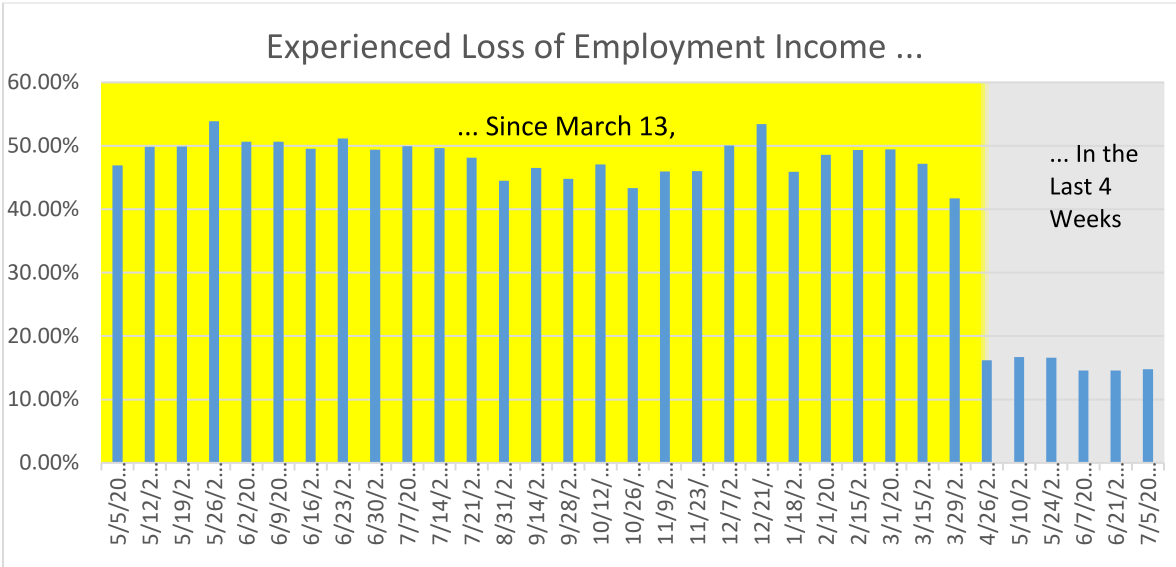

Figure 2[2]

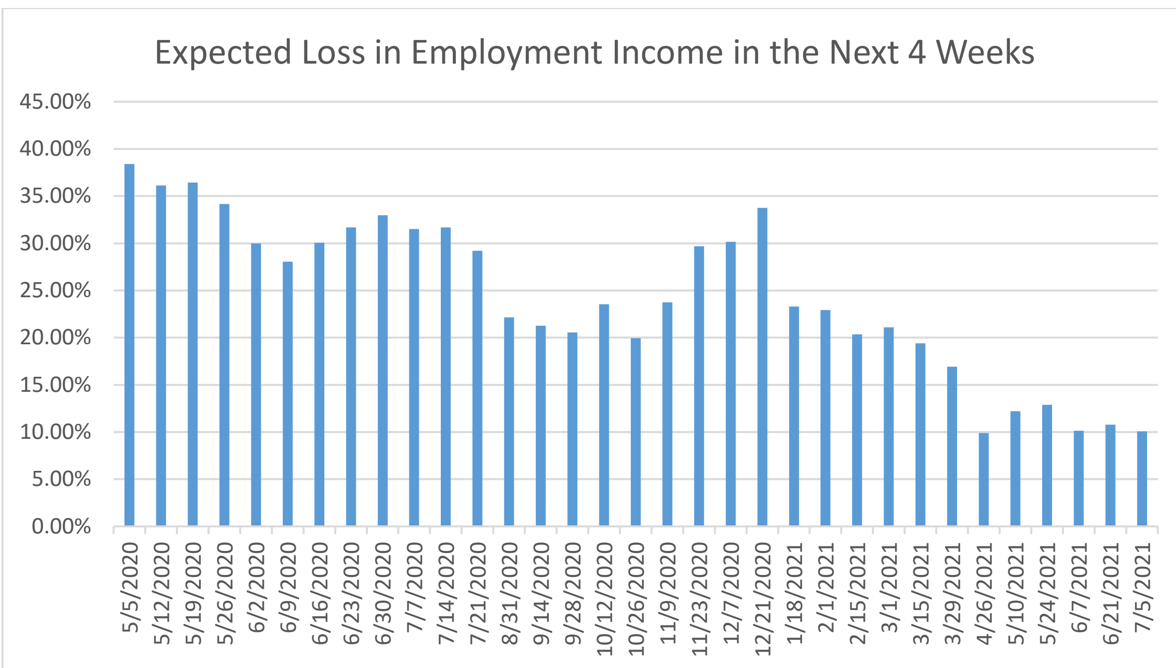

Figure 3[3]

[2] U.S. Census Bureau. (2021). Household Pulse Survey. https://www.census.gov/data/tables/2021/demo/hhp/hhp31.html

[3] Ibid.

<u>Updates to the Business Pulse Survey</u>

Q. Have there been any drastic changes in the responses to the Business Pulse survey?

A. No. While there has been slight fluctuations, the share of businesses that expect to return to its normal operations in 6 months or less is relatively unchanged. Currently, 57.4% of businesses are back to their normal level of operation or expect to be within 6 months or less, while the remaining 42.6% don't expect to return to their normal level of operation for at least 6 months.

<u>Job Growth</u>

Q. Were any job growth numbers released since you filed your Direct Testimony?

A. Yes. The April and May job numbers were revised, which I reconciled on figure 4 below. Also, the June 2021 job numbers were released, and employment increased by 850,000. These changes brought the average monthly employment growth for 2021 to 542,667 per month.

	Total Non-Farm Employment	Change in Employment
Jan-21	142,736,000	233,000
Feb-21	143,272,000	536,000
Mar-21	144,057,000	785,000
Apr-21	144,326,000	269,000
May-21	144,909,000	583,000
Jun-21	145,759,000	850,000
Average 2021		542,667

Figure 4[4]

<u>Response to I&E Witness Patel</u>

Q. Do you agree with Witness Patel's arguments that the economic climate is improving in such a way that the RRP is unnecessary?

A. No. As I have laid out in my Direct and this Surrebuttal Testimony, while the economy has shown major improvements since the Pandemic began in early 2020, it has been very slow improvement over the last 11 months. For example, unemployment was flat for most of late 2020 and early 2021, and very recently in the PECO Electric Territory unemployment rates increased. The Household Pulse and Business Pulse Survey's find that people are still incredibly uncertain about the future, as 10% of households still expect a reduction in income and more than 40% of businesses expect 6 months or more to return to their normal level of operations.

Vaccination rates have slowed dramatically over recent weeks and children are still ineligible for any vaccine. Moreover, in the time since Direct Testimony was filed in this case, a new variant of the COVID-19 virus has led to large increases in cases across many states. This variant threatens the unvaccinated population of Pennsylvania (no doses yet received), which stands at 42.2% of the state population.[5]

While there has been improvements, and the response to the pandemic has been generally positive by the PUC and utilities, the most powerful force at play during the pandemic

[4] Federal Reserve Bank of St. Louis. *All Employees, Total Nonfarm, Thousands of Persons, Monthly, Seasonally Adjusted.* https://fred.stlouisfed.org/series/PAYEMS

[5] COVID-19 Vaccine Dashboard. (2021). PA Department of Health. (Retrieved 08/04/2021) https://www.health.pa.gov/topics/disease/coronavirus/Vaccine/Pages/Dashboard.aspx (

leading up to this point and into the future is: uncertainty. Until we have achieved drastically low levels of infections combined with much higher levels of vaccinations, it would be irresponsible to assume that economic recovery is certain or permanent.

<u>Conclusion</u>

Q. Are there any other updates you would like to present?

A. No, I have no more updates that at this time. The data that I have updated should confirm that the labor market and the economy as a whole are still recovering, and it will take time before it returns to pre-pandemic levels.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes. However, I reserve the right to modify or supplement my testimony if necessary.

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OCA Exhibit NDE-1S
PECO Energy Company - Electric
Docket No. R-2021-3024601
Unemployment Rate by County

Month	Philadelphia County	Montgomery County	Delaware County	Bucks County	Chester County	York County
January	5.80%	3.80%	4.30%	4.30%	3.40%	4.30%
February	5.80%	3.80%	4.40%	4.40%	3.40%	4.40%
March	6.70%	4.30%	4.90%	4.80%	3.80%	4.60%
April	17.50%	13.70%	15.20%	15.20%	11.60%	15.60%
May	17.30%	12.10%	14.00%	13.20%	10.20%	13.10%
June	18.40%	11.90%	14.20%	12.80%	10.00%	11.70%
July	19.50%	11.60%	14.30%	12.40%	9.90%	11.60%
August	15.60%	8.70%	11.00%	9.30%	7.20%	8.80%
September	11.00%	5.90%	7.60%	6.40%	4.90%	5.80%
October	10.10%	5.30%	6.80%	5.70%	4.40%	5.40%
November	10.20%	5.30%	6.70%	5.60%	4.30%	5.40%
December	10.20%	5.40%	6.70%	5.70%	4.40%	5.60%
January	11.20%	6.20%	7.70%	6.50%	5.10%	6.70%
February	11.20%	6.10%	7.60%	6.60%	5.20%	6.60%
March	10.60%	5.60%	7.10%	6.00%	4.70%	6.00%
April	9.20%	4.70%	6.10%	5.10%	4.00%	5.10%
May	8.50%	4.50%	5.70%	4.80%	3.70%	4.90%
June	9.40%	5.00%	6.40%	5.30%	4.30%	5.60%

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024601
	:	
PECO Energy Company – Electric Division	:	

<u>VERIFICATION</u>

I, Noah D. Eastman, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 5-SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: August 5, 2021
*314891

Signature: ______________________
Noah D. Eastman

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5th Floor, Forum Place
Harrisburg, PA 17101-1923

OCA STATEMENT NO. 6-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
V.	:	
	:	DOCKET NO. R-2021-3024601
	:	
PECO ENERGY COMPANY – ELECTRIC DIVISION	:	

SURREBUTTAL TESTIMONY

OF

RON NELSON
DIRECTOR
STRATEGEN CONSULTING

ON BEHALF OF
THE OFFICE OF CONSUMER ADVOCATE

(PUBLIC VERSION)

August 5, 2021

Table of Contents

I. INTRODUCTION

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

A. My name is Ron Nelson. I am a Director with Strategen Consulting. My business address is Suite 400, 2150 Allston Way, Berkeley, California 94704.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted direct testimony marked as OCA Statement No. 6, on behalf of the Office of the Consumer Advocate. My background and qualifications are set forth in that statement.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address issues regarding PECO Energy Company's ("PECO" or "Company") proposed Electric Vehicle Charging Pilot. I will respond to certain parties who submitted rebuttal testimony in this proceeding responding to my direct testimony. I will discuss the rebuttal testimony of Ms. Jacqueline Golden on behalf of PECO, Ms. Danita Park on behalf of the Retail Energy Supply Association and NRG Energy, Inc. ("RESA-NRG"), and Mr. Matthew Deal on behalf of ChargePoint, Inc.

II. RESPONSE TO REBUTTAL TESTIMONY OF PECO WITNESS GOLDEN ON PILOT DATA COLLECTION, LOAD MANAGEMENT, AND TRANSIT CHARGING PROGRAM

Q. PECO states that in light of your and other parties' recommendations regarding data collection and reporting, the Company will formalize a data collection plan and reporting format. Is this sufficient?

A. No. While it is appropriate for PECO to develop a more detailed and formal data collection plan and reporting format, the data points listed[1] by the Company need to correspond to clear pilot objectives and outcomes, particularly those related to load management, within an evaluation and assessment plan.

Q. While PECO claims that it will use pilot data to create load management programs, it is recommending to not collect pricing data for publicly available charging sites.[2] Do you find this logic consistent and reasonable?

A. No. Pricing data is key for the development of load management programs. The Commission should require PECO to collect and disclose pricing data for publicly available chargers, provided that the data is anonymized. These are optional programs that customers choose to accept funds provided by ratepayers. Thus, the programs must provide clear value to ratepayers, including through the collection of data and

[1] Witness Golden Rebuttal at 6.
[2] Witness Golden Rebuttal at 6.

identification of benefits. If customers do not want to provide critical data, they do not need to participate.

Q. PECO claims that the OCA's load management recommendation is premature, and that PECO would need 2-3 years of data from the EV Charging Pilot, as well as additional time for program set up and program evaluation, before PECO can develop load management offerings. Do you agree?

A. No. While load management offerings would benefit from additional data, I do not believe that PECO would be unable to develop load management offerings without 2 to 3 years of data from the EV Charging Pilot. The Company should already have some data on customer charging behavior through its existing EV offerings, including the EV-FC Rider, the EV registration incentive, and the EV charger incentive, that can inform the development of load management offerings. The Company can also take learnings and data from other jurisdictions to inform initial load management offerings. The Company should consider other sources of data that can be used as a substitute for pilot data to inform planning and load management efforts.

A clear example that shows additional data is not necessary is that the Company was able to develop a TOU rate, approved in Docket No. P-2020-3019290 to be implemented in September 2021, without the data to be collected through the EV Charging Pilot. Another example is Automated Load Management (ALM), which does not require individually metered EV load profiles. The Company provided no clear explanation why these offerings could not be developed without additional data.

Additionally, any load management offerings will likely have to undergo several iterations as more data becomes available, particularly since current and near-future EV owners are early adopters who may not represent the charging behavior of all future EV customers. The need for iterations, however, does not mean that load management should be delayed until large amounts of infrastructure investments have already been made. Rather, load management should be prioritized in order to ensure that investments in EV charging infrastructure are efficient and do not unreasonably burden ratepayers.

Q. PECO argues that limiting incentives under the Transit Charging Program to 50% of make-ready costs for sites in an Environmental Justice ("EJ") Area and 33% for sites not in an EJ Area is unreasonable and that PECO should be able to, in its sole discretion, prioritize applications that best advance large-scale public transit electrification.[3] Do you agree?

A. No. Not imposing any limits on the Transit Charging Program incentives allows PECO too much discretion on how to allocate program funds and could lead to a situation in which a single customer installing a single charging site can take up most of the total budget. Limiting the amount of an incentive that a single site can receive ensures that multiple charging sites can benefit from the program. Comparatively, for the Commercial and Industrial Level 2 Charging Program, PECO proposed incentive limits of 75% of make-ready costs for sites in an EJ Area and 50% for sites not in an EJ

[3] Witness Golden Rebuttal at 13.

Area. The Company failed to demonstrate why a similar approach for the Transit Pilot would be unreasonable.

III. RESPONSE TO REBUTTAL TESTIMONY OF RESA-NRG WITNESS PARK ON LOAD MANAGEMENT

Q. RESA-NRG argues that the magnitude of EV load in the coming years is exaggerated, and therefore the OCA's load management recommendation is premature. Do you agree?

A. No. To support this claim, RESA-NRG cites the relatively small sales figures of EVs compared to the total US vehicle fleet.[4] However, this claim does not consider the fact that EVs will likely achieve cost-parity with internal combustion engine vehicles within the next few years. Once this milestone is reached, conversion to electric vehicles will likely increase much more rapidly. Apart from price, another barrier to EV adoption thus far has been the lack of charging infrastructure, but EVs and charging infrastructure have never been as significant a policy goal around the country as they currently are. As more infrastructure is deployed and the prices of EVs fall, EV adoption rates will likely increase faster than historic rates.

Moreover, as discussed in my direct testimony, load management needs to be implemented early, not when a significant portion of the vehicle fleet has already been electrified. Load management options factor into customers', including transit agencies',

[4] RESA/NRG Witness Park Rebuttal at 24.

decisions whether to purchase electric vehicles, as load management can affect both charging and infrastructure costs and can facilitate electrification by lowering these costs.

Q. RESA-NRG claims that the OCA falsely implied that EVs represent a threat to utilities and failed to consider technologies that allow for the coordination of EV load.[5] Do you agree?

A. RESA-NRG appears to be misunderstanding my argument regarding the necessity of load management. While it is true that unmanaged EV load can unreasonably increase costs to ratepayers, I never denied that there exist many technologies that allow for the communication to and coordination of EV load. In fact, it is my understanding that EV load can be managed to not only reduce grid costs but also serve as grid resources that informed my recommendations that PECO develop load management offerings.

Q. RESA-NRG argues that framing load management as a solution only utilities can solve is shortsighted and ignores electric generation suppliers' load management capabilities.[6] Do you agree?

A. RESA-NRG seems to again be misunderstanding my recommendations. I do not believe that only utilities can provide load management offerings. My load management recommendations in no way prevent third parties, such as electric

[5] RESA-NRG Witness Park Rebuttal at 27-28.
[6] RESA-NRG Witness Park Rebuttal at 26.

generation suppliers, from offering and implementing load management programs. As part of a load management offering, PECO may develop an overall program structure (such as an incentive level for off-peak charging, load curtailment parameters for a demand response program, and/or technical requirements for ALM implementation, etc.) and allow third-party vendors to engage with customers and perform the management of EV load. The utility does not necessarily have to develop these technical capabilities itself. However, without programs in place, customers who receive electric supply from PECO would not have incentives to participate in third-party load management.

Q. RESA-NRG argue that third parties can provide load management offerings. Is this an appropriate reason for PECO to not implement load management?

A. No. PECO should develop load management offerings for customers who are not taking electric supply from a third-party supplier, since its failure to do so will increase costs to ratepayers, including distribution costs that are also allocated to customers of electric generation suppliers.

IV. RESPONSE TO REBUTTAL TESTIMONY OF CHARGEPOINT WITNESS DEAL ON LOAD MANAGEMENT

Q. ChargePoint argues that a TOU rate with Critical Peak Pricing ("CPP") is not appropriate for DC Fast Charging (DCFC) stations since the demand for DCFC is not elastic.[7] Do you agree?

A. No. Even if the demand for DCFC is not elastic, it is not reasonable for ratepayers to have to subsidize the costs that DCFC causes to the overall grid when they charge during peak periods with high energy costs.[8] A TOU rate with CPP would most accurately reflect the costs of DCFCs to the grid, and customers could choose to manage their load to align better with grid needs. Furthermore, I am not recommending that DCFC stations should be required to take service under a TOU rate with CPP, rather that it should be provided as an option.

Q. Have any jurisdictions adopted optional TOU with CPP tariffs for customer classes that DCFC stations could take service under?

A. Yes. The Minnesota Public Utilities Commission recently adopted a TOU with CPP tariff for piloting in Docket No. 20-86. It is my understanding that this tariff will be available to EV chargers and will be considered for the default tariff for the large C&I class, likely including DCFC stations, after the piloting phase.

[7] ChargePoint witness Deal Rebuttal at 13.
[8] Additionally, charging during peak system times can lead to additional capacity costs.

V. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3024601
	:	
PECO Energy Company – Electric Division	:	

VERIFICATION

I, Ron Nelson, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 6-SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Ron Nelson

DATED: August 5, 2021
*314842

Signature: ___________________________
Ron Nelson

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