PECO ENERGY COMPANY
STATEMENT NO. 3-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY

DOCKET NO. R-2018-3000164

REBUTTAL TESTIMONY

WITNESS: BENJAMIN S. YIN

SUBJECTS: PRESENTING PECO ENERGY COMPANY'S UPDATED OVERALL REVENUE REQUIREMENT; AND RESPONDING TO THE DIRECT TESTIMONY OF WITNESSES FOR THE BUREAU OF INVESTIGATION AND ENFORCEMENT; THE OFFICE OF CONSUMER ADVOCATE; AND THE PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP

DATED: JULY 24, 2018

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REBUTTAL TESTIMONY
OF
BENJAMIN S. YIN

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your full name and business address.

A. My name is Benjamin S. Yin, and my business address is PECO Energy Company ("PECO" or the "Company"), 2301 Market Street, Philadelphia, Pennsylvania 19103.

2. Q. Have you previously submitted testimony in this proceeding?

A. Yes. My direct testimony, PECO Statement No. 3, was a part of the Company's initial filing on March 29, 2018. My background and qualifications are set forth in that statement.

3. Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is two-fold. First, I will describe the changes PECO is making to the revenue requirement previously presented in PECO Exhibit BSY-1 in order to update certain estimated costs with actual data and to reflect revisions it identified in its responses to other parties' interrogatories. Second, I respond to certain adjustments advanced by Office of Consumer Advocate ("OCA") witness David J. Effron, Bureau of Investigation and Enforcement ("I&E") witnesses Christine Wilson, Joseph Kubas and John Zalesky, and Philadelphia Area Industrial Energy Users Group ("PAIEUG") witness Jeffry Pollock.

4. Q. Are you sponsoring all or portions of any exhibits in conjunction with your rebuttal testimony?

A. Yes, and I will describe those exhibits during the course of my update and response to the other parties.

II. UPDATE OF COMPANY REVENUE REQUIREMENT

5. Q. As developed herein, what is PECO's updated Fully Projected Future Test Year ("FPFTY") revenue requirement?

A. PECO's updated FPFTY revenue requirement, as shown in PECO Exhibit BSY-5, Schedule A-1, is $2.238 billion, which translates into updated pro forma present rate revenue of $2.098 billion. This represents an approximate $2.8 million reduction to PECO's initial increase request of $142.5 million.

6. Q. Please describe PECO Exhibit BSY-5.

A. PECO Exhibit BSY-5 is an update of PECO Exhibit BSY-1. The schedules that are included with PECO Exhibit BSY-5 are updated versions of the original schedules included with PECO Exhibit BSY-1. Pages that have been updated from the original schedules are marked "UPDATE 7-24-2018."

7. Q. Please summarize the revisions reflected in PECO Exhibit BSY-5.

A. PECO Exhibit BSY-5 reflects two revisions that affect the Company's revenue requirement claim. First, as I explain in more detail later in my rebuttal testimony, the Company is updating its claim for normalized storm expenses to substitute actual storm costs incurred in the first quarter of 2018 for the estimated data reflected in the Company's original filing. As a result of this update, the Company's normalized storm expense, which is based on inflation-adjusted storm expenses for the 60-month period ended March 31, 2018, is reduced by $2.543 million and its revenue requirement is reduced by $2.740 million.

Second, as explained in PECO's response to Interrogatory IE-V-RB-23-D, the Company is reducing its claim for intangible plant in service by $269,555 and is reducing its associated claims for accumulated depreciation and annual depreciation by $39,201 and $29,986, respectively. These changes are shown on Schedules C-2, C-3 and D-17, respectively, of PECO Exhibit BSY-5. The net impact of these changes reduces the Company's revenue requirement by approximately $61,000.

III. RESPONSE TO OPPOSING PARTY ADJUSTMENTS

A. FPFTY Plant-In-Service Additions – Average Versus Year-End Rate Base; Annualization of FPFTY Depreciation, Expenses And Revenues; Associated Accumulated Deferred Income Tax ("ADIT") And Plant-Related Income Tax Deductions

8. Q. How did the Company develop its FPFTY claims for plant additions, annual depreciation expense, annual salary and wage expense, employee benefit expense and pro forma present rate revenues?

A. The Company has presented supporting data for a FPFTY consisting of the twelve months ending December 31, 2019, as permitted by amendments to the Pennsylvania Public Utility Code made by Act 11 of 2012 that, among other revisions, changed Section 315(e) to authorize the use of a FPFTY. Additionally, Act 11 altered

Section 1315 by providing: "Notwithstanding section 1315 (relating to limitation on consideration of certain costs for electric utilities), the commission may permit facilities which are projected to be in service during the fully projected future test year to be included in rate base."

Consistent with the Act 11 amendments to Sections 315(e) and 1315, the Company's rate base claim in this case, as set forth in PECO Exhibit BSY-1, reflects its projection of the original cost of utility plant that will be in service as of December 31, 2019, and, therefore, includes the original cost of all plant additions and retirements forecasted to occur during the FPFTY. Accordingly, PECO's claims for FPFTY accumulated depreciation and annual depreciation expense are based on its projected plant balances as of December 31, 2019. PECO also projected the balance of its ADIT and the regulatory liability for "excess" ADIT as of December 31, 2019, which are reflected in its rate base claim. In addition, PECO reflected an annual amount of plant-related tax deductions, which are included in PECO's calculation of its claimed income tax in this case.

Similarly, the Company's salary and wages expense and employee benefit expenses reflect, on a fully annualized basis, the impact of salary and wage increases that will occur during the FPFTY or, as to certain wage increases, slightly after December 31, 2019, and the annualized level of employees as of the end of the FPFTY.

Correspondingly, PECO annualized changes in present rate revenue through the end of the FPFTY, which increased pro forma revenues at present rates. However, and contrary to I&E witness Joseph Kubas's assumption, PECO did *not* annualize the reductions in present rate revenues that will occur during the FPFTY and the two succeeding years as a result of PECO's compliance with the mandatory demand and usage reductions required by the energy efficiency and conservation measures required by Act 129 of 2008.

9. Q. Have any parties contested the Company's use of plant in service balances as of December 31, 2019 to establish its rate base and associated annual depreciation and its annualization of revenues and expenses as of that date?

A. Yes, I&E witness Kubas and OCA witness Effron disagree with the Company's approach. It should be noted that, in PECO's last base rate case, at Docket No. R-2015-2468981, where the Company used the same approach to calculating its rate base, revenues and operating expenses at end-of-FPFTY levels, I&E accepted the Company's methodology as consistent with the FPFTY concept and the Commission's policies and practices for use of a FPFTY test year for ratemaking purposes. For that reason, in the Company's 2015 base rate case, I&E only recommended that PECO report to I&E and to the Commission's Bureau of Technical Utility Services, by specified future dates, its actual monthly plant balances through the end of the future test year ("FTY") and the end of the FPFTY. The Company accepted that recommendation, which was incorporated in the Joint Petition for Settlement of its 2015 base rate case. PECO has complied with that settlement term and has submitted the requested reports.

10. Q. Explain briefly I&E witness Kubas's and OCA witness Effron's proposed adjustments to the Company's FPFTY claims.

A. Both Mr. Kubas and Mr. Effron acknowledge that the Pennsylvania Public Utility Code, as amended by Act 11, authorizes the use of a FPFTY. Both witnesses contend, however, that it is not appropriate to use plant balances as of the end of the FPFTY (December 31, 2019) to determine the Company's rate base and annual depreciation accruals. Specifically, they contend that: (1) the FPFTY in this case generally corresponds to the first year that new base rates will be in effect; (2) calculating PECO's rate base and annual depreciation expense on the basis of projected plant balances at December 31, 2019 would allow the Company to earn a return on, and to depreciate, some portion of its investment in 2019 capital additions before the plant represented by that investment is actually in service; and (3) therefore, the calculation of rate base would not match the other elements of revenue requirement and income that the Company will experience during the rate application year (I&E St. 3, pp. 8-10; OCA St. 1, p. 6). Accordingly, both Mr. Kubas and Mr. Effron propose that the Company's rate base reflect only the annual "average" of FPFTY capital additions, which they calculated by averaging December 31, 2018 and December 31, 2019 plant balances and accumulated depreciation. Both witnesses also adjusted the amount of ADIT deducted from rate base to reflect only one-half of the deferred income taxes associated with total FPFTY plant additions to correspond to their use of "average" plant additions for 2019. Additionally, they recommend reducing the Company's claim for annual depreciation expense to reflect a level that corresponds to their proposed "average" capital additions for 2019. The net effect of Mr. Kubas's approach would be to reduce PECO's rate base by $154.630 million and correspondingly to reduce PECO's claim for depreciation expense by $11.832 million. The net effect of Mr. Effron's adjustments would be to reduce PECO's rate base by $159.949 million and correspondingly to reduce PECO's claim for depreciation expense by $11.226 million.

Similarly, Mr. Effron recommends that annual salary and wages expenses and employee benefit expense should only reflect the average level for 2019 instead of annualizing those expenses as of December 31, 2019. As a result, Mr. Effron has proposed eliminating the Company's salary, wages and employee benefit annualizations (including the annualization of wage increases that become effective shortly after the end of the FPFTY) to reflect only the "average" for 2019. Mr. Effron also proposed eliminating the annualization of FPFTY revenues, which reduces pro forma present rate revenues by approximately $3.233 million. I&E witness John Zalesky also proposed adjustments to salary, wages and employee benefit annualizations (including the annualization of wage increases that become effective shortly after the end of the FPFTY) to reflect only the "average" for 2019. I&E witness Kubas proposed eliminating the annualization of FPFTY revenues, which reduces pro forma present rate revenues by approximately $2.812 million.

11. Q. Do you agree with Mr. Kubas's and Mr. Effron's proposals?

A. No, I do not, for several reasons. First, there is no reason to reject the Company's use of year-end plant balances in developing its proposed rate base simply because some portion of the plant additions for the FPFTY will not be in service when new rates are in effect. The very nature of the FPFTY is anticipatory. Even the "average" rate base methodology employed by Mr. Kubas and Mr. Effron reflects FPFTY plant additions that will not be in service when new rates are in effect.

Second, as I previously noted, Act 11 amended Section 315 of the Pennsylvania Public Utility Code to specifically provide that "the commission may permit facilities which are projected to be in service during the FPFTY to be included in the rate base." Therefore, the contention that the Company's rate base claim should be substantially reduced simply because, if approved, the Company would earn a return and depreciation on investment before the corresponding plant is in service conflicts with the plain language of amended Section 315.

Third, if the Company's rate base is established as of December 31, 2019 and its depreciation expense is annualized as of that date, the Company will not seek to impose a charge in 2019 under its Distribution System Improvement Charge ("DSIC"). And, in fact, adopting the Company's approach, the earliest that any charge would be imposed under the Company's DSIC would be April 2020 for DSIC-eligible utility plant placed in service after the end of the FPFTY.

In contrast, using the "average" rate base approach proposed by witnesses Kubas and Effron, the Company's base rates would reflect only one-half of its total investment in 2019 plant additions, which, as Mr. Kubas has shown (I&E St. 3, p. 9), is similar to setting rates on the basis of the Company's rate base, expenses and revenues at approximately mid-year 2019. Under that approach, the Company would have to be able to implement a DSIC by October 1, 2019, just to begin recovering the costs associated with the portion of its 2019 plant additions not included in the average (mid-year) rate base that Mr. Kubas and Mr. Effron propose. Notably, the Joint Petition for Settlement of the Company's 2015 rate case included a term requiring the approach I described above (no implementation of a DSIC charge during the FPFTY). Furthermore, although Mr. Kubas acknowledges that the DSIC would have to be initiated *during* the FPFTY if an "average" rate base were employed, he does not address the Commission's Supplemental Implementation Order entered September 21, 2016 in *Implementation of Act 11 of 2012* at Docket No. M-2012-2293611 ("Supplemental Implementation Order"). That Order set rules for reinstituting a DSIC following the end of a base rate case that clearly contemplate the use of end-of-test-year plant balances to establish utilities' base rates when a FPFTY is employed.

More importantly, if a test-year average rate base were employed, the Company's annual rate of return during and immediately following the FPFTY would fall below the rate of return granted in this case. The only way to mitigate the attrition that using test-year average rate base and expenses would create would be to file another base rate case by the end of March 2019. It does not appear reasonable that the authorization of a FPFTY should increase the need for utilities to seek rate relief on a more or less annual basis. Moreover, setting up conditions that require more frequent base rate cases is contrary to efforts to increase rate stability. It would also increase rate case expenses ultimately borne by customers and would impose increased demands on the resources of the Commission and other parties associated with more frequent base rates cases.

12. Q. Would the use of an end-of-FPFTY rate base (and annualizing expenses and revenues as of that date) result in a mismatch of allowed revenue requirement and the Company's actual rate base, expenses and revenues during the rate application period, as Mr. Kubas and Mr. Effron contend?

A. No, it would not. Both witnesses' contentions about a possible mismatch tacitly assume that the first year new base rates would be in effect (calendar year 2019 in this case) is the only year that those rates would remain in effect. There is not a valid basis for that assumption, as the pattern of post-Act 11 base rate filings for PECO and other utilities shows.

Filing another base rate case on the heels of receiving a final order in a prior rate case has not been the practice of utilities that employed a FPFTY, and it has not been PECO's practice. The historic pattern that emerges from major FPFTY base rate filings shows that the rates established in those cases remain in effect for at least two years and, in several instances, even longer. In PECO's case, it has been three years since its last base rate case. Moreover, PECO is proposing to normalize its rate case expense to reflect a three-year interval between this and its next base rate filing, while I&E witness Zalesky contends that the interval should be four years (I&E St. No. 4, pp. 4-5). Viewed over a rate application period of at least two years, it is not reasonable to assert that rates reflecting end-of-FPFTY rate base and end-of-FPFTY-annualized revenues and expenses are mismatched with a utility's actual plant in service, expenses and revenues. Focusing solely on the first year that new base rates are in effect ignores the reality that rate application periods in FPFTY cases have not been as short as one year. In contrast, an "average" rate base produces a significant mismatch that begins to emerge *during* the FPFTY and pushes the affected utility off a revenue deficiency cliff by (or before) the end of the FPFTY.

13. Q. What did the Joint Petition for Settlement of PECO's 2015 electric base rate case provide regarding the implementation of a DSIC after the conclusion of that case?

A. At the time PECO's 2015 base rate case was settled, PECO did not have a DSIC for its electric operations. PECO had filed a Petition to obtain Commission approval to include a DSIC Rider in its tariff, but that Petition had not been granted. In PECO's 2015 base rate case, it employed a FPFTY ending December 31, 2016. The relevant language appears in Paragraph No. 22 of the Joint Petition for Settlement:

> As of the effective date of the Settlement Rates in this proceeding, PECO will be eligible to include plant additions in its proposed DSIC, if approved, once eligible account balances exceed the levels projected by PECO at December 31, 2016. The foregoing provision is included solely for purposes of calculating the DSIC, and is not determinative for future ratemaking purposes of the projected additions to be included in rate base in a FPFTY filing.

Paragraph No. 22, as quoted above, provides that, if PECO's DSIC Rider were approved, PECO could not implement a DSIC until eligible plant account balances exceeded the level projected by PECO for the FPFTY in its 2015 case. As I previously explained, Paragraph No. 22 is consistent with, and assumes, that the rate base reflected in the base rates established pursuant to the Joint Petition for Settlement reflected rate base as of December 31, 2016.

I acknowledge the last sentence of Paragraph No. 22, which was added so that the settlement would not be cited as precedent binding the parties in a future case, and I am not suggesting it does. However, I think it is important to review what was done in PECO's 2015 case and in all of the other FPFTY cases that were settled prior to the issuance of the Supplemental Implementation Order, because those settlements provide the proper context for understanding the terms of the Supplemental Implementation Order and make its meaning clear.

14. Q. Was I&E a party to the PECO's 2015 base rate case, and did it join in executing the Joint Petition for Settlement of that case?

A. Yes, I&E witness Kokou Apetoh submitted I&E Statement No. 3 and addressed PECO's claims for FPFTY additions at pages 11-12 of his statement. Mr. Apetoh did not propose any adjustment to the Company's claim to reflect FPFTY additions at their end-of-FPFTY level, but did recommend that the Company file reports comparing its projections of end-of-FPFTY plant levels to its actual performance. With regard to the Company's claim for FPFTY rate base, Mr. Apetoh stated as follows:

> Through use of the FPFTY, a utility is allowed to require ratepayers in essence to pre-pay a return on its projected investment in future facilities that are not only not in place and providing service at the time the new rates take effect, but also that are not subject to any guarantee of being completed and placed into service. While the FPFTY provides for such

> projections, there should be some timely verification of the projections. Therefore, requiring the Company to provide updates demonstrating that actual investment comports with projections used in setting rates using the FPFTY allows the Commission to measure and verify the accuracy of PECO's projected investments in future facilities on a timely basis.

I&E also filed a Statement in Support of the Joint Petition for Settlement where, at pages 16-17, it addressed the use of a FPFTY and the appropriate level of FPFTY plant additions. I&E's Statement in Support summarized its position that end-of-FPFTY plant additions may properly be included in rate base, subject to I&E's recommended reporting requirement:

> Consistent with Act 11, the Company uses a Fully Projected Future Test Year (FPFTY) in its filing. The use of a FPFTY resulted in the inclusion of $193,217,000 of rate base associated solely with the FPFTY ending December 31, 2016. While use of the FPFTY is permitted under Act 11, I&E witness Apetoh discussed the potential conflict that can arise with the "used and useful" requirement for including investments in rate base. It is for these reasons that Mr. Apetoh recommended that the Company provide interim reports until the filing of its next base rate case to allow the Commission to measure and verify the accuracy of PECO's projected investments in future facilities.
>
> In paragraph 21 of the Joint Petition, PECO agrees to provide to I&E, OCA, OSBA, and the Commission's Bureau of Technical Utility Services (TUS) updates by April 1, 2016, setting forth its electric division's actual capital expenditures, plant additions, and requirements by month. Additionally, PECO will file an update providing these actual amounts, for the twelve months ending December 31, 2016, no later than April 1, 2017. This provision is in the public interest as it ensures that the Commission will receive data sufficient to allow for the evaluation and confirmation of the accuracy of PECO's projections.

15. Q. Did PECO submit the reports discussed in I&E's Statement in Support?

A. Yes, PECO submitted those reports as PECO Exhibits PSB-1 and PSB-2, which show that the Company's actual plant in service additions for its FTY and FPFTY ($603.6 million) exceeded the level of plant additions PECO projected in its last rate case ($593.6 million).

16. Q. At page 12 of I&E Statement No. 3, Mr. Kubas lists the 2016 UGI-PNG base rate case and the 2016 consolidated base rate cases of FirstEnergy's four Pennsylvania utility subsidiaries as cases where utilities claimed an end-of-FPFTY rate base, those claims were opposed by the OCA (and in UGI-PNG by the Office of Small Business Advocate), and the cases were resolved by settlements. He also lists Pennsylvania-American Water Company's ("PAWC") 2017 rate case as a case where the utility claimed an end-of-FPFTY rate base, it was opposed by the OCA and I&E and it was resolved by settlement. Finally, he notes that I&E is also opposing UGI Electric Division's claim for end-of-FPFTY rate base in its pending base rate case. Is that a complete list of major utility cases where utilities claimed end-of-FPFTY rate bases, their claims were opposed by the OCA or other parties and the cases were resolved by settlement?

A. No, it is not. The list is much longer and includes the following:

Pa. P.U.C. v. Columbia Gas of Pennsylvania, Inc., Docket No. R-2012-2321748
Pa. P.U.C. v. Peoples TWP LLC, Docket No. R-2013-2355886
Pa. P.U.C. v. Pennsylvania-American Water Co., Docket No. R-2013-2355276
Pa. P.U.C. v. Columbia Gas of Pennsylvania, Inc., Docket No. R-2014-2406274
Pa. P.U.C. v. Metropolitan Edison Co., Pennsylvania Electric Co., Pennsylvania

Power Co., and West Penn Power Co., Docket Nos. Docket Nos. R-2014-2428745, R-2014-2428743, R-2014-2428744, and R-2014-2428742
Pa. P.U.C. v. PPL Electric Utilities Corp., Docket No. R-2015-2469275
Pa. P.U.C. v. PECO Energy Company, Docket No. 2015-2468981
Pa. P.U.C. v. Metropolitan Edison Co., Pennsylvania Electric Co., Pennsylvania Power Co., and West Penn Power Co., Docket Nos. R-2016-2537349, R- 2016-2537352, R-2016-2537355, and R-2016-2537359
Pa. P.U.C. v. Columbia Gas of Pennsylvania, Inc., Docket No. R-2015-2468056
Pa. P.U.C. v. UGI Utilities, Inc. – Gas Division, Docket No. R-2015-2519438
Pa. P.U.C. v. Pennsylvania-American Water Company, Docket No. R-2017-2595853

17. Q. Did Mr. Kubas explain why I&E began to advocate the use of average rate base for the first time only in 2017?

A. No, he did not explain I&E's change of position either in his direct testimony or in his answer to PECO-I&E-II-22, which directly asked Mr. Kubas that question. I am providing Mr. Kubas's response to PECO-I&E-II-22 as PECO Exhibit BSY-6. In that response, Mr. Kubas tries to characterize I&E's pre-2017 testimony as essentially neutral on the issue of average versus end-of-FPFTY rate base: "I&E did not take a position on the application of the FPFTY in any of those proceedings." I do not see how I&E can assert it "did not take a position" when it accepted, in each of the pre-2017 FPFTY cases, the utility's use of an end-of-FPFTY rate base (and annualization of expenses and revenues as of that date) and used that same approach in developing its litigation positions.

18. Q. What did the settlements provide in each of the cases you listed previously?

A. The settlements in each of the cases I identified previously, except the 2014 base rate cases for the FirstEnergy Companies,[1] included provisions substantially like the one

[1] The FirstEnergy companies' settlements of their 2014 base rate cases did not include the DSIC-related provision I discuss because they did not have DSIC Riders at the time those settlements occurred. The FirstEnergy companies

in the Joint Petition for Settlement of PECO's 2015 base rate case. I&E submitted testimony in each case and was a party to each of the settlements. The settlements in UGI-PNG, the consolidated FirstEnergy 2016 base rate cases and PAWC's 2017 base case also state a specific baseline of FPFTY plant in service that must be exceeded before each utility can reinstitute its DSIC, as required by the terms of the Supplemental Implementation Order. In the UGI-PNG case, each of the FirstEnergy cases and the PAWC case, the baseline was set at the end-of-FPFTY plant in service levels claimed by the utility. To illustrate, Paragraph No. 15 of the Joint Petition for Settlement in PAWC's 2017 base rates, which employed a FPFTY ending December 31, 2018, provides as follows:

> The Company will not implement a Distribution System Improvement Charge ("DSIC") during the calendar year ending December 31, 2018. The first DSIC in 2019 will be effective no earlier than April 1, 2019 based on DSIC-eligible expenditures during January and February 2019. In any event, the Company will not begin to impose a DSIC until the total aggregate gross plant costs (before depreciation or amortization) associated with the eligible property that has been placed in service exceeds the following total aggregate plant costs claimed by the Company in the FPFTY:
>
> Water - $149,660,658 (as shown in detail on Appendix E)
>
> Total Wastewater - $6,770,153 (as shown in detail on Appendix E)
>
> In compliance with the Supplemental Implementation Order entered on September 21, 2016 at Docket No. M-2012-2293611, the amounts shown in Appendix E constitute the baseline of gross plant balances to be achieved in order to restart charges under the Company's DSIC. This provision relates solely to the calculation of the DSIC during the time that the Settlement Rates are in effect and is not determinative for future ratemaking purposes of the projected

filed petitions to implement DSIC Riders in 2015, which the Commission granted. Consequently, as I previously noted, a DSIC-related provision was included in their 2016 base rate case settlements.

> plant additions to be included in rate base in a fully projected future test year filing.

Similarly, Paragraph No, 13 of Metropolitan Edison Company's Joint Petition for Partial Settlement provides as follows:

> The Joint Petitioners agree that the baseline for restating charges under the Company's DSIC Rider (Rider R) will be based on gross plant additions per Exhibit RAD-46, which includes Commission-approved 2016 and 2017 Long-Term Infrastructure Improvement Plan ("LTIIP") plant total investment of $16.68 million.

Metropolitan Edison Exhibit RAD-46 set forth that company's claim for plant additions based on end-of-FPFTY levels. Paragraph No. 13 of the Joint Petitions for Partial Settlement of each of the FirstEnergy Companies (which were substantially similar to the language set forth above for Metropolitan Edison Company) was quoted by the Commission in its Final Order entered January 19, 2017 (pp. 10-16) approving the settlements for the FirstEnergy companies.

19. Q. Turning to the Supplemental Implementation Order, please explain the guidance that Order furnishes regarding how FPFTY rate base should be determined.

A. Initially, it should be kept in mind that the settlements of the major base rate cases approved by the Commission prior to entering the Supplemental Implementation Order formed the context in which that Order was considered and adopted. Significantly, the OCA itself stated that the settlements of prior FPFTY base rate cases provided the proper context for assessing the OCA's comments and those of other stakeholders, as the Commission summarized in the Supplemental Implementation Order (pp. 11-12):

> The OCA proffered two clarifications: (1) only the fixed costs of *new, additional investment will be eligible for recovery in a positive DSIC* rate and (2) *the final order establishing new base rates should specify the total aggregate dollar amount that is associated with the DSIC-eligible property that is used to set rates*. OCA Comments at 7.
>
> The OCA explains that both of these clarifications recognize that the base rate used to determine revenue requirement can be a contested issue in the rate case that is resolved through settlement or litigation. OCA Comments at 8. The OCA states that if the Commission adopts its clarification, it will support the Commission's proposal for resuming a positive DSIC rate after a base rate case, because, in OCA's view, these proposals will help the parties and Commission to monitor and ensure that costs recovered in base rates are not also recovered in the DSIC rate. *Id. The OCA states that these proposals are consistent with the base rate case settlements where the Commission has approved terms specifying that the DSIC "stay-out" would continue until eligible property account balances exceed the levels agreed upon for purposes of the settlement. Id.* Lastly, the OCA also supports the Commission's proposal that utilities continue to file DSIC quarterly updates, even during the entirety of the stay-out period. *Id*. (Emphasis added.)

Second, as the OCA noted in its comments, summarized above, the post-rate case reinstitution of a DSIC necessarily requires a determination of the level of FPFTY plant a utility would be permitted to claim in setting its base rates. Therefore, the Commission clearly identified the property that is included in rate base where a FPFTY is employed (Supplemental Implementation Order, p. 13):

> The test year can consist of a future test year or a fully projected future test year (FPFTY) as its baseline for setting new base rates. *See* 66 Pa. C.S. § 315. As such, a utility requesting to establish new base rates pursuant to a filing under Section 1308(d) of the Code, is seeking to recover the costs of all DSIC-eligible plant in service, plus the DSIC-eligible plant that is *projected to be in service either within 9 to 21*

> *months depending on if the utility has used a future test year or a FPFTY to calculate its rates*. (Emphasis in original.)

The projection period of nine months reflects, as to an FTY, three months of actual plant data and nine months of projected plant additions (because the Commission assumed that the filing utility would use the entire 120 days provided by its regulations between the end of the Historic Test Year and the filing date). Thus, if a utility filed a general base rate case on April 30 (120 days after the end of its Historic Test Year), the Commission also assumed the utility would have plant data through March 31 (three months) and would project its additions through the end of the FTY (nine months). If the same utility also submitted supporting data for a FPFTY, it would project plant additions for an additional 12 months, or a total projection of 21 months. Thus, a 21-month projection runs to the end of the FPFTY. This timeline was the basis for the PUC's determination of the rules for reinstituting a DSIC that it adopted in the Supplemental Implementation Order, and, as I pointed out above, assumes that utilities' employing a FPFTY will use end-of-test-year original cost of plant additions, not an annual average.

20. Q. What rule did the Supplemental Implementation Order establish for reinstituting a DSIC after it was set to zero at the conclusion of a base rate case?

A. The Supplemental Implementation Order (pp. 13-14) established the following rule for reinstituting a DSIC charge after the charge is set at zero on the effective date of new base rates:

> The Commission determines that if a utility has surpassed the prospective recovery amount associated with all of the DSIC-eligible plant placed in service and which was previously reflected in the utility's base rates or projected to be in service as a result of using a future test year or FPFTY, it is then eligible to begin to recover again the fixed costs associated with any *new* repair, replacement or improvement of DSIC-eligible property reflected in that quarterly DSIC update. (Emphasis in original.)

The Commission's rule can be applied in an understandable and straight-forward manner if a utility's rate base is set at its end-of-FPFTY level. In that case, the utility's base rates would recover the costs of all DSIC-eligible plant projected to be in service through the end of the FPFTY. Only when the utility had actually placed in service plant equal to that reflected in its base rates would any "new" plant (not previously reflected in base rates) become eligible for DSIC recovery. This is exactly the same approach followed in the prior Commission-approved settlements that I previously discussed.

However, if the average rate base approach were adopted, as Mr. Kubas and Mr. Effron propose, the requirement imposed by the Supplemental Implementation Order simply does not work as designed. If only one-half of the value of a utility's FPFTY plant additions is reflected in base rates, the language of the Supplemental Implementation Order, as written, would preclude reinstituting a DISC until 100% (not just half) of that plant has been placed in service ("any *new* repair, replacement or improvement of DSIC-eligible property"). The resulting discontinuity between plant reflected in base rates and the limitation on DSIC-eligible investment would unjustifiably prevent a utility from recovering the fixed costs of DSIC-eligible property through its DSIC even though that property is in service and is not reflected in the utility's base rates. In short, the average rate base approach would contradict the express terms of the DSIC. On the other hand, if a DSIC could be reinstituted when amounts equal to the FPFTY average plant balances for DSIC property were achieved, a utility would have to be allowed to initiate a DSIC before the end of the FPFTY – as Mr. Kubas concedes (I&E St. 3, p. 11). That approach is not consistent with the language of the Supplemental Implementation Order and is also contrary to the practice approved in the settlements of prior FPFTY cases, which, as I explained, properly form the context in which the Supplemental Implementation Order has to be read and understood. The only conclusion that is consistent with the Supplemental Implementation Order's requirements for implementing a DSIC after a base rate case where a FPFTY is used is that the Supplemental Implementation Order's DSIC requirements anticipate and assume the use of an end-of-FPFTY rate base to establish base rates. Thus, the Supplemental Implementation Order provides clear guidance that rate base (and, correspondingly, annual and accrued depreciation, ADIT, expenses and revenues) are to be established at a utility's end-of-FPFTY levels.

21. Q. Did Mr. Kubas base his proposal to employ average FPFTY rate base upon the assumption that the DSIC could be implemented during the FPFTY of a previously concluded base rate case?

A. Yes, he did. In his direct testimony (I&E St. 3, p. 11), Mr. Kubas stated:

> Further, utilizing an average rate base could allow earlier implementation of a distribution system improvement charge ("DSIC") if the Company demonstrated that the plant-in-service used to establish rates had been added to rate base. Usage of the DSIC earlier would

> mitigate the impact of the rate increase that would result from assuming an end-of-year rate base in establishing rates and still provide the Company the opportunity to recover later DSIC-eligible plant investments, potentially within the FPFTY.

22. Q. Did Mr. Kubas discuss whether his assumption is correct in light of the guidance furnished by the Commission in the Supplemental Implementation Order?

A. No, Mr. Kubas did not address the Supplemental Implementation Order in his direct testimony. In PECO's Interrogatory to I&E (PECO-I&E-II-21), the Company asked Mr. Kubas to consider whether his direct testimony was inconsistent with the Supplemental Implementation Order. In his answer to that interrogatory, Mr. Kubas said he "disagrees with the premise of the question" that PECO posed and asserted that "[t]he 'earlier implementation of a distribution system improvement charge ("DSIC")' was not the basis for his recommendation to employ 'average' rate base." Mr. Kubas's answer contradicts the portion of his direct testimony I quoted previously. Moreover, in his answer to PECO-I&E-II-20, Mr. Kubas acknowledged and agreed that the "purpose" of the portion of the Supplemental Implementation Order PECO asked him to consider expressly addressed "the 'Stay-Out Period After the Effective Date of New Base Rates.'" Nonetheless, he inexplicably denies that the time when a DSIC may be implemented following the conclusion of a FPFTY base rate case is a function of whether average or end-of-FPFTY rate base is employed. His answer to PECO-I&E-II-20 is also contrary to his direct testimony, which stated that his average rate base recommendation is explicitly premised on the Company having the "opportunity to recover later DSIC-eligible plant investments, potentially within the FPFTY" (I&E St. 3, p. 11). (I am providing copies of Mr. Kubas's answers to PECO-I&E-II-20 and PECO-I&E-II-21 as PECO Exhibit BSY-7.)

23. Q. Mr. Kubas and Mr. Effron contend that an "average" rate base is required by the Illinois Commerce Commission for use with a test year that, they assert, corresponds to the FPFTY in this case. In addition, Mr. Effron believes that Rhode Island mandates an "average" rate base in establishing base rates for Rhode Island utilities. Please address these contentions.

A. I was unable to verify whether Rhode Island requires the use of an "average" rate base. With regard to Illinois, it is not correct to contend that the future test year authorized by statute in that state corresponds to the FPFTY as defined under the Pennsylvania Public Utility Code. While Illinois may use "average" rate base, it allows utilities (as Mr. Kubas and Mr. Effron acknowledge) to use a future test year consisting of "[a]ny consecutive 12 month period … beginning no earlier than the date new tariffs are filed and ending no later than 24 months after the date new tariffs are filed" (Illinois Administrative Code, Title 83, Section 287.20b, provided as I&E Exhibit 3, Schedule 3). Under the Illinois rules, the Company could have used a FPFTY in this case ending March 29, 2020, the mid-point of which would be September 30, 2019. As Mr. Kubas explained in his direct testimony (p. 9), a proposed "average" rate base would provide a mid-point rate base as of June 30, 2019 in this case, which is one full calendar quarter less than the mid-point for allowable future test year plant additions permitted in Illinois. Consequently, the attempt to analogize Mr. Kubas's and Mr. Effron's "average" rate base in this case to the practice in Illinois is not correct.

24. Q. Did I&E's revenue requirement witnesses and OCA witness Effron reflect all of the adjustments that would attend the use of an average level of FPFTY plant additions?

A. No, they did not. They failed to propose an adjustment to the repairs deduction that would be needed if their proposal to reflect average FPFTY plant additions were adopted. Specifically, the Company has used a repairs deduction of $96.9 million to reflect a full year of plant that qualifies for the repairs deduction. If the average rate base approach were adopted, as I&E and the OCA propose, only one-half of the repairs deduction should be used to calculate the Company's income tax expense allowance in this case.

25. Q. What is the repairs deduction?

A. In summary, the repairs deduction represents certain expenditures for plant additions that are capitalized for book (i.e., GAAP) reporting purposes but are treated as maintenance expenses (repairs) for income tax purposes. As a consequence, these expenditures, while capitalized and depreciated for book purposes, are deductible in their entirety as maintenance expenses for tax purposes.

26. Q. Did any I&E witness or Mr. Effron propose to adjust the amount PECO used as a repairs deduction to calculate its state and federal income taxes in this case

to match their proposals to include only one-half of PECO's FPFTY plant additions in rate base?

A. No, they did not. Both the I&E witnesses and OCA witness Effron used the entire annual amount of the repairs deduction to calculate the Company's state and federal income taxes without adjustment to match their proposals to allow only one-half of PECO's FPFTY plant additions. Mr. Effron proposed an adjustment to reduce the repairs deduction by $600,000 for reasons unrelated to the use of average rate base.

27. Q. Would it be proper to use the full annual amount of the repairs deduction to calculate the Company's state and federal income taxes if only one-half of the Company's FPFTY plant additions were reflected in rate base?

A. No, it would not. On an intuitive level, it would be apparent that it would not be appropriate to include a full annual amount of the repairs deduction for the FPFTY when only one-half of FPFTY plant additions would be included in rate base. In addition, a provision of Section 1301.1(a), which was added to the Public Utility Code by Act 40 of 2016, states as follows:

> 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.

I am not a lawyer, and I am not offering a legal opinion. I assume that legal issues will be addressed by counsel in the briefs filed in this case. However, the Company wants to put the parties on notice during the evidentiary phase of this case that it is its position that the language of Section 1301.1(a) I quoted above would not permit using a full annual amount of the repairs deduction for 2019 to calculate the Company's income tax expense when only one-half of FPFTY plant additions is reflected in its rate base.

28. Q. What would be the revenue requirement effect of reducing the repairs deduction by half to calculate the Company's FPFTY state and federal income taxes?

A. The Company's revenue requirement would increase by approximately $20 million if one-half of the repairs deduction were used in calculating state and federal income taxes.

B. Cash Working Capital

29. Q. Please describe the adjustment to PECO's cash working capital ("CWC") claim proposed by Mr. Effron with regard to Gross Receipt Tax ("GRT").

A. Mr. Effron disagrees with the lag in payment of GRT that PECO employed in calculating CWC. PECO calculated the lag in making GRT payments using the payment method PECO actually employs, which is to pay its entire estimated GRT liability on March 15 of the reporting year. This method complies with the Commonwealth's instructions for paying GRT. Mr. Effron (OCA St. 1, pp. 9-10) proposes lengthening the lag to reflect what he refers to as a "safe-harbor" provision in the Department of Revenue's instructions for paying GRT. His adjustment would reduce PECO's CWC by $12.02 million. Mr. Effron contends that the so-called safe harbor provision would permit the Company to pay 90% of its estimated GRT on March 15, 2019 and the remaining 10% on March 15, 2020.

30. Q. Where are the payment instructions for GRT set forth?

A. Estimated Payment Instructions are provided with Pennsylvania Department of Revenue Form RCT-112. These instructions set forth the following general rule for remitting estimated GRT payments:

> All accounts are expected to remit estimated prepayments toward the final liability a corporation estimates is due for the taxable year. Prepayment for gross receipts tax is due March 15 of the reported year. Tax remaining due at the close of the taxable year must be paid on or before March 15th of the following year.

In general, taxpayers are expected to remit the full amount of their estimated GRT by March 15 of the year for which they are reporting and any "tax remaining due at the close of the taxable year must be paid on or before March 15th of the following year." Those two dates, with respect to the FPFTY in this case would be March 15, 2019 and 2020, respectively.

31. Q. What is the "safe harbor" that Mr. Effron is referring to?

A. The so-called safe harbor does not alter the general rule. Rather it provides the benchmarks that will be used by the Department of Revenue for determining if interest and penalties will be imposed for underpayments of estimated tax remitted on March 15 of the reporting year. This provision is not nearly as simple or as clear as Mr. Effron tries to portray it. The Department of Revenue's instructions in this regard are as follows:

> Should a corporation realize estimated tax is underpaid, additional payments should be submitted to minimize underpayment penalty. Underpayment is measured against 90 percent of the tax reported due for the taxable year. However, if the final total tax increases the self-reported tax by 10 percent or more, the underpayment will be measured against 90 percent of the final total tax. The period of underpayment is measured from the due date of the installment to the date the underpayment is paid or the date the safe harbor is satisfied.
>
> A corporation may avoid interest charges by timely paying estimated tax equal to the liability in the second-prior taxable year (safe harbor). This amount must be adjusted to reflect the tax rate and law for the estimated tax year and must reflect the total liability if it exceeds the self-reported liability by 10 percent or more. Where the second-prior year is a short period, the safe harbor is annualized. Second year corporations may use the immediate prior year (annualized if necessary) as the base year for the safe harbor.

Mr. Effron is proposing, in effect, that PECO intentionally underpay its estimated GRT due on March 15 of the reporting year by trying to estimate the minimum amount that must be remitted to hit the 90% target. This approach also requires PECO to make detailed and highly uncertain projections about how its "second-prior taxable year (safe harbor)" tax "must be adjusted to reflect the tax rate and law for the estimated tax." It is also subject to the further condition that the payment "must reflect the total liability if it exceeds the self-reported liability by 10 percent or more." If any of those projections and adjustments do not accurately predict PECO's total future tax liability – and it is likely that they will not – PECO will be subject to interest and penalties for underpaying its estimated GRT notwithstanding the so-called "safe harbor."

In short, Mr. Effron wants to impute a shorter lead in payment of estimated GRT by asking PECO to roll the dice on whether the complicated “safe harbor” projections can be made accurately and the associated conditions can be satisfied. Of course, if PECO rolls a loser, customers will win by getting the benefit of an imputed shorter payment lead, while PECO will be stuck paying interest and penalties.

32. Q. What are some of the factors that make it difficult to accurately project estimates of total tax liability in the manner necessary to get away with intentionally underpaying estimated GRT due on March 15 of the reporting year as Mr. Effron urges PECO to do?

A. There are a number of factors. Some of the most significant include volatility in power prices and changes in weather-related demand that affect electric sales, which can cause a large increase in the Company’s GRT liability over a short period of time. If any of those or other similar factors occur, the attempt to pay only 90% of estimated GRT on March 15 of the reporting year will fall short, the “safe harbor” will cease to apply, and PECO will be exposed to interest and penalties.

33. Q. Should Mr. Effron’s proposal to impute an intentional underpayment of estimated GRT be accepted?

A. Certainly not. PECO is adhering to the generally applicable payment schedule for GRT. Attempting to get away with remitting less than its estimated GRT on March 15 of a reporting year by relying on the so-called “safe harbor” requires uncertain projections and estimates that, if not accurate, will make PECO ineligible for the “safe harbor” and subject it to interest and penalties. The Commission should not accept that highly speculative approach. Moreover, the Commission should not require PECO to adhere to a payment strategy predicated on *intentionally* underpaying its estimated GRT on the March 15 due date of the reporting year.

C. Pension Asset

34. Q. Before addressing the adjustments proposed by I&E witness Wilson (I&E St. 1, pp. 9-10) and OCA witness Effron (OCA St. 1, pp. 10-13) to disallow PECO's pension asset in its entirety, please explain what the pension asset is.

A. As I explained in my direct testimony (PECO St. 3, pp. 28-29), the pension asset arises because of a difference in the calculation of pension costs for ratemaking purposes in Pennsylvania and the calculation of pension costs under generally accepted accounting principles or "GAAP." The Commission has generally required that pension costs for ratemaking purposes should be based upon a utility's cash contribution to its pension fund, while GAAP requires pension costs to be determined on the basis of different rules, which are set forth in the Statement of Financial Accounting Standards No. 87 ("SFAS 87").[2] Use of these two different procedures results in an annual difference between the amount of pension costs recovered in rates established by the Commission (based on cash contributions) and the amount of pension costs reflected on the accounting records of the Company (based on SFAS 87). The pension asset represents the accumulated amount of that

[2] SFAS 87 was issued by the American Institute of Certified Public Accountants ("AICPA") and has been adopted by the Securities and Exchange Commission ("SEC") as the required method for calculating and recording pension costs for financial reporting purposes in accordance with GAAP. AICPA "codified" its statement of financial accounting standards and now uses a different naming convention, which references SFAS 87 as Accounting Standards Codification 715 or "ASC 715." I will continue to use the designation SFAS 87 because it is the one that most parties are familiar with.

annual difference related to the portion of the pension costs that are capitalized and included in the utility plant accounts. PECO must capitalize and include in its plant accounts an amount that is based on pension costs calculated on the basis of SFAS 87. This means that the amounts that are assumed for ratemaking to be included in PECO's plant accounts (based on the application of a capitalization rate to the cash pension contribution) necessarily differ from the amounts that are actually capitalized by PECO by applying, as it must, GAAP rules.

The pension asset reflects the difference between: (1) the amount of pension cost the Commission's assumes was included in PECO's plant accounts; and (2) the amount of pension costs actually included in PECO's plant accounts. That difference is $95.2 million. The pension asset, therefore, consists of $95.2 million of investor-supplied capital that was actually contributed to PECO's pension fund; was assumed for ratemaking purposes to be included in PECO's plant accounts; but, in fact, was not recorded in PECO's plant accounts because GAAP rules will not allow it. PECO has included the pension asset in rate base in this case because, unless it is given rate base recognition, PECO will never recover the carrying costs it incurs on those investor-supplied funds. In that regard, I want to emphasize that PECO is only proposing to include the pension asset in rate base to recover the associated carrying costs on a prospective basis. PECO recognizes that it must bear those previously-unrecovered prior-period carrying costs and is not seeking their recovery in this case.

35. Q. Is there any disagreement with the fundamental concept you described above?

A. No, I do not believe there is a disagreement that the method the Commission uses to reflect pension costs in operating expenses for ratemaking purposes necessarily causes a real and material difference between the amounts the Commission assumes will be capitalized (based on cash pension contributions) and the amounts that are actually capitalized (based on GAAP rules that public companies follow).

In addition to being demonstrably correct, the conceptual basis for including a pension asset in rate base was adopted and affirmed in two consecutive rate cases for Duquesne Light Company ("Duquesne"). In Duquense's 2010 base rate case at Docket No. R-2010-2179522, the parties entered into a Joint Petition for Settlement of All Issues ("2010 Settlement"). Although the 2010 Settlement was a "black box" with respect to the allowed level of revenue requirement, there were important exceptions for settlement terms affecting how Duquesne would record costs between rate cases and how it would be permitted to present its claims in subsequent base rate cases. Those black box exceptions were specifically delineated for review and approval by the Commission. One of those specifically delineated items was set forth in Paragraph No. 36 of the 2010 Settlement, which embodies a method for recognizing a pension asset that directly corresponds to the pension asset PECO has claimed in this case. Paragraph No. 36 provides, in relevant part, as follows:

> 50% of actual pension contributions from January 1, 2007, forward, net of related accumulated deferred income taxes, [will be included] in rate base for rate making purposes. The rate base adjustment for pensions shall be the amount necessary to adjust the SPAS 87 capitalized pension amounts to equal accumulated capitalized pension contributions, net of applicable deferred

> income taxes, from January 1, 2007, forward. The depreciation expenses for book and ratemaking purposes will be based on the SFAS 87 capitalized amounts.

In that case, where Mr. Effron also testified on behalf of the OCA, the OCA submitted a Statement in Support of the Settlement that discussed each of the black box exceptions, including the pension asset. The OCA stated that the treatment of the pensions asset afforded by the Settlement should be affirmed by the Administrative Law Judges ("ALJs") and the Commission for the following reasons:

> This provision will permit the Company to include the capitalized portion of its cash contributions to the pension in its rate base without affecting depreciation expenses. Allowing this change resolves the unfavorable differences in recording pension contributions for ratemaking purposes and recording pension contributions for financial accounting purposes.

OCA Statement in Support of Settlement at Docket No. R-2010-2179522, pp. 7-8.

On January 28, 2011, the ALJs issued a Recommended Decision adopting and approving all of the terms of the Settlement, including the pension asset and accounting provision (pp. 27, 42 and 60-61). On February 24, 2012, the Commission entered a final order that adopted the ALJs' Recommended Decision in total.

Duquesne filed another base rate case in 2013, which was the subject of a Commission investigation at Docket No. R-2013-2372129. Mr. Effron also participated in that case as the OCA's accounting witness. Duquesne's 2013 case was resolved by a Joint Petition for Approval of Non-Unanimous Settlement ("2013 Settlement") that, like the 2010 Settlement, carved out exceptions to the "black box" revenue requirement for certain specific items that would have an on-going effect on the way Duquesne accounted for costs and set forth its claims in future base rate cases. Paragraph 29 of the 2013 Settlement incorporated the same provision as the 2010 Settlement with respect to including a pension asset in Duquesne's rate base:

> The rate base adjustment for pensions shall be the amount necessary to adjust the ASC 715 [SFAS 87] capitalized pension amounts to equal accumulated capitalized pensions contributions, net of applicable deferred income taxes from January 1, 2007 forward. The depreciation expense for book and accounting purposes will be based on the ASC 715 capitalized amounts. The adjusted amounts will be used for reporting rate base to the Commission.

Like its Statement in Support of the 2010 Settlement, the OCA's Statement in Support of the 2013 Settlement specifically addressed the pension asset issue, asked the ALJ and the Commission to adopt it, and stated that the Settlement provision on this matter is "consistent with sound ratemaking principles." OCA Statement in Support of the 2013 Settlement (pp. 7-8).

On March 27, 2014, the ALJ issued his Recommended Decision, which discussed all of the terms of the 2013 Settlement including the pension asset and accounting provision (Recommended Decision, pp. 25 and 36-37) and adopted and approved all of the Settlement terms (pp. 58-61). On April 23, 2014, the Commission entered a final order that adopted the ALJ's Recommended Decision.

36. Q. Did I&E oppose Duquesne Light's proposed pension asset in either its 2010 or 2013 base rate cases?

A. It does not appear that it did.

37. Q. Why does Mr. Effron object to recognizing a pension asset for PECO in this case as was done for Duquesne?

A. Mr. Effron presents several alleged reasons for opposing PECO's pension asset in this case.

First, Mr. Effron attempts to minimize the significance of Duquesne's 2010 and 2013 rate case decisions by noting that they approved, in each case, "a comprehensive settlement" (OCA Statement No. 1, p. 11).

Second, he contends that, if the Duquesne cases were given the weight that PECO believes they deserve, the period used to calculate the pension asset should be much shorter. Specifically, he acknowledges that the Duquesne settlement provisions allowed Duquesne to establish a pension asset reflecting the difference between amounts deemed to be capitalized for ratemaking purposes based on Duquesne's pension contribution and amounts actually capitalized under GAAP rules. However, he points out that Duquesne started the quantification of its pension asset at January 1, 2007 and contends that the starting date was chosen only because it was the effective date of the rates established in Duquesne's rate case immediately preceding its 2010 case (OCA Statement No. 1, p. 15). The unstated assumption in Mr. Effron's testimony is that there is no basis for recognizing a pension asset for PECO for any period prior to the effective date of rates established in its 2010 base rate (January 1, 2011). As I will explain, Mr. Effron left out some very important facts about what was done, and why it was done, in the 2010 Duquesne base rate case. Based on the correct rationale that actually supported the use of January 1, 2007 as the starting date for calculating Duquesne's pension asset, PECO should begin measuring its pension asset as of the conclusion of its 1989 base rate case.

Third, Mr. Effron asserts that, because PECO did not file a base rate case between its fully litigated case in 1989 and its base rate case filed on March 31, 2010, "it would be extremely difficult, if not impossible, to determine what pension costs (or other costs) were or were not recovered in rates during that time period" (OCA Statement No. 1, p. 12). As I will explain, it is neither necessary nor consistent with ratemaking principles to impose the kind of cost reconciliation Mr. Effron demands before recognizing PECO's pension asset.

Fourth and finally, Mr. Effron attempts to match up the electric distribution pension contributions PECO made in 2011 through 2017 with the pension cost PECO claimed in its 2010 and 2015 base rate cases, which were settled on a "black box" basis with no exception carved out for pension costs (OCA Statement No. 1, pp. 12-13). Based on that arithmetical exercise, Mr. Effron suggests that, because PECO's 2010 and 2015 cases were settled, it should be assumed that its base rates are recovering all of the pension expense PECO claimed. And, based on that assumption, Mr. Effron contends that PECO's rate recovery was more than PECO's cash contributions to its pension fund during the 2011 through 2017 timeframe.

There is no basis for Mr. Effron's assumption that PECO's claims for pension expense was incorporated in its entirety in the "black box" settlement rates, and his argument should be rejected for that reason alone. However, even if Mr. Effron's assumption were accepted, I have demonstrated in PECO Exhibit BSY-8 that PECO's actual pension contributions for electric distribution operations exceeded the pension costs it claimed for ratemaking purposes since 1989 by more than $26 million. Consequently, there is no basis for Mr. Effron's speculation that PECO may have over-recovered its pension costs in the past.

38. Q. Please address Mr. Effron's first contention, that the provisions that were carved out from, and specifically addressed outside of, the "black box" terms in the Duquesne cases should be ignored because they were part of "comprehensive settlements."

A. Just to be clear, I have not contended that the two consecutive Duquesne base rate case Settlements, and the Commission orders approving them, are necessarily legal precedent that, on that basis alone, would require the Commission to approve including PECO's pension asset in rate base in this case. That point is also clear from PECO's answer to the OCA's interrogatory, which Mr. Effron quotes (OCA St. No. 1, pp. 11). Rather, I am making a more fundamental point that is based on sound, well-accepted accounting and ratemaking principles, namely, that the way the Commission recognizes pension costs for ratemaking purposes assumes that a portion of pension costs are capitalized (i.e., included in plant accounts) when, in fact, they are not. The pension asset represents investor-supplied funds that the

Commission's ratemaking method, based on cash contributions, hypothesizes are earning a return as part of PECO's plant accounts even though they are not. The Duquesne Settlements, the OCA's Statements in Support of those Settlements, the ALJs' Recommended Decisions in those cases, and Commission's final orders approving them affirm the fundamental accounting and ratemaking principles and concepts underlying PECO's claim to include its pension asset in rate base. The significance of the principles and concepts expressly affirmed in the Duquesne 2010 and 2013 cases cannot be marginalized simply by attributing them to "settlements."

39. Q. Please address Mr. Effron's second contention, that if any weight were given to the Duquesne decisions, the period used to calculate PECO's pension asset should be much shorter.

A. This contention also has no valid basis because Mr. Effron misunderstands and, therefore, mischaracterizes, the reason that January 1, 2007 was used as the "starting point" for measuring Duquesne's pension asset.

Mr. Effron contends that January 1, 2007 was selected as the starting point because "it was the effective date of the rates established in its previous case" (OCA Statement No. 1, p. 12). I agree that January 1, 2007 was the approximate effective date of new rates established in Duquesne's base rate case filed in 2006 at Docket No. Docket No. R-00061346. However, that is *not* the reason January 1, 2007 was selected as the starting point for calculating Duquesne's pension asset.

I have reviewed Duquesne's base rate case filing history. Before 2006, Duquesne had last filed a base rate case on June 26, 1987. In that case, Duquesne's pension costs were based on its SFAS 87 accrual. It was not until the conclusion of Duquesne's 2006 base rate case that it obtained a Commission order establishing rates that reflected pension costs based on Duquesne's pension contributions. Consequently, prior to Duquesne's 2006 base rate case, there was no difference in pension costs for ratemaking and GAAP purposes because Duquesne was using SFAS 87 for both. The divergence between pension costs recognized for ratemaking (based on Duquesne's pension contributions) and pension cost recorded for GAAP purposes did not begin until January 1, 2007. The same is not true for PECO because, as I noted before, it filed a base rate case in 1989 that resulted in a final Commission order entered May 16, 1990 at Docket No. R-891364. PECO had adopted SFAS 87 before its 1989 case was filed. In its 1989 case, the pension costs that PECO claimed were based on its pension contribution. Its total cash contribution was reduced by the amount that was assumed would be capitalized and the remainder was claimed for recovery as an operating expense. From and after the May 16, 1990 final order, PECO's pension costs for ratemaking purposes assumed the capitalization of pension costs that were different from the pension costs PECO was actually including in its plant accounts under SFAS 87.

Recognizing the differences between Duquesne and PECO that I described above – and the correct reason for Duquesne's use of a January 1, 2007 starting date for its pension asset – there is no basis for Mr. Effron's contention that the period used to calculate PECO's pension asset is too long. Each Company's starting point reflects its own pension asset accumulation from the time that the Commission authorized the use of cash pension contributions to establish rates. The Duquesne approach, properly understood, fully supports calculating PECO's pension asset from the effective date of rates established in its 1989 base rate case.

40. Q. Please address Mr. Effron's third point.

A. Mr. Effron observes that PECO did not file a base rate case between its fully litigated 1989 case, which resulted in a May 16, 1990 final order, and the base rate case filed on March 31, 2010. On that basis, he contends that "it would be extremely difficult, if not impossible, to determine what pension costs (or other costs) were or were not recovered in rates during that time period" (OCA Statement No. 1, p. 12). Mr. Effron assumes, without stating it directly, that there needs to be a line-by-line reconciliation of each element of revenue requirement PECO claimed in its 1989 case versus the costs it actually experienced between 1989 and 2010 and, absent such a reconciliation, he is free to speculate that PECO recovered an excessive amount of pension cost. There are two errors in Mr. Effron's argument.

First, I am not aware of any requirement that a utility provide a dollar-for-dollar reconciliation of each element of its revenue requirement claimed in a prior case versus its "actual" costs in order to claim an item for recovery on a prospective basis in a subsequent base rate case. Under that unprecedented approach, a utility would have to prove that it did not recover too much of every expense item claimed in a prior case before it could justify its claim for any expense item in a subsequent base rate case. It is clear that Mr. Effron's argument relies on a premise that is both unprecedented and contrary to fundamental ratemaking policy and practice.

Second, and also contrary to Mr. Effron's contention, for ratemaking purposes it is generally assumed that a utility's base rates recover the utility's actual expenses – not more or less – during the period those rates are in effect. Therefore, any difference between the total revenue requirement used in setting a utility's base rates and its actual costs during the rate-effective period is fully reflected in its achieved return on equity.[3]

In contrast, the Company's pension asset reflects investor-supplied *capital* actually contributed to its pension fund, and does not rely upon speculation that PECO either over-recovered or under-recovered any *expense* item. Simply stated, conjecture and speculation about expenses PECO may or may not have recovered in the past provides no valid basis for rejecting a known and certain difference between capital costs the Commission assumes, in setting rates, were recorded in PECO's plant accounts and the lesser amounts actually recorded in those plant accounts. That difference, for which there is a precise accounting on PECO's books of account, is a current asset – not a prior cost that PECO is trying to recover retrospectively. All PECO is seeking in this case is the prospective recognition of the capital costs associated with that asset; PECO acknowledges that the costs it incurred to carry its pension asset in the past are not recoverable now, and it is not asking to recover them. For that reason, Mr. Effron's observation that PECO did not claim the pension asset in its 2010 base rate case (OCA St. No. 1, p. 11) is irrelevant to the claim

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[3] Significantly, PECO's revenue requirement was reviewed in connection with its restructuring case in 1996-1997, and there was no finding in the Commission's final order that PECO was over-recovering any element of its revenue requirement. *Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code*, R-00973953 et al (Final Order entered December 23, 1997). PECO was also subject to "caps" on its distribution rates until January 1, 2006.

PECO is actually making in this case. Mr. Effron's argument boils down to a bare assertion that because PECO has borne the cost of carrying the pension asset in the past, it should be forced to continue to bear the costs associated with carrying that asset in the future despite the fact that the pension asset represents investor supplied capital used to meet a legitimate business purpose directly related to furnishing service to electric customers. Furthermore, neither the OCA nor Mr. Effron raised this "over recovery" argument in either of Duquesne's cases.

41. Q. Please address Mr. Effron's fourth point.

A. As I previously noted, Mr. Effron attempts to match the electric distribution cash pension contributions PECO made in 2011 through 2015 and 2016-2017 with the cash pension contribution PECO forecast in its 2010 and 2015 base rate cases as the basis for its pension expense claim (OCA St. No. 1, pp. 1213). PECO's 2010 and 2015 cases were resolved by "black box" settlements with no exception carved out for pension expense. Mr. Effron contends that because those cases were settled, it should be assumed that its base rates recovered, and are recovering, the entire pension expense PECO claimed, which Mr. Effron asserts is more than PECO's cash contributions allocated to electric distribution expense in the years 2011 through 2017.

Mr. Effron points out that, in its 2010 case, PECO claimed a cash pension contribution attributable to electric distribution operations of $48.29 million, of which $30.8 million was allocated to operating expenses (OCA Statement No. 1, p. 13). I would note that Mr. Effron did not reflect the update that PECO made in the rebuttal phase of the 2010 case, which reduced its projected total electric distribution cash pension contribution to $47.8 million and reduced the portion allocated to operating expense to $30.6 million. Additionally, in PECO's 2010 case, Mr. Effron, on behalf of the OCA, contested PECO's pension expense claim, contending that PECO's total cash contribution for electric distribution operations would be only $19.2 million, of which $12.3 million would be allocated to operating expenses. The I&E's witness in that case also challenged PECO's pension claim and contended that PECO's cash pension contribution for electric operations would approximate $31.4 million, of which $20.1 million was allocable to operating expenses. In short, there was substantial disagreement about what PECO's cash pension contribution for electric operations – and the associated pension expense – would be.

In PECO's last (2015) base rate case, PECO claimed a cash pension contribution attributable to electric distribution operations of $28.29 million, of which $18.3 million was allocated to operating expenses. Mr. Effron, on behalf of the OCA, contested PECO's pension expense claim, contending that PECO's total cash contribution for electric distribution operations would be only $18.65 million, of which $11.8 million would be allocated to operating expenses.

Notwithstanding the parties' significant disagreements about the pension expense that should be recoverable in the 2010 and 2015 cases and the fact that those cases were resolved by black box settlements, Mr. Effron assumes that the settlement rates allowed recovery of the entire amount of PECO's pension expense claims. On that basis, he contends that PECO's total electric distribution cash pension contributions for the period 2011 through 2017 were less (by something greater than $30 million) than just the expense portion of pension costs he hypothesizes PECO recovered in rates during that period. Thus, Mr. Effron is arguing – based on assumptions biased in his favor – that PECO's actual cash pension contributions during the period 2011 through 2017 were less than the contributions it claimed in its 2010 and 2015 rate cases. And, on the basis of an assumed over-recovery of pension costs for that seven-year period, Mr. Effron contends that PECO's entire pension asset should be excluded from rate base. There are several errors in Mr. Effron's argument.

42. Q. Please continue with your explanation of the errors underlying Mr. Effron's fourth argument.

A. First, because the 2010 and 2015 cases were resolved by a "black box" settlement and pension costs were a major issue in both case, there is not a valid basis for Mr. Effron's assumption that the settlement rates recovered the entire amount of PECO's claimed expenses.

Second, Mr. Effron's analysis suffers from the same fundamental conceptual flaw I discussed in connection with his third point, namely, that he assumes the need for a line-by-line reconciliation of elements of revenue requirement allowed in a prior base rate case with "actual" costs incurred during the rate effective period. That assumption is particularly inappropriate when applied to rates established by a black box settlement with respect to an expense that was vigorously contested. The generally applicable presumption, subject to only limited exceptions that do not apply here, is that a utility's base rates are recovering its actual expenses, not more or less, and any divergence between the revenue requirement allowed to be recovered in base rates and the revenue requirement actually recovered is reflected in the utility's achieved rate of return. Accordingly, Mr. Effron's claims that PECO over-recovered its pension expense have no foundation and should be rejected.

43. Q. Have you conducted an analysis that demonstrates the significant error in Mr. Effron's contention that PECO's pension costs claimed for ratemaking purposes were less than the cash contributions it actually made to its pension fund?

A. Yes, I did, and that analysis is provided in PECO Exhibit BSY-8. That exhibit has two columns of data that are displayed for the years 1990 through 2017. Those years encompass the period from when the rates established in PECO's 1989 base rate case became effective (May 1990) through the end of 2017 (the last calendar year in the 2011 to 2017 period that figured prominently in Mr. Effron's testimony).

The first column sets forth the total cash pension contribution attributable to PECO's electric distribution operations that was claimed by PECO: (1) in its 1989 base rate case (1990 through 2010, reflecting the period that the rates established in that case were in effect); (2) in its 2010 base rate case (2011 through the effective date of new rates established in its 2015 case); and (3) in its 2015 base rate case (2016-2017). In PECO's fully litigated 1989 case, the ALJs issued a Recommended Decision on March 1, 1990, which recommended a total pension cash contribution of $10.5

million for ratemaking purposes.[4] On May 16, 1990, the Commission entered a final order that adopted the ALJs' recommended total pension cash contribution. Consequently, I started with PECO's total cash pension contribution that formed the basis for its pension expense claim in that case, which I allocated to PECO's electric distribution operations by applying the ratio of electric distribution salary and wage expense to total-Company salary and wage expense. As shown, that amount is $2.188 million per year. For the years 2011 through 2015, I accepted Mr. Effron's underlying assumption and used the entire amount (capital and expense) of the cash pension contribution attributable to electric distribution operations that formed the basis for PECO's claim for pension expense (but, unlike Mr. Effron, I used the corrected figure that PECO provided in its rebuttal testimony in the 2010 case). That figure is $47.806 million per year. For 2016 and 2017, I used the entire amount (capital and expense) of the cash pension contribution attributable to electric distribution operations that formed the basis for PECO's claim for pension expense. The total for all years from 1990 through 2017 is $342.676 million.

The second column on PECO Exhibit BSY-8 shows by year the actual cash pension contributions attributable to electric distribution operations. Unfortunately, data for the contributions made between 1990 and 2000 are not available. Consequently, I assumed that *no contributions* were made, although it was likely that contributions in some amount were made for some or all of those years. As a result, my analysis is

[4] *Pa. P.U.C. v. Philadelphia Electric Co.*, Docket No. R-891364 (Recommended Decision issued March 1, 1990), p. 403.

extremely conservative. As shown on PECO Exhibit BSY-8, the total of the second column is $368.836 million.

The difference between the first column (pension contributions that were used to calculate PECO's expense claims) and second column (PECO's actual cash contributions for electric distribution operations for the period 2001 through 2017) is $26.16 million. Thus, actual cash pension contributions for just the 17-year period 2001 through 2017 exceeded by $26.16 million the projected contributions on which PECO's pension expense claims were based for the entire period from 1990 through 2017. As PECO Exhibit BSY-8 demonstrates, there is no basis to contend that PECO over-recovered its pension costs or that any alleged over-recovery could offset its pension asset. Furthermore, as I previously explained, the analysis I performed on PECO Exhibit BSY-8 uses the same assumptions that underlie Mr. Effron's assertions that PECO allegedly over-recovered its pension costs.

44. Q. Please address Ms. Wilson's proposal to disallow the Company's pension asset.

A. Initially, I would note that, while I&E witness Wilson proposes disallowing recognition of PECO's pension asset in this case, I&E did not oppose PECO's pension asset claim in the Company's last case. Significantly, Ms. Wilson acknowledges the fundamental basis for the pension asset, namely, that there is "a mismatch from an accounting perspective (use of an accrual method for plant accounts and a cash contribution method for the expense account)" (I&E St. 1, p. 9). Notwithstanding that acknowledgment, Ms. Wilson contends that "it makes most sense for ratemaking purposes to disallow a switch in methods at this point." As alleged support for her position, Ms. Wilson also contends that: "The Company is earning a return over time on these monies inside the pension fund after the cash contributions are made. Thus, requiring ratepayers to pay a return on an inflated rate base amount would be duplicative . . ." There are a number of errors in Ms. Wilson's argument.

45. Q. Please explain the errors underlying Ms. Wilson's proposed adjustment.

A. First, Ms. Wilson does not even acknowledge the guidance provided by the pension asset provisions approved in Duquesne's 2010 and 2013 base rate cases. Those cases, which I previously explained, contradict the fundamental position Ms. Wilson relies upon to support her proposed adjustment.

Second, Ms. Wilson's claim that the Company is proposing a "switch in methods" is not correct. PECO is proposing to continue to reflect pension expense for ratemaking purposes based on its cash pension contributions and, under GAAP, it must continue to determine the pension costs to be capitalized based on SFAS 87 accruals. If, on the other hand, Ms. Wilson is asserting that PECO did not previously claim a pension asset, her assertion is also wrong. PECO claimed a pension asset (calculated in the same manner as the pension asset it reflected in this case) in its 2015 base rate case. PECO's 2015 base rate case was its first case filed after the Commission approved a pension asset in Duquesne's 2010 rate case, in which a final order was entered on January 28, 2011.

Third, Ms. Wilson's reference to the "return" on the amounts it contributes to its pension fund and her claim that recognizing a pension asset would be "duplicative" of that return confuses two fundamentally different things. Returns earned on pension assets within the pension fund remain within the fund, reduce pension costs on a going-forward basis, and, in that way, benefit customers. None of the returns on the assets held within the pension fund accrue to PECO, nor do they in any way compensate PECO for the costs that have gone unrecognized because of the "mismatch" between calculating pension expense based on pension contributions and calculating the amount of pension costs capitalized based on SFAS 87. Consequently, Ms. Wilson is simply wrong to assert that there would be any duplication of "return" if the investor-supplied funds represented by the pension asset are recognized for ratemaking purposes.

Finally, I want to note that the calculation of the pension asset is not a one-way street. As it happens, the pension fund contributions, used to calculate pension expense for ratemaking, have thus far been more than the pension accruals under SFAS 87, used to calculate the amount of pension costs included in plant accounts. However, that relationship could change over time, and PECO has made it perfectly clear that if that were to occur, it will reflect the net cumulative pension liability as a deduction from rate base for ratemaking purposes.

46. Q. Please summarize your conclusions regarding the Company's claim to recognize its pension asset for ratemaking purposes.

A. The fundamental principles and concepts on which PECO based its claim to include its pension asset in rate base are sound and have been affirmed in two consecutive Duquesne base rate cases. In those cases, the OCA concluded that including

Duquesne's pension asset in rate base was "consistent with sound ratemaking principles." PECO has made a reasonable calculation of its pension asset. Mr. Effron's attempts to minimize the significance of the Duquesne decisions and to distinguish the Duquesne case from this one are totally incorrect, for the reasons I previously explained. Finally, Mr. Effron's speculation that PECO over-recovered its pension expense attributable to electric distribution operations has no foundation and has been demonstrated to be incorrect by the conservative study I performed in PECO Exhibit BSY-8, which applies Mr. Effron's own assumptions and mode of analysis. Ms. Wilson's proposed adjustment ignores the guidance provided by the Duquesne decisions and is based on the fundamentally erroneous assumption that pension fund earnings accrue to PECO and could compensate PECO for the investor-supplied funds represented by the pension asset, which is clearly not the case.

D. ADIT Tax Asset Created By The Limit On Deductions For Other Post-Employment Benefits ("OPEBs")

47. Q. What is the ADIT tax asset created by PECO's OPEB contributions?

A. OPEBs are non-pension benefits provided to eligible retired employees. PECO is required to determine its OPEB liability based on actuarial methods comparable to those used to determine its pension costs. PECO has established separate trusts to fund its OPEB liabilities, and makes contributions to those trusts based on actuarial determinations of the amounts that must be paid to the trusts to meet its future OPEB obligations to eligible retirees.

However, rules established by the Internal Revenue Service pursuant to applicable provisions of the Internal Revenue Code limit the amount of annual contributions to OPEB trusts that are deductible expenses for income tax purposes. As a consequence, there are years when PECO cannot claim a deduction for income tax purposes equal to the amount it contributes to its OPEB trusts. Thus, PECO has a tax "asset," representing an expense it incurred for book purposes but cannot deduct in the year incurred for tax purposes. It is a tax "asset" because it may become a deduction in a subsequent tax year. As a consequence, the Company's tax expense is higher than it otherwise would be in a year when OPEB contributions exceed the tax-deductible limit. However, the difference between OPEB contributions and deductible limitations could "turn around" in a subsequent year and, in that event, the Company's contribution for a prior year in excess of that prior year's deduction limit could be used in a subsequent year (within that subsequent year's deduction limit) to reduce tax expense. However, in the interim, the Company has to bear the cost of the higher income tax expense attributable to the non-deductible portion of its contribution, and investor-supplied funds must be used to make up that difference. Unless a tax asset is recognized for ratemaking purposes, the Company will not recover the carrying costs (i.e., the time value) of the investor-supplied funds used to pay the higher income tax expense attributable to the deduction limitation.

A tax asset may be compared and contrasted to ADIT. ADIT represents the net total of amounts that a taxpayer may deduct for tax purposes in excess of the amounts of the corresponding categories of expense it recognizes for book purposes. For example, accelerated depreciation that exceeds, on an annual basis, the amount of depreciation expense recorded on a utility's books generates ADIT (accumulated deferred income taxes) representing amounts that reduce tax expense in one year, but will "turn around" and increase tax expense is a future year. As a consequence, net positive ADIT (representing deductions in excess of expenses actually incurred) is a source of non-investor supplied capital and, therefore, is deducted from rate base.

ADIT and tax assets are two sides of the same coin. ADIT represents non-investor supplied capital available for use by the Company, while a tax asset represents investor-supplied capital used to fund the increased level of tax expense associated with non-deductible expenses. Accordingly, tax assets are reflected as a reduction to ADIT – that is, the tax asset offsets a portion of the rate base reduction associated with ADIT.

PECO has recorded a tax asset in the amount of $94.3 million that it has determined represents the net cumulative amount of tax it paid related to contributions to its OPEB trusts that exceeded the amounts it was permitted to deduct for income tax purposes. Thus, investors had to supply the money to fund the $94.3 million tax asset, and they are entitled to have the carrying costs (time value) of their funds reflected in the ratemaking process to compensate them for the use of their funds – just as they are compensated when their money is used to fund plant in service or other investments in used and useful assets. Accordingly, PECO reflected its $94.3 million tax asset as a reduction to its ADIT balance, which increases it rate base by a like amount.

48. Q. Has any party contested the Company's claim to reflect the OPEB-related ADIT tax asset?

A. Only OCA witness Effron has contested the Company's claim. He has proposed an adjustment to disallow $69.97 million of the Company's claim (OCA St. 1, pp. 13-16).

49. Q. Why has Mr. Effron proposed disallowing PECO's OPEB tax asset?

A. Mr. Effron asserts that the tax asset consists of two parts: (1) the net difference between the OPEB contributions and the smaller deductible amounts since December 31, 2014 (including reversals projected to occur in 2018 and 2019), which is $24.97 million; and (2) the cumulative difference between OPEB "accruals" and OPEB contributions. Mr. Effron contends that PECO's claim is different from its last case, where its claim more closely corresponded to (1) above and did not include the cumulative difference between OPEB accruals and OPEB contributions. Mr. Effron contends that the cumulative difference between OPEB accruals and contributions does not give rise to ADIT and should not be reflected as a tax asset either.

50. Q. Do you agree with Mr. Effron's characterization of the two-part nature of the Company's OPEB-related ADIT tax asset?

A. No, I do not. The OPEB-related ADIT tax asset does not represent the difference between "accruals" of OPEB expense and the amounts contributed to its OPEB trusts. Rather, as I previously explained, the tax asset claimed by PECO is the income tax effect of the net difference between the amounts PECO contributed to its OPEB trusts and the amounts it was permitted to deduct for income tax purposes. As such, the tax asset depicts the additional amount of income tax expense that has been paid with investor-supplied funds and, therefore, should be reflected as an offset to the rate base reduction for ADIT. The entire amount of the Company's OPEB-related tax asset should be reflected in this manner.

E. Act 40 of 2016

51. Q. Please explain how Act 40 amended the Public Utility Code.

A. Act 40 added Section 1301.1 to the Public Utility Code.[5] Given its effective date, as set forth in Section 1301.1(c)(2), Section 1301.1 applies in this case.

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[5] The text of Section 1301.1 is as follows:

> **§ 1301.1. Computation of income tax expense for ratemaking purposes.**
>
> **(a) Computation**.--If an expense or investment is allowed to be included in a public utility's rates for ratemaking purposes, the related income tax 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 applicable statutory income tax rates.
>
> **(b) 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.
>
> **(c) Application.--**The following shall apply:
>
> (1) Subsection (b) shall no longer apply after December 31, 2025.
>
> (2) This section shall apply to all cases where the final order is entered after the effective date of this section.
>
> (June 12, 2016, P.L.332, No.40, eff. 60 days)

52. Q. Please provide an overview of Section 1301.1.

A. Section 1301.1(a) specifies how the Commission is to compute income tax expense for ratemaking purposes in base rate cases. Section 1301.1(b) describes how incremental utility operating income produced by the operation of Section 1301.1(a) should be invested by affected utilities until the sunset of Section 1301.1(b) on December 31, 2025. Thus, subsection (a) deals with ratemaking, while subsection (b) deals with the use of utility operating income generated by the ratemaking change made by subsection (a).

53. Q. What does Section 1301.1(a) provide?

A. Subsection (a) – the ratemaking provision – requires that the Commission employ a "stand-alone" computation; a utility's allowable income tax expense for ratemaking purposes is calculated without regard to the taxable income, deductions or credits of other companies that may join with the utility in filing a consolidated federal income tax return. There is no dispute that Section 1301.1(a) terminates the practice of making a "consolidated tax adjustment" ("CTA") when calculating a utility's federal income taxes for ratemaking purposes in Pennsylvania.

Under the Modified Effective Tax Rate Method, as it was used by the Commission, a CTA captured a portion of the deductions – including taxable losses – of unregulated affiliates of public utilities and gave those benefits to the utilities' customers in the form of a lower income tax expense allowance than the utilities would bear on a "stand-alone" basis. That expense reduction was appropriated for the benefit of customers despite the fact that a utility's customers paid none of the expenses that generated the tax benefits they received from the CTA. With the enactment of Act 40, Pennsylvania joins the other 46 jurisdictions (45 states and the Federal Energy Regulatory Commission) that do not recognize any CTAs for ratemaking purposes.[6]

54. Q. What does Section 1301.1(b) provide?

A. Section 1301.1(b) specifies how the additional utility operating income that subsection (a) may produce (the "differential" between making and not making a CTA for ratemaking purposes) should be "used." Thus, correcting the unfairness that forced utilities to absorb the income tax expense they were denied by a CTA, subsection (a) – the ratemaking provision – freed up funds that utilities otherwise have to use to pay their unrecovered income tax expense. Thus, because subsection (a) would provide additional internally-generated funds that could be reinvested in critical infrastructure, subsection (b) directs how a portion of those funds should be invested in "*rate-base eligible* capital investment" (emphasis added). Specifically, subsection (b)(1) imposes an obligation (until 2025) on affected utilities to reinvest a portion (50%) of that incremental utility operating income in "rate-base eligible" infrastructure to support reliability, while subsection (b)(2) makes clear there are no corresponding restrictions on the rest of the "differential," which a utility is free to use for "general corporate purposes."

[6] Pennsylvania House of Representatives Consumer Affairs Committee, Public Hearing In Re: House Bill 1436 (Sept. 29, 2015), Transcript at page 5, lines 3-4, and page 9, lines 11-14.

55. Q. Has the Company calculated the "differential" between making and not making a CTA in this case?

A. Yes, it has. That differential is $917,000, as shown on PECO Exhibt BSY-1, Schedule D-18, page 3.

56. Q. Has the Company explained how it will use the 50% of the "differential" to comply with Section 1301.1(a)?

A. Yes, 50% of the differential will be used to target reliability projects and other infrastructure improvements, as I explained in my direct testimony (PECO St. 3, p. 57).

57. Q. Has any witness proposed adjustments that that the witness claims is required by Section 1301.1?

A. Yes, Mr. Effron has proposed adjustments to reduce the Company's plant in service and CWC to reflect 100% of the "differential" calculated pursuant to Section 1301.1(b). Thus, Mr. Effron proposes to reduce the Company's rate base by the entire amount ($917,000) of the "differential."

58. Q. Why does Mr. Effron proposed to deduct 100% of the "differential" from the Company's rate base?

A. Mr. Effron contends that the entire differential represents "ratepayer supplied funds" (OCA St. 1, p. 19). Therefore, 50% of the differential that Section 1301.1(b)(1) directs be "used for" infrastructure and to increase reliability he proposes to deduct from PECO's utility plant in service, as if it were a contribution in aid of construction ("CIAC"). He also claims that the portion of the differential Section 1301.1(b)(2) states may be used for "general corporate purposes" should be deducted from CWC as funds provided by customers to offset operating expenses.

59. Q. Is there anything in Section 1301.1 that states the "differential" should be treated as "ratepayer supplied funds?"

A. There is none that I can discern. In fact, Section 1301.1(b) states that the "differential accrues to a public utility." That language does not appear to me to be consistent with the differential being anything other than what it is – funds that belong to a utility and that, when invested, produces rate base a utility entitled to a return on and a return of – like any other investment. In fact, Section 1301.1(b)(1) specifically states that the investment is "rate-base eligible." Mr. Effron proposal would, in effect, convert the Company's investment from "rate-base eligible" to rate-base excluded property.

60. Q. Is there any basis for Mr. Effron's contention that the "differential" should be regarded as "ratepayer supplied funds?"

A. No, there is not. There are several fundamental conceptual errors in Mr. Effron's position.

First, notwithstanding Section 1301.1(a), Mr. Effron seems to assume that the arguments for a CTA – which the Legislature rejected by enacting Act 40 – have some continuing validity and, therefore, should control the way the Commission implements Act 40 in this case. This is illustrated by his assertion (p. 19) that the “differential” represents “ratepayer supplied funds.” It would appear that those arguments were invalidated by the passage of Act 40.

Second, and related to the prior point, it appears that Mr. Effron (and the OCA) refuse to acknowledge what the Legislature said it was doing by enacting Act 40. Specifically, Act 40 eliminates the use of CTAs in setting base rates in order to assure that a utility’s income tax expense for ratemaking is not reduced by the tax attributes of separate, affiliated companies, none of whose costs or investments are borne by the utilities’ customers.

Third, Mr. Effron’s approach would improperly blend the separate subsections of Section 1301.1. As I explained previously, Section 1301.1(a) deals with ratemaking, while Section 1301.1(b), which only addresses “uses,” specifies how a portion of the funds freed-up by subsection (a) must be reinvested until the end of 2025. The implicit assumption underlying the OCA’s interpretation is that Section 1301.1(b) requires the Commission to treat the “differential” as if it were a contribution to capital – similar to CIAC – and, therefore, it should be deducted from the utility’s rate base. Mr. Effron’s approach is wrong on several levels. As explained before, subsection (a) is the ratemaking provision of Section 1301.1. It says nothing about deducting any part of the "differential" from rate base. Subsection (b), in turn, deals with the “uses” of the differential and embodies the Legislature’s directive that fifty percent of those funds is to be invested in vital infrastructure and reliability – while the other fifty percent has no such strings attached to its uses. Subsection (b) does not even purport to address any ratemaking issue. And, as I discussed previously, there is nothing in either subsection (a) or (b) that mentions a deduction from rate base or treating the "differential" like CIAC. To the contrary, Section 1301.1(b)(1) says that the required investment must be "rate-base eligible."

Fourth, Mr. Effron's proposed adjustments would simply substitute one form of CTA for another. In that regard, I would note that, while this Commission has used the Modified Effective Tax Rate Method to calculate CTAs for Pennsylvania utilities, the very few commissions that still recognize CTAs have used other methods. In particular, the method historically used by the New Jersey Board of Public Utilities ("BPU") aggregated annual CTAs and deducted the aggregate amount from utilities' rate bases. This is fundamentally the very same thing Mr. Effron is recommending in this case. In fact, because of relatively recent changes in how the BPU calculates CTAs,[7] Mr. Effron's proposal would produce even larger rate base reductions than the method the BPU now employs, even though the BPU is deliberately making a CTA. Act 40 was enacted to separate Pennsylvania from the small and declining number of jurisdictions that use some form of CTA for utility ratemaking. Applying Act 40 as Mr. Effron recommends would be contrary to that purpose; it would improperly substitute one form of CTA for another.

[7] Significantly, the BPU realized the approach it has used in the past was deeply flawed and made substantial revisions to curtail CTAs by limiting the historic look-back period to only five years and allowing only 25% of the calculated CTA to be used as a rate base deduction. *In the Matter of the Board's Review of the Applicability and Calculation of a Consolidated Tax Adjustment, Order Modifying the Board's Current Consolidated Adjustment Policy*, Docket No. EO1212772 (Order entered October 22, 2014).

F. Leap-Year Revenue Normalization

61. Q. Please describe the leap-year normalization adjustment PECO made to its forecasted revenues.

A. One year in every four-year cycle has 366 days. Consequently, over a four-year period, the average number of days per year is 365.25 [(365x3+366)/4]. Consequently, PECO normalized 2019 sales by adding 0.25 days to reflect the average number of days over a four-year cycle. This adjustment works in customers' favor by increasing pro forma test year revenue at present rates by $479,000.

62. Q. Has any party contested the manner in which PECO normalized 2019 revenues to reflect the normalized number of days per year over a four-year cycle?

A. Only OCA witness Effron disagrees with the Company's approach. He has proposed reducing the Company's pro forma revenues at present rates by $479,000 to eliminate the leap-year normalization adjustment.

63. Q. What is the alleged basis for Mr. Effron's proposed adjustment?

A. Mr. Effron does not disagree with the facts or the logic underlying the Company's normalization adjustment. He nonetheless recommends rejecting the normalization adjustment because: (1) PECO's normalization adjustment of 0.25 days is a refinement that is not customarily made in rate case presentations; and (2) PECO did not adjust its operating expenses to also reflect an additional 0.25 days of expense.

64. Q. Do you agree with Mr. Effron's contentions.

A. No, I do not. Since the adjustment to normalize revenues to reflect the number of days-per-year over a four-year cycle provides a more accurate depiction of sales revenue, it is appropriate to make that adjustment whether or not it is "customary." Moreover, the only category of operating expenses that might be subject to a similar normalizing adjustment is salary and wages, which are a function of the number of work-days in a calendar year period. However, the number of non-weekend days in 2019 are the same as the average number of non-weekend days for the period 2019 to 2022. Consequently, there would not be any material basis for attempting to normalize operating expenses in the same fashion as revenues.

G. Salary And Wage Expense – January And March 2020 Wage Increase

65. Q. Other than the adjustment to eliminate the annualization of salary and wage expense to reflect only "average" salaries and wages for the FPFTY, did any party propose any other adjustments to salary and wage expense?

A. Yes, as part of their reversal of the annualization of FPFTY salary and wage increase, Mr. Zalesky on behalf of I&E (I&E St. 4, p. 9) and Mr. Effron (OCA St. 1, p. 24) proposed to eliminate in their entirety the wage increases that are projected to become effective in January and March 2020 by making an adjustment to reduce salary and wage expense by $3.55 million.

66. Q. Should the proposed adjustments be approved?

A. No, they should not. The increase in January 2020 is for a wage rate increase expected to take place under a collective bargaining agreement with PECO's unionized workers, as I explained in my direct testimony (PECO St. 3, p. 44). PECO has included a 2.5% increase that is called for by the collective bargaining agreement with its unionized employees. The increase in March 2020 is for a wage rate increase for non-unionized workers, and PECO has tracked the same reasonable 2.5% increase for this group as well, as I also explained in my direct testimony. It is certain that some level of increase will occur in January and March 2020, and the proposed increases that have been reflected in PECO's pro forma operating expenses are reasonable. The argument advanced by Mr. Zalesky and Mr. Effron that these increases should be ignored simply because they will occur shortly after the end of the FPFTY should also be rejected because it ignores the fact that the rates established in this case will remain in effect for longer than one year. In fact, PECO has proposed normalizing rate case expense over three years (PECO St. 3, p. 46), and I&E purposes a four-year normalization. It is entirely appropriate to reflect the January and March 2020 wage rate increases in the Company's operating expenses in this case where: (1) it is certain that wage increases will occur; (2) the level of those increases reflected in the development of the Company's pro forma wage expense is clearly reasonable; (3) the increases will become effective shortly after the end of the FPFTY; and (4) the rates established in this case will remain in effect for well into, and beyond, 2020.

H. Uncollectible Accounts Expense

67. Q. How did the Company calculate general uncollectible accounts expense in this case?

A. The Company calculated general uncollectible accounts expense (that is, uncollectible accounts expense excluding pre-program arrearages and in-program arrearages associated with its Customer Assistance Program (“CAP”)) by first calculating net-uncollectible accounts written-off as a percentage of total tariff revenue based on a three-year average of such write-offs and a three-year average of associated annual tariff revenues, as shown on PECO Exhibit BSY-1, Schedule D-10. The result of that calculation – 0.89% – was applied to pro forma revenues at present rates for the FPFTY to calculate the general pro forma uncollectible accounts expense of $28.6 million shown in Schedule D-10 of PECO Exhibit BSY-1. This is the same method that has been used by PECO to calculate its uncollectible accounts expense in its 2015 and 2010 base rate cases.

68. Q. Has any party proposed an adjustment to the Company’s claim for uncollectible accounts expense?

A. OCA witness Effron has proposed an adjustment to reduce the Company’s claim by $3.362 million (OCA St. 1, p. 29).

69. Q. What is the alleged basis for Mr. Effron’s adjustment?

A. Mr. Effron has proposed to remove data for one of the years in the Company’s three-year average. In other words, he is basing his calculation on only two data points, which correspond to the two most recent years' experience – 2016 and 2017. Mr. Effron contends that the net charge-offs for 2015 were not "normal" (OCA St. 1, p. 28) and, therefore, data for any year prior to 2016 should be ignored in calculating the "average" used to determine pro forma uncollectible accounts expense for the FPFTY. Mr. Effron based his characterization of 2015 as not "normal" on a Company interrogatory response explaining that a larger number of higher-balance accounts were written-off in 2014 and 2015 than in 2016 or 2017 (OCA St. 1, pp. 27-28).

70. Q. Do you agree with Mr. Effron's proposal to base pro forma uncollectible accounts expense solely on two data points – for 2016 and 2017?

A. No, I do not. As I previously mentioned, the Company has used a three-year average to calculate uncollectible accounts expense in prior cases. Mr. Effron proposes to employ only two data points in this case, which is a small sample and does not provide any assurance that the peaks and valleys that inherently occur in the level of charge-offs from year-to-year are properly reflected in the calculation. Although the Company did charge-off a higher level of high-balance accounts in 2014 and 2015, which increased its charge-off percentages in those years, the development of high-balance arrearages and their eventual write-off can, and historically has, occurred in cycles, which exhibit peaks and valleys in the charge-offs and the attendant charge-off percentages. The Company has consistently used a three-year average of charge-offs to smooth out peaks and valleys. And, in its last case, based its claim on an average for the years 2012-2014.

Selecting a narrow, two-data-point set, as Mr. Effron proposes, fails to capture the range of variations that occur in the level of charge-offs. In fact, during the eleven-year period from 2007 through 2017, PECO has experienced general charge-off percentages as high as 1.94% and as low as 0.91%. In that regard, I would note that general charge-offs for 2013 and 2012 – the two years prior to those (2014-2015) when PECO wrote-off a larger percentage of higher-balance accounts – produced charge-off percentages of 1.11% and 1.14%, respectively. Both of those values are higher than the 1.10% experienced in 2015. The 2012 and 2013 data also show why it is important to use a data base that captures the variability in charge-offs, which can be higher or lower from year-to-year for a number of reasons. Therefore. including data for 2015 as one additional data point in calculating the average provides a more appropriate representation of PECO's charge-off percentage than restricting the calculation to only the two most recent data points, as Mr. Effron proposes.

I. Storm Expense Normalization

71. Q. How did the Company develop its claim for normalized storm expense?

A. The Company used a sixty-month average, reflecting the five annual periods ending March 31, 2018, and adjusting storm expense for inflation, as I explained in my direct testimony (PECO St. 3, p. 49). As shown on PECO Exhibit BSY-1, Schedule D-13, the Company's claim as set forth in its filing on March 29, 2018, totaled $43.83 million.

The five-year period ending March 31, 2018 includes the costs PECO incurred for two major winter storms that the U.S. Weather Service named “Riley” and “Quinn.” Those storms occurred back-to-back on March 2 and 6, 2018 and represented the third-largest storm event in the Company’s history. The size and impact of these back-to-back storms is explained in more detail by Mr. Barnett in PECO Statement No. 2-R.

In the Company’s March 29, 2018 rate filing, the costs incurred in the first quarter of 2018 that were used in the sixty-month average included costs for winter storms Riley and Quinn totaling $68 million. Those costs consisted of a mixture of actual and estimated data because not all expenses incurred for the two large March storms had been finally determined at that time. The Company now has the final actual cost for all storms in the first quarter of 2018, which is $55.88 million or approximately $12.12 million less than the amount reflected in PECO Exhibit BSY-1, Schedule D-13. The Company provided its actual costs for the March 2018 storms in its revised response to OCA Interrogatory III-52. The actual cost data are also explained in more detail in Mr. Barnett’s rebuttal testimony (PECO St. 2-R).

Based on the availability of actual cost data, the Company has revised its claim for normalized storm expense from $43.83 million to $41.29 million (PECO Exhibit BSY-5, Schedule D-13), and the revised amount is reflected in the revised revenue requirement claim set forth in PECO Exhibit BSY-5, as I previously explained in Section II, above.

72. Q. Have any parties proposed adjustments to the Company's claim?

A. Yes, adjustments to the Company's claim for normalized storm expense were proposed by Ms. Wilson, on behalf of I&E, and Mr. Effron, on behalf of the OCA.

73. Q. Please address the adjustment proposed by Ms. Wilson.

A. Ms. Wilson proposed an adjustment to reduce the Company's original claim ($43.83 million) by $14.32 million, to $29.50 million (I&E St. 1, p. 14). Based on the Company's revised claim for normalized storm damage expense ($41.29 million), Ms. Wilson's adjustment would represent a reduction of $11.79 million.

74. Q. What is the basis for Ms. Wilson's proposed adjustment?

A. Ms. Wilson proposed that the Company's sixty-month average should consist of the five calendar years ending December 31, 2017. Her calculation would remove data for the first quarter of 2018, which includes the costs of winter storms Riley and Quinn. Ms. Wilson explained that she calculated the average based on five calendar years "because the Company has not provided actual expenses associated with the first three months of 2018 (which are likely to become available during the course of this instant proceeding) . . .". (I&E St. 1, p. 14)

75. Q. Has the Company now addressed the concern expressed by Ms. Wilson and provided the actual cost data for the first quarter of 2018 that she referenced in her testimony?

A. Yes, it has, and the Company has also revised its claim for normalized storm expense, as I explained in my response to Question No. 71. Therefore, I believe that Ms. Wilson's concern has been addressed and, therefore, there is no longer any basis for her proposed adjustment.

76. Q. Ms. Wilson also stated that the Company referred to a "storm reserve" account in portions of its supporting data, and she questioned whether the Company could create and maintain a "reserve" account absent approval from the Commission (I&E St. 1, p. 15). Please respond to Ms. Wilson's concerns.

A. The Company does not have a "reserve" account for storm expense. In responses to certain Commission filing requirements, the Company presented data that showed budgeted and actual storm expense separated into categories, one of which was referenced as "storm reserve." However, the Company uses that term in a non-technical sense to refer to storm costs above a baseline level. It is simply an internal budgeting tool that is used to separately identify costs associated with larger storms that exceed baseline levels. The Company does not use reserve accounting for storm costs.

77. Q. What is the adjustment Mr. Effron has proposed to the Company's claim for normalized storm expense?

A. Mr. Effron has proposed an adjustment of $14.5 million to the Company's original claim of $43.83 million for normalized storm expense and, therefore, would allow normalized storm expense of $29.3 million (OCA St. 1, p. 32). Based on the Company's revised claim for normalized storm damage expense ($41.29 million), Mr. Effron's adjustment would represent a reduction of $12 million.

78. Q. What is the basis for Mr. Effron's proposed adjustment?

A. Mr. Effron contends that because the Company used a five-year average consisting of five calendar years in its last two base rate cases, it should not be permitted to use five years beginning April 1, 2013 and ending March 31, 2018 in this case, notwithstanding the extraordinary circumstances presented by the two major back-to-back winter storms that occurred on March 2 and 6, 2018. In short, Mr. Effron contends that because a five-calendar-year average was used in the Company's two prior base rate cases, any variation in the five-year period is impermissible regardless of the surrounding circumstances that might justify the small variation in the end-point that PECO has used in this case.

79. Q. Did PECO experience any majors storm events in the first quarter of 2010 or the first quarter of 2015?

A. No, it did not. That is the point. It would have made little difference to the calculation of the five-year averages in the Company's 2010 and 2015 cases if five-year periods ending March 31, 2010 or March 31, 2015 had been used, respectively, in those cases. The Company employed five calendar years in those case because they provide five annual periods of historical data and because there were no extraordinary weather events in the first quarter of 2010 and 2015 that would have justified using a more current sixty-month period. If the Company had experienced extraordinary storm events in the first quarter of 2010 or the first quarter of 2015, it would have had a sound basis for advancing the five-year average by one quarter, and would have done so in order to reflect that current experience. Consequently, the fact that five calendar years were used for the five-year average in the Company's two prior cases has no relevance to the reasonableness of the sixty-month experience band that the Company is using in this case.

80. Q. Mr. Effron also contends that, in addition to excluding the March 2018 actual costs from the Company's five-year historical average, the Commission should, in this case, preclude the Company from petitioning to defer the March 2018 storm costs. Please respond to this contention.

A. At the outset, the Company's actual storm experience for the first quarter of 2018 should not be excluded from the calculation of normalized storm expense. Those events occurred during the future test year in this case, and the actual costs incurred for those events are now known. Including that actual experience in the five-year average assures that all relevant data are included in the calculation of normalized storm costs. Mr. Effron's contention that, if the Commission accepts his adjustment, it should also prohibit the Company from petitioning to defer the March 2018 storm costs should also be rejected. This point is addressed by Mr. Barnett. However, it should be noted that, in addition to asking the Commission to issue a hypothetical ruling on something that has not yet occurred, Mr. Effron's positions are internally inconsistent. On the one hand, he proposed to exclude first quarter 2018 cost data from the five-year average of normalized storm costs because that period includes the cost of the extraordinary winter storms Riley and Quinn,[8] while, on the other hand, he opposes deferral of those costs notwithstanding that deferral is permitted – and, in fact, is predicated upon – the events giving rise to deferred costs being extraordinary and non-recurring. Mr. Effron is simply making proposals to foreclose the recognition of the costs of the March 2018 storms in this case, which is entirely unreasonable for the reasons I previously explained.

81. Q. Mr. Effron also contends that the Company has actually recovered in its base rates more than its actual storm expense. Is that correct?

A. Absolutely not. Mr. Effron presents that conclusion based on cherry-picking his data set to achieve a pre-determined result. He simply restricts his experience band to the two years since the Company's last base rate case (2016-2017). As Mr. Effron has acknowledged, the Company has been using a five-year historical average to calculate normalized storm expense since its 2010 case (OCA St. 1, pp. 29-30). Nonetheless, Mr. Effron has ignored the Company's experience for the period from 2011 (rates established in PECO's 2010 case became effective January 1, 2011) through June 2018 (the last date for which data are available). As explained by Mr. Barnett (PECO St. 2-R), over that entire period, PECO has incurred storm costs that

[8] There would be no reason for Mr. Effron to challenge the modest three-month shift in the five-year historical periods between this case and the Company's 2010 and 2015 cases but for the fact that the last quarter of the five-year period used in this case includes the effects of two major storm events.

exceed the amounts it claimed for recovery in rates by approximately $70 million. Consequently, there is no basis in fact for Mr. Effron's assertion that PECO has somehow already been compensated for the costs of the major storms that swept across its service territory in March 2018.

J. Rate Case Expense Normalization

82. Q. Has any party proposed an adjustment to the Company claim for normalized rate case expense?

A. Yes, I&E witness John Zalesky has proposed an adjustment to reduce the Company's claim for normalized rate case expense by $217,000. Mr. Zalesky's adjustment is based on his proposal that a normalization period of four years should be used in lieu of the three-year normalization period the Company employed (I&E St. 4, pp. 4-5). Mr. Zalesky based his proposed four-year normalization period on an average of the historical intervals between the filing of the Company's 2010 and 2015 rate cases (60 months) and between its 2015 and current base rate cases (36 months) (I&E St. 4, p. 5).

83. Q. Is it reasonable to impose a five-year normalization period?

A. No, it is not. Mr. Zalesky has included in his average the five-year interval between PECO's 2010 and 2015 rate cases. The current case was filed three years after PECO's 2015 rate case, and PECO projects that it will need to file another case in three years, which formed the basis for the three-year normalization period the Company used in this case. Assuming a longer filing interval, as Mr. Zalesky does, is totally at odds with Mr. Barnett's testimony (PECO St. 2, p. 5) that PECO needs to invest nearly $2.5 billion in new electric distribution plant and equipment over the 2018-2022 period. With that level of investment and even marginal year-over-year increases in operating and maintenance expenses, it is not reasonable to assume that PECO could delay a subsequent base rate filing for four years.

Additionally, Mr. Zalesky's reliance on historical rate case filing intervals to dictate the normalization period to be used in this case is contrary to the Commission's most recent statement of its policy and practice on this issue. In its final order in PPL Electric Utilities Corporation's ("PPL") 2012 base rate case, the Commission made it clear that rate case normalization periods should not be backward looking, as Mr. Zalesky proposes, but, instead, should reflect "future expectations." In that case, the Commission stated: "As previously discussed, this proceeding is premised upon a FTY and, based on that criterion, certain expenses may be now based on future expectations. We believe the normalization period for rate case expense is one of those expenses."[9] The Company's proposed three-year normalization period for rate case expense is consistent with the Commission's decision in PPL's 2012 base rate case.

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[9] *Pa. P.U.C. v. PPL Electric Utilities Corporation*, Docket No. R-2012-2290597 (Final Order entered December 28, 2012), pp. 47-48.

K. Income Taxes – Effects Of The Tax Cuts and Jobs Act ("TCJA")

84. Q. Please address OCA witness Effron's direct testimony regarding the Company's calculation of TCJA tax savings ($68 million) for 2018 that it proposes to credit to customers through a Federal Tax Adjustment Credit ("FTAC").

A. Mr. Effron has reviewed PECO Exhibit BSY-5 and accepts the Company's calculation of the TCJA tax savings PECO proposed to credit to customers through its FTAC. Mr. Effron's had suggested, however, that the Company consider providng "a one or two-month credit" to customers in 2018.

85. Q. Please address Mr. Effron's suggestion to consider starting the FTAC during November or December 2018.

A. The Company continues to believe that it is more appropriate to start the FTAC on the same date new base rates established in this case become effective, so that the FTAC application period will be coextensive with the first full year that new rates are in effect.

86. Q. Please address PAIEUG witness Jeffry Pollock's direct testimony regarding the amortization of "excess" ADIT that PECO has recorded in a regulatory liability account (PAIEUG St. 1, p. 13-14).

A. This issue relates to the flow-back to customers of the deferred taxes that were recorded as ADIT when the corporate tax rate was 35% (i.e., prior to January 1, 2018). The difference between the ADIT recorded at a 35% tax rate and the amount of ADIT that would have been recorded at a tax rate of 21% is considered "excess" ADIT.

If nothing were done to recognize that "excess," it would still flow back to customers as the ADIT "reverses" over time (that is, when book costs catch up with the amount of such costs that were deducted for income tax purposes in prior years). However, the flow-back period would be longer because the ADIT would have been recorded at a 35% tax rate but the "reversal" would reflect the 21% tax rate used to calculate the amounts returned to customers. For that reason, the "excess" ADIT has been identified and recorded as a regulatory liability.

In order to comply with the normalization requirements of the Internal Revenue Code, ADIT reflecting tax-book timing differences subject normalization will be returned to customers using the Average Rate Assumption Method or "ARAM," which is designed to approximate the life of the underlying assets. However, for ADIT related to property that is not subject to a normalization requirement, the flow-back period is not dictated by the tax law and regulations. PECO has proposed to flow-back the excess "unprotected" ADIT over five years, which is the same period the Commission used to flow-back unprotected excess ADIT when corporate tax rates were reduce pursuant to the Tax Reform Act of 1986 ("TRA 86").

Mr. Pollock contends that the flow-back period for unprotected ADIT should occur over one year as part of the credit under the FTAC or, if that period is unacceptably short, the flow-back should occur in base rates over a period not to exceed four years (PAIEUG St. 1, p. 14).

87. Q. Do you agree with Mr. Pollock's recommendation?

A. No, I do not. Five years is a reasonable amortization period. Although Mr. Pollock tries to minimize the validity of the five-year amortization period the Commission approved to flow-back excess ADIT created by TRA 86, he cannot point to any substantive change in facts and circumstances that make the Commission's prior decision inapplicable or unreasonable. Moreover, the build-up of excess ADIT occurred over periods longer than one-year. Therefore, flowing excess ADIT back over a period as short as one-year does not match the period over which the costs originated. Moreover, both I&E and the OCA have reviewed the Company's proposed flow-back period for unprotected ADIT and do not disagree with the Company's approach. With regard to Mr. Pollock's alternative proposal, it is noteworthy that the Commission specifically rejected intervenors' proposal to amortize excess ADIT created by the TRA-86 tax rate reductions over four years and, instead, selected five years as the appropriate amortization period. Accordingly, Mr. Pollock's proposals should be rejected.

L. Quarterly Earnings Report

88. Q. Please describe the issue pertaining to PECO's Quarterly Earnings Report ("QER") for the twelve months ended September 30, 2017 that was raised by Mr. Kubas.

A. In its QER for the twelve months ended September 30, 2017, PECO presented its "actual per books" (unadjusted) financial results of operation as well as the financial results of operation adjusted on a ratemaking basis to reflect several customary ratemaking adjustment, including levels of plant investment that would correspond to plant additions for a FTY and FPFTY. This is clearly shown in PECO's QER, which was provided as I&E Exhibit 3, Schedule 12.

Mr. Kubas does not have a problem with the actual results of operation that PECO reported for the twelve months ended September 20, 2017. In fact, those data were available for the Commission and the public to review, and the Commission's Bureau of Technical Utility Service ("TUS") reflected PECO's actual results (including its rate of return on equity) in its *Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended September 20, 2017* (Attachment A), which was issued on January 18, 2018 ("TUS Report") . Rather, Mr. Kubas takes issue with the "adjusted" results of operations that PECO reported for that period. Specifically, Mr. Kubas contends that plant additions reflective of Company investment in periods that would generally correspond to a FTY or FPFTY should not be incorporated in the ratemaking adjustments used to present the "adjusted" results of operations.

89. Q. What does Mr. Kubas contend is the basis for his recommendation?

A. Mr. Kubas contends that incorporating ratemaking adjustments to reflect plant investment during periods corresponding to a FTY or FPFTY: (1) are not authorized by the Commission's regulations at 52 Pa. Code Chapter 71 prescribing the rules for presenting "adjusted" results of operations in QERs; (2) unjustifiably (in his opinion) reduces a utility's overall and equity return rates reflected by the adjusted results of operations; (3) are based on "projections" of future plant additions and not "verifiable current data;" (4) do not provide an accurate picture of the utility's "current financial position;" and (5) make it difficult to compare results across utilities because some companies incorporate future plant investment and others do not (I&E St. 3, pp. 61-65). Mr. Kubas also contends that including future plant investment in the calculation of "adjusted" financial results of operations depresses the rate of return on equity reflected for the applicable period, which could allow a utility to "continue collecting a DSIC from customers" even though its equity return rate calculated without such adjustments may be above the "cap" imposed by Section 1358(b)(3) (I&E St. 1, pp. 60-61).

90. Q. Please respond to Mr. Kubas' contentions.

A. Initially, it is important to reiterate the point I made earlier, in its QER for the twelve months ended September 30, 2017, PECO provided, in addition to its adjusted results of operations, its "actual per books" (unadjusted) results of operations. Far from trying to conceal its actual equity return rate, it is plainly shown in Attachment A to the publicly-available TUS Report. Consequently, all of Mr. Kubas's contentions that, it seems, assume that PECO's (and other utilities') actual results of operations are not provided in their QERs along with "adjusted" results are somewhat misleading. The Commission has all the data it needs to review and compare utilities' "actual per books" results of operations; those data are simply augmented by the "adjusted" data that are also provided.

Additionally, Mr. Kubas's speculation that PECO is "collecting a DSIC from customers" based on the QER as of September 30, 2017 is inapplicable. While

PECO has an approved DSIC Rider, it was not charging a DSIC in September 30, 2017 (or as of December 31, 2017, for that matter).

91. Q. Would Mr. Kubas's recommendations regarding what he believes should be permissible ratemaking adjustments to the QERs have any impact on the revenue requirement in this case?

A. No, it would not, and Mr. Kubas agreed that they would not in his response to the Company's Interrogatory PECO-I&E-II-28 (PECO Exhibit BSY-9).

92. Q. Has Mr. Kubas made similar recommendations in any other base rate case?

A. Yes, he made the same recommendations in the UGI Electric Division base rate case at Docket No. R-2017-2640058. I understand UGI moved to strike Mr. Kubas's testimony on that subject on the grounds that it raised issues that were not properly presented in a base rate case and should be raised either in a proceeding on a particular utility's QER filing or, because the issue is generic to all utilities' QERs, in an industry-wide, generic proceeding. The presiding Administrative Law Judges denied UGI's Motion in an Order entered on June 25, 2018 at Docket No. R-2017-2640058. In that Order (p. 4), the Judges stated as follows:

> We will deny UGI's motion and allow Mr. Kubas's testimony to remain a part of the evidentiary record. We believe that, in the most general sense, there may be some relevance in reviewing the claims made by UGI in past QER filings while investigating and evaluating the company's claims of projected future earnings in this proceeding. We will, therefore, admit Mr. Kubas's testimony into the evidentiary record. We tend to agree with UGI, however, that any Commission decision on Mr. Kubas's ultimate recommendation, that no projected plant additions should be included in future QERs, would have no impact on either the amount of increase granted in this proceeding,

> or on the allocation or rate design of that increase. We also tend to agree with UGI that a determination on Mr. Kubas's recommendation would be more appropriately made in the context of a QER filing proceeding or an industry-wide proceeding, where all utilities that may be affected by resolution of this issue would have an opportunity to participate. Accordingly, although we are denying UGI's motion to strike, we retain the right to decide what evidentiary weight, if any, to assign to any testimony in general or Mr. Kubas's testimony in particular.

93. Q. What is PECO's position in this case regarding Mr. Kubas's recommendations?

A. Mr. Kubas's recommendations should properly be considered outside of a base rate case. Because his recommendations relate to issues that affect the rules for QERs filed by all utilities that are subject to the QER requirement, they are more appropriately considered in a proceeding relating to QERs filing requirements and, in particular, an industry-wide proceeding where all potentially-affected parties would have the opportunity to provide input. Furthermore, because the UGI Electric Division case is being litigated, a decision will likely be made by the Commission on Mr. Kubas's recommendations in that case before this case is decided.

IV. CONCLUSION

94. Q. Does this complete your rebuttal testimony?

A. Yes, it does.