R-2020-3018929
2/17/21 JK

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018929
	:	
PECO Energy Company – Gas Division	:	

LIST OF WITNESS STATEMENTS AND EXHIBITS OF THE OFFICE OF CONSUMER ADVOCATE

Please see the following list of Testimony and Exhibits that the Office of Consumer Advocate will seek to admit into the evidentiary record in the above-captioned proceeding:

I. DIRECT TESTIMONY

a. OCA Statement 1, The Direct Testimony of Scott J. Rubin, which includes an Appendix A, Schedules SJR-1 through SJR-6, and a signed verification;

b. OCA Statement 2, The Direct Testimony of Lafayette K. Morgan (Confidential and Public Version), which includes Schedules LKM-1 through LKM-30, Appendices A and B, and a signed verification;

c. OCA Statement 3, The Direct Testimony of Kevin W. O'Donnell, which includes an Appendix A, Exhibits KWO-1 through KWO-8, and a signed verification;

d. OCA Statement 4, The Direct Testimony of Glenn A. Watkins (Confidential and Public Versions), which includes Schedules GAW-1 through GAW-4 and a signed verification;

e. OCA Statement 5, The Direct Testimony of Roger D. Colton, which includes Schedule RDC-1, Appendix A, and a signed verification.

f. OCA Statement 6, The Direct Testimony of Geoffrey C. Crandall, which includes Schedules GCC-1 through GCC-9 and a signed verification.

II. REBUTTAL TESTIMONY

a. OCA Statement 3R, The Rebuttal Testimony of Kevin W. O'Donnell, which includes a signed verification;

b. OCA Statement 4R, The Rebuttal Testimony of Glenn A. Watkins, which includes Schedules GAW-1R through GAW-3R and a signed verification;

c. OCA Statement 5R, The Rebuttal Testimony of Roger D. Colton, which includes Schedule RDC-1R and a signed verification.

III. SURREBUTTAL TESTIMONY

a. OCA Statement 1-SR, The Surrebuttal Testimony of Scott J. Rubin, which includes Schedules SJR-7S through SJR-10S and a signed verification;

b. OCA Statement 2-SR, The Surrebuttal Testimony of Lafayette K. Morgan (Confidential and Public Version), which includes Schedules LKM-1 through LKM-31 and a signed verification;

c. OCA Statement 3-SR, The Surrebuttal Testimony of Kevin W. O'Donnell, which includes a signed verification;

d. OCA Statement 4-SR, The Surrebuttal Testimony of Glenn A. Watkins, which includes Schedules GAW-1SR through GAW-2SR and a signed verification;

e. OCA Statement 5-SR, The Surrebuttal Testimony of Roger D. Colton, which includes a signed verification.

f. OCA Statement 6-SR, The Surrebuttal Testimony of Geoffrey C. Crandall, which includes Schedules GCC-SR-1 through GCC-SR-6 and a signed verification.

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OCA Statement 1

R-2020-3018929
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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pa. Public Utility Commission	:	
	:	Docket No. R-2020-3018929
v.	:	
	:	
PECO Energy Co. – Gas Division		

Direct Testimony of
Scott J. Rubin

ON BEHALF OF
THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

December 22, 2020

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Introduction

Q. Please state your name and business address.

A. My name is Scott J. Rubin. My business address is 333 Oak Lane, Bloomsburg, PA 17815.

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

A. I am an independent consultant and an attorney. My practice is limited to matters affecting the public utility industry.

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

A. I have been asked by the Office of Consumer Advocate ("OCA") to provide an overview of this case from a public policy perspective, particularly in light of the COVID-19 pandemic affecting the world at this time. I also will introduce the OCA's other witnesses who will address various aspects of the rate request filed by PECO Energy Co. ("PECO" or "Company").

Q. What are your qualifications to provide this testimony in this case?

A. I have testified on more than 200 occasions as an expert witness before utility commissions or courts in the District of Columbia, the province of Nova Scotia, and the states of Alaska, Arizona, California, Connecticut, Delaware, Illinois, Kentucky, Maine, Maryland, Massachusetts, Minnesota, Mississippi, New Hampshire, New Jersey, New York, North Dakota, Ohio, Pennsylvania, South Carolina, Washington, and West Virginia. I also have testified as an expert witness before two committees of the U.S. House of Representatives and various state and local legislative committees. I also have served as a consultant to the staffs of four utility commissions, several national utility trade associations in the United States, and state and local governments throughout the United States. Prior to establishing my own consulting and law practice, I was employed by the OCA from 1983 through January 1994 in increasingly responsible positions. From 1990 until I left the OCA, I was one of two senior attorneys in that office. Among my other responsibilities in that position, I had a major role in setting the office's policy positions on water and electric matters. In addition, I was responsible for supervising the technical staff of the office. I also testified as an expert witness for the OCA on rate design, cost of service issues, and policy matters.

Throughout my career, I developed substantial expertise in matters relating to the economic regulation of public utilities. I have published articles, contributed to books, written speeches, and delivered numerous presentations relating to regulatory issues. I have attended numerous continuing education courses involving the utility industry. I also have participated as a faculty member in utility-related educational programs for the Institute for Public Utilities at Michigan State University, the American Water Works Association, and the Pennsylvania Bar Institute. My complete curriculum vitae is provided as Appendix A.

Q. Do you have any experience that is particularly relevant to the issues in this case?

A. Yes, I do. Over the years, I have testified concerning numerous types of regulatory policy issues before utility commissions and legislative committees. Obviously, before this year, I did not have experience recommending an appropriate regulatory response during a global pandemic, but I believe my more than 35 years of experience in utility regulation can provide some useful insights and recommendations. Recently, I submitted testimony on the same topic in several other rate proceedings, including three other gas distribution utilities operating in Pennsylvania (Columbia Gas, Philadelphia Gas Works, and UGI Utilities).

Q. Do you have any other preliminary matters to address?

A. Yes. My testimony deals with regulatory policy issues. Given the nature of public utility regulation, much of the public policy in this field is contained in decisions by regulatory agencies and courts; or in statutes, ordinances, or regulations. I may be citing or referring to these types of sources. This should not be taken as a legal opinion (though I am qualified to provide expert testimony as a regulatory attorney in Pennsylvania), but rather as sources supporting my expert opinion concerning appropriate public policy and regulatory practice.

Summary

Q. Please summarize your conclusions and recommendations.

A. I summarize my conclusions and recommendations as follows:

- As a consequence of the pandemic devastating the health and economy of the Commonwealth and the world, the Commission cannot rely on many of the assumptions made in PECO's filing. It also would not be just or reasonable to impose a rate increase on customers at this time.

- I recommend that the Commission deny any rate increase to PECO in this case.

Purpose of this Case

Q. What is your understanding of the purpose of this proceeding?

A. As I understand it, the purpose of this case is to determine the "just and reasonable" rates for PECO under Chapter 13, and other provisions, of the Public Utility Code.

Q. In your more than 35 years of experience with utility rate-setting, are there standards or criteria used to determine whether a rate is "just and reasonable"?

A. Yes. There are thousands of administrative and judicial decisions throughout the United States that interpret the phrase "just and reasonable" as it relates to utility rates. Without going into all of the nuances and jurisdictional differences that arise from those decisions, and without providing a legal opinion, I will provide my general understanding of how that phrase is used in the field of public utility ratemaking.

In general, we regulate the rates (and other terms of service) of public utilities because they are natural monopolies, meaning that it would be economically inefficient (more expensive) to have competing enterprises provide the service. It is often stated that regulation is a substitute for competitive market forces. At its core, regulation is designed to protect utility consumers from what otherwise would be the unfettered power of a monopoly to set prices and the conditions of service. In protecting consumers, however, regulators cannot confiscate the property of the utility's investors. That is, regulators cannot tilt the scale so far in favor of consumers (for example by providing free service) that the utility's investors are deprived of an opportunity to earn a reasonable return on their investment.

Importantly, though, regulation is not designed to insulate the utility or its investors from normal market forces, technological improvements, or general economic conditions. If market forces (such as technological change) result in significant reductions in the demand for service, then the utility may not be able to recover its costs. That is not a failure of regulation, but a natural evolution of the market -- businesses fail if they cannot keep up with changes in consumers' preferences or respond to technological innovations.

Similarly, if economic conditions change such that rates become unaffordable to many customers, rates may need to be reduced in order to remain "just and reasonable" from the perspective of customers.

Q. Is there a general framework in which to evaluate whether a rate is just and reasonable?

A. Yes, regulators, analysts, and courts often speak of a "zone of reasonableness." In setting rates, regulators should attempt to balance the interests of all relevant sectors of the public. This includes the utility's investors, the utility's officers and employees, the customers (recognizing that different customer classes also have different interests), and local governments whose residents are served by the utility. Ideally, rates should be set within a "zone of reasonableness" which represents a range within which all of the relevant interests intersect. To help explain the concept, I have provided Figure 1 which illustrates this zone of reasonableness as a simplified diagram, showing only consumers as a whole and investors.

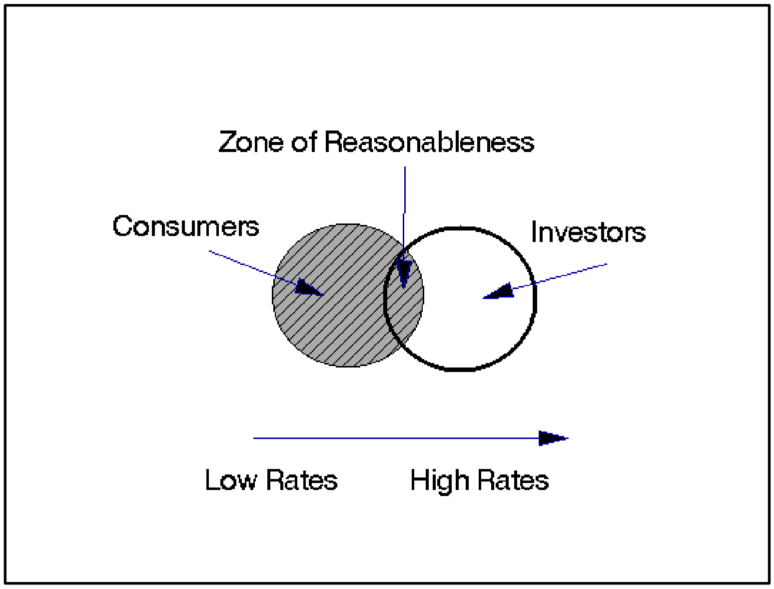

Figure 1. Traditional Zone of Reasonableness

In this example, which illustrates the situation in which rate regulators usually find themselves, there is an overlap between the interests of consumers and investors. That is, there is a range of rates that consumers are willing and able to pay (ranging from zero at the low end to a rate which is so high that they can no longer afford utility service) and a range of rates which will provide investors with what they consider to be a reasonable return on their investment (presumably ranging from something more than the risk-free rate of return up to a return well above that which the market provides to similar-risk investments). In this illustration, these two ranges overlap. This provides the regulator with a range within which it can set rates that still meet the needs of both consumers and investors. The size and relative position of the range may change, but we are used to having at least a partial convergence of these ranges.

It is possible, however, that the interests of investors and consumers might diverge. This divergence is illustrated in Figure 2.

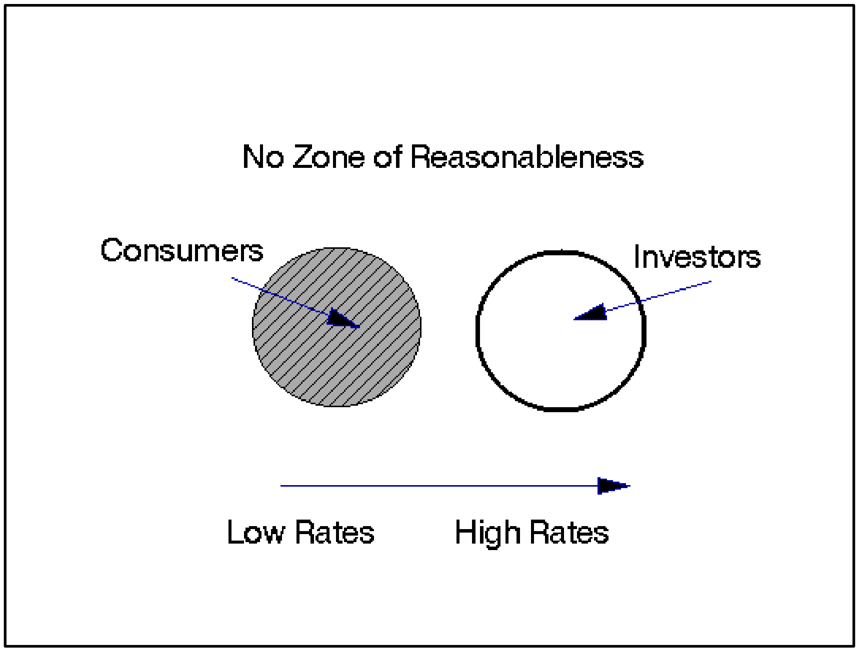

Figure 2. Divergent Interests: A Null Zone of Reasonableness

For example, if a utility is providing poor service (or a service which is becoming obsolete), the highest price which consumers are willing to pay may be very small, thereby falling below the low end of the investors' range. Similarly, if interest rates or the levels of investment become very high, investors' minimum return requirements may become so high as to fall above the range of rates which consumers can afford to pay. When this happens, the rate regulators may have to set rates which fall outside of the normal zone of reasonableness, but which still attempt to fairly balance the interests of all parties to the extent possible.

It also must be remembered that while these concepts can be easily illustrated using circles on a diagram, the real world is not so simple. There is no bright line delineating any of these interests. The regulator is forced to discern the relative interests of the parties from the arguments and evidence which are placed on the record.

Q. Are you saying that the Commission should not set rates outside the zone of reasonableness?

A. No, I am not saying that. In fact, in certain instances it may be impossible for the Commission to simultaneously satisfy all aspects of the public interest. As I view the role of rate regulators, they must act within the broad public interest. Sometimes, that may mean setting rates which fail to meet the needs of a certain segment of the public. I believe, however, that whenever it sets rates, the Commission must attempt to determine whose needs are being met and whose are not.

Q. Isn't that usually done in the traditional ratemaking process?

A. Unfortunately, it is not usually done. In most cases, the investors' interest becomes a central focus of the case, by attempting to determine the return on capital which investors require in order to continue to invest money in the utility. This is usually examined in great detail, with each side spending thousands of dollars on attorneys and expert witnesses skilled in the presentation of this subject. Very rarely, though, do regulators or parties place as much emphasis on attempting to define the consumers' interest.

Determining "Just and Reasonable" Rates at this Time

Q. You have testified on numerous occasions before this Commission. Do you always go into such detail about "just and reasonable" rates or the "zone of reasonableness"?

A. No. As best as I can recall, prior to this year, the only time I raised these issues in such detail before this Commission was in 1993 in a rate case involving Colony Water Company, Docket No. R-00922375. As I remember it, that utility was proposing extremely high rates that would be unaffordable for many of its customers. I recommended a ratemaking approach that would have set rates based on the rates charged by that small utility's water supplier, even though the rates would be below the traditional revenue requirement calculation for the utility.

Q. Why are you raising these concerns in this case?

A. PECO filed this case on September 30, 2020, when its service area -- indeed the entire world -- was being devastated with the worst pandemic in a century. While I understand that it takes months to prepare a rate filing, and that PECO prepared this case assuming "business as usual," there was nothing that compelled it to actually file the case. To state the obvious, life and business in the Company's service territory are now anything but normal.

I recognize that PECO delayed the filing of this case, presumably with an expectation that the pandemic would be nearing its end by the fall. Unfortunately, as I describe in more detail below, that is not the case. Tragically, during the past several weeks the pandemic has worsened significantly. Pennsylvania and the Company's service territory are experiencing a skyrocketing number of cases of COVID-19, the death toll is climbing,[1] hospitals through the region are nearing capacity,[2] and economic activity (especially in local shops and restaurants) is greatly diminished[3].

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[1] According to data from the PA Department of Health, during July, August, and September the counties in PECO's service area (Bucks, Chester, Delaware, Lancaster, and Montgomery) averaged fewer than three COVID deaths per day. From mid-November through December 14, the average death rate in the five-county area was more than 10 per day -- a more than three-fold increase. https://data.pa.gov/Health/COVID-19-Aggregate-Death-Data-Current-Daily-County/fbgu-sqgp.

[2] As of December 15, 2020, the Pa. Department of Health reports that in PECO's five-county service area, only about 20% of adult ICU beds are available. https://data.pa.gov/Health/COVID-19-Aggregate-Hospitalizations-Current-Daily-/kayn-sjhx/data.

[3] The U.S. Census Bureau reports that more than 78% of the small businesses in the Philadelphia metropolitan area have experienced moderate or large negative impacts from the pandemic, and that more than one-third of small

In particular, I am very concerned about the impact that significant rate increases would have on PECO's customers at this time. To be blunt, this is not the time to impose higher costs on either people or businesses.

If regulation is supposed to be a substitute for market forces, then we must recognize that, except for those commodities experiencing significant imbalances of supply and demand due to the pandemic, competitive businesses cannot sustainably raise prices when their customers' incomes have decreased significantly. During 2020, we have seen supply gluts of necessities such as gasoline, certain types of food, skyrocketing unemployment, and a significant reduction in hours for many people who are still employed. Simply stated, what may have been a "just and reasonable" rate earlier this year may be unreasonable today.

The Pandemic's Impact on People

Q. Can you be more specific about the impacts of the pandemic on people in the Company's service area and throughout Pennsylvania?

A. Yes, I can be more specific to some extent. Data on new statewide unemployment claims are released each week, but county-level data are released only monthly. Schedule SJR-1 shows the devastating effect the pandemic has had on unemployment in the Commonwealth.

The huge spike in unemployment claims during the weeks ending March 21 and March 28 coincides with the entry of the Governor's order of March 19 closing all dine-

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businesses in the region continue to experience decreased revenues. https://portal.census.gov/pulse/data/#weekly (Filter: MSA, 37980: Philadelphia-Camden-Wilmington; Survey Questions: Overall effect and Change in revenues).

in restaurants on that date and all non-life-sustaining businesses on March 21. To put these figures in perspective, according to the U.S. Census Bureau, Pennsylvania had a workforce of approximately 6,576,000 people in 2018.[4] In the past eight months, approximately 2.78 million Pennsylvanians have filed initial unemployment claims -- approximately 42% of Pennsylvania's workforce.

Q. Can you quantify the pandemic's impact on employment in PECO's service territory?

A. County-level unemployment data are published monthly in Pennsylvania. As I am preparing this testimony, the most recent information was published on December 1. The data are labeled for the month of October, but they are collected during the second week of each month. The number of initial unemployment claims per week has declined since mid-May, though initial claims remain at approximately twice the pre-pandemic level of initial unemployment claims.

Q. Can you estimate the effects on employment in the counties PECO serves?

A. Yes. Schedule SJR-2 shows the counties served (in whole or in part) by the Company and their unemployment rates as of mid-October. The rates range from 4.9% in Chester County to 7.2% in Delaware County.

Q. Generally, what effect has the pandemic had on families' finances?

A. The Federal Reserve System is attempting to measure the effects of the pandemic on household finances. On May 14, 2020, the Federal Reserve System released its annual

[4] U.S. Census Bureau, 2018 American Community Survey, Table S2301: Employment Status.

report on the economic well-being of households.[5] Most of the report is based on surveys conducted during 2019, but a supplemental survey was conducted in the first week of April 2020 to assess the impacts of the pandemic on household finances. I am attaching as Schedule SJR-3, the cover page and the portion of the report dealing with the April 2020 supplemental survey (pages 53-56 of the report).

The survey found that "20 percent of people who had been working in February reported that they lost a job or were furloughed in March or the beginning of April 2020."[6] Among lower-income households, however, the impact was even more severe. The report states: "Thirty-nine percent of people working in February with a household income below $40,000 reported a job loss in March."[7] Further, approximately 9 percent of people who were still working had their hours reduced or were required to take unpaid leave.[8]

Overall, "23 percent of adults said their income in March was lower than in February."[9] Of those who lost their job or had their hours reduced, only 64% said they would be able to pay all of their bills in full during April.[10] That is, more than one-third of the families that suffered a loss in income during March will not be able to pay all of their bills the following month.

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[5] Board of Governors of the Federal Reserve System, Report on the Economic Well-Being of U.S. Households in 2019, Featuring Supplemental Data from April 2020 (May 2020), https://www.federalreserve.gov/publications/files/2019-report-economic-well-being-us-households-202005.pdf.
[6] Schedule SJR-3, p. 2.
[7] Id.
[8] Id. The report states that 6% of all adults had their hours reduced. Given the number of all adults in the workforce, this would equate to approximately 9% of working adults.
[9] Id., p. 3.
[10] Id., pp. 3-4.

Data for Pennsylvania show an even more serious result. The U.S. Census Bureau conducted special weekly surveys of households from April 23 to the week ending July 21, known as the Household Pulse Survey. The Census Bureau restarted the survey on August 19, collecting data over two-week time periods (though they are still referred to as "weeks" in the reported data). In the first week (the end of April), 46.9% of Pennsylvania households reported a loss of at least some employment income since March 13. By the most recent two-week period reported (the period ending November 23), the percentage had remained fairly constant at about 46% of households, as shown in Figure 3.[11]

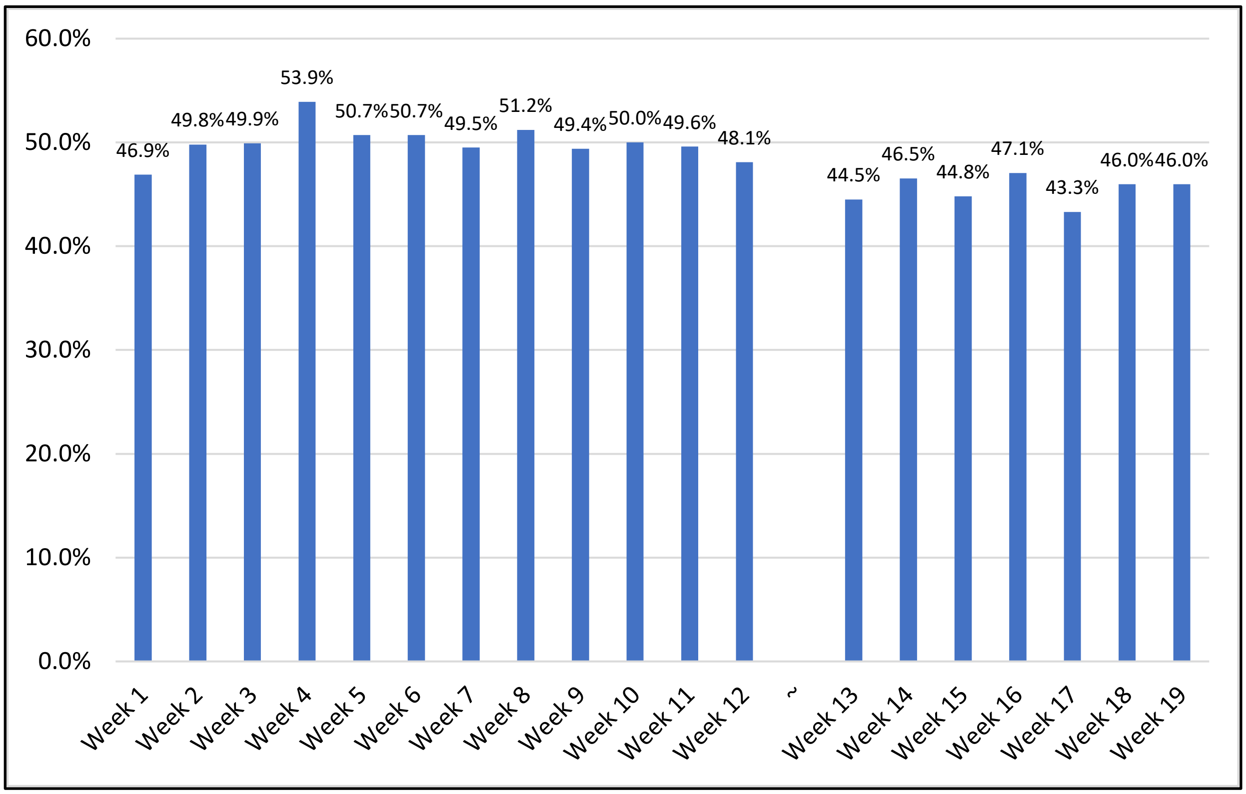

Figure 3. Percentage of Pennsylvania Households Experiencing

[11] U.S. Census Bureau, Household Pulse Survey, https://www.census.gov/data-tools/demo/hhp/#/table.

Loss in Employment Income Since March 13 (week 1 begins April 23)

Q. Does the Census Bureau's Household Pulse Survey contain other information that helps to define the scope of the pandemic's impacts in Pennsylvania?

A. Yes. In addition to asking about income loss during the pandemic, the Census survey also asks about expected income loss during the next four weeks. The results in Schedule SJR-4 were collected during the two-week period ending November 23, so the next four weeks cover the end of November and the first three weeks of December. Almost 30% of Pennsylvania's workforce expects to suffer an additional income loss during that four-week period.

I also find it noteworthy that the lower a household's income, the greater the impact of the pandemic on income loss. Similarly, households headed by a person who the Census Bureau categorizes as being Black, Hispanic, or Asian are much more likely to have experienced an income loss -- and to expect additional income loss during December -- than are households headed by a person classified as White, Non-Hispanic.

Q. With such a significant loss of income, how are Pennsylvanians paying their bills?

A. The Census Bureau's Household Pulse Survey began asking exactly that question in week 7 of the survey; specifically, asking how households that lost some of their employment income paid their bills in the past seven days. In Schedule SJR-5, I show the results for the most recent two-week survey period ending November 23. People were able to report multiple sources of funds to pay their bills. Only 50% of Pennsylvanians who lost income said they used their normal source of income to pay bills in the previous week. About 20% cited unemployment benefits and 21% referred to the

CARES Act stimulus payments. More people, however, relied on credit card debt or loans (including loans from family or friends) (45.8%) or money from savings or asset sales (29.5%) than relied on short-term government benefits.

Q. Are people concerned about being able to afford their utility bills during this time?

A. Yes. A recent survey conducted by the Electric Power Research Institute ("EPRI") found that about two-thirds of people who lost their jobs during the pandemic are concerned about being able to pay their energy bills.[12] Moreover, more than 20% of survey respondents reported that their energy bills were higher because of the pandemic.[13] Interestingly, the survey also found that more than 25% of people who lost their jobs are planning to skip at least one utility bill payment,[14] but a much lower percentage were planning to contact their utilities for assistance.[15]

The Pandemic's Impact on Small Businesses

Q. Are there any indicators of the condition of Pennsylvania's economic outlook as a result of the pandemic?

A. Yes. A small-business survey by the U.S. Census Bureau provides insights into the condition of small businesses in Pennsylvania. The Census Bureau estimates that, as of the week ending May 2, 31.6% of small businesses in Pennsylvania said they would not return to normal operations for more than six months and 6.6% of the Commonwealth's

[12] Omar Siddiqui and Min Long, Impact of COVID-19 on Consumer Energy Use & Outlook: Results of EPRI National Survey (April 29, 2020), http://mydocs.epri.com/Docs/public/covid19/COVID-19_survey_report.pdf, a copy of which is attached as Schedule SJR-6. The referenced question is on page 4 of Schedule SJR-6.
[13] Schedule SJR-6, p. 3.
[14] Schedule SJR-6, p. 7.
[15] Schedule SJR-6, p. 12 (15% of those who lost their jobs said they planned to contact the utility about alternate rate plans or other ways to lower their bills).

small businesses expected to never return to their pre-pandemic level of operations.[16] By the first week in December, the small-business outlook was considerably worse with more than 57% of businesses selecting these two categories. I show the trend graphically in Figure 4.

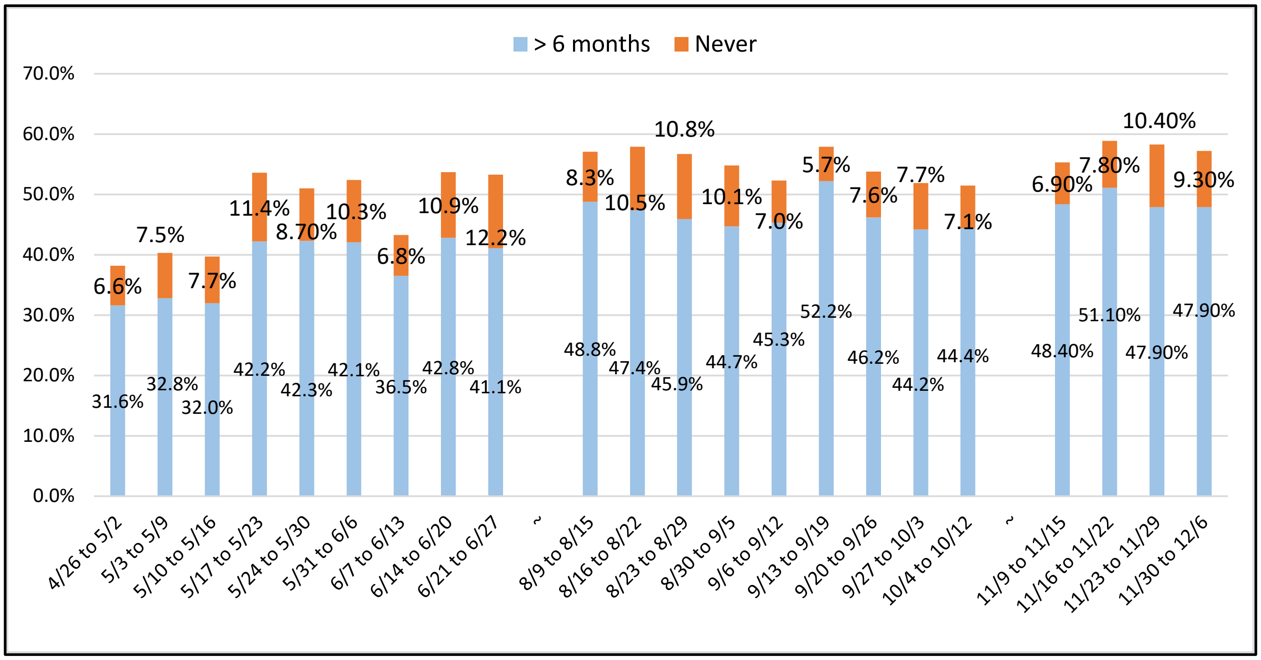

Figure 4. Percentage of Small Businesses in Pennsylvania Expecting it to Take at Least Six Months to Return to Usual Level of Operations (April 26 to December 6, 2020)

Q. Has there been an overall assessment of the pandemic's effects on Pennsylvania's economy?

A. Yes. Each month, the Federal Reserve Bank calculates a "coincident index" for each state and the country as a whole. The index is described as follows: "The coincident indexes combine four state-level indicators to summarize current economic conditions in

[16] U.S. Census Bureau, Small Business Pulse Survey, https://www.census.gov/data/experimental-data-products/small-business-pulse-survey.html.

a single statistic. The four state-level variables in each coincident index are nonfarm payroll employment, average hours worked in manufacturing by production workers, the unemployment rate, and wage and salary disbursements plus proprietors' income deflated by the consumer price index (U.S. city average)."[17] The index is set so that the level of economic activity in 2007 is equal to 100.

Between January and April, Pennsylvania's coincident index plunged from 122.56 to 97.43, a decline of 20%. The index recovered to 112.91 in October, which is still 8% below the pre-pandemic level of economic activity. Indeed, Figure 5 shows that Pennsylvania's level of economic activity in April was the lowest it had been in a decade.

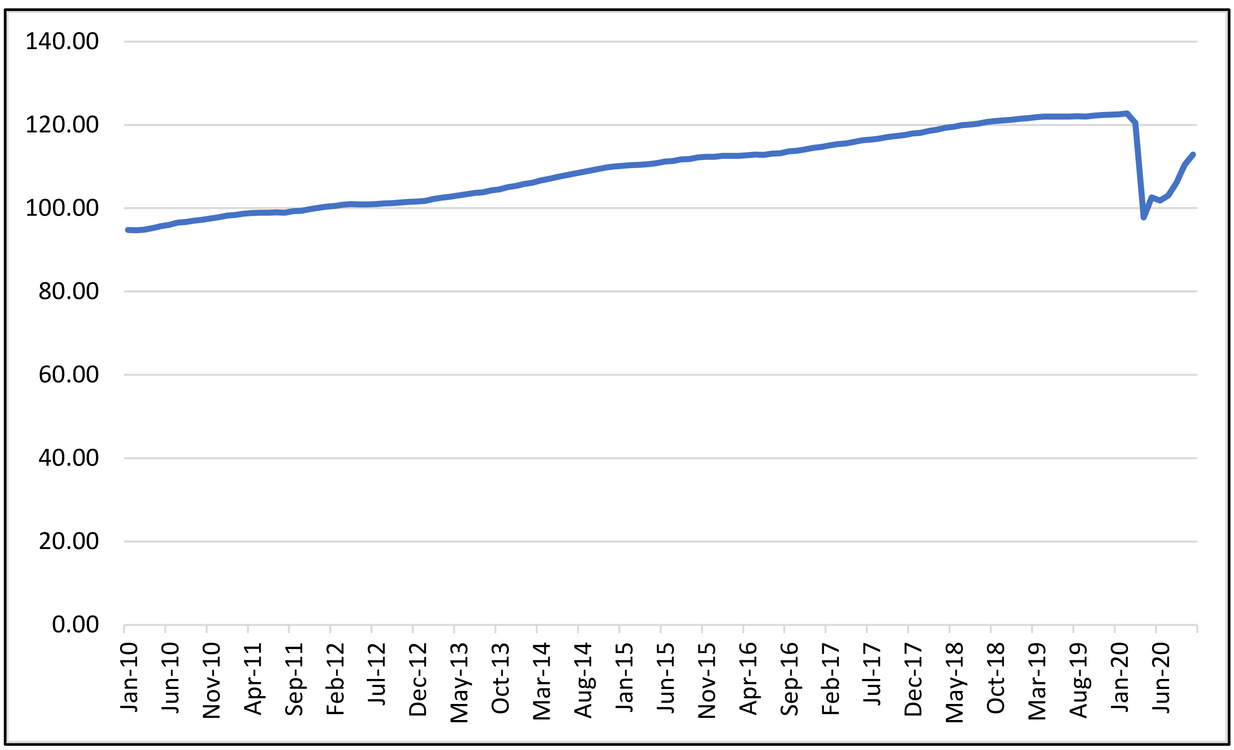

Figure 5. Federal Reserve Bank Coincident Index (Measure of Economic Activity) in Pennsylvania January 2010 to October 2020

[17] https://www.philadelphiafed.org/research-and-data/regional-economy/indexes/coincident

Regulatory Response

Q. How does this affect the decisions the Commission must make in this case?

A. Faced with this unprecedented public health and economic crisis, I respectfully submit that the Commission cannot treat this case as "business as usual." Almost no other business in PECO's service area is conducting business as usual; residential consumers are using PECO's services differently than they do during normal circumstances (few if any people are usually at home 24 hours per day, 7 days a week, preparing every meal at home, and so on).

Respectfully, the Commission cannot focus on PECO's historic costs, or on cost projections prepared before the pandemic, and assume that the resulting rates will be "just and reasonable." The Commission must focus on what rates are reasonable for consumers to pay under these extraordinary conditions.

Q. Are you aware of any regulatory precedents that discuss ratemaking during a pandemic?

A. While the research is difficult (especially with most libraries closed), there is some precedent from regulatory commissions during the last nationwide pandemic, the influenza pandemic in 1918 and 1919. From these early days of utility regulation in this country, it was recognized that circumstances in the economy (including disease outbreaks) could affect utilities in the same way that other businesses were affected. When that occurred, regulation would <u>not</u> protect utilities from the adverse consequences.

I have not conducted exhaustive research, but I did locate a case decided by the Supreme Judicial Court of Massachusetts in 1919 where the owner of a streetcar service challenged a public service commission ratemaking order.[18] Among the challenges faced by the business in 1918 were increases in the cost of raw materials (presumably due to the war effort), reduction in ridership, and "the wide prevalence of the epidemic known as influenza, a factor seriously affecting receipts during October and November, 1918."[19]

The Massachusetts court cited with approval a federal appellate decision that held as follows:

> To be just and reasonable, within the meaning of the constitutional guaranty, the rates must be prescribed with reasonable regard for the cost to the carrier of the service rendered and for the value of the property employed therein; but <u>this does not mean that regard is to be had only for the interests of the carrier, or that the rates must necessarily be such as to render its business profitable, for reasonable regard must also be had for the value of the service to the public</u>. And where the cost to the carrier is not kept within reasonable limits, or <u>where for any reasons its business cannot reasonably be so conducted as to render it profitable the misfortune must fall upon the carrier, as would be the case if it were engaged in any other line of business</u>.[20]

The court went on to uphold the regulatory commission's ratesetting order that was not expected to result in the utility earning a profit. The court reasoned that "the times are recognized as abnormal," but that did not deprive the commission of its regulatory responsibility to "exercise its judgment for the protection of the public interests when it does not reduce substantially the revenue proposed to be exacted from

[18] *Donham v. Public Service Commission*, 232 Mass. 309, 122 N.E. 397 (1919).
[19] *Id.*, 232 Mass. at 315, 122 N.E. at 400.
[20] *Id.*, 232 Mass. at 317, 122 N.E. at 401 (emphases added; quoting from *Missouri, Kansas & Topeka Railway Co. v. Interstate Commerce Commission*, 164 Fed. 645 (1908)).

the public by the owners of the public utility."[21] The court also emphasized that the rates were "likely to be impermanent and experimental."[22]

In other words, the idea that ratemaking must adapt to extraordinary conditions is neither new nor novel. A century ago during another serious pandemic, regulators adapted, took actions that provided relief to the public, and did not inflict long-term harm on the utility.

Q. Are you aware of any Pennsylvania regulatory actions during a severe economic downturn?

A. Yes, in another rate case pending before the Commission, a consultant for the utility made me aware of a 1934 resolution by the Pennsylvania Public Service Commission ("PSC") that strongly encouraged utilities to reset their rates using a 6% rate of return.[23]

The PSC's 1934 resolution is referred to in a published history of the Philadelphia Electric Company as follows:

> In 1934, the [Public Service] Commission limited the return allowable to utilities to six percent (it had been seven per cent), and between January 1, 1933, and June 30, 1936, it obtained rate reductions totaling $15,000,000 from Pennsylvania operating companies. … [The Philadelphia Electric] Company lowered its rates substantially in 1933, 1934, 1935, and 1936.[24]

[21] *Id.*, 232 Mass. at 326, 122 N.E. at 405.
[22] *Id.*
[23] *Re Utility Rates During Economic Emergency*, 3 P.U.R. NS 123 (Pa. P.S.C. 1934).
[24] Nicholas B. Wainwright, *History of the Philadelphia Electric Company: 1881-1961* (Philadelphia, PA 1961), p. 246.

Thus, it appears that this Commission's predecessor lowered rates substantially during the Great Depression based (at least in part) on prevailing economic conditions, as stated in the 1934 resolution.

Q. Are there any recent regulatory actions by the Commission that support your recommendation?

A. Yes. On December 4, 2020, Administrative Law Judge Dunderdale issued her Recommended Decision in the pending Columbia Gas rate case.[25] ALJ Dunderdale addressed similar concerns that I raised in that case about raising rates during a pandemic. She agreed with me and recommended that Columbia Gas should not receive any rate increase at this time.

Q. How are other utilities and regulators addressing these unprecedented circumstances?

A. I have not conducted exhaustive research to try to identify every regulatory and utility response to ratesetting during the pandemic. I can, however, provide a few examples.

Hydro One, a large electric utility in Ontario, Canada, temporarily modified its rate structure to eliminate peak-period pricing, recognizing that people are at home 24-hours per day and cannot avoid peak-period usage. The utility estimates this will reduce a typical customer's bills by more than 14%.[26]

[25] Pa. PUC v. Columbia Gas of Pa., Inc., Docket No. R-2020-3018835.
[26] https://www.hydroone.com/about/corporate-information/rate-relief.

The Halifax (Nova Scotia) Regional Water Commission withdrew its request to increase water rates. It also delayed and significantly reduced its proposed increase in wastewater rates.[27]

Utilities throughout the United States also are deferring rate increases or implementing rate reductions during this period. These actions provide some relief to customers who are facing a horrible confluence of events: an increase in home utility bills (as they are home essentially 24 hours per day, 7 days per week) coupled with declines in income. A few examples are summarized as follows:

- Minnesota Power significantly reduced its requested rate increase and is refunding more than $12 million to customers to help alleviate pandemic-related financial concerns.[28]
- California Water Service Co. eliminated all scheduled rate increases during 2020.[29]
- Chelan County (Washington) Public Utility District postponed previously approved increases in electric, water, and wastewater rates by six months to provide customers some relief during the pandemic.[30]
- The City of Austin (Texas) reduced its electricity rates by about 4%, eliminated the residential price increment for usage in excess of 1,000 kilowatt-hours per month, and reduced rates for residential water and wastewater consumption by 10%.[31] I note that Austin also delayed a proposed rate increase proceeding by a full year.
- PEPCO, the electric utility serving the District of Columbia and surrounding areas, announced on June 1st that it would forego a $25 million rate increase scheduled for this year in D.C., make a shareholder

[27] https://www.canlii.org/en/ns/nsuarb/doc/2020/2020nsuarb113/2020nsuarb113.html.
[28] Minnesota Power Proposes Plan to Resolve Rate Request in Response to Economic Challenges of COVID-19; Customers will receive refund on bills and lower rates under proposal to state regulators, Business Wire, April 23, 2020.
[29] Utility; Cal Water requests a delay in rate changes, Oroville Mercury Register (California), April 30, 2020.
[30] Chelan PUD delays rate increase by 6 months, S&P Global Market Intelligence, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/chelan-pud-delays-rate-increase-by-6-months-58041707.
[31] https://austinenergy.com/ae/rates/residential-rates/residential-electric-rates-and-line-items.

donation to its low-income assistance fund, and take other actions to assist customers during the pandemic.[32]

- A report by Moody's Investors Service expects similar delays in numerous electric, gas, and water utility rate proceedings throughout the U.S. as a way of providing some relief to consumers during the pandemic.[33]

- Philadelphia Water Department withdrew its pending request for increases in water, wastewater, and stormwater rates that would have become effective in September 2020 and September 2021. In a June 2020 filing, the utility cited "the on-going pandemic and the uncertainty over the anticipated duration of continuing emergency measures."[34]

Q. What do you recommend?

A. I recommend that the Commission deny PECO's request to increase rates in this case. Now is not the time to impose additional, unavoidable costs on consumers. Residential customers are experiencing unprecedented levels of unemployment and other economic dislocation (such as reduced hours of work), while many are battling the COVID-19 infection. Businesses of all sizes, as well as local governments, schools, universities, and nonprofit organizations are struggling to remain viable. I expect many will not be able to survive or, if they do, it might take them months or years to return to pre-pandemic levels of operations.

To put all of this in terms of utility ratemaking: it would be neither just nor reasonable for PECO to increase its rates at this time. The Commission should deny

[32] PEPCO press release, PEPCO Proposes to Freeze DC Customer Energy Delivery Rates Until 2022, https://www.pepco.com/News/Pages/PepcoProposestoFreezeDCCustomerEnergyDeliveryRatesUntil2022andAssistCustomerswithPandemicEconomicRecovery.aspx.

[33] Moody's Investors Service, Coronavirus outbreak delays rate cases, but regulatory support remains intact, April 6, 2020, https://www.eenews.net/assets/2020/04/09/document_ew_04.pdf.

[34] https://www.phila.gov/departments/water-sewer-storm-water-rate-board/rate-proceedings/2020-rate-proceeding/.

PECO's request in its entirety and keep PECO's existing rates (and all other tariff provisions) in effect.

Q. Other than the information you provided above, is there any other information that lends support to your recommendation?

A. Yes. PECO's filing is based on data for the utility under normal conditions. In the pro forma historic test year (twelve months ending June 30, 2020), under its existing rates, PECO earned a return on equity of 10.87%.[35] Even under PECO's claims for the fully projected future test year ("FPFTY") ending June 30, 2022, PECO shows that, if present rates remained in effect, it would recover all of its expenses and debt costs and earn a return on equity of 7.27%.[36]

Q. How does your recommendation compare to the recommendation developed by the OCA's other experts, assuming we were not in the midst of a pandemic?

A. Those witnesses' testimonies and exhibits will speak for themselves, but I can provide my basic understanding of their in-depth analyses of PECO's operations. As I understand it, the OCA's experts have concluded that PECO has overstated the need for an increase in revenues in the FPFTY. I also would note that this assumes none of PECO's costs or

[35] PECO Exh. MJT-3, Sch. A-1, p. 1, shows an overall rate of return of 7.61%. Using the historic test year capital structure on Sch. B-7, p. 13, of that exhibit, I calculate the return on equity was 10.87%, calculated as follows: overall return of 7.61% - 1.89% weighted cost of debt = 5.72% weighted return on equity. 5.72% ÷ 52.62% equity capitalization = 10.87% return on equity.

[36] PECO Exh. MJT-1, Sch. A-1, p. 1, shows an overall rate of return of 5.73% for the FPFTY under present rates. Using the FPFTY capital structure on Sch. B-7, p. 13, of that exhibit, I calculate the return on equity was 7.27%, calculated as follows: overall return of 5.73% - 1.85% weighted cost of debt = 3.88% weighted return on equity. 3.88% ÷ 53.38% equity capitalization = 7.269% return on equity. See also PECO's Statement of Reasons, p. 2, where it states the FPFTY return on equity under present rates would be 7.26%. The difference appears to be due to rounding.

revenues are affected by the pandemic or the ongoing economic fallout from the past few months.

I would emphasize that we are not living under normal conditions. Businesses, small and large, throughout Pennsylvania are facing the very real prospect of not being able to pay their out-of-pocket expenses and laying off most or all of their workforce. They are facing negative returns on their investments. That is the real-world competitive market that regulation is trying to mirror.

I am not suggesting that PECO should have rates that are inadequate to ensure the provision of safe and reliable service to its customers. My recommendation allows PECO to continue operations, recover all of its expenses, and earn a profit. Most of PECO's customers would be absolutely thrilled if they could pay all their bills (including various increases in expenses that may or may not occur next year), make all of their debt payments, and still have enough left over to earn a profit on their equity investment. Most businesses would find that result absolutely amazing at this time. When compared to the economic devastation gripping its service territory, I cannot find anything just or reasonable about increasing PECO's rates at this time.

Moreover, it is my opinion that the Commission cannot lend any credence to PECO's projections for the FPFTY. That applies to essentially every aspect of PECO's projections. While PECO was preparing this case, interest rates dropped to near zero;[37]

[37] Board of Governors of the Federal Reserve System, Policy Tools (interest rates were decreased to the range of 0% to 0.25% on March 16, 2020), https://www.federalreserve.gov/monetarypolicy/openmarket.htm.

oil prices plunged;[38] and inflation fell to the lowest level experienced in decades.[39] No one can say how much gas PECO will sell and to which customer classes. How many restaurants will be open? How many children will be in school remotely this winter and into the spring? How many colleges and universities will be able to open their classrooms and dormitories next semester?

Based on all of these factors, I conclude that the Commission cannot have any confidence in the projections made by PECO for the FPFTY; there is simply too much uncertainty. It would be neither just nor reasonable to set rates based on the assumptions PECO made when it filed this case in late September. Virtually every assumption is changing as a result of the pandemic. As a consequence, it is my opinion that it is reasonable -- I would go so far as to say required -- for the Commission to reject PECO's request to increase its rates. The Commission cannot have any certainty about the appropriate, ongoing level of expenses, interest rates, consumption patterns, and the numerous other factors that affect the determination of an appropriate level of rates.

Q. If the economic situation worsens significantly and cash flow becomes a concern for PECO, are there other actions it could take?

A. Yes, one obvious way to preserve cash is to defer construction projects that are not needed to ensure the current provision of safe and reliable service to existing customers.

[38] U.S. Department of Energy, Energy Information Administration, Petroleum and Other Liquids (the price of a standard crude oil contract fell from $53.14 on January 27 to less than $20 per barrel in late April. The price has since recovered to $45.34 as of November 30) -- still about 15% less than the price at the end of January. https://www.eia.gov/dnav/pet/hist/RCLC1D.htm.

[39] U.S. Bureau of Labor Statistics, Consumer Price Index (the CPI fell 0.4% in March, 0.8% in April, and another 0.1% in May), https://data.bls.gov/timeseries/CUSR0000SA0. The consumer price level in October 2020 (260.325) represents an annual inflation rate of only 1.2%. I also note that the monthly inflation rate from September to October was zero, so it is unclear what direction prices will take as the pandemic continues to worsen.

For example, growth-related projects or system rehabilitation activities that are longer-term in nature (that is, projects that are not needed to ensure current levels of service within the next six to 12 months) could be delayed by several months to preserve cash, if necessary.

Introduction of OCA's Other Witnesses

Q. If the Commission disagrees with you and decides to determine PECO's revenue requirement and rates as if we were not in the midst of a pandemic, what do you recommend?

A. The OCA is sponsoring the testimony of five other witnesses who will provide a more traditional rate case presentation.

Q. Who are the OCA's other expert witnesses?

A. In OCA Statement 2, Lafayette Morgan calculates the Company's rate base, pro forma operating income under present rates, and overall revenue deficiency based on his recommended adjustments. Mr. Morgan also discusses the reasons why PECO cannot meet its burden of proving the reasonableness of its FPFTY projections in light of all of the changes caused by the pandemic.

In developing his recommendations, Mr. Morgan relies on the rate of return analysis presented by Kevin O'Donnell in OCA Statement 3. Mr. O'Donnell also discusses some of the pandemic's effects on capital markets and the uncertainties created when attempting to determine the fair rate of return for the FPFTY.

In OCA Statement 4, Glenn Watkins discusses the Company's cost-of-service study, allocation of any rate increase among the customer classes, and issues associated with the design of residential rates.

In OCA Statement 5, Roger Colton addresses the effectiveness of PECO's current CAP program as well as the particular plight of PECO's low-income customers during this time. He recommends changes in the Company's universal-service programs, and related matters to help all of PECO's residential customers afford essential utility service.

Finally, in OCA Statement 6, Geoffrey Crandall examines PECO's existing energy efficiency and conservation programs, PECO's proposed expansion of these programs, and whether this proposal is just and reasonable. Mr. Crandall recommends specific program adjustments, as well as a revised budget for the programs.

Conclusion

Q. Please summarize your conclusions and recommendations.

A. I strongly recommend that the Commission deny any rate increase to PECO in this case. PECO's projections for the FPFTY cannot be relied upon to make reasonable findings or conclusions about its level of revenues, expenses, or any of the other elements that enter into the ratemaking calculus.

Moreover, given the current economic situation, I conclude that it is neither just nor reasonable to increase rates to PECO's customers at this time. People's incomes are declining and uncertain, businesses are closed or conducting limited operations, schools and universities face tremendous uncertainty, nonprofit organizations are stressed to the breaking point, and local government tax revenues are declining. I cannot identify any segment of PECO's customer base for which a rate increase would be just or reasonable at this time. Finally, as I explained above, PECO would not suffer severe financial hardship if rates remained at their current level through the FPFTY.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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Appendix A

Scott J. Rubin
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Current Position

Public Utility Attorney and Consultant. 1994 to present. I provide legal, consulting, and expert witness services to various organizations interested in the regulation of public utilities.

Previous Positions

Lecturer in Computer Science, Susquehanna University, Selinsgrove, PA. 1993 to 2000.

Senior Assistant Consumer Advocate, Office of Consumer Advocate, Harrisburg, PA. 1990 to 1994. I supervised the administrative and technical staff and shared with one other senior attorney the supervision of a legal staff of 14 attorneys.

Assistant Consumer Advocate, Office of Consumer Advocate, Harrisburg, PA. 1983 to 1990.

Associate, Laws and Staruch, Harrisburg, PA. 1981 to 1983.

Law Clerk, U.S. Environmental Protection Agency, Washington, DC. 1980 to 1981.

Research Assistant, Rockville Consulting Group, Washington, DC. 1979.

Current Professional Activities

Member, American Bar Association, Infrastructure and Regulated Industries Section.

Member, American Water Works Association.

Admitted to practice law before the Supreme Court of Pennsylvania, the New York State Court of Appeals, the United States District Court for the Middle District of Pennsylvania, the United States Court of Appeals for the Third Circuit, and the Supreme Court of the United States.

Served as peer reviewer for *Electricity Journal*, J*ournal American Water Works Association*, *Journal of Benefit-Cost Analysis*, and *Utilities Policy*.

Previous Professional Activities

Member, American Water Works Association, Rates and Charges Subcommittee, 1998-2001.

Member, Federal Advisory Committee on Disinfectants and Disinfection By-Products in Drinking Water, U.S. Environmental Protection Agency, Washington, DC. 1992 to 1994.

Chair, Water Committee, National Association of State Utility Consumer Advocates, Washington, DC. 1990 to 1994; member of committee from 1988 to 1990.

Member, Board of Directors, Pennsylvania Energy Development Authority, Harrisburg, PA. 1990 to 1994.

Member, Small Water Systems Advisory Committee, Pennsylvania Department of Environmental Resources, Harrisburg, PA. 1990 to 1992.

Member, Ad Hoc Committee on Emissions Control and Acid Rain Compliance, National Association of State Utility Consumer Advocates, 1991.

Member, Nitrogen Oxides Subcommittee of the Acid Rain Advisory Committee, U.S. Environmental Protection Agency, Washington DC. 1991.

Education

J.D. with Honors, George Washington University, Washington, DC. 1981.

B.A. with Distinction in Political Science, Pennsylvania State University, University Park, PA. 1978.

Publications and Presentations (* denotes peer-reviewed publications)

1. "Quality of Service Issues," a speech to the Pennsylvania Public Utility Commission Consumer Conference, State College, PA. 1988.

2. K.L. Pape and S.J. Rubin, "Current Developments in Water Utility Law," in *Pennsylvania Public Utility Law* (Pennsylvania Bar Institute). 1990.

3. Presentation on Water Utility Holding Companies to the Annual Meeting of the National Association of State Utility Consumer Advocates, Orlando, FL. 1990.

4. "How the OCA Approaches Quality of Service Issues," a speech to the Pennsylvania Chapter of the National Association of Water Companies. 1991.

5. Presentation on the Safe Drinking Water Act to the Mid-Year Meeting of the National Association of State Utility Consumer Advocates, Seattle, WA. 1991.

6. "A Consumer Advocate's View of Federal Pre-emption in Electric Utility Cases," a speech to the Pennsylvania Public Utility Commission Electricity Conference. 1991.

7. Workshop on Safe Drinking Water Act Compliance Issues at the Mid-Year Meeting of the National Association of State Utility Consumer Advocates, Washington, DC. 1992.

8. Formal Discussant, Regional Acid Rain Workshop, U.S. Environmental Protection Agency and National Regulatory Research Institute, Charlotte, NC. 1992.

9. S.J. Rubin and S.P. O'Neal, "A Quantitative Assessment of the Viability of Small Water Systems in Pennsylvania," *Proceedings of the Eighth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute (Columbus, OH 1992), IV:79-97.

10. "The OCA's Concerns About Drinking Water," a speech to the Pennsylvania Public Utility Commission Water Conference. 1992.

11. Member, Technical Horizons Panel, Annual Meeting of the National Association of Water Companies, Hilton Head, SC. 1992.

12. M.D. Klein and S.J. Rubin, "Water and Sewer -- Update on Clean Streams, Safe Drinking Water, Waste Disposal and Pennvest," *Pennsylvania Public Utility Law Conference* (Pennsylvania Bar Institute). 1992.

13. Presentation on Small Water System Viability to the Technical Assistance Center for Small Water Companies, Pa. Department of Environmental Resources, Harrisburg, PA. 1993

14. "The Results Through a Public Service Commission Lens," speaker and participant in panel discussion at Symposium: "Impact of EPA's Allowance Auction," Washington, DC, sponsored by AER*X. 1993.

15. "The Hottest Legislative Issue of Today -- Reauthorization of the Safe Drinking Water Act," speaker and participant in panel discussion at the Annual Conference of the American Water Works Association, San Antonio, TX. 1993.

16. "Water Service in the Year 2000," a speech to the Conference: "Utilities and Public Policy III: The Challenges of Change," sponsored by the Pennsylvania Public Utility Commission and the Pennsylvania State University, University Park, PA. 1993.

17. "Government Regulation of the Drinking Water Supply: Is it Properly Focused?," speaker and participant in panel discussion at the National Consumers League's Forum on Drinking Water Safety and Quality, Washington, DC. 1993. Reprinted in *Rural Water*, Vol. 15 No. 1 (Spring 1994), pages 13-16.

18. "Telephone Penetration Rates for Renters in Pennsylvania," a study prepared for the Pennsylvania Office of Consumer Advocate. 1993.

19. "Zealous Advocacy, Ethical Limitations and Considerations," participant in panel discussion at "Continuing Legal Education in Ethics for Pennsylvania Lawyers," sponsored by the Office of General Counsel, Commonwealth of Pennsylvania, State College, PA. 1993.

20. "Serving the Customer," participant in panel discussion at the Annual Conference of the National Association of Water Companies, Williamsburg, VA. 1993.

21. "A Simple, Inexpensive, Quantitative Method to Assess the Viability of Small Water Systems," a speech to the Water Supply Symposium, New York Section of the American Water Works Association, Syracuse, NY. 1993.

22. * S.J. Rubin, "Are Water Rates Becoming Unaffordable?," *Journal American Water Works Association*, Vol. 86, No. 2 (February 1994), pages 79-86.

23. "Why Water Rates Will Double (If We're Lucky): Federal Drinking Water Policy and Its Effect on New England," a briefing for the New England Conference of Public Utilities Commissioners, Andover, MA. 1994.

24. "Are Water Rates Becoming Unaffordable?," a speech to the Legislative and Regulatory Conference, Association of Metropolitan Water Agencies, Washington, DC. 1994.

25. "Relationships: Drinking Water, Health, Risk and Affordability," speaker and participant in panel discussion at the Annual Meeting of the Southeastern Association of Regulatory Commissioners, Charleston, SC. 1994.

26. "Small System Viability: Assessment Methods and Implementation Issues," speaker and participant in panel discussion at the Annual Conference of the American Water Works Association, New York, NY. 1994.

27. S.J. Rubin, “How much should we spend to save a life?,” *Seattle Journal of Commerce*, August 18, 1994 (Protecting the Environment Supplement), pages B-4 to B-5.

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29. S.J. Rubin, “Small System Monitoring: What Does It Mean?,” *Impacts of Monitoring for Phase II/V Drinking Water Regulations on Rural and Small Communities* (National Rural Water Association 1994), pages 6-12.

30. “Surviving the Safe Drinking Water Act,” speaker at the Annual Meeting of the National Association of State Utility Consumer Advocates, Reno, NV. 1994.

31. “Safe Drinking Water Act Compliance -- Ratemaking Implications,” speaker at the National Conference of Regulatory Attorneys, Scottsdale, AZ. 1995. Reprinted in *Water*, Vol. 36, No. 2 (Summer 1995), pages 28-29.

32. S.J. Rubin, “Water: Why Isn’t it Free? The Case of Small Utilities in Pennsylvania,” *Utilities, Consumers & Public Policy: Issues of Quality, Affordability, and Competition, Proceedings of the Fourth Utilities, Consumers and Public Policy Conference* (Pennsylvania State University 1995), pages 177-183.

33. S.J. Rubin, “Water Rates: An Affordable Housing Issue?,” *Home Energy*, Vol. 12 No. 4 (July/August 1995), page 37.

34. Speaker and participant in the Water Policy Forum, sponsored by the National Association of Water Companies, Naples, FL. 1995.

35. Participant in panel discussion on “The Efficient and Effective Maintenance and Delivery of Potable Water at Affordable Rates to the People of New Jersey,” at The New Advocacy: Protecting Consumers in the Emerging Era of Utility Competition, a conference sponsored by the New Jersey Division of the Ratepayer Advocate, Newark, NJ. 1995.

36. J.E. Cromwell III, and S.J. Rubin, *Development of Benchmark Measures for Viability Assessment* (Pa. Department of Environmental Protection 1995).

37. S. Rubin, “A Nationwide Practice from a Small Town in Pa.,” *Lawyers & the Internet – a Supplement to the Legal Intelligencer and Pa. Law Weekly* (February 12, 1996), page S6.

38. “Changing Customers’ Expectations in the Water Industry,” speaker at the Mid-America Regulatory Commissioners Conference, Chicago, IL. 1996, reprinted in *Water* Vol. 37 No. 3 (Winter 1997), pages 12-14.

39. “Recent Federal Legislation Affecting Drinking Water Utilities,” speaker at Pennsylvania Public Utility Law Conference, Pennsylvania Bar Institute, Hershey, PA. 1996.

40. “Clean Water at Affordable Rates: A Ratepayers Conference,” moderator at symposium sponsored by the New Jersey Division of Ratepayer Advocate, Trenton, NJ. 1996.

41. "Water Workshop: How New Laws Will Affect the Economic Regulation of the Water Industry," speaker at the Annual Meeting of the National Association of State Utility Consumer Advocates, San Francisco, CA. 1996.

42. * E.T. Castillo, S.J. Rubin, S.K. Keefe, and R.S. Raucher, "Restructuring Small Systems," *Journal American Water Works Association*, Vol. 89, No. 1 (January 1997), pages 65-74.

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44. "Capacity Development – More than Viability Under a New Name," speaker at National Association of Regulatory Utility Commissioners Winter Meetings, Washington, DC. 1997.

45. * E. Castillo, S.K. Keefe, R.S. Raucher, and S.J. Rubin, *Small System Restructuring to Facilitate SDWA Compliance: An Analysis of Potential Feasibility* (AWWA Research Foundation, 1997).

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47. Briefing on Issues Affecting the Water Utility Industry, Annual Meeting of the National Association of State Utility Consumer Advocates, Boston, MA. 1997.

48. "Capacity Development in the Water Industry," speaker at the Annual Meeting of the National Association of Regulatory Utility Commissioners, Boston, MA. 1997.

49. "The Ticking Bomb: Competitive Electric Metering, Billing, and Collection," speaker at the Annual Meeting of the National Association of State Utility Consumer Advocates, Boston, MA. 1997.

50. Scott J. Rubin, "A Nationwide Look at the Affordability of Water Service," *Proceedings of the 1998 Annual Conference of the American Water Works Association*, Water Research, Vol. C, No. 3, pages 113-129 (American Water Works Association, 1998).

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54. "Consumer Advocacy for the Future," speaker at the Age of Awareness Conference, Changes and Choices: Utilities in the New Millennium, Carlisle, PA. 1999.

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59. Janice A. Beecher and Scott J. Rubin, presentation on “Special Topics in Rate Design: Affordability” at the Annual Conference and Exhibition of the American Water Works Association, Denver, CO. 2000.

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66. “Be Utility Wise in a Restructured Utility Industry,” Keynote Address at Be UtilityWise Conference, Pittsburgh, PA. 2000.

67. Scott J. Rubin, Jason D. Sharp, and Todd S. Stewart, “The Wired Administrative Lawyer,” *5th Annual Administrative Law Symposium*, Pennsylvania Bar Institute, Harrisburg, PA. 2000.

68. Scott J. Rubin, “Current Developments in the Water Industry,” *Pennsylvania Public Utility Law Conference*, Pennsylvania Bar Institute, Harrisburg, PA. 2000.

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87. Scott J. Rubin, *Understanding Telephone Penetration in Pennsylvania*, Council on Utility Choice, Harrisburg, PA. 2003.

88. Scott J. Rubin, *The Cost of Water and Wastewater Service in the United States*, National Rural Water Association, 2003.

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90. George M. Aman, III, Jeffrey P. Garton, Eric Petersen, and Scott J. Rubin, Challenges and Opportunities for Improving Water Supply Institutional Arrangements, *Water Law Conference*, Pennsylvania Bar Institute, Mechanicsburg, PA. 2004.

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93. Scott J. Rubin, Buying and Selling a Water System – Ratemaking Implications, *Pennsylvania Public Utility Law Conference*, Pennsylvania Bar Institute, Harrisburg, PA. 2005.

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97. * Robert S. Raucher, et al., *Regional Solutions to Water Supply Provision*, American Water Works Association Research Foundation, Denver, CO. 2007; 2nd edition published in 2008.

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99. * John Cromwell and Scott Rubin, *Estimating Benefits of Regional Solutions for Water and Wastewater Service*, American Water Works Association Research Foundation, Denver, CO. 2008.

100. Scott J. Rubin, "Current State of the Water Industry and Stimulus Bill Overview," in *Pennsylvania Public Utility Law* (Pennsylvania Bar Institute). 2009.

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103.* John Cromwell III, et al., *Best Practices in Customer Payment Assistance Programs*, Water Research Foundation, Denver, CO. 2010.

104.* Scott J. Rubin, What Does Water Really Cost? Rate Design Principles for an Era of Supply Shortages, Infrastructure Upgrades, and Enhanced Water Conservation, , National Regulatory Research Institute. 2010.

105. Scott J. Rubin and Christopher P.N. Woodcock, Teleseminar: Water Rate Design, National Regulatory Research Institute. 2010.

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110. Scott J. Rubin, Current Topics in Water: Rate Design and Reliability. Presentation to the Water Committee of the National Association of Regulatory Utility Commissioners, Washington, DC. 2011.

111. Scott J. Rubin, Water Reliability and Resilience Standards, *Pennsylvania Public Utility Law Conference* (Pennsylvania Bar Institute). 2011.

112. Member of Expert Panel, Leadership Forum: Business Management for the Future, Annual Conference and Exposition of the American Water Works Association, Washington, DC. 2011.

113. Scott J. Rubin, Evaluating Community Affordability in Storm Water Control Plans, *Flowing into the Future: Evolving Water Issues* (Pennsylvania Bar Institute). 2011.

114. Invited Participant, Summit on Declining Water Demand and Revenues, sponsored by The Alliance for Water Efficiency, Racine, WI. 2012.

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1. *Pa. Public Utility Commission v. Pennsylvania Gas and Water Co. - Water Division*, Pa. Public Utility Commission, Docket R-00922404. 1992. Concerning rate design, on behalf of the Pa. Office of Consumer Advocate.

2. *Pa. Public Utility Commission v. Shenango Valley Water Co.*, Pa. Public Utility Commission, Docket R-00922420. 1992. Concerning cost allocation, on behalf of the Pa. Office of Consumer Advocate

3. *Pa. Public Utility Commission v. Pennsylvania Gas and Water Co. - Water Division*, Pa. Public Utility Commission, Docket R-00922482. 1993. Concerning rate design, on behalf of the Pa. Office of Consumer Advocate

4. *Pa. Public Utility Commission v. Colony Water Co.*, Pa. Public Utility Commission, Docket R-00922375. 1993. Concerning rate design, on behalf of the Pa. Office of Consumer Advocate

5. *Pa. Public Utility Commission v. Dauphin Consolidated Water Supply Co. and General Waterworks of Pennsylvania, Inc.*, Pa. Public Utility Commission, Docket R-00932604. 1993. Concerning rate design and cost of service, on behalf of the Pa. Office of Consumer Advocate

6. *West Penn Power Co. v. State Tax Department of West Virginia*, Circuit Court of Kanawha County, West Virginia, Civil Action No. 89-C-3056. 1993. Concerning regulatory policy and the effects of a taxation statute on out-of-state utility ratepayers, on behalf of the Pa. Office of Consumer Advocate

7. *Pa. Public Utility Commission v. Pennsylvania Gas and Water Co. - Water Division*, Pa. Public Utility Commission, Docket R-00932667. 1993. Concerning rate design and affordability of service, on behalf of the Pa. Office of Consumer Advocate

8. *Pa. Public Utility Commission v. National Utilities, Inc.*, Pa. Public Utility Commission, Docket R-00932828. 1994. Concerning rate design, on behalf of the Pa. Office of Consumer Advocate

9. *An Investigation of the Sources of Supply and Future Demand of Kentucky-American Water Company*, Ky. Public Service Commission, Case No. 93-434. 1994. Concerning supply and demand planning, on behalf of the Kentucky Office of Attorney General, Utility and Rate Intervention Division.

10. *The Petition on Behalf of Gordon's Corner Water Company for an Increase in Rates*, New Jersey Board of Public Utilities, Docket No. WR94020037. 1994. Concerning revenue requirements and rate design, on behalf of the New Jersey Division of Ratepayer Advocate.

11. *Re Consumers Maine Water Company Request for Approval of Contracts with Consumers Water Company and with Ohio Water Service Company*, Me. Public Utilities Commission, Docket No. 94-352. 1994. Concerning affiliated interest agreements, on behalf of the Maine Public Advocate.

12. *In the Matter of the Application of Potomac Electric Power Company for Approval of its Third Least-Cost Plan*, D.C. Public Service Commission, Formal Case No. 917, Phase II. 1995. Concerning Clean Air Act implementation and environmental externalities, on behalf of the District of Columbia Office of the People's Counsel.

13. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of the Dayton Power and Light Company and Related Matters*, Ohio Public Utilities Commission, Case No. 94-105-EL-EFC. 1995. Concerning Clean Air Act implementation (case settled before testimony was filed), on behalf of the Office of the Ohio Consumers' Counsel.

14. *Kennebec Water District Proposed Increase in Rates*, Maine Public Utilities Commission, Docket No. 95-091. 1995. Concerning the reasonableness of planning decisions and the relationship between a publicly owned water district and a very large industrial customer, on behalf of the Maine Public Advocate.

15. *Winter Harbor Water Company, Proposed Schedule Revisions to Introduce a Readiness-to-Serve Charge*, Maine Public Utilities Commission, Docket No. 95-271. 1995 and 1996. Concerning standards for, and the reasonableness of, imposing a readiness to serve charge and/or exit fee on the customers of a small investor-owned water utility, on behalf of the Maine Public Advocate.

16. *In the Matter of the 1995 Long-Term Electric Forecast Report of the Cincinnati Gas & Electric Company*, Public Utilities Commission of Ohio, Case No. 95-203-EL-FOR, and *In the Matter of the Two-Year Review of the Cincinnati Gas & Electric Company's Environmental Compliance Plan Pursuant to Section 4913.05, Revised Cost*, Case No. 95-747-EL-ECP. 1996. Concerning the reasonableness of the utility's long-range supply and demand-management plans, the reasonableness of its plan for complying with the Clean Air Act Amendments of 1990, and discussing methods to ensure the provision of utility service to low-income customers, on behalf of the Office of the Ohio Consumers' Counsel..

17. *In the Matter of Notice of the Adjustment of the Rates of Kentucky-American Water Company*, Kentucky Public Service Commission, Case No. 95-554. 1996. Concerning rate design, cost of service, and sales forecast issues, on behalf of the Kentucky Office of Attorney General.

18. *In the Matter of the Application of Citizens Utilities Company for a Hearing to Determine the Fair Value of its Properties for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, and to Approve Rate Schedules Designed to Provide such Rate of Return*, Arizona Corporation Commission, Docket Nos. E-1032-95-417, *et al.* 1996. Concerning rate design, cost of service, and the price elasticity of water demand, on behalf of the Arizona Residential Utility Consumer Office.

19. *Cochrane v. Bangor Hydro-Electric Company*, Maine Public Utilities Commission, Docket No. 96-053. 1996. Concerning regulatory requirements for an electric utility to engage in unregulated business enterprises, on behalf of the Maine Public Advocate.

20. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Monongahela Power Company and Related Matters*, Public Utilities Commission of Ohio, Case No. 96-106-EL-EFC. 1996. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

21. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cleveland Electric Illuminating Company and Toledo Edison Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 96-107-EL-EFC and 96-108-EL-EFC. 1996. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

22. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Ohio Power Company and Columbus Southern Power Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 96-101-EL-EFC and 96-102-EL-EFC. 1997. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

23. *An Investigation of the Sources of Supply and Future Demand of Kentucky-American Water Company (Phase II)*, Kentucky Public Service Commission, Docket No. 93-434. 1997. Concerning supply and demand planning, on behalf of the Kentucky Office of Attorney General, Public Service Litigation Branch.

24. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cincinnati Gas and Electric Co. and Related Matters*, Public Utilities Commission of Ohio, Case No. 96-103-EL-EFC. 1997. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

25. *Bangor Hydro-Electric Company Petition for Temporary Rate Increase*, Maine Public Utilities Commission, Docket No. 97-201. 1997. Concerning the reasonableness of granting an electric utility's request for emergency rate relief, and related issues, on behalf of the Maine Public Advocate.

26. *Testimony concerning H.B. 1068 Relating to Restructuring of the Natural Gas Utility Industry*, Consumer Affairs Committee, Pennsylvania House of Representatives. 1997. Concerning the provisions of proposed legislation to restructure the natural gas utility industry in Pennsylvania, on behalf of the Pennsylvania AFL-CIO Gas Utility Caucus.

27. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cleveland Electric Illuminating Company and Toledo Edison Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 97-107-EL-EFC and 97-108-EL-EFC. 1997. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

28. *In the Matter of the Petition of Valley Road Sewerage Company for a Revision in Rates and Charges for Water Service*, New Jersey Board of Public Utilities, Docket No. WR92080846J. 1997. Concerning the revenue requirements and rate design for a wastewater treatment utility, on behalf of the New Jersey Division of Ratepayer Advocate.

29. *Bangor Gas Company, L.L.C., Petition for Approval to Furnish Gas Service in the State of Maine*, Maine Public Utilities Commission, Docket No. 97-795. 1998. Concerning the standards and public policy

concerns involved in issuing a certificate of public convenience and necessity for a new natural gas utility, and related ratemaking issues, on behalf of the Maine Public Advocate.

30. *In the Matter of the Investigation on Motion of the Commission into the Adequacy of the Public Utility Water Service Provided by Tidewater Utilities, Inc., in Areas in Southern New Castle County, Delaware*, Delaware Public Service Commission, Docket No. 309-97. 1998. Concerning the standards for the provision of efficient, sufficient, and adequate water service, and the application of those standards to a water utility, on behalf of the Delaware Division of the Public Advocate.

31. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cincinnati Gas and Electric Co. and Related Matters*, Public Utilities Commission of Ohio, Case No. 97-103-EL-EFC. 1998. Concerning fuel-related transactions with affiliated companies and the appropriate ratemaking treatment and regulatory safeguards involving such transactions, on behalf of the Ohio Consumers' Counsel.

32. *Olde Port Mariner Fleet, Inc. Complaint Regarding Casco Bay Island Transit District's Tour and Charter Service*, Maine Public Utilities Commission, Docket No. 98-161. 1998. Concerning the standards and requirements for allocating costs and separating operations between regulated and unregulated operations of a transportation utility, on behalf of the Maine Public Advocate and Olde Port Mariner Fleet, Inc.

33. *Central Maine Power Company Investigation of Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design*, Maine Public Utilities Commission, Docket No. 97-580. 1998. Concerning the treatment of existing rate discounts when designing rates for a transmission and distribution electric utility, on behalf of the Maine Public Advocate.

34. *Pa. Public Utility Commission v. Manufacturers Water Company*, Pennsylvania Public Utility Commission, Docket No. R-00984275. 1998. Concerning rate design on behalf of the Manufacturers Water Industrial Users.

35. *In the Matter of Petition of Pennsgrove Water Supply Company for an Increase in Rates for Water Service*, New Jersey Board of Public Utilities, Docket No. WR98030147. 1998. Concerning the revenue requirements, level of affiliated charges, and rate design for a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

36. *In the Matter of Petition of Seaview Water Company for an Increase in Rates for Water Service*, New Jersey Board of Public Utilities, Docket No. WR98040193. 1999. Concerning the revenue requirements and rate design for a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

37. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Ohio Power Company and Columbus Southern Power Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 98-101-EL-EFC and 98-102-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

38. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Dayton Power and Light Company and Related Matters*, Public Utilities Commission of Ohio, Case No. 98-105-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

39. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Monongahela Power Company and Related Matters*, Public Utilities Commission of Ohio, Case No. 99-106-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

40. *County of Suffolk, et al. v. Long Island Lighting Company, et al.*, U.S. District Court for the Eastern District of New York, Case No. 87-CV-0646. 2000. Submitted two affidavits concerning the calculation and collection of court-ordered refunds to utility customers, on behalf of counsel for the plaintiffs.

41. *Northern Utilities, Inc., Petition for Waivers from Chapter 820*, Maine Public Utilities Commission, Docket No. 99-254. 2000. Concerning the standards and requirements for defining and separating a natural gas utility's core and non-core business functions, on behalf of the Maine Public Advocate.

42. *Notice of Adjustment of the Rates of Kentucky-American Water Company*, Kentucky Public Service Commission, Case No. 2000-120. 2000. Concerning the appropriate methods for allocating costs and designing rates, on behalf of the Kentucky Office of Attorney General.

43. *In the Matter of the Petition of Gordon's Corner Water Company for an Increase in Rates and Charges for Water Service*, New Jersey Board of Public Utilities, Docket No. WR00050304. 2000. Concerning the revenue requirements and rate design for a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

44. *Testimony concerning Arsenic in Drinking Water: An Update on the Science, Benefits, and Costs*, Committee on Science, United States House of Representatives. 2001. Concerning the effects on low-income households and small communities from a more stringent regulation of arsenic in drinking water.

45. *In the Matter of the Application of The Cincinnati Gas & Electric Company for an Increase in Gas Rates in its Service Territory*, Public Utilities Commission of Ohio, Case No. 01-1228-GA-AIR, *et al.* 2002. Concerning the need for and structure of a special rider and alternative form of regulation for an accelerated main replacement program, on behalf of the Ohio Consumers' Counsel.

46. *Pennsylvania State Treasurer's Hearing on Enron and Corporate Governance Issues*. 2002. Concerning Enron's role in Pennsylvania's electricity market and related issues, on behalf of the Pennsylvania AFL-CIO.

47. *An Investigation into the Feasibility and Advisability of Kentucky-American Water Company's Proposed Solution to its Water Supply Deficit*, Kentucky Public Service Commission, Case No. 2001-00117. 2002. Concerning water supply planning, regulatory oversight, and related issue, on behalf of the Kentucky Office of Attorney General.

48. *Joint Application of Pennsylvania-American Water Company and Thames Water Aqua Holdings GmbH*, Pennsylvania Public Utility Commission, Docket Nos. A-212285F0096 and A-230073F0004. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the Pennsylvania Office of Consumer Advocate.

49. *Application for Approval of the Transfer of Control of Kentucky-American Water Company to RWE AG and Thames Water Aqua Holdings GmbH*, Kentucky Public Service Commission, Case No. 2002-00018. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the Kentucky Office of Attorney General.

50. *Joint Petition for the Consent and Approval of the Acquisition of the Outstanding Common Stock of American Water Works Company, Inc., the Parent Company and Controlling Shareholder of West Virginia-American Water Company*, West Virginia Public Service Commission, Case No. 01-1691-W-PC. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the Consumer Advocate Division of the West Virginia Public Service Commission.

51. *Joint Petition of New Jersey-American Water Company, Inc. and Thames Water Aqua Holdings GmbH for Approval of Change in Control of New Jersey-American Water Company, Inc.*, New Jersey Board of Public Utilities, Docket No. WM01120833. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

52. *Illinois-American Water Company, Proposed General Increase in Water Rates*, Illinois Commerce Commission, Docket No. 02-0690. 2003. Concerning rate design and cost of service issues, on behalf of the Illinois Office of the Attorney General.

53. *Pennsylvania Public Utility Commission v. Pennsylvania-American Water Company*, Pennsylvania Public Utility Commission, Docket No. R-00038304. 2003. Concerning rate design and cost of service issues, on behalf of the Pennsylvania Office of Consumer Advocate.

54. *West Virginia-American Water Company,* West Virginia Public Service Commission, Case No. 03-0353-W-42T. 2003. Concerning affordability, rate design, and cost of service issues, on behalf of the West Virginia Consumer Advocate Division.

55. *Petition of Seabrook Water Corp. for an Increase in Rates and Charges for Water Service,* New Jersey Board of Public Utilities, Docket No. WR3010054. 2003. Concerning revenue requirements, rate design, prudence, and regulatory policy, on behalf of the New Jersey Division of Ratepayer Advocate.

56. *Chesapeake Ranch Water Co. v. Board of Commissioners of Calvert County*, U.S. District Court for Southern District of Maryland, Civil Action No. 8:03-cv-02527-AW. 2004. Submitted expert report concerning the expected level of rates under various options for serving new commercial development, on behalf of the plaintiff.

57. *Testimony concerning Lead in Drinking Water*, Committee on Government Reform, United States House of Representatives. 2004. Concerning the trade-offs faced by low-income households when drinking water costs increase, including an analysis of H.R. 4268.

58. *West Virginia-American Water Company,* West Virginia Public Service Commission, Case No. 04-0373-W-42T. 2004. Concerning affordability and rate comparisons, on behalf of the West Virginia Consumer Advocate Division.

59. *West Virginia-American Water Company,* West Virginia Public Service Commission, Case No. 04-0358-W-PC. 2004. Concerning costs, benefits, and risks associated with a wholesale water sales contract, on behalf of the West Virginia Consumer Advocate Division.

60. *Kentucky-American Water Company,* Kentucky Public Service Commission, Case No. 2004-00103. 2004. Concerning rate design and tariff issues, on behalf of the Kentucky Office of Attorney General.

61. *New Landing Utility, Inc.*, Illinois Commerce Commission, Docket No. 04-0610. 2005. Concerning the adequacy of service provided by, and standards of performance for, a water and wastewater utility, on behalf of the Illinois Office of Attorney General.

62. *People of the State of Illinois v. New Landing Utility, Inc.*, Circuit Court of the 15th Judicial District, Ogle County, Illinois, No. 00-CH-97. 2005. Concerning the standards of performance for a water and wastewater utility, including whether a receiver should be appointed to manage the utility's operations, on behalf of the Illinois Office of Attorney General.

63. *Hope Gas, Inc. d/b/a Dominion Hope*, West Virginia Public Service Commission, Case No. 05-0304-G-42T. 2005. Concerning the utility's relationships with affiliated companies, including an appropriate level of revenues and expenses associated with services provided to and received from affiliates, on behalf of the West Virginia Consumer Advocate Division.

64. *Monongahela Power Co. and The Potomac Edison Co.*, West Virginia Public Service Commission, Case Nos. 05-0402-E-CN and 05-0750-E-PC. 2005. Concerning review of a plan to finance the construction of pollution control facilities and related issues, on behalf of the West Virginia Consumer Advocate Division.

65. *Joint Application of Duke Energy Corp., et al., for Approval of a Transfer and Acquisition of Control,* Case Kentucky Public Service Commission, No. 2005-00228. 2005. Concerning the risks and benefits associated with the proposed acquisition of an energy utility, on behalf of the Kentucky Office of the Attorney General.

66. *Commonwealth Edison Company proposed general revision of rates, restructuring and price unbundling of bundled service rates, and revision of other terms and conditions of service,* Illinois Commerce Commission, Docket No. 05-0597. 2005. Concerning rate design and cost of service, on behalf of the Illinois Office of Attorney General.

67. *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, Pennsylvania Public Utility Commission, Docket No. R-00051030. 2006. Concerning rate design and cost of service, on behalf of the Pennsylvania Office of Consumer Advocate.

68. *Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP, proposed general increases in rates for delivery service*, Illinois Commerce Commission, Docket Nos. 06-0070, et al. 2006. Concerning rate design and cost of service, on behalf of the Illinois Office of Attorney General.

69. *Grens, et al., v. Illinois-American Water Co.*, Illinois Commerce Commission, Docket Nos. 5-0681, et al. 2006. Concerning utility billing, metering, meter reading, and customer service practices, on behalf of the Illinois Office of Attorney General and the Village of Homer Glen, Illinois.

70. *Commonwealth Edison Company Petition for Approval of Tariffs Implementing ComEd's Proposed Residential Rate Stabilization Program*, Illinois Commerce Commission, Docket No. 06-0411. 2006. Concerning a utility's proposed purchased power phase-in proposal, in behalf of the Illinois Office of Attorney General.

71. *Illinois-American Water Company, Application for Approval of its Annual Reconciliation of Purchased Water and Purchased Sewage Treatment Surcharges Pursuant to 83 Ill. Adm. Code 655*, Illinois Commerce

Commission, Docket No. 06-0196. 2006. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General and the Village of Homer Glen, Illinois.

72. *Illinois-American Water Company, et al.*, Illinois Commerce Commission, Docket No. 06-0336. 2006. Concerning the risks and benefits associated with the proposed divestiture of a water utility, on behalf of the Illinois Office of Attorney General.

73. *Joint Petition of Kentucky-American Water Company, et al.*, Kentucky Public Service Commission, Docket No. 2006-00197. 2006. Concerning the risks and benefits associated with the proposed divestiture of a water utility, on behalf of the Kentucky Office of Attorney General.

74. *Aqua Illinois, Inc. Proposed Increase in Water Rates for the Kankakee Division*, Illinois Commerce Commission, Docket No. 06-0285. 2006. Concerning various revenue requirement, rate design, and tariff issues, on behalf of the County of Kankakee.

75. *Housing Authority for the City of Pottsville v. Schuylkill County Municipal Authority*, Court of Common Pleas of Schuylkill County, Pennsylvania, No. S-789-2000. 2006. Concerning the reasonableness and uniformity of rates charged by a municipal water authority, on behalf of the Pottsville Housing Authority.

76. *Application of Pennsylvania-American Water Company for Approval of a Change in Control*, Pennsylvania Public Utility Commission, Docket No. A-212285F0136. 2006. Concerning the risks and benefits associated with the proposed divestiture of a water utility, on behalf of the Pennsylvania Office of Consumer Advocate.

77. *Application of Artesian Water Company, Inc., for an Increase in Water Rates*, Delaware Public Service Commission, Docket No. 06-158. 2006. Concerning rate design and cost of service, on behalf of the Staff of the Delaware Public Service Commission.

78. *Central Illinois Light Company, Central Illinois Public Service Company, and Illinois Power Company: Petition Requesting Approval of Deferral and Securitization of Power Costs*, Illinois Commerce Commission, Docket No. 06-0448. 2006. Concerning a utility's proposed purchased power phase-in proposal, in behalf of the Illinois Office of Attorney General.

79. *Petition of Pennsylvania-American Water Company for Approval to Implement a Tariff Supplement Revising the Distribution System Improvement Charge*, Pennsylvania Public Utility Commission, Docket No. P-00062241. 2007. Concerning the reasonableness of a water utility's proposal to increase the cap on a statutorily authorized distribution system surcharge, on behalf of the Pennsylvania Office of Consumer Advocate.

80. *Adjustment of the Rates of Kentucky-American Water Company*, Kentucky Public Service Commission, Case No. 2007-00143. 2007. Concerning rate design and cost of service, on behalf of the Kentucky Office of Attorney General.

81. *Application of Kentucky-American Water Company for a Certificate of Convenience and Necessity Authorizing the Construction of Kentucky River Station II, Associated Facilities and Transmission Main*, Kentucky Public Service Commission, Case No. 2007-00134. 2007. Concerning the life-cycle costs of a planned water supply source and the imposition of conditions on the construction of that project, on behalf of the Kentucky Office of Attorney General.

82. *Pa. Public Utility Commission v. Pennsylvania-American Water Company*, Pennsylvania Public Utility Commission, Docket No. R-00072229. 2007. Concerning rate design and cost of service, on behalf of the Pennsylvania Office of Consumer Advocate.

83. *Illinois-American Water Company Application for Approval of its Annual Reconciliation of Purchased Water and Purchased Sewage Treatment Surcharges*, Illinois Commerce Commission, Docket No. 07-0195. 2007. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General.

84. *In the Matter of the Application of Aqua Ohio, Inc. to Increase Its Rates for Water Service Provided in the Lake Erie Division*, Public Utilities Commission of Ohio, Case No.07-0564-WW-AIR. 2007. Concerning rate design and cost of service, on behalf of the Office of the Ohio Consumers' Counsel.

85. *Pa. Public Utility Commission v. Aqua Pennsylvania Inc.,* Pennsylvania Public Utility Commission, Docket No. R-00072711. 2008. Concerning rate design, on behalf of the Masthope Property Owners Council.

86. *Illinois-American Water Company Proposed increase in water and sewer rates*, Illinois Commerce Commission, Docket No. 07-0507. 2008. Concerning rate design and demand studies, on behalf of the Illinois Office of Attorney General.

87. *Central Illinois Light Company, d/b/a AmerenCILCO; Central Illinois Public Service Company, d/b/a AmerenCIPS; Illinois Power Company, d/b/a AmerenIP: Proposed general increase in rates for electric delivery service*, Illinois Commerce Commission Docket Nos. 07-0585, 07-0586, 07-0587. 2008. Concerning rate design and cost of service studies, on behalf of the Illinois Office of Attorney General.

88. *Commonwealth Edison Company: Proposed general increase in electric rates*, Illinois Commerce Commission Docket No. 07-0566. 2008. Concerning rate design and cost of service studies, on behalf of the Illinois Office of Attorney General.

89. *In the Matter of Application of Ohio American Water Co. to Increase Its Rates*, Public Utilities Commission of Ohio, Case No. 07-1112-WS-AIR. 2008. Concerning rate design and cost of service, on behalf of the Office of the Ohio Consumers' Counsel.

90. *In the Matter of the Application of The East Ohio Gas Company d/b/a Dominion East Ohio for Authority to Increase Rates for its Gas Service*, Public Utilities Commission of Ohio, Case Nos. 07-829-GA-AIR, et al. 2008. Concerning the need for, and structure of, an accelerated infrastructure replacement program and rate surcharge, on behalf of the Office of the Ohio Consumers' Counsel.

91. *Pa. Public Utility Commission v. Pennsylvania American Water Company*, Pennsylvania Public Utility Commission, Docket No. R-2008-2032689. 2008. Concerning rate design, cost of service study, and other tariff issues, on behalf of the Pennsylvania Office of Consumer Advocate.

92. *Pa. Public Utility Commission v. York Water Company*, Pennsylvania Public Utility Commission, Docket No. R-2008-2023067. 2008. Concerning rate design, cost of service study, and other tariff issues, on behalf of the Pennsylvania Office of Consumer Advocate.

93. *Northern Illinois Gas Company d/b/a Nicor Gas Company*, Illinois Commerce Commission, Docket No. 08-0363. 2008. Concerning rate design, cost of service, and automatic rate adjustments, on behalf of the Illinois Office of Attorney General.

94. *West Virginia American Water Company*, West Virginia Public Service Commission, Case No. 08-0900-W-42T. 2008. Concerning affiliated interest charges and relationships, on behalf of the Consumer Advocate Division of the Public Service Commission of West Virginia.

95. *Illinois-American Water Company Application for Approval of its Annual Reconciliation of Purchased Water and Purchased Sewage Treatment Surcharges*, Illinois Commerce Commission, Docket No. 08-0218. 2008. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General.

96. *In the Matter of Application of Duke Energy Ohio, Inc. for an Increase in Electric Rates*, Public Utilities Commission of Ohio, Case No. 08-0709-EL-AIR. 2009. Concerning rate design and cost of service, on behalf of the Office of the Ohio Consumers' Counsel.

97. *The Peoples Gas Light and Coke Company and North Shore Gas Company Proposed General Increase in Rates for Gas Service*, Illinois Commerce Commission, Docket Nos. 09-0166 and 09-0167. 2009. Concerning rate design and automatic rate adjustments on behalf of the Illinois Office of Attorney General, Citizens Utility Board, and City of Chicago.

98. *Illinois-American Water Company Proposed Increase in Water and Sewer Rates*, Illinois Commerce Commission, Docket No. 09-0319. 2009. Concerning rate design and cost of service on behalf of the Illinois Office of Attorney General and Citizens Utility Board.

99. *Pa. Public Utility Commission v. Aqua Pennsylvania Inc.*, Pennsylvania Public Utility Commission, Docket No. R-2009-2132019. 2010. Concerning rate design, cost of service, and automatic adjustment tariffs, on behalf of the Pennsylvania Office of Consumer Advocate.

100. *Apple Canyon Utility Company and Lake Wildwood Utilities Corporation Proposed General Increases in Water Rates*, Illinois Commerce Commission, Docket Nos. 09-0548 and 09-0549. 2010. Concerning parent-company charges, quality of service, and other matters, on behalf of Apple Canyon Lake Property Owners' Association and Lake Wildwood Association, Inc.

101. *Application of Aquarion Water Company of Connecticut to Amend its Rate Schedules*, Connecticut Department of Public Utility Control, Docket No. 10-02-13. 2010. Concerning rate design, proof of revenues, and other tariff issues, on behalf of the Connecticut Office of Consumer Counsel.

102. *Illinois-American Water Company Annual Reconciliation of Purchased Water and Sewage Treatment Surcharges*, Illinois Commerce Commission, Docket No. 09-0151. 2010. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General.

103. *Pa. Public Utility Commission v. Pennsylvania-American Water Co.*, Pennsylvania Public Utility Commission, Docket Nos. R-2010-2166212, et al. 2010. Concerning rate design and cost of service study for four wastewater utility districts, on behalf of the Pennsylvania Office of Consumer Advocate.

104. *Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, Illinois Power Company d/b/a AmerenIP Petition for accounting order*, Illinois Commerce

Commission, Docket No. 10-0517. 2010. Concerning ratemaking procedures for a multi-district electric and natural gas utility, on behalf of the Illinois Office of Attorney General.

105. *Commonwealth Edison Company Petition for General Increase in Delivery Service Rates*, Illinois Commerce Commission Docket No. 10-0467. 2010. Concerning rate design and cost of service study, on behalf of the Illinois Office of Attorney General.

106. *Pa. Public Utility Commission v. City of Lancaster Bureau of Water*, Pennsylvania Public Utility Commission, Docket No. R-2010-2179103. 2010. Concerning rate design, cost of service, and cost allocation, on behalf of the Pennsylvania Office of Consumer Advocate.

107. *Application of Yankee Gas Services Company for Amended Rate Schedules*, Connecticut Department of Public Utility Control, Docket No. 10-12-02. 2011. Concerning rate design and cost of service for a natural gas utility, on behalf of the Connecticut Office of Consumers' Counsel.

108. *California-American Water Company*, California Public Utilities Commission, Application 10-07-007. 2011. Concerning rate design and cost of service for multiple water-utility service areas, on behalf of The Utility Reform Network.

109. *Little Washington Wastewater Company, Inc., Masthope Wastewater Division*, Pennsylvania Public Utility Commission Docket No. R-2010-2207833. 2011. Concerning rate design and various revenue requirements issues, on behalf of the Masthope Property Owners Council.

110. *In the matter of Pittsfield Aqueduct Company, Inc.*, New Hampshire Public Utilities Commission Case No. DW 10-090. 2011. Concerning rate design and cost of service on behalf of the New Hampshire Office of the Consumer Advocate.

111. *In the matters of Pennichuck Water Works, Inc. Permanent Rate Case and Petition for Approval of Special Contract with Anheuser-Busch, Inc.*, New Hampshire Public Utilities Commission Case Nos. DW 10-091 and DW 11-014. 2011. Concerning rate design, cost of service, and contract interpretation on behalf of the New Hampshire Office of the Consumer Advocate.

112. *Artesian Water Co., Inc. v. Chester Water Authority*, U.S. District Court for the Eastern District of Pennsylvania Case No. 10-CV-07453-JP. 2011. Concerning cost of service, ratemaking methods, and contract interpretation on behalf of Chester Water Authority.

113. *North Shore Gas Company and The Peoples Gas Light and Coke Company Proposed General Increases in Rates for Gas Service*, Illinois Commerce Commission, Docket Nos. 11-0280 and 11-0281. 2011. Concerning rate design and cost of service on behalf of the Illinois Office of Attorney General, the Citizens Utility Board, and the City of Chicago.

114. *Ameren Illinois Company: Proposed general increase in electric delivery service rates and gas delivery service rates*, Illinois Commerce Commission, Docket Nos. 11-0279 and 11-0282. 2011. Concerning rate design and cost of service for natural gas and electric distribution service, on behalf of the Illinois Office of Attorney General and the Citizens Utility Board.

115. *Pa. Public Utility Commission v. Pennsylvania-American Water Co.*, Pennsylvania Public Utility Commission, Docket No. R-2011-2232243. 2011. Concerning rate design, cost of service, sales forecast,

and automatic rate adjustments on behalf of the Pennsylvania Office of Consumer Advocate.

116. *Aqua Illinois, Inc. Proposed General Increase in Water and Sewer Rates*, Illinois Commerce Commission, Docket No. 11-0436. 2011. Concerning rate design and cost of service on behalf of the Illinois Office of Attorney General.

117. *City of Nashua Acquisition of Pennichuck Corporation*, New Hampshire Public Utilities Commission, Docket No. DW 11-026. 2011. Concerning the proposed acquisition of an investor-owned utility holding company by a municipality, including appropriate ratemaking methodologies, on behalf of the New Hampshire Office of Consumer Advocate.

118. *An Application by Heritage Gas Limited for the Approval of a Schedule of Rates, Tolls and Charges*, Nova Scotia Utility and Review Board, Case NSUARB-NG-HG-R-11. 2011. Concerning rate design and cost of service, on behalf of the Nova Scotia Consumer Advocate.

119. *An Application of Halifax Regional Water Commission for Approval of a Cost of Service and Rate Design Methodology*, Nova Scotia Utility and Review Board , Case NSUARB-W-HRWC-R-11. 2011. Concerning rate design and cost of service, on behalf of the Nova Scotia Consumer Advocate.

120. *National Grid USA and Liberty Energy Utilities Corp.*, New Hampshire Public Utilities Commission, Docket No. DG 11-040. 2011. Concerning the costs and benefits of a proposed merger and related conditions, on behalf of the New Hampshire Office of Consumer Advocate.

121. *Great Northern Utilities, Inc., et al.*, Illinois Commerce Commission, Docket Nos. 11-0059, et al. 2012. Concerning options for mitigating rate impacts and consolidating small water and wastewater utilities for ratemaking purposes, on behalf of the Illinois Office of Attorney General.

122. *Pa. Public Utility Commission v. Aqua Pennsylvania, Inc.*, Pennsylvania Public Utility Commission, Docket No. R-2011-2267958. 2012. Concerning rate design, cost of service, and automatic rate adjustment mechanisms, on behalf of the Pennsylvania Office of Consumer Advocate.

123. *Golden State Water Company*, California Public Utilities Commission, Application 11-07-017. 2012. Concerning rate design and quality of service, on behalf of The Utility Reform Network.

124. *Golden Heart Utilities, Inc. and College Utilities Corporation*, Regulatory Commission of Alaska, Case Nos. U-11-77 and U-11-78. 2012. Concerning rate design and cost of service, on behalf of the Alaska Office of the Attorney General.

125. *Illinois-American Water Company*, Illinois Commerce Commission, Docket No. 11-0767. 2012. Concerning rate design, cost of service, and automatic rate adjustment mechanisms, on behalf of the Illinois Office of Attorney General.

126. *Application of Tidewater Utilities, Inc., for a General Rate Increase in Water Base Rates and Tariff Revisions*, Delaware Public Service Commission, Docket No. 11-397. 2012. Concerning rate design and cost of service study, on behalf of the Staff of the Delaware Public Service Commission.

127. *In the Matter of the Philadelphia Water Department's Proposed Increase in Rates for Water and Wastewater Utility Services*, Philadelphia Water Commissioner, FY 2013-2016. 2012. Concerning rate

design and related issues for storm water service, on behalf of Citizens for Pennsylvania's Future.

128. *Corix Utilities (Illinois) LLC, Hydro Star LLC, and Utilities Inc. Joint Application for Approval of a Proposed Reorganization*, Illinois Commerce Commission, Docket No. 12-0279. 2012. Concerning merger-related synergy savings and appropriate ratemaking treatment of the same, on behalf of the Illinois Office of Attorney General.

129. *North Shore Gas Company and The Peoples Gas Light and Coke Company*, Illinois Commerce Commission, Docket Nos. 12-0511 and 12-0512. 2012. Concerning rate design, cost of service study, and automatic rate adjustment tariff on behalf of the Illinois Office of Attorney General.

130. *Pa. Public Utility Commission v. City of Lancaster Sewer Fund*, Pennsylvania Public Utility Commission, Docket No. R-2012-2310366. 2012. Concerning rate design, cost of service, and cost allocation, on behalf of the Pennsylvania Office of Consumer Advocate.

131. *Aquarion Water Company of New Hampshire*, New Hampshire Public Utilities Commission, Docket No. DW 12-085. 2013. Concerning tariff issues, including an automatic adjustment clause for infrastructure improvement, on behalf of the New Hampshire Office of Consumer Advocate.

132. *In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Electric Distribution Rates*, Public Utilities Commission of Ohio, Case No. 12-1682-EL-AIR, et al. 2013. Concerning rate design and tariff issues, on behalf of the Office of the Ohio Consumers' Counsel.

133. *In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Natural Gas Distribution Rates*, Public Utilities Commission of Ohio, Case No. 12-1685-GA-AIR, et al. 2013. Concerning cost-of-service study, rate design, and tariff issues, on behalf of the Office of the Ohio Consumers' Counsel.

134. *In the Matter of the Application of The Dayton Power and Light Company to Establish a Standard Service Offer in the Form of an Electric Security Plan*, Public Utilities Commission of Ohio, Case No. 12-426-EL-SSO, et al. 2013. Concerning rate design, on behalf of the Office of the Ohio Consumers' Counsel.

135. *Application of the Halifax Regional Water Commission, for Approval of Amendments to its Schedule of Rates and Charges and Schedule of Rules and Regulations for the delivery of water, public and private fire protection, wastewater and stormwater services*, Nova Scotia Utility and Review Board, Matter No. M05463. 2013. Concerning rate design, cost-of-service study, and miscellaneous tariff provisions, on behalf of the Consumer Advocate of Nova Scotia.

136. *California Water Service Co. General Rate Case Application* , California Public Utilities Commission, Docket No. A.12-07-007. 2013. Concerning rate design, phase-in plans, low-income programs, and other tariff issues, on behalf of The Utility Reform Network.

137. *Application of The United Illuminating Company to Amend its Rate Schedules*, Connecticut Public Utility Regulatory Authority, Docket No. 13-01-19. 2013. Concerning sales forecast, rate design, and other tariff issues, on behalf of the Connecticut Office of Consumer Counsel.

138. *Application of Aquarion Water Company of Connecticut to Amend its Rate Schedules*, Connecticut Public Utility Regulatory Authority, Docket No. 13-02-20. 2013. Concerning sales forecast and rate design on

behalf of the Connecticut Office of Consumer Counsel.

139. *Ameren Illinois Company, Proposed General Increase in Natural Gas Delivery Service Rates*, Illinois Commerce Commission, Docket No. 13-0192. 2013. Concerning rate design and revenue allocation, on behalf of the Illinois Office of Attorney General and Citizens Utility Board.

140. *Commonwealth Edison Company, Tariff filing to present the Illinois Commerce Commission with an opportunity to consider revenue neutral tariff changes related to rate design*, Docket No. 13-0387. 2013. Concerning rate design and cost of service study issues, on behalf of the Illinois Office of Attorney General.

141. *In the Matter of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*, District of Columbia Public Service Commission, Formal Case No. 1103. 2013. Concerning rate design, revenue allocation, and cost-of-service study issues, on behalf of the District of Columbia Office of Peoples' Counsel.

142. *Pa. Public Utility Commission v. Pennsylvania-American Water Co.*, Pennsylvania Public Utility Commission, Docket No. R-2013-2355276. 2013. Concerning rate design, revenue allocation, and regulatory policy, on behalf of the Pennsylvania Office of Consumer Advocate.

143. *In the Matter of the Revenue Requirement and Transmission Tariff Designated as TA364*-8 *filed by Chugach Electric Association, Inc.*, Regulatory Commission of Alaska, U-13-007. 2013. Concerning rate design and cost-of-service study issues, on behalf of the Alaska Office of the Attorney General.

144. *Ameren Illinois Company: Tariff filing to present the Illinois Commerce Commission with an opportunity to consider revenue neutral tariff changes related to rate design*, Docket No. 13-0476. 2013. Concerning rate design and cost of service study issues, on behalf of the Illinois Office of Attorney General.

145. *Pa. Public Utility Commission v. City of Bethlehem Bureau of Water*, Pennsylvania Public Utility Commission, Docket No. R-2013-2390244. 2014. Concerning rate design, cost of service study, and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

146. *In the Matter of the Tariff Revision Designated as TA332-121 filed by the Municipality of Anchorage d/b/a Municipal Light and Power Department*, Regulatory Commission of Alaska, U-13-184. 2014. Concerning rate design and cost-of-service study issues, on behalf of the Alaska Office of the Attorney General.

147. *Pa. Public Utility Commission v. Pike County Light and Power Co. - Gas*, Pennsylvania Public Utility Commission, Docket No. R-2013-2397353. 2014. Concerning rate design and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

148. *Pa. Public Utility Commission v. Pike County Light and Power Co. - Electric*, Pennsylvania Public Utility Commission, Docket No. R-2013-2397237. 2014. Concerning rate design, cost of service study, and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

149. *The Peoples Gas Light and Coke Company North Shore Gas Company Proposed General Increase in Rates for Gas Service*, Illinois Commerce Commission, Docket Nos. 14-0224 and 14-0225. 2014. Concerning rate design on behalf of the Illinois Office of the Attorney General and the Environmental

Law and Policy Center.

150. *Apple Valley Ranchos Water Company*, California Public Utilities Commission, Docket No. A.14-01-002. 2014. Concerning rate design and automatic rate adjustment mechanisms on behalf of the Town of Apple Valley.

151. *Application by Heritage Gas Limited for Approval to Amend its Franchise Area*, Nova Scotia Utility and Review Board, Matter No. M06271. 2014. Concerning criteria, terms, and conditions for expanding a utility's service area and using transported compressed natural gas to serve small retail customers, on behalf of the Nova Scotia Consumer Advocate.

152. *Notice of Intent of Entergy Mississippi, Inc. to Modernize Rates to Support Economic Development, Power Procurement, and Continued Investment*, Mississippi Public Service Commission Docket No. 2014-UN-132. 2014. Concerning rate design and tariff issues, on behalf of the Mississippi Public Utilities Staff.

153. *Pa. Public Utility Commission v. City of Lancaster Bureau of Water*, Pennsylvania Public Utility Commission, Docket No. R-2014-2418872. 2014. Concerning rate design, cost of service study, and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

154. *Pa. Public Utility Commission v. Borough of Hanover Municipal Water Works*, Pennsylvania Public Utility Commission, Docket No. R-2014-2428304. 2014. Concerning rate design, cost of service study, and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

155. *Investigation of Commonwealth Edison Company's Cost of Service for Low-Use Customers in Each Residential Class*, Illinois Commerce Commission, Docket No. 14-0384. 2014. Concerning rate design on behalf of the Illinois Office of Attorney General.

156. *Application of the Halifax Regional Water Commission, for Approval of its Schedule of Rates and Charges and Schedule of Rules and Regulations for the Provision of Water, Public and Private Fire Protection, Wastewater and Stormwater Services*, Nova Scotia Utility and Review Board, Matter No. M06540. 2015. Concerning rate design, cost of service study, and tariff issues on behalf of the Nova Scotia Consumer Advocate.

157. *Testimony concerning organization and regulation of Philadelphia Gas Works*, Philadelphia City Council's Special Committee on Energy Opportunities. 2015.

158. *Testimony concerning proposed telecommunications legislation*, Maine Joint Standing Committee on Energy, Utilities, and Technology. 2015.

159. *Pa. Public Utility Commission v. United Water Pennsylvania, Inc.*, Pennsylvania Public Utility Commission, Docket No. R-2015-2462723. 2015. Concerning rate design, cost of service study, and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

160. *Ameren Illinois Company Proposed General Increase in Gas Delivery Service Rates*, Illinois Commerce Commission, Docket No. 15-0142. 2015. Concerning rate design on behalf of the Illinois Office of Attorney General.

161. *Maine Natural Gas Company Request for Multi-Year Rate Plan*, Maine Public Utilities Commission, Docket No. 2015-00005. 2015. Concerning rate design and automatic rate adjustment tariffs on behalf of the Maine Office of the Public Advocate.

162. *Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer*, Public Utilities Commission of Ohio, Case No. 14-1297-EL-SSO. 2015. Concerning rate design and proposed rate discounts on behalf of the Office of the Ohio Consumers' Counsel.

163. *An Application of the Halifax Regional Water Commission, for approval of revisions to its Cost of Service Manual and Rate Design for Stormwater Service*, Nova Scotia Utility and Review Board, Matter No. M07147. 2016. Concerning stormwater rate design and cost of service, on behalf of the Nova Scotia Consumer Advocate.

164. *In the Matter of An Application by Heritage Gas Limited for Enhancement to Its Existing Residential Retro-Fit Assistance Fund*, Nova Scotia Utility and Review Board, Matter No. M07146. 2016. Concerning costs and benefits associated with utility system expansion, on behalf of the Nova Scotia Consumer Advocate.

165. *In the Matter of the Application of UNS Electric, Inc. for the Establishment of Just and Reasonable Rates and Charges*, Arizona Corporation Commission, Docket No. E-04204A-15-0142. 2016. Concerning rate design and residential demand charges on behalf of Arizona Utility Ratepayer Alliance.

166. *In the Matter of Application of Water Service Corporation of Kentucky for a General Adjustment in Existing Rates*, Kentucky Public Service Commission, Case No. 2015-00382. 2016. Concerning rate design and service area consolidation on behalf of the Kentucky Office of the Attorney General.

167. *Massachusetts Electric Company and Nantucket Electric Company*, Massachusetts Department of Public Utilities, Docket No. DPU 15-155. 2016. Concerning rate design and cost-of-service studies on behalf of the Massachusetts Office of Attorney General.

168. *In the Matter of Abenaki Water Company*, New Hampshire Public Utilities Commission, Docket No. DW 15-199. 2016. Concerning rate design on behalf of the New Hampshire Office of the Consumer Advocate.

169. *In the Matter of an Application by Heritage Gas Limited for Approval of its Customer Retention Program*, Nova Scotia Utility and Review Board Matter No. M07346. 2016. Concerning a regulatory response to competition and potential business failure on behalf of the Nova Scotia Consumer Advocate.

170. *Joint Application of Pennsylvania-American Water Company and the Sewer Authority of the City of Scranton*, Pennsylvania Public Utility Commission Docket No. A-2016-2537209. 2016. Concerning the lawfulness, costs and benefits, and ratemaking treatment of a proposed acquisition of a combined wastewater and storm water utility on behalf of the Pennsylvania Office of Consumer Advocate.

171. *Application of The United Illuminating Company to Amend its Rate Schedules*, Connecticut Public Utility Regulatory Authority Docket No. 16-06-04. 2016. Concerning rate design, cost-of-service study, and other tariff issues on behalf of the Connecticut Office of Consumer Counsel.

172.*Ameren Illinois Company Tariff filing to present the Illinois Commerce Commission with an opportunity to consider revenue neutral tariff changes related to rate design*, Illinois Commerce Commission Docket No. 16-0387. 2016. Concerning rate design and cost-of-service study on behalf of the Illinois Office of the Attorney General.

173.*Unitil Energy Systems, Inc.*, New Hampshire Public Utilities Commission Docket No. 16-384. 2016. Concerning rate design and cost-of-service study on behalf of the New Hampshire Office of Consumer Advocate.

174.*Liberty Utilities (Granite State Electric) Corp.*, New Hampshire Public Utilities Commission Docket No. 16-383. 2016. Concerning rate design and cost-of-service study on behalf of the New Hampshire Office of Consumer Advocate.

175.*Arizona Public Service Co.*, Arizona Corporation Commission Docket No. E-01345A-16-0123. 2017. Concerning rate design and cost-of-service study on behalf of the Arizona Utility Ratepayer Alliance.

176.*Commonwealth Edison Company, Tariff filing to present the Illinois Commerce Commission with an opportunity to consider revenue neutral tariff changes related to rate design*, Illinois Commerce Commission Docket No. 17-0049. 2017. Concerning rate design and cost of service study issues, on behalf of the Illinois Office of Attorney General.

177.*NSTAR Electric Company and Western Massachusetts Electric Company*, Massachusetts Department of Public Utilities Docket No. D.P.U. 17-05. 2017. Concerning rate design and cost of service study issues, on behalf of the Massachusetts Office of Attorney General.

178.*In the Matter of the Tariff Revision Designated as TA857-2 Filed by Alaska Power Company*, Regulatory Commission of Alaska No. U-16-078. 2017. Concerning rate design and cost of service study issues on behalf of the Alaska Office of the Attorney General.

179.*In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota*, Minnesota Public Utilities Commission Docket No. E015/GR-16-664. 2017. Concerning rate design and cost of service study issues on behalf of AARP.

180.*Pennsylvania Public Utility Commission v. Pennsylvania-American Water Company*, Pennsylvania Public Utility Commission, Docket No. R-2017-2595853. 2017. Concerning rate design, cost of service, and policy issues, on behalf of the Pennsylvania Office of Consumer Advocate.

181.*Aqua Illinois, Inc. Proposed Rate Increases for Water and Sewer Services*, Illinois Commerce Commission, Docket No. 17-0259. 2017. Concerning rate design and single-tariff pricing, on behalf of the Illinois Office of Attorney General.

182.*Petition of Pennsylvania-American Water Company for Approval of Tariff Changes and Accounting and Rate Treatment Related to Replacement of Lead Customer-Owned Service Pipes*, Pennsylvania Public Utility Commission, Docket No. P-2017-2606100. 2017. Concerning public policy and ratemaking issues associated with the replacement of customer-owned lead service lines, on behalf of the Pennsylvania Office of Consumer Advocate.

183.*In the Matter of Application and Notice of Change in Natural Gas Rates of Montana-Dakota Utilities Co.*, North Dakota Public Service Commission, Case No. PU-17-295. 2017. Concerning rate design and cost of service study issues, on behalf of AARP.

184. *Aqua Illinois, Inc. Petition for the Issuance of a Certificate of Public Convenience and Necessity to Operate a Water and Wastewater System in the Village of Peotone*, Illinois Commerce Commission, Docket No. 17-0314. 2018. Concerning rate consolidation and rate design, on behalf of the Illinois Office of Attorney General.

185. *Application of the Connecticut Light and Power Company d/b/a Eversource Energy to Amend its Rate Schedules, Connecticut Public Utilities Regulatory Authority*, Docket No. 17-10-46. 2018. Concerning rate design issues, on behalf of the Connecticut Office of Consumer Counsel.

186. *Application by Heritage Gas for Approval of a Long-Term Natural Gas Transportation Contract and Cost Recovery Mechanism*, Nova Scotia Utility and Review Board, Matter M08473. 2018. Concerning evaluation of costs, benefits, and risks of a long-term natural gas pipeline contract, on behalf of the Consumer Advocate of Nova Scotia.

187. *Boston Gas Company and Colonial Gas Company*, Massachusetts Department of Public Utilities, D.P.U. 17-170. 2018. Concerning class revenue allocation and rate design, on behalf of the Massachusetts Office of Attorney General.

188. *In the Matter of the Application of Maryland-American Water Company for Authority to Adjust its Existing Schedule of Tariffs and Rates*, Maryland Public Service Commission, Case No. 9487. 2018. Concerning cost-of-service study, on behalf of the Staff of the Maryland Public Service Commission.

189. *Joint Application and Petition of South Carolina Electric & Gas Company and Dominion Energy, Inc. for review and approval of a proposed business combination between SCANA Corporation and Dominion Energy, Inc., as may be required, and for a prudency determination regarding the abandonment of the V.C. Summer Units 2 & 3 Project and associated merger benefits and cost recovery plans*, South Carolina Public Service Commission, Docket No. 2017-370-E. 2018. Concerning regulatory policy, prudency of decision-making, and cost sharing, on behalf of AARP.

190. *Application of Transource Pennsylvania, LLC for approval of the Siting and Construction of the 230 kV Transmission Line Associated with the Independence Energy Connection - East and West Projects in portions of York and Franklin Counties, Pennsylvania*, Pennsylvania Public Utility Commission, Docket Nos. A-2017-2640195, et al. 2018. Concerning regulatory policy and benefit-cost analysis for a proposed high-voltage electric transmission line, on behalf of the Pennsylvania Office of Consumer Advocate.

191. *Pa. Public Utility Commission v. Pittsburgh Water and Sewer Authority*, Pennsylvania Public Utility Commission, Docket Nos. R-2018-3002645, et al. 2018. Concerning cost-of-service study and rate design for a water and wastewater utility, on behalf of the Pennsylvania Office of Consumer Advocate.

192. *West Virginia-American Water Company Rule 42T Tariff Filing to Increase Rates and Charges*, West Virginia Public Service Commission, Case No. 18-0573-W-42T, et al. 2018. Concerning revenue decoupling, on behalf of the Consumer Advocate Division.

193. *Philadelphia Gas Works and Philadelphia Facilities Management Corporation Petition for Approval and Recommendation for Approval of Certain Transactions and Contracts for the Purchase, Storage, Distribution and/or Transmission of Natural and Other Gas, and also Certain Transactions and Contracts Respecting Real Property Owned by the City of Philadelphia and Operated by the Philadelphia

Gas Works, Philadelphia Gas Commission. 2018. Concerning regulatory policy and cost-benefit analysis for a proposed public-private partnership, on behalf of the Philadelphia Public Advocate.

194. *Pa. Public Utility Commission v. Aqua Pennsylvania, Inc., and Aqua Pennsylvania Wastewater, Inc.*, Pennsylvania Public Utility Commission, Docket Nos. R-2018-3003558, et al. 2018. Concerning rate design, class revenue allocation, and automatic rate adjustment mechanism, on behalf of the Pennsylvania Office of Consumer Advocate.

195. *In the Matter of Commission Initiated Investigation into Rates and Revenue Requirements and Customer Service and Communication Issues Pertaining to Central Maine Power Company,* Maine Public Utilities Commission, Docket No. 2018-00194. 2019. Concerning cost-of-service studies and rate design, on behalf of the Maine Office of Public Advocate.

196. *Northern Illinois Gas Company d/b/a Nicor Gas Company: Proposed general increase in gas rates,* Illinois Commerce Commission, Docket No. 18-1775. 2019. Concerning rate design, cost-of-service study, class revenue allocation, and automatic rate adjustment mechanisms, on behalf of the Illinois Office of the Attorney General.

197. *Massachusetts Electric Co. and Nantucket Electric Co., d/b/a/ National Grid*, Massachusetts Department of Public Utilities, D.P.U. 18-150. 2019. Concerning rate design, cost-of-service study, class revenue allocation, and time-of-use rates, on behalf of the Massachusetts Office of Attorney General.

198. *Implementation of Chapter 32 of the Public Utility Code Regarding Pittsburgh Water and Sewer Authority – Stage 1*, Pennsylvania Public Utility Commission, Docket Nos. M-2018-2640802 and M-2018-2640803. 2019. Concerning billing, metering, rate design, and other compliance issues for a municipal water authority, on behalf of the Pennsylvania Office of Consumer Advocate.

199. *Commonwealth Edison Company Petition for approval of a Revision to Integrated Distribution Company Implementation Plan. Creation of Rate Residential Time of Use Pricing Pilot ("Rate RTOUPP").* Illinois Commerce Commission, Docket Nos. 18-1725/18-1824 (Cons.). Concerning time-of-use rates, on behalf of the Illinois Office of Attorney General.

200. *Washington Utilities and Transportation Commission v. Northwest Natural Gas Co.*, Washington Utilities and Transportation Commission, Docket UG-181053. 2019. Concerning a proposed revenue decoupling automatic rate adjustment mechanism, on behalf of the Washington Office of Attorney General, Public Counsel Unit.

201. *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and to Revise its Terms and Conditions for Gas Service*, Maryland Public Service Commission, Case No. 9605. 2019. Concerning cost-of-service study on behalf of the Staff of the Maryland Public Service Commission.

202. *Public Service Company of New Hampshire, d/b/a Eversource Energy,* New Hampshire Public Utilities Commission, Docket No. DE 19-057. 2019. Concerning class revenue allocation, rate design, revenue decoupling, other automatic rate adjustment mechanisms, and miscellaneous tariff issues on behalf of AARP.

203. *In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the*

Properties of Southwest Gas Corporation Devoted to its Arizona Operations, Arizona Corporation Commission, Docket No. G-01551A-19-0055. 2020. Concerning certain relationships with affiliates, premature pipe replacement, revenue decoupling, automatic rate adjustment mechanisms, and rate design on behalf of Arizona Grain, Inc.

204. *Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of an Increase in Base Distribution Rates*, Massachusetts Department of Public Utilities, Docket No. D.P.U. 19-120. 2020. Concerning cost-of-service study, class revenue allocation, surcharges, and miscellaneous tariff provisions, on behalf of the Massachusetts Office of Attorney General.

205. *In the Matter of an Application of the Halifax Regional Water Commission for Approval of a Schedule of Rates and Charges*, Nova Scotia Utility and Review Board, Matter M09589. 2020. Concerning regulatory policy, cost-of-service study, and rate design, on behalf of the Nova Scotia Consumer Advocate.

206. *Pa. Public Utility Commission v. UGI Utilities Inc. - Gas Division*, Pennsylvania Public Utility Commission, Docket No. R-2019-3015162. 2020. Concerning regulatory policy, on behalf of the Pennsylvania Office of Consumer Advocate.

207. *Pa. Public Utility Commission v. Philadelphia Gas Works*, Pennsylvania Public Utility Commission, Docket No. R-2020-3017206. 2020. Concerning regulatory policy, on behalf of the Pennsylvania Office of Consumer Advocate.

208. *Pa. Public Utility Commission v. Pittsburgh Water and Sewer Authority*, Pennsylvania Public Utility Commission, Docket Nos. R-2020-3017951, *et al.* 2020. Concerning regulatory policy, cost-of-service study, and rate design, on behalf of the Pennsylvania Office of Consumer Advocate.

209. *Pa. Public Utility Commission v. Columbia Gas of Pa.*, Pennsylvania Public Utility Commission, Docket No. R-2020-3018835. 2020. Concerning regulatory policy, on behalf of the Pennsylvania Office of Consumer Advocate.

210. *Pa. Public Utility Commission v. Pennsylvania-American Water Co.*, Pennsylvania Public Utility Commission, Docket No. R-2020-3019369. 2020. Concerning regulatory policy, cost-of-service studies, rate design, and tariff issues, on behalf of the Pennsylvania Office of Consumer Advocate.

211. *In the Matter of the Application of Arizona Public Service Company*, Arizona Corporation Commission, Docket No. E-01345A-19-0236. 2020. Concerning residential rate design, on behalf of AARP.

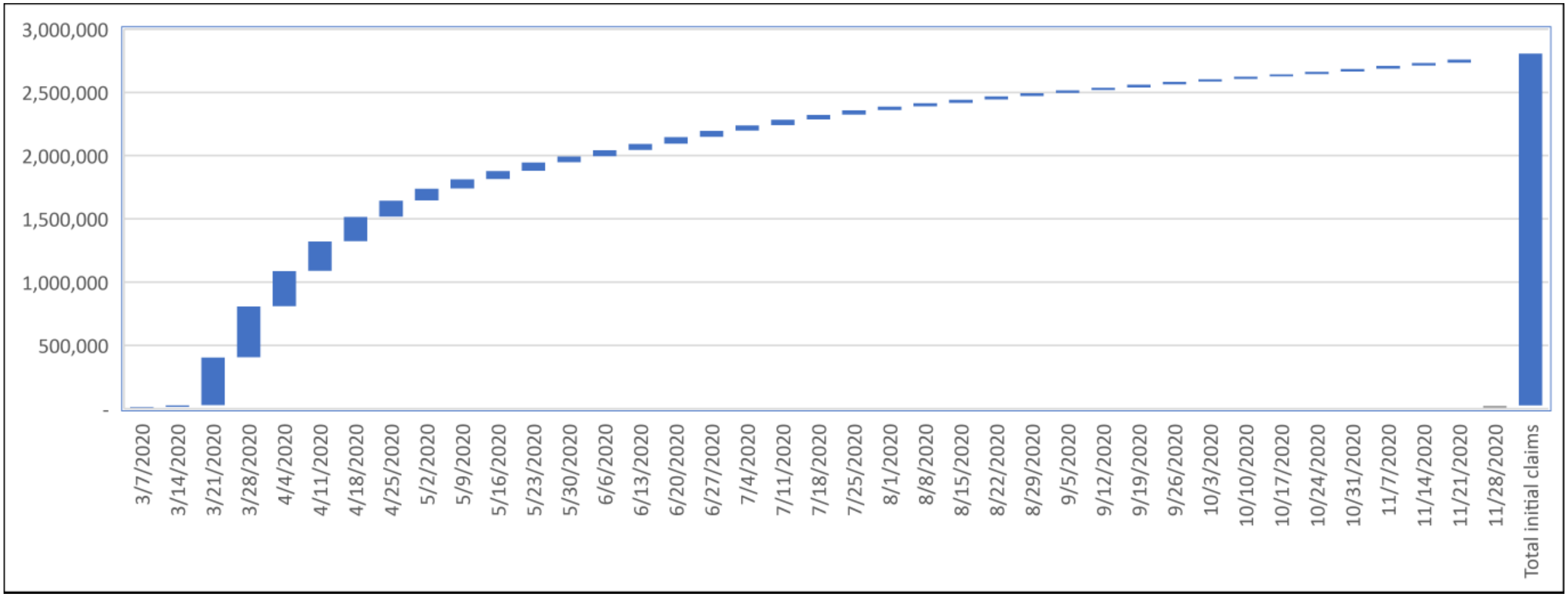
212. *Pa. Public Utility Commission v. City of Bethlehem - Water Department*, Pennsylvania Public Utility Commission, Docket No. R-2020-3020256. 2020. Concerning regulatory policy, on behalf of the Pennsylvania Office of Consumer Advocate.

213. *Tyson Fellman, et al. v. Public Utility District No. 1 of Franklin County*, Superior Court of Franklin County (Washington), Case No. 18-2-50589-11. 2020. Expert declaration concerning cost-of-service studies and rate design, on behalf of the plaintiffs.

214. *Application of Dominion Energy South Carolina, Inc. for Adjustment of Rates and Charges*, South Carolina Public Service Commission, Docket No. 2020-125-E. 2020. Concerning residential rate design, on behalf of AARP.

215. *Pa. Public Utility Commission v. Audubon Water Co.*, Pennsylvania Public Utility Commission, Docket No. R-2020-3020919. 2020. Concerning regulatory policy, on behalf of the Pennsylvania Office of Consumer Advocate.

Initial Unemployment Claims in Pennsylvania: Weeks Ending March 7 to November 28, 2020



Source: U.S. Department of Labor, Weekly Unemployment Report, http://oui.doleta.gov/unemploy/archive.asp

Week ending:	Initial Unemployment Claims	Week ending:	Initial Unemployment Claims
3/7/2020	12,227	8/8/2020	27,094
3/14/2020	15,439	8/15/2020	25,584
3/21/2020	377,451	8/22/2020	27,510
3/28/2020	404,677	8/29/2020	24,883
4/4/2020	277,640	9/5/2020	22,626
4/11/2020	234,868	9/12/2020	21,747
4/18/2020	194,594	9/19/2020	22,762
4/25/2020	127,896	9/26/2020	22,955
5/2/2020	94,445	10/3/2020	19,844
5/9/2020	75,557	10/10/2020	20,251
5/16/2020	64,078	10/17/2020	19,223
5/23/2020	66,980	10/24/2020	19,974
5/30/2020	48,930	10/31/2020	23,742
6/6/2020	48,827	11/7/2020	23,051
6/13/2020	49,197	11/14/2020	22,756
6/20/2020	54,083	11/21/2020	26,983
6/27/2020	49,986	11/28/2020	23,878
7/4/2020	44,086		
7/11/2020	44,798		
7/18/2020	37,986		
7/25/2020	35,808		
8/1/2020	29,371	Total	2,783,787

Pandemic-related data for counties served by PECO Gas
(Note: PECO Gas does not serve entire population of all counties listed)

County	Population (2018)	COVID-19 Cases as of 12/7/2020	Cases per 100,000	Unemployment Rate as of February 2020	Unemployment Rate as of April 2020	Unemployment Rate as of October 2020	% Change from Feb.
Bucks	626,370	21,146	3,376	4.1	15.4	6.4	56%
Chester	517,156	14,178	2,742	3.3	11.9	4.9	48%
Delaware	563,527	22,470	3,987	4.2	15.1	7.2	71%
Lancaster	538,347	19,426	3,608	3.7	15.2	5.3	43%
Montgomery	821,301	25,277	3,078	3.7	14.0	5.9	59%
Total	3,066,701	102,497	3,342	3.8	14.3	6.0	57%

Sources:

Population:	US Census Bureau, American Community Survey, Table B01003 Total Population (5-year estimate, 2014-2018)
COVID-19 cases:	https://www.health.pa.gov/topics/disease/coronavirus/Pages/Cases.aspx
Unemployment:	Pa. Dept. of Labor & Industry, seasonally adjusted unemployment rates (2nd week in each month) https://www.workstats.dli.pa.gov/MediaCenter/MonthlyNews/Pages/default.aspx

Report on the Economic Well-Being of U.S. Households in 2019, Featuring Supplemental Data from April 2020

May 2020

Board of Governors of the Federal Reserve System

Financial Repercussions from COVID-19

For many families, financial circumstances in 2020 look very different than they did in late 2019 when the SHED was fielded. In order to gain further information about these changing circumstances, the Federal Reserve Board fielded a supplemental survey in April 2020. From the start of March through early April 2020, 19 percent of adults reported losing a job, being furloughed, or having their hours reduced. Among those experiencing these employment disruptions, over one-third expected to have difficulty with their bills in April. Yet, for those not experiencing an employment disruption, financial outcomes at the time of the supplemental survey were largely similar to those observed in the fourth quarter of 2019.

Employment and Work from Home

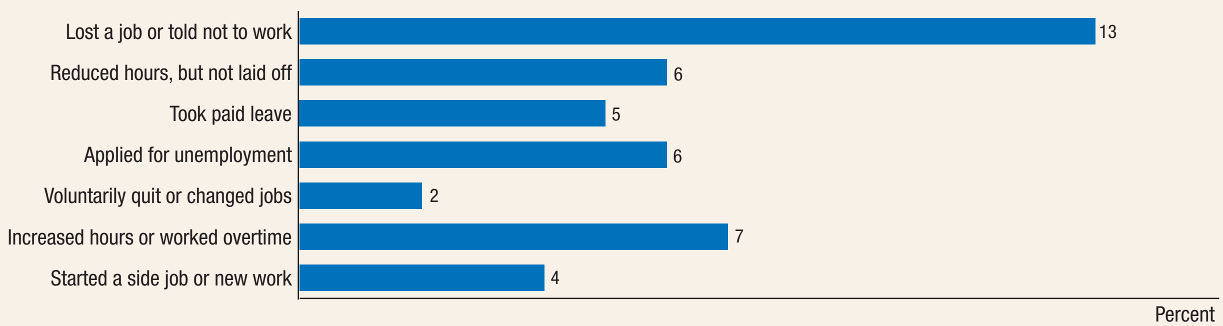
Thirteen percent of adults, representing 20 percent of people who had been working in February, reported that they lost a job or were furloughed in March or the beginning of April 2020 (figure 39).[50] These job losses were most severe among workers with lower incomes. Thirty-nine percent of people working in February with a household income below $40,000 reported a job loss in March. Another 6 percent of all adults had their hours reduced or took unpaid leave. Taken together, 19 percent of all adults reported either losing a job or experiencing a reduction in work hours in March.

Despite these widespread employment losses, some people took on new or additional employment in March. Seven percent of adults reported that they increased their hours worked or worked overtime. Four percent of adults, including 8 percent of those who experienced a job loss, took on a side job to supplement their income. Some people who lost jobs may also have started other full-time employment or already had second jobs.

Many people who lost a job remained connected to their employer and expected to return to the same job eventually. Nine in 10 people who lost a job said that their employer indicated that they would return to their job at some point. In general, however, people were not told specifically when to expect to return to work. Seventy-seven percent said that their

[50] Respondents were asked about employment events between March 1 and when they took the survey. The survey was in the field from April 3 through April 6. Subsequent references in this section to events in March include the beginning of April prior to the respondent taking the survey; 1,030 adults responded to the supplemental survey, and results were weighted to be nationally representative. Additional details can be found in the "Description of the Survey" section of this report.

Figure 39. Employment events in March 2020



Note: April 2020 supplemental survey data.

employer told them to expect to return, but did not give them a return date. A smaller 14 percent were given a specific return date or had already returned to work. It is difficult to predict, however, how long layoffs will ultimately last.

Many of those who were still working worked from home. More than half of workers (53 percent) did at least some work from home in the last week of March, and 41 percent did all their work from home. For comparison, in October 2019, 7 percent of people working for someone else usually worked from home (see the "Employment" section of this report).

Workers with higher levels of education, particularly bachelor's degrees, were more likely to work from home. Sixty-three percent of workers with at least a bachelor's degree worked entirely from home. Among workers with a high school degree or less, 20 percent worked entirely from home, as did 27 percent of workers who have completed some college or an associate degree (figure 40).

Some people also said that childcare, family obligations, or health concerns contributed to them working less in March. Including those taking paid leave or who had their hours reduced but who were not laid off, 9 percent of adults worked fewer hours in March. Among this group, 21 percent said they worked fewer hours because of family responsibilities or childcare. Seventeen percent said that illness or health limitations had contributed to their reduction in hours. Nevertheless, 47 percent of those working fewer hours said it was due to fewer hours offered by their employer.

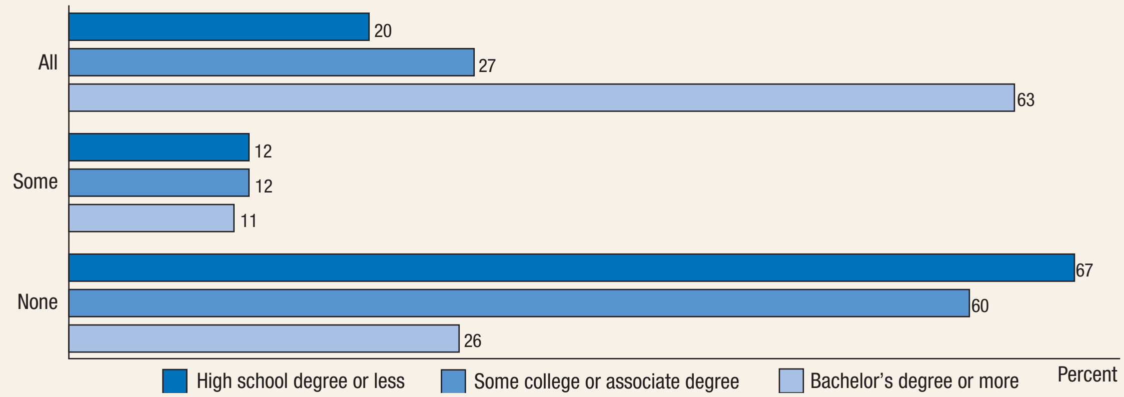
Effects on Family Finances

For the majority of adults, income, ability to pay current bills, and their approach to covering a hypothetical $400 unexpected expense appear to be generally stable during the initial period of the COVID-19 pandemic. Yet among those who experienced employment losses, financial well-being is substantially lower.

Consistent with the employment declines in March, many people experienced declines in their incomes. Overall, 23 percent of adults said their income in March was lower than in February, while 5 percent said their income increased and the rest indicated it was about the same (figure 41). Among those who lost a job or had their hours reduced, 70 percent reported that their income declined. Most people who did not report a job loss or reduced hours said that their income was about the same, although 12 percent said their month-to-month income declined between February and March.

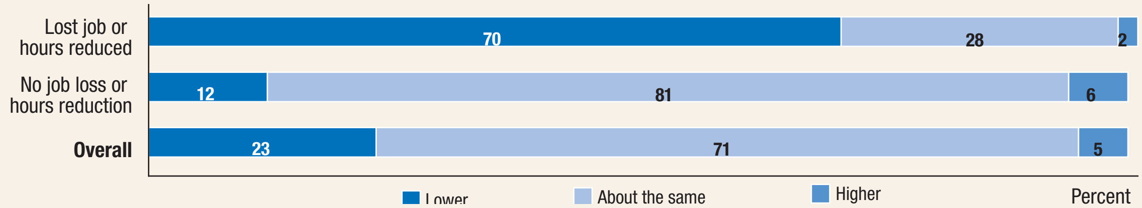
A loss of income can affect people's ability to pay regular monthly bills. Eighty-one percent of adults said they could pay all the current month's bills in full in April, which was essentially unchanged from the fourth quarter of 2019 (table 32). Yet, the survey found far greater rates of difficulty among those experiencing employment disruptions. Sixty-

Figure 40. Amount of work performed remotely in week ending April 4, 2020 (by education)



Note: Key identifies bars in order from top to bottom. April 2020 supplemental survey data. Among employed and self-employed adults. Education categories in the April supplement differ from those used for the full SHED.

Figure 41. Income in March 2020 relative to February (by employment disruptions since March 1)



Note: Key identifies bars in order from left to right. April 2020 supplemental survey data.

Table 32. Financial resiliency measures (by year and employment disruptions since March 1)
Percent

Year and employment disruption	Able to pay all current month's bills in full	Would pay $400 expense with cash or equivalent
2019 SHED		
Overall	84	63
2020 April supplement		
Lost job or hours reduced	64	46
No job loss or hours reduction	85	68
Overall	81	64

Note: Data from both the 2019 SHED and April 2020 supplemental survey.

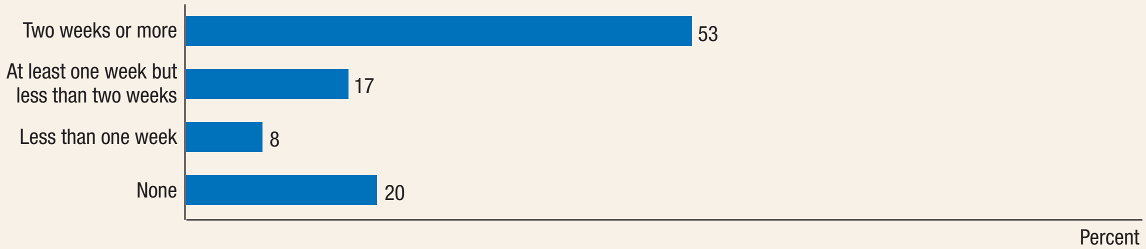
four percent of adults who reported a job loss or reduction in hours expected to be able to pay all their bills in full in April, compared to 85 percent of those without an employment disruption.[51]

[51] The April supplement was conducted after the passage of the Families First Coronavirus Response Act and the CARES Act, which provided financial relief to many families and expanded the availability of paid leave for some workers who contract COVID-19. However, the survey was conducted before most benefits were received, so it is unclear how many respondents considered these new policies when responding to the survey.

Similarly, for adults overall in April, the share who reported they would pay an unexpected $400 emergency expense entirely using cash, savings, or a credit card paid off at the next statement was essentially unchanged from the fall of 2019. Yet those who experienced the loss of a job or work hours were less likely to report they would pay an unexpected $400 expense in these ways.

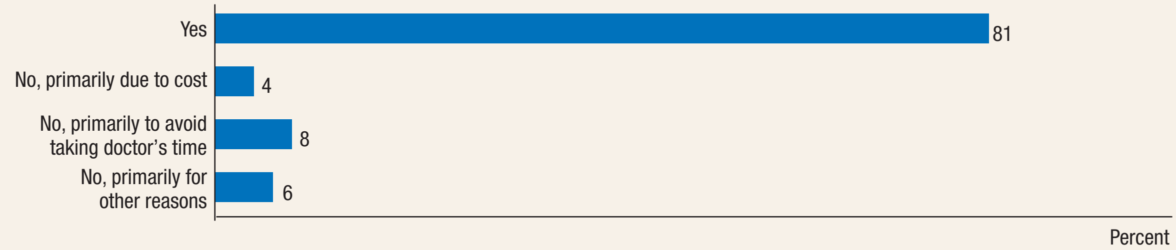
In addition to the economic effects from the broader employment disruptions related to COVID-19, individuals may experience additional financial challenges if they, or someone close to them, gets sick. Workers who lack paid leave are more likely to face financial hardships or deplete financial resources if they become sick with coronavirus symptoms. Fifty-three percent of employed adults, including those who are self-employed, indicated that could take two or more weeks of paid leave if they got sick with coronavirus symptoms (figure 42). Nonetheless, one-fifth of employed adults reported that they could not take any time off without a reduction in income under these circumstances. On average, those with more education had more leave available. Sixty-four percent of adults with a bachelor's degree or more said that they had at least two weeks of leave, while 42 percent of adults with a high school

Figure 42. Amount of leave available to use if sick with coronavirus symptoms without a reduction in pay



Note: April 2020 supplemental survey data. Among employed and self-employed adults.

Figure 43. Would you try to contact a doctor if sick with symptoms of the coronavirus?



Note: April 2020 supplemental survey data.

degree or less said that they could take off at least two weeks without a reduction in income.

Financial circumstances can also affect decisions to seek medical care. Most adults (81 percent) said they would try to contact a doctor if they were to get sick with coronavirus symptoms, although a small share (4 percent) indicated that concerns about cost would deter them (figure 43). Those who experienced a job loss or reduced hours were more likely not to contact a doctor because of costs (8 percent), relative to those who had not (3 percent). However, this is well below the share who reported in the fall that they skipped any medical care due to an inability to pay (see the "Dealing with Unexpected Expenses" section of this report). This lower rate of expecting to skip medical care for COVID-19 likely reflects its serious nature.

Results from the supplemental survey reflect financial conditions at the beginning of April 2020 and indicate the nature of families' experiences of financial conditions at that time. However, the financial repercussions from COVID-19 continue to evolve, and the Federal Reserve Board will continue to monitor the financial conditions of households.

Experienced loss of employment income since mid-March, and expected income loss in the next four weeks, Pennsylvania households by selected characteristics, as of the two-week period ending November 23, 2020

	Lost income since mid-March	Expect to lose income in next 4 weeks
Hispanic origin and Race		
Hispanic or Latino (may be of any race)	47.6%	36.4%
White alone, not Hispanic	44.1%	27.4%
Black alone, not Hispanic	59.0%	41.6%
Asian alone, not Hispanic	41.3%	29.2%
Education		
Less than high school	60.7%	39.0%
High school or GED	45.4%	32.0%
Some college/associate’s degree	49.0%	33.6%
Bachelor’s degree or higher	41.4%	21.7%
Household income		
Less than $25,000	48.0%	41.6%
$25,000 - $34,999	47.3%	31.6%
$35,000 - $49,999	38.9%	35.3%
$50,000 - $74,999	48.1%	32.8%
$75,000 - $99,999	48.9%	27.0%
$100,000 - $149,999	46.5%	23.7%
$150,000 - $199,999	39.1%	19.0%
$200,000 and above	32.2%	16.8%
All households in Pennsylvania	**46.0%**	**29.7%**

Source: U.S. Census Bureau Household Pulse Survey, Week 19 (two weeks ending Nov. 23, 2020). Employment Table 1. Experienced and Expected Loss of Employment Income, by Select Characteristics: Pennsylvania

How Pennsylvania households who lost employment income since mid-March paid their bills in the past 7 days, as of the two weeks ending November 23, 2020

Regular income sources like those used before the pandemic	50.0%
Credit cards or loans	29.6%
Money from savings or selling assets	29.5%
Borrowing from friends or family	16.2%
Unemployment insurance (UI) benefit payments	20.0%
Stimulus (economic impact) payment	21.2%
Money saved from deferred or forgiven payments (to meet spending needs)	5.2%
Supplemental Nutrition Assistance Program (SNAP)	9.7%
Did not report	13.5%

Source: U.S. Census Bureau Household Pulse Survey, Week 19 (two weeks ending Nov. 23, 2020). Employment Table 1. Experienced and Expected Loss of Employment Income, by Select Characteristics: Pennsylvania

ELECTRIC POWER RESEARCH INSTITUTE

Impact of COVID-19 on Consumer Energy Use & Outlook

Results of EPRI National Survey

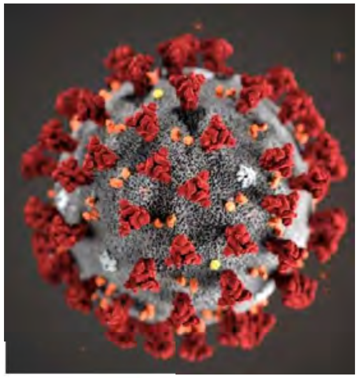
Omar Siddiqui
Min Long

April 29, 2020

www.epri.com

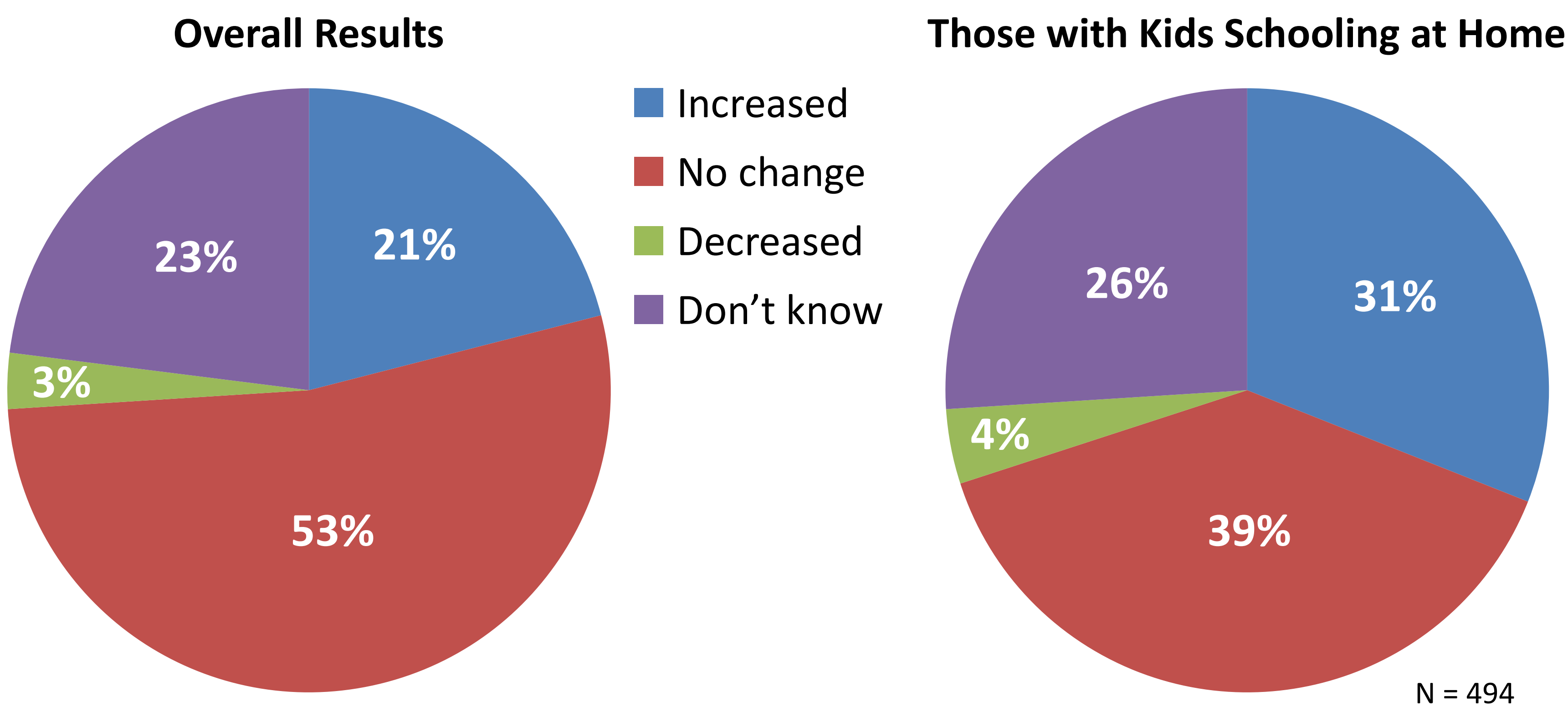
Introduction

- National EPRI survey on COVID-19 impact on consumer energy use and outlook
- Online panel through YouGov
- Nationally representative sample
  - 2,000 respondents
  - Geographic (census regions and divisions)
  - Demographic (household size, age, education, rent vs. own home, income, etc.)
  - Margin of error +/- 2.3%
- Administered week of April 13



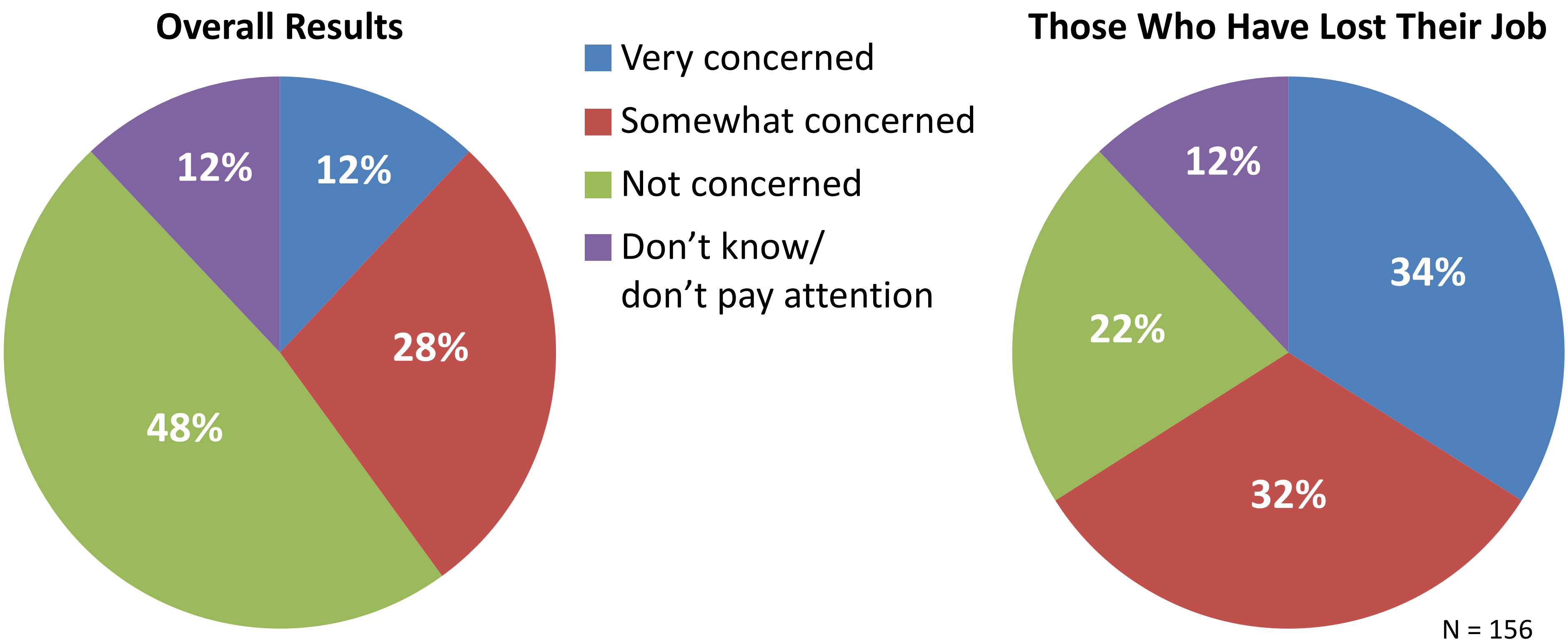
 www.epri.com

How has the current situation affected your energy bills?



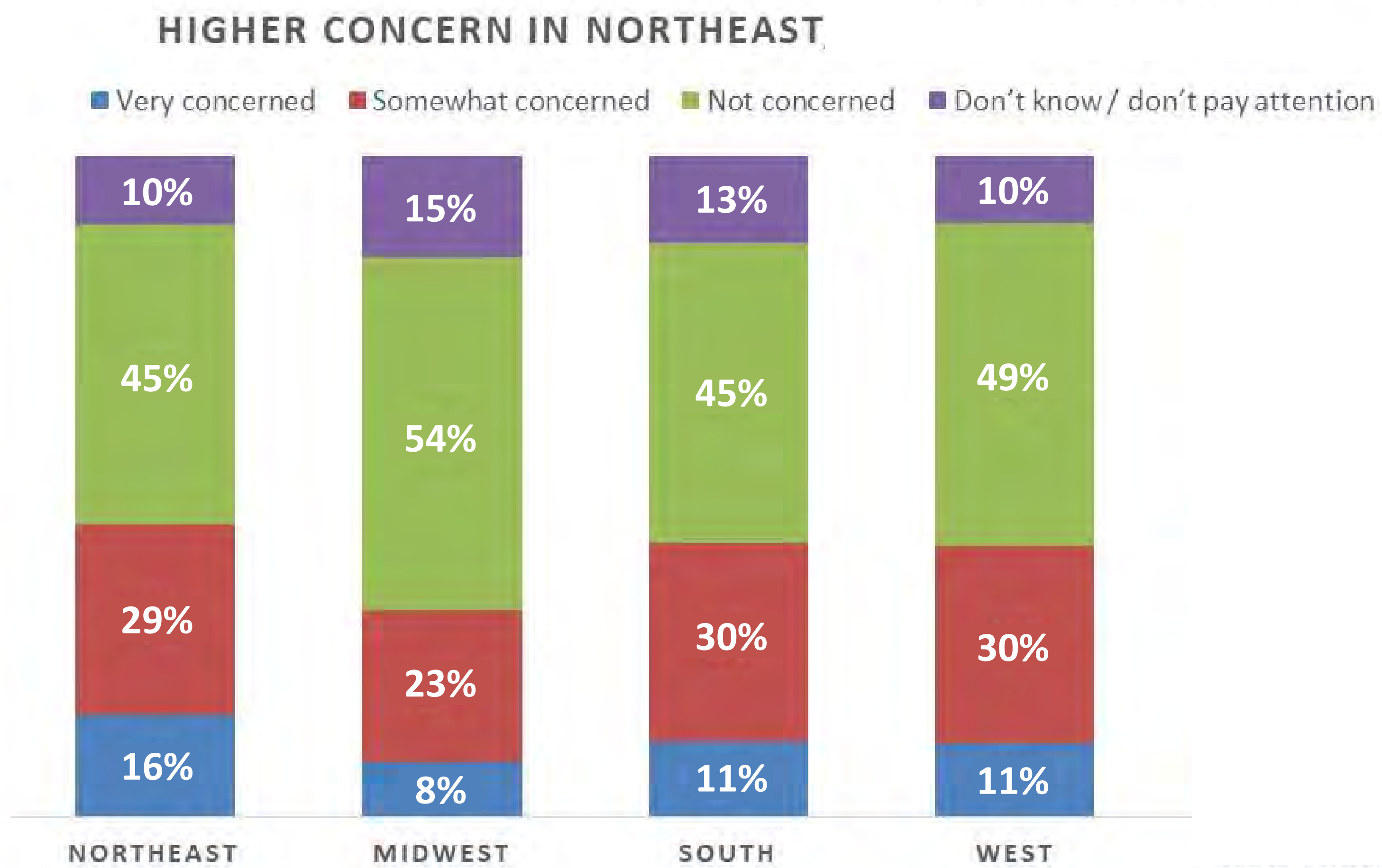
Statistical margin of error +/- 2.3%

How do you feel about your energy bills as a result of the current situation?



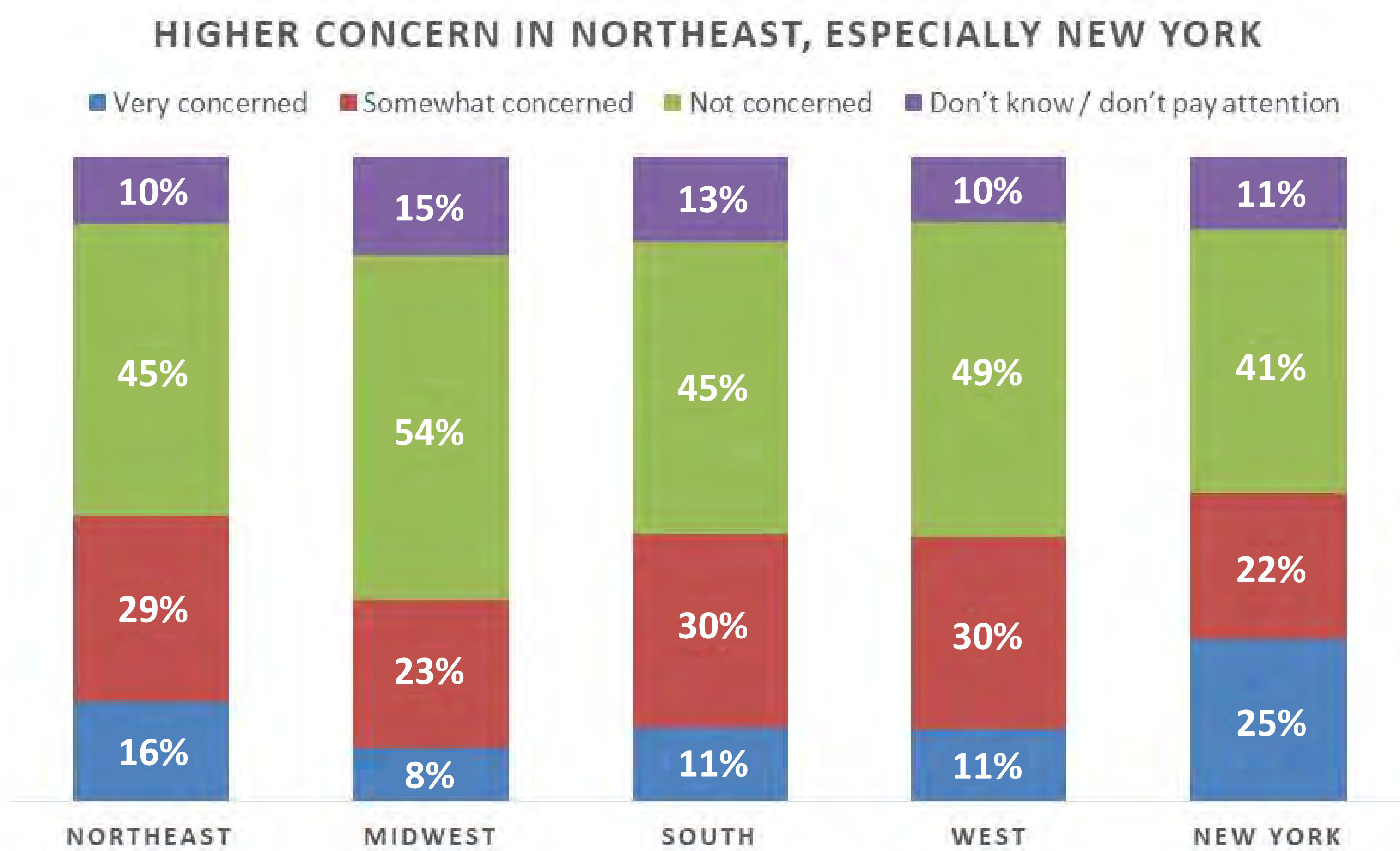
Statistical margin of error +/- 2.3%

How do you feel about your energy bills as a result of the current situation?



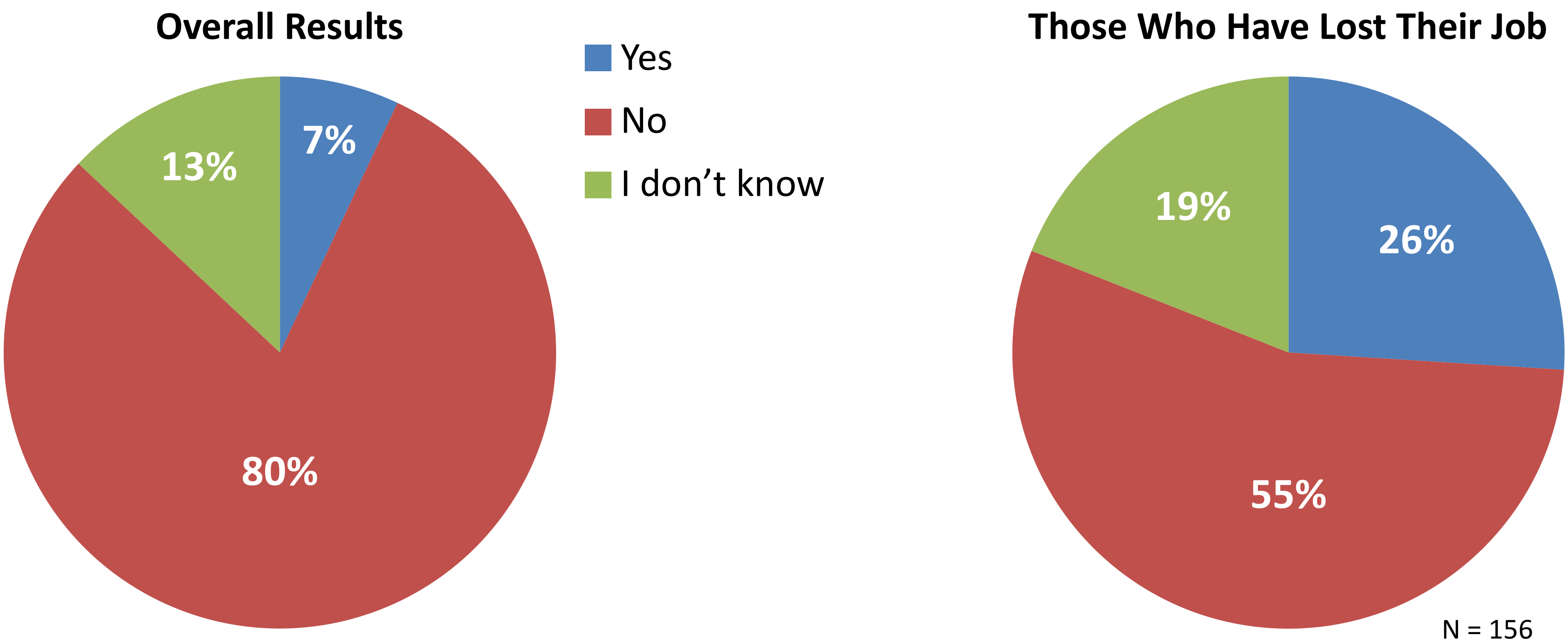
Statistical margin of error +/- 2.3%

How do you feel about your energy bills as a result of the current situation?



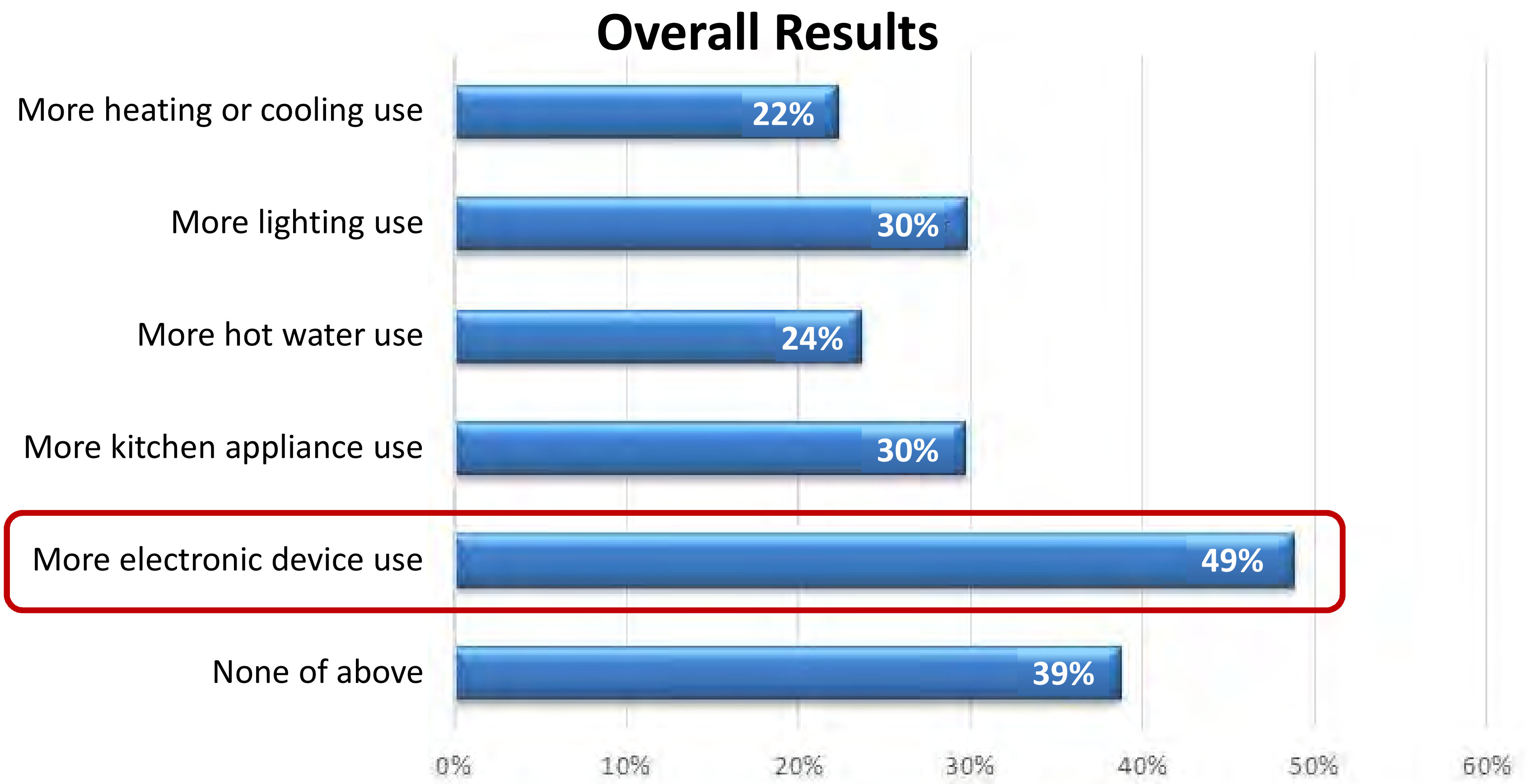
Statistical margin of error +/- 2.3%

Have you skipped, or do you intend to skip, an electric or gas bill payment during this crisis?



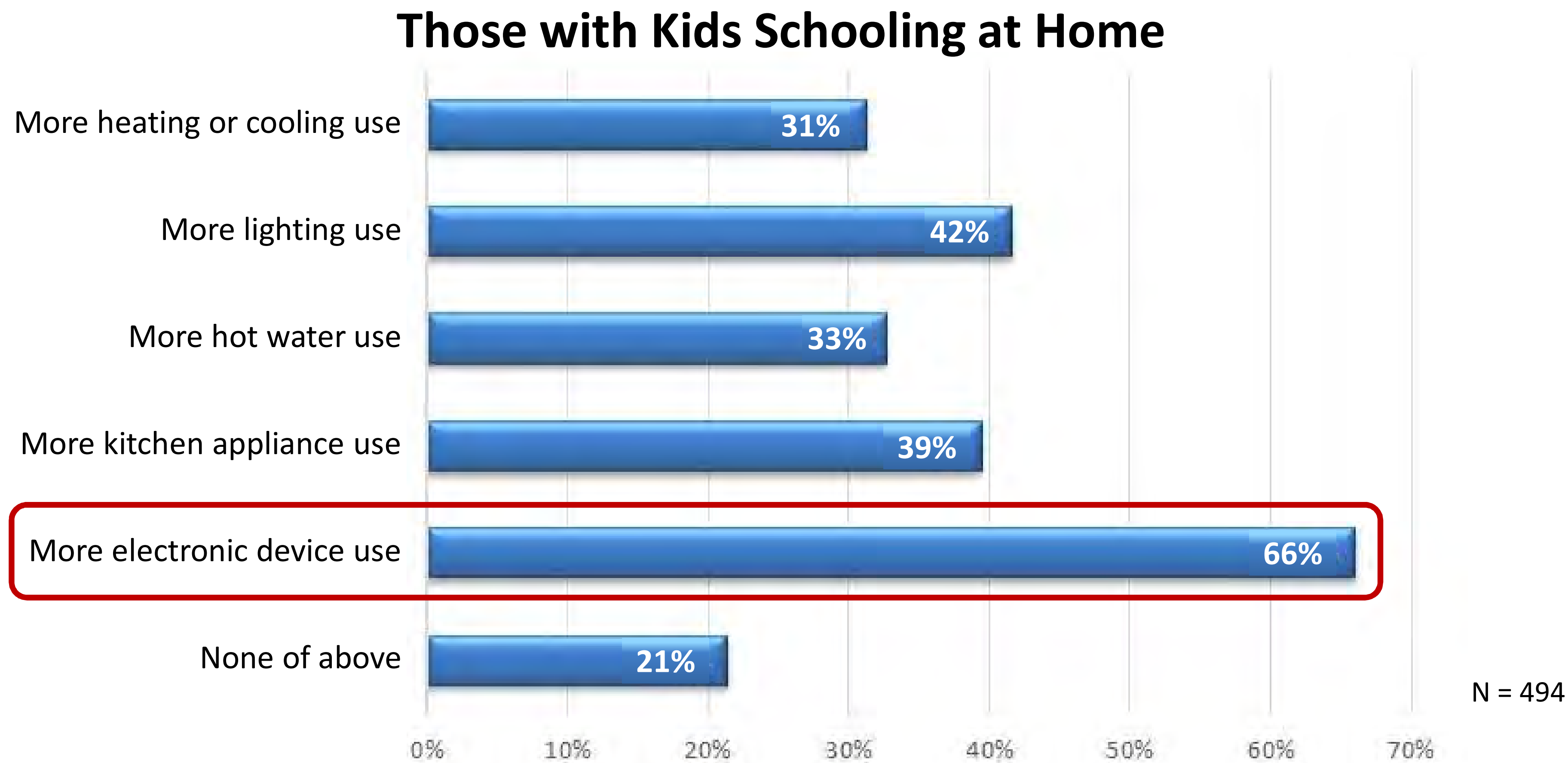
Statistical margin of error +/- 2.3%

What changes have you noticed in your home energy use as a result of COVID-19?

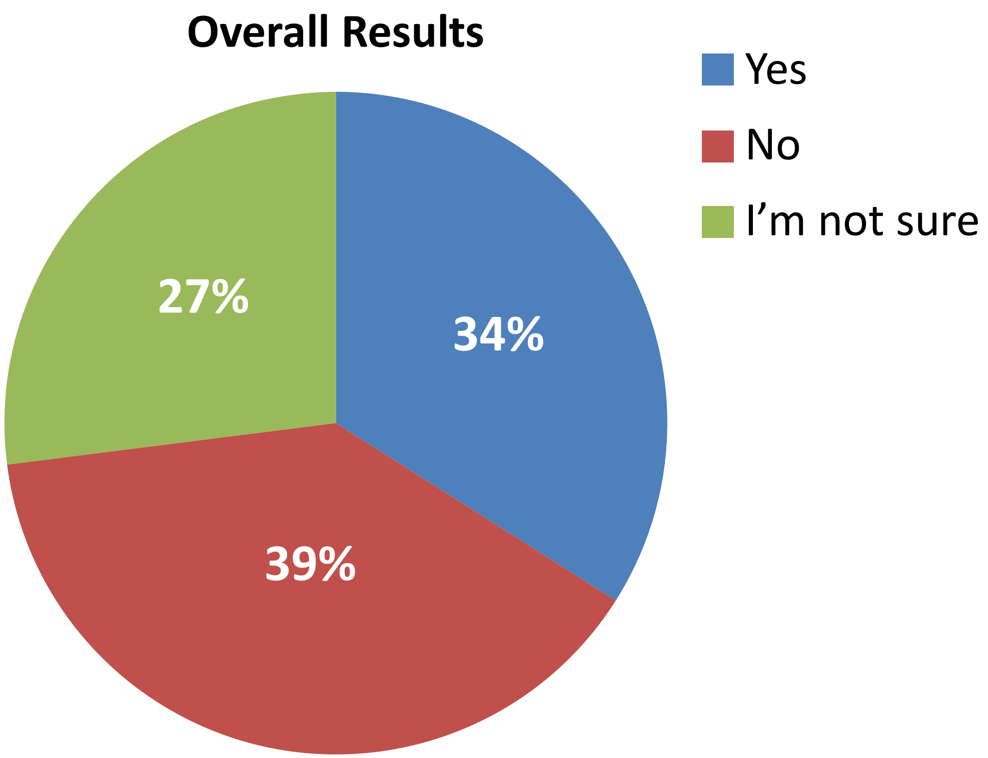


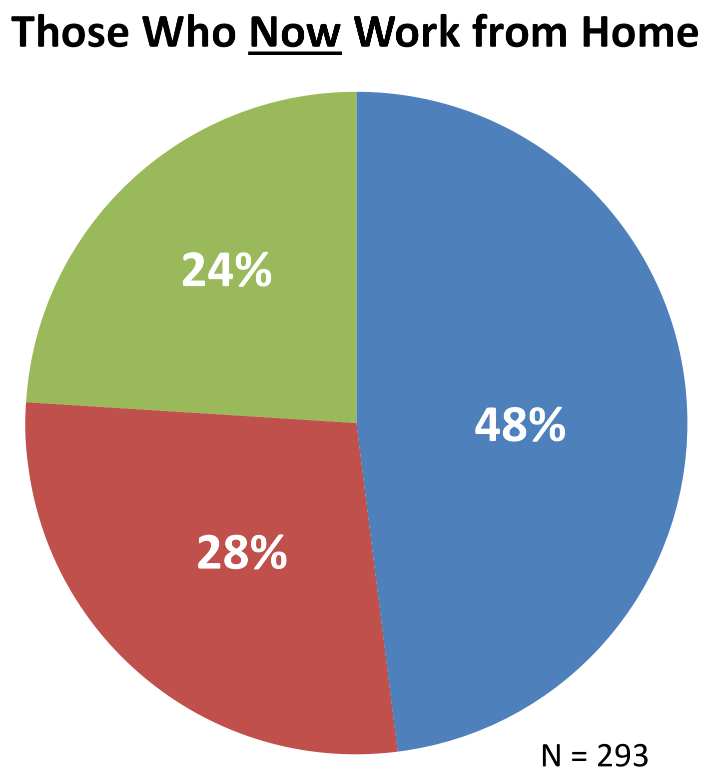
Statistical margin of error +/- 2.3%

What changes have you noticed in your home energy use as a result of COVID-19?



Are savings from other expenses offsetting any increases in your energy bills?

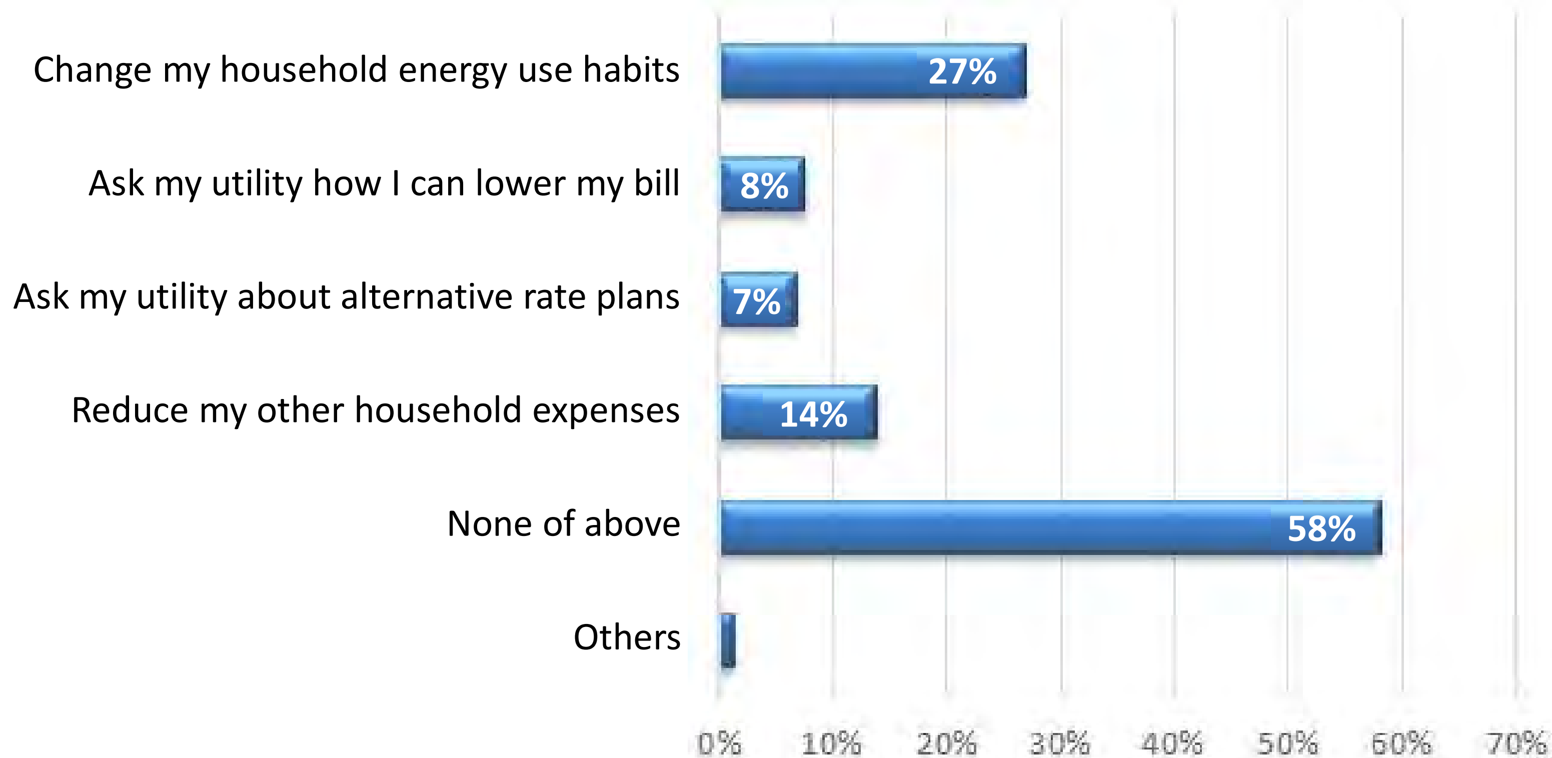




Statistical margin of error +/- 2.3%

Does the current crisis make you more likely to take the following actions related to your energy use?

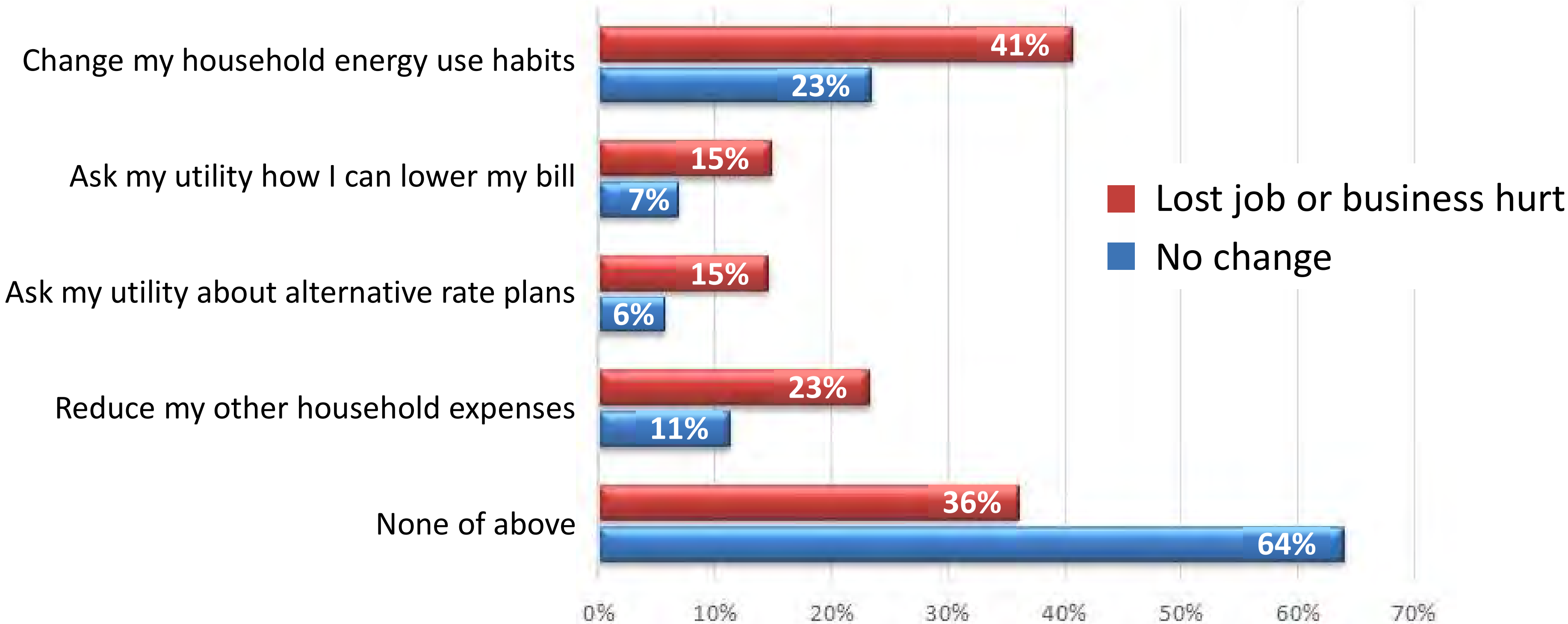
Overall Results



Statistical margin of error +/- 2.3%

Does the current crisis make you more likely to take the following actions related to your energy use?

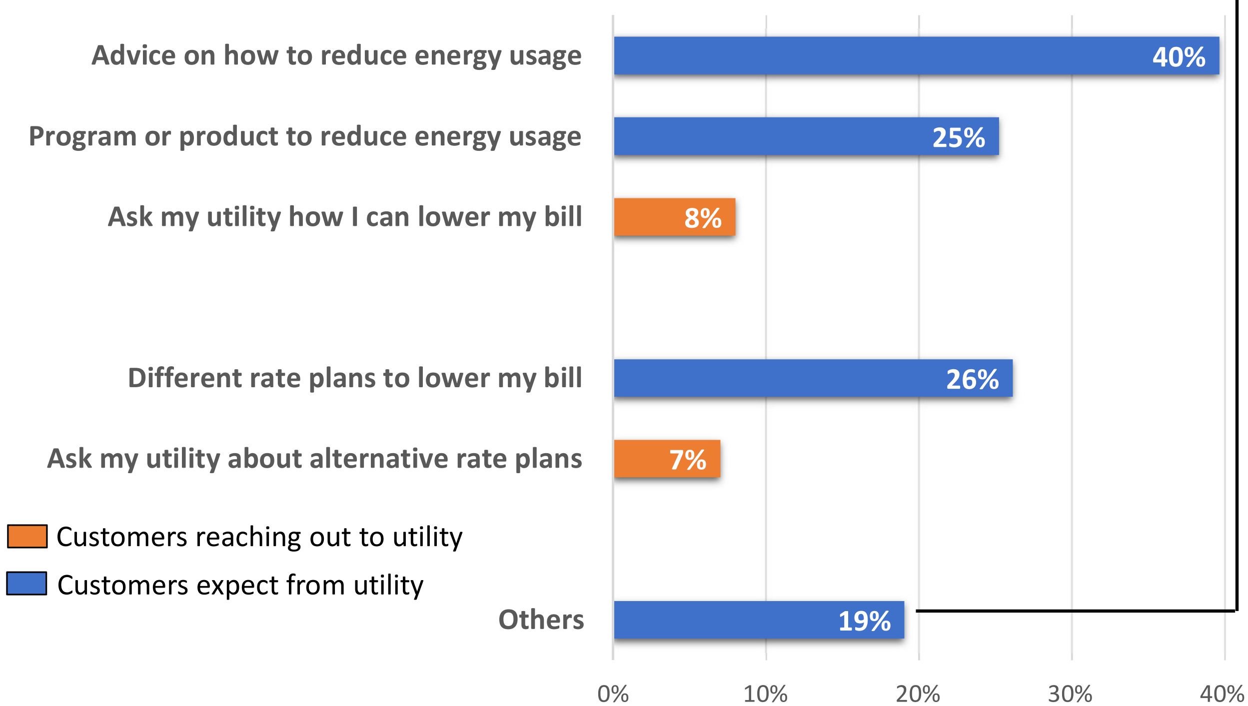
Results Segmented by Impact of COVID-19 on Employment Status



Statistical margin of error +/- 2.3%

What actions do you expect your electric utility to take?

- ***Few customers are proactively asking their utility for help*** to reduce their energy use and bills; however
- ***More customers still expect their utility to help*** by providing advice, programs, or rate plans to reduce their energy bills



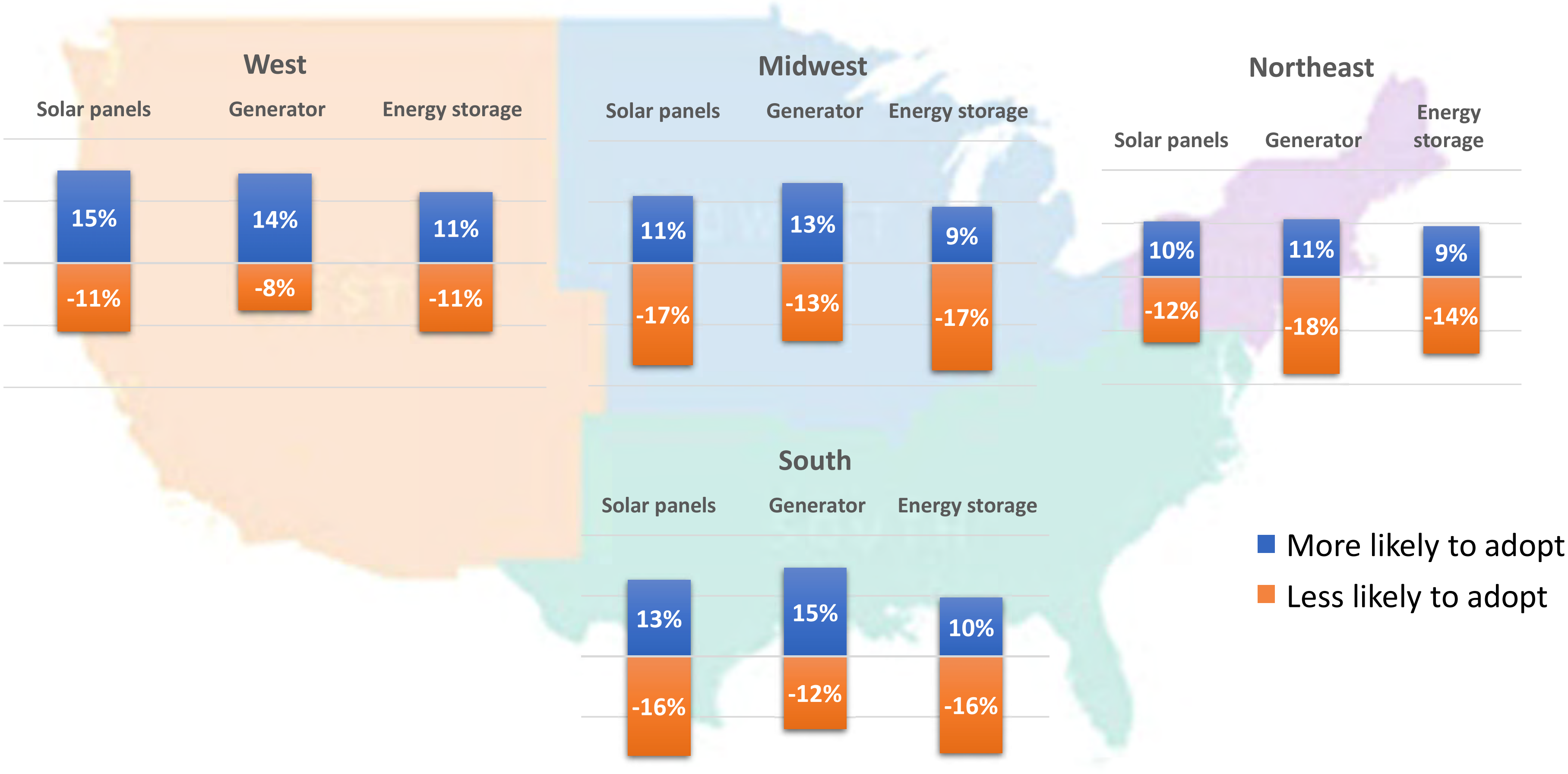
"Other" Explained

No Need	None Nothing now… might change if my job status changes Utilities included in my rent
Actions Expected	Keep the electricity flowing Reduce rates for those in need Waive late fees Give me extra time to pay bill Provide a credit on my bill
Negatives	Expect utility to raise prices Utility won't do anything Utility hasn't contacted me

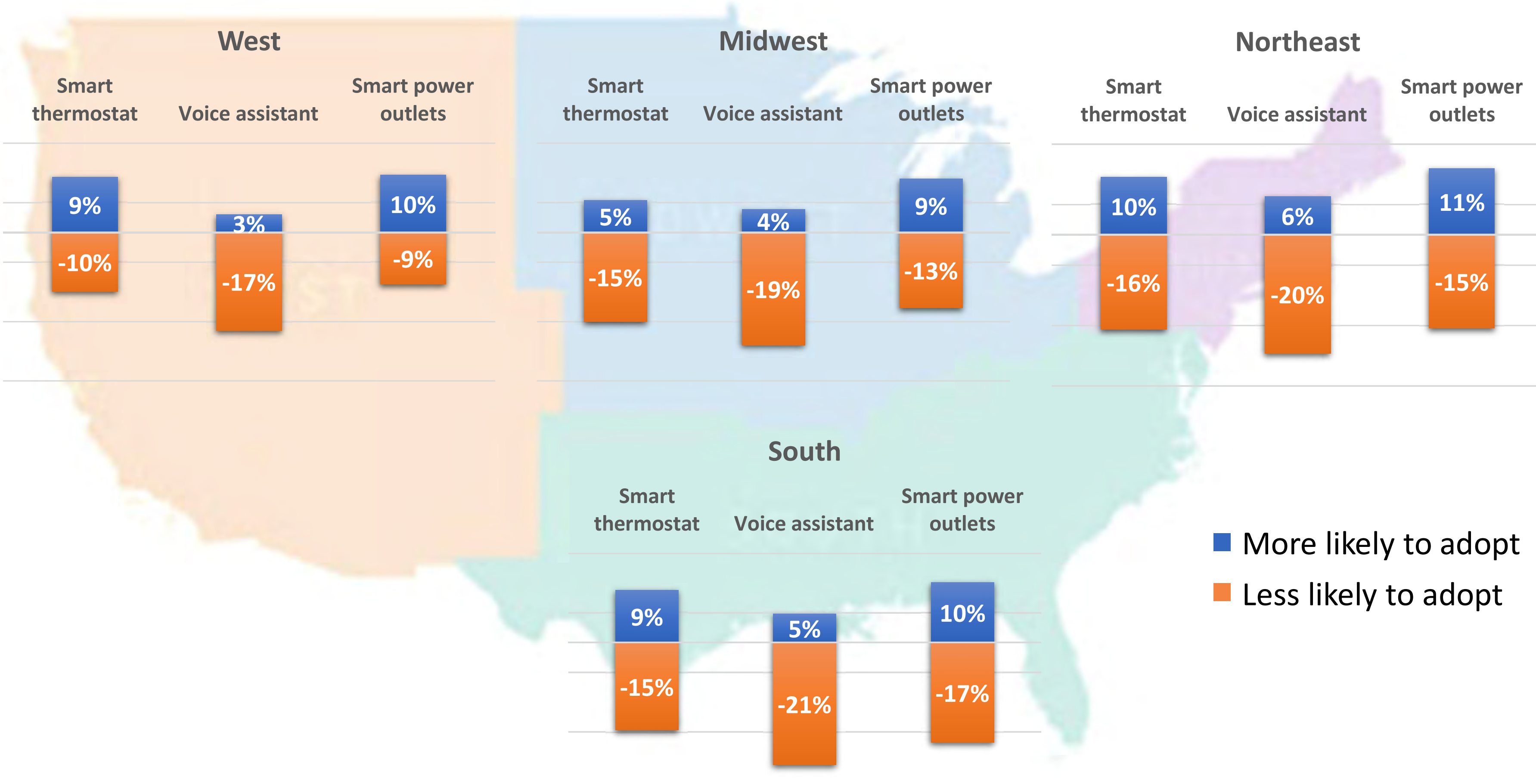
"Does the current crisis make you more likely or less likely to purchase any of the following within this year?"

Results by U.S. census regions

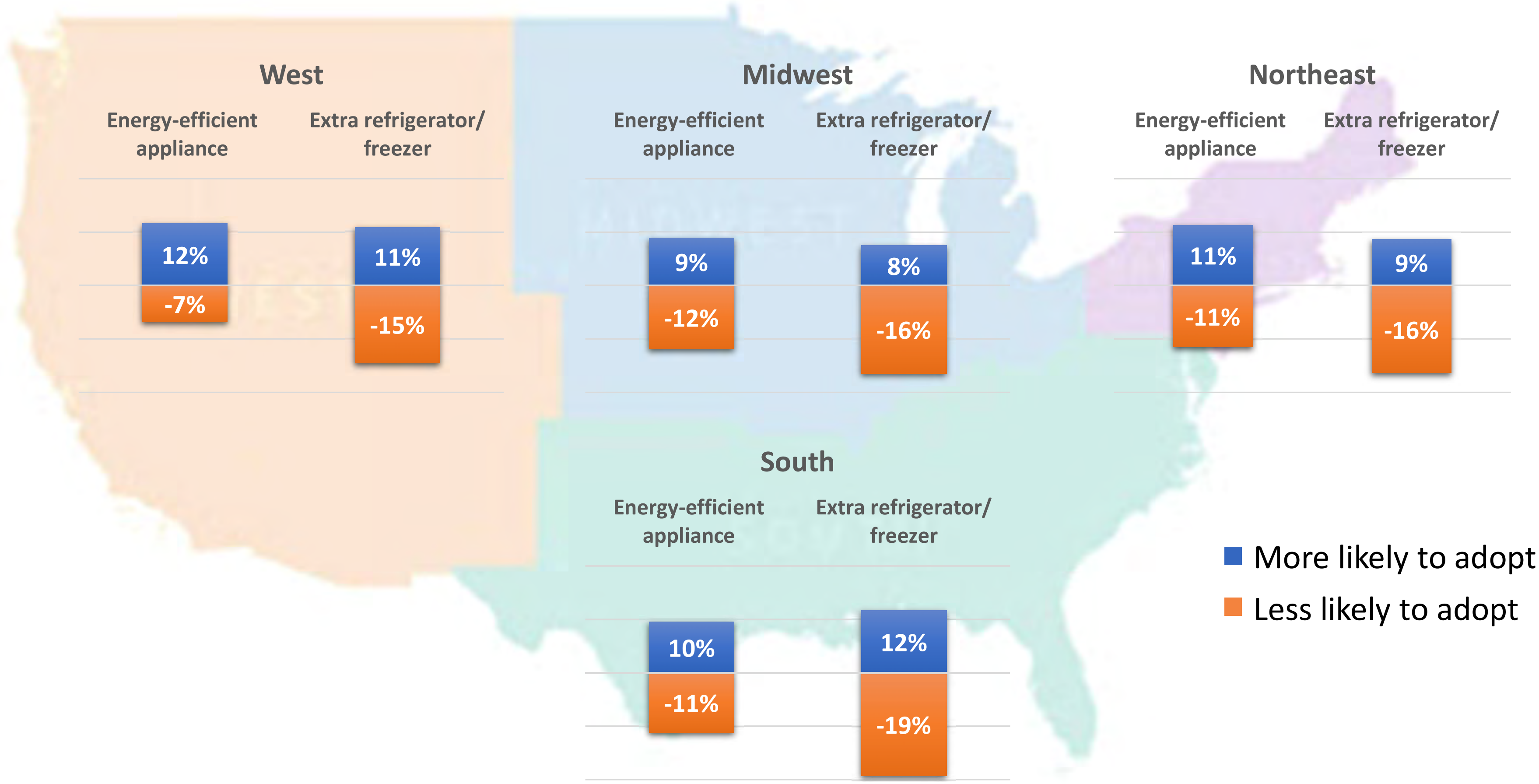
Power Generation & Storage



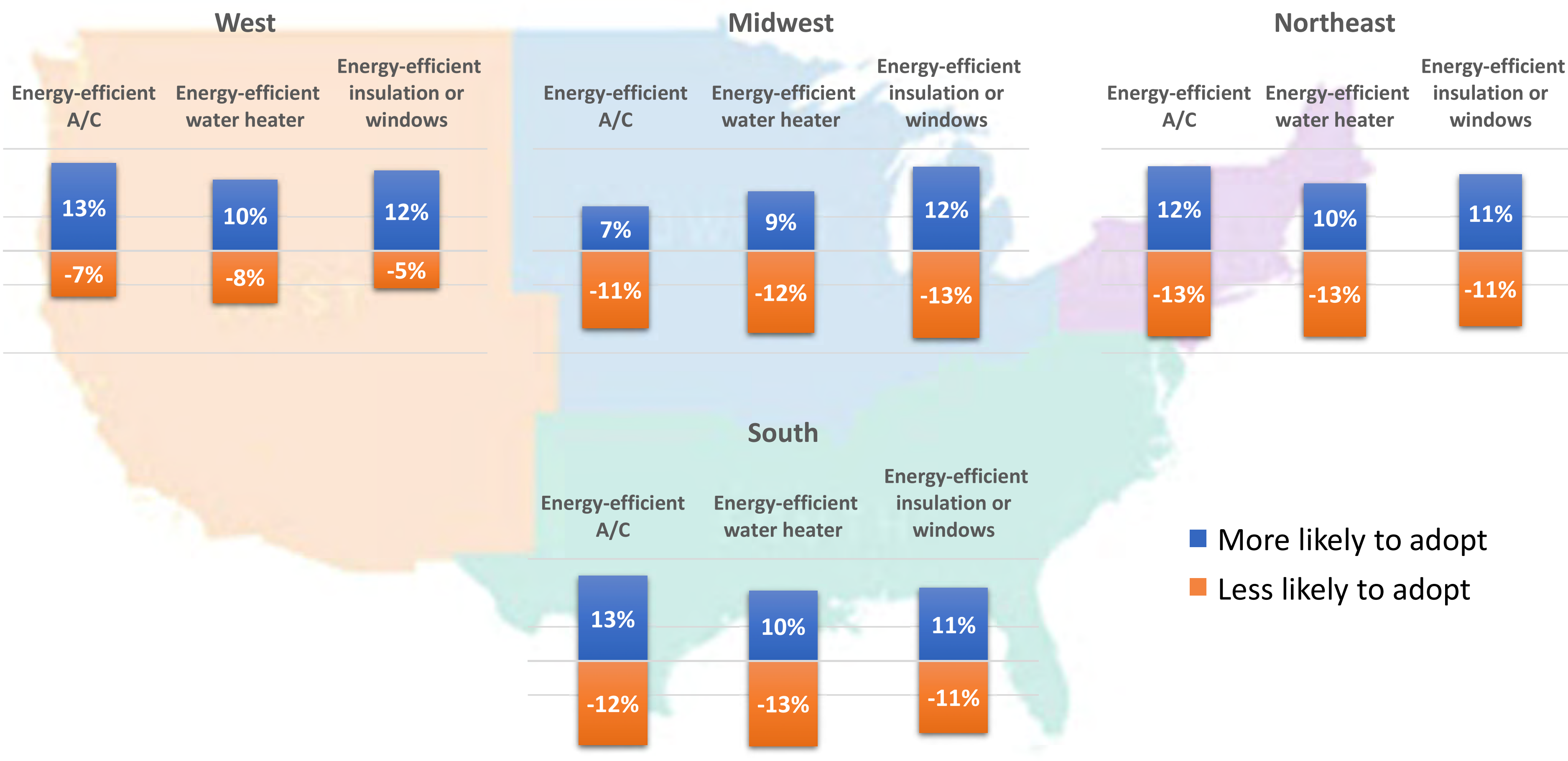
Smart Devices



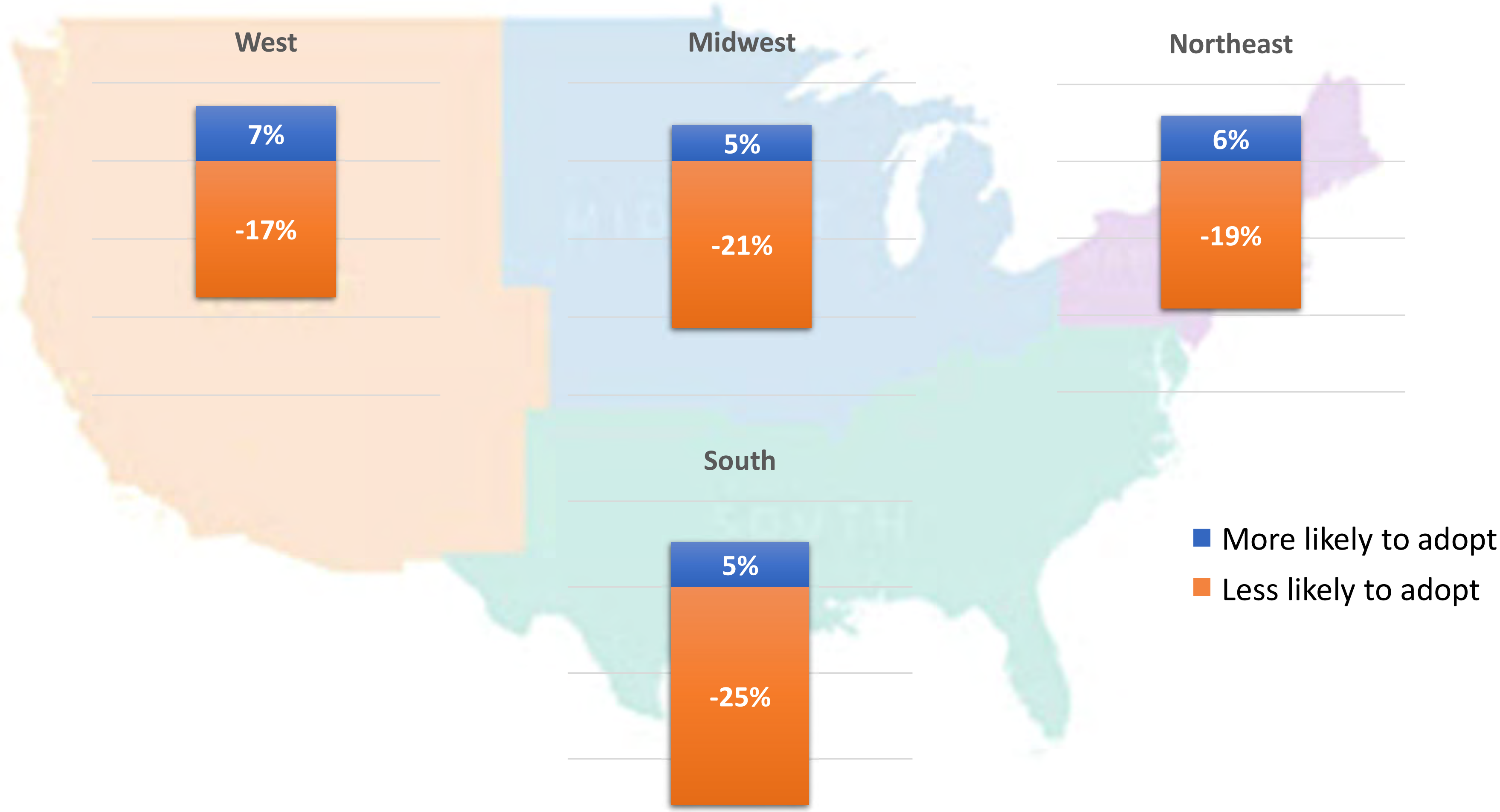
Home Appliances



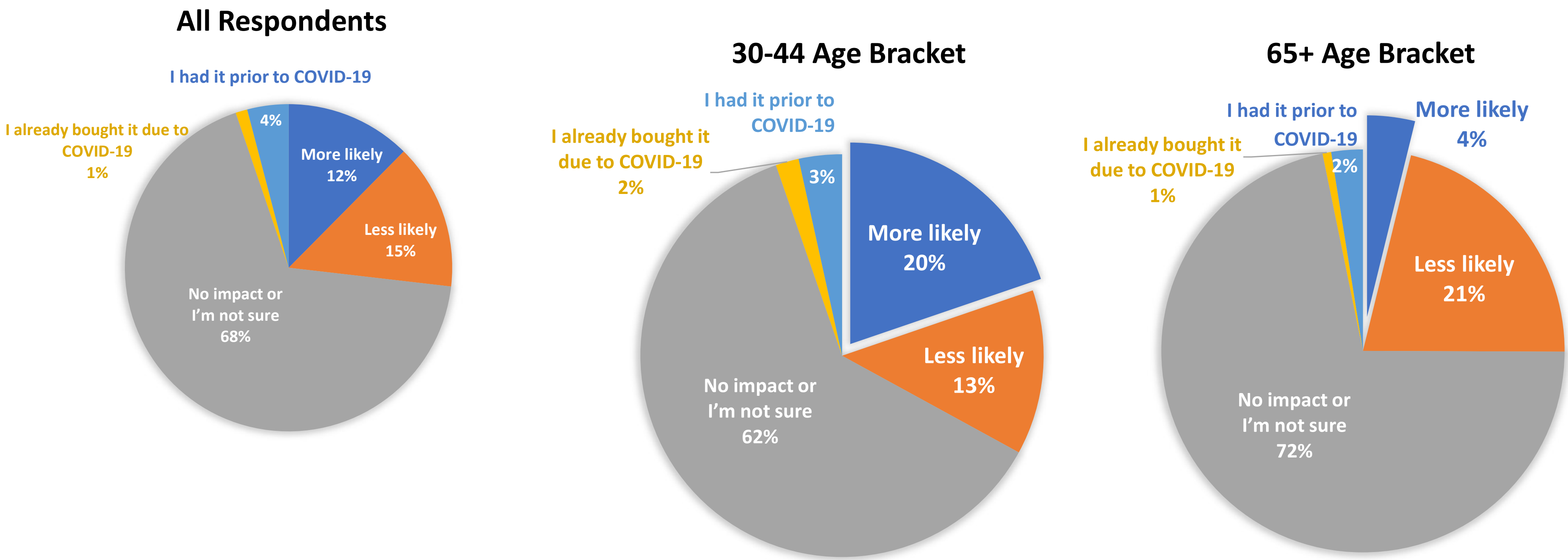
Energy-efficient Upgrades



Electric Vehicles



COVID-19 spurs greatest uptick in solar panel interest among 30-44 age bracket; least among 65+ age bracket



Similar age-segment trend for COVID-19 impact on interest in other technologies

Together...Shaping the Future of Electricity

ELECTRIC POWER RESEARCH INSTITUTE

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018929
	:	
PECO Energy Company – Gas Division	:	

VERIFICATION

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

DATED: December 22, 2020
*300673

Signature: Scott J. Rubin
Scott J. Rubin

Consultant Address: 333 Oak Lane
Bloomsburg, PA 17815

OCA Statement No. 2

R-2020-3018929
2/17/21 JK

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	**Docket No. R-2020-3018929**
v.	)	
	)	
PECO Energy Company - Gas Division	)	

DIRECT TESTIMONY

OF

LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

<u>PUBLIC VERSION</u>

December 22, 2020

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

TABLE OF CONTENTS

Appendix B – **PECO Responses to Discovery**

INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lafayette K. Morgan, Jr. My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland, 21044. I am a Public Utilities Consultant working with Exeter Associates, Inc. (Exeter). Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND QUALIFICATIONS.

A. I received a Master of Business Administration degree from The George Washington University. The major area of concentration for this degree was Finance. I received a Bachelor of Business Administration degree with concentration in Accounting from North Carolina Central University. I was previously a CPA licensed in the state of North Carolina, however, in 2009, I elected to place my license in an inactive status as I focused on start-up activities for other business interests.

Q. WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE?

A. From May 1984 until June 1990, I was employed by the North Carolina Utilities Commission - Public Staff in Raleigh, North Carolina. I was responsible for analyzing testimony, exhibits, and other data presented by parties before the North Carolina Utilities Commission. I had the additional responsibility of performing the examination of books and records of utilities involved in rate proceedings and summarizing the results into testimony and exhibits for presentation before that Commission. I was also involved in numerous special projects, including participating in compliance and prudence audits of a major utility and conducting research on several issues affecting natural gas and electric utilities.

From June 1990 until July 1993, I was employed by Potomac Electric Power Company (Pepco) in Washington, D.C. At Pepco, I was involved in the preparation of the cost of service, rate base and ratemaking adjustments supporting the company's requests for revenue increases in the State of Maryland and the District of Columbia.

From July 1993 through 2010, I was employed by Exeter. as a Senior Regulatory Analyst. During that period, I was involved in the analysis of the operations of public utilities, with emphasis on utility rate regulation. I reviewed and analyzed utility rate filings, focusing primarily on revenue requirements determination. This work involved natural gas, water, electric, and telephone companies.

In 2010, I left Exeter to focus on start-up activities for other ongoing business interests. In late 2014, I returned to Exeter continuing to work in a similar capacity as prior to my hiatus.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A. Yes. I have previously presented testimony and affidavits on numerous occasions before the North Carolina Utilities Commission, the Pennsylvania Public Utility Commission, the Virginia Corporation Commission, the Louisiana Public Service Commission, the Georgia Public Service Commission, the Maine Public Utilities Commission, the Kentucky Public Service Commission, the Public Utilities Commission of Rhode Island, the Vermont Public Service Board, the Illinois Commerce Commission, the West Virginia Public Service Commission, the Maryland Public Service Commission, the Corporation Commission of Oklahoma, Kansas Corporation Commission, the Philadelphia Water, Sewer and Storm Water Rate Board, the Colorado Public Utilities Commission, the Public Service Commission of South Carolina, and the Federal Energy Regulatory Commission (FERC). My resume is attached hereto as Appendix A.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am presenting testimony on behalf of the Office of Consumer Advocate (OCA).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Exeter has been retained by the OCA to assist in the evaluation of the General Rate Filing submitted by PECO Energy Company - Gas Division (PECO or the Company). I have been asked by the OCA to determine the level of revenues that PECO should be authorized in this proceeding. In this testimony, I agree with the recommendation of OCA witness Scott Rubin that rates should not be increased at this time. However, under a 'business as usual' case, I present my findings regarding PECO's test year rate base and net operating income at present rates. Based on these amounts, I have determined the revenues that are required to generate the overall rate of return on rate base recommended by Mr. Kevin O'Donnell on behalf of the OCA.

Q. IN CONNECTION WITH THIS CASE, HAVE YOU PERFORMED AN EXAMINATION AND REVIEW OF THE COMPANY'S TESTIMONY AND EXHIBITS?

A. Yes. I have reviewed PECO's testimony, exhibits and its rate filing. I have also reviewed the Company's responses to the OCA, the Bureau of Investigation & Enforcement (I&E) and the Office of Small Business Advocate's (OSBA) interrogatories.

Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR TESTIMONY?

A. Yes. I have prepared Schedules LKM-1 through LKM-30. Schedule LKM-1 provides a summary of revenues and expenses under present and proposed rates. My adjustments to PECO's claimed revenues and operating expenses are presented on Schedules LKM-4 through LKM-30.

SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE RATE RELIEF REQUESTED BY PECO IN ITS FILING.

A. On September 30, 2020, PECO filed this rate increase request that is intended to raise annual jurisdictional revenues by $68.7 million, or 8.9% on a total retail revenue basis. The Company is also seeking an overall rate of return on rate base of 7.70 percent for the Fully Projected Future Test Year (FPFTY) ending June 30, 2022. In its application, PECO states that, without an increase in revenue, its base rates are no longer sufficient to provide a reasonable return on its ongoing investment in facilities to provide safe and reliable service, as the Company continues to invest in new and replacement plant and O&M expenses continue to rise.

Q. PLEASE SUMMARIZE YOUR CONCERNS, FINDINGS AND RECOMMENDATIONS.

A. Based on my review of the Company's filing, I have concerns about whether the accounting and financial data contained in the Company's filing provides a fair or reasonable projection of the Company's cost of service during the rate effective period. My first concern, as I will discuss further below, relates to the budgeted or forecasted data. The preparation of the forecast used for the cost of service appears to be independent of the Company's normal budgeting process. Hence, it may be that the actual budget that guides the Company's operation during the rate-effective period may be different.

Second, I am concerned about whether the forecasted/budgeted data can be relied upon given the uncertainty in the US economy as a result of the COVID-19 pandemic. The Company indicates that the budget, for a FPFTY that ends June 30, 2022, was prepared between July and August 2020.[1] Considering the fact that during this period the economic data painted a picture of an uncertain and volatile economy, the assumptions made during that period could be off the mark. For instance, the U.S. real GDP growth fell during the second quarter of 2020 by 31.40 percent and, in April, the unemployment rate increased to 14.7 percent compared to 3.5 percent in February. With this knowledge, growth projections (for example) would be quite different than in a more robust economy. However, this uncertainty still exists currently. While in recent months the unemployment decreased, there was a sharp increase in the number of new unemployment claims during the first week of December 2020. It remains to be seen if this is the beginning of a trend. Based on these uncertainties, no one can accurately forecast two years into the future.

Despite my concerns about the reasonableness of the underlying budgeted data, and the recommendation of OCA witness Scott Rubin, I have made a determination of the revenue requirement based on the FPFTY cost of service as filed by the Company. The determination of the revenue requirement is being made as a matter of prudence in the event the Commission decides to consider all elements of the rate increase sought by the Company.

As shown on Schedule LKM-1, if the Commission determines that a rate increase would be just and reasonable at this time, I have determined that the

[1] See PECO Response to OCA Set II-2.

Company's proposed revenue should be reduced to reflect a decrease of $24.9 million for the FPFTY ending June 30, 2022. This represents a decrease of $93.7 million from PECO's requested increase of $68.7 million. This is the amount by which revenues exceed those required to generate an overall rate of return of 6.30 percent after accounting for the OCA's adjustments to PECO's claimed rate base and operating income. The overall return of 6.30 percent represents Mr. O'Donnell's findings regarding the Company's overall rate of return.

Schedule LKM-2 summarizes my adjustments to PECO's proposed rate year rate base. Schedule LKM-3 provides a summary of my adjustments to rate year revenues and expenses and the resulting operating income. My adjustments to the Company's claimed revenues and operating expenses are presented on Schedules LKM 4 through LKM 29.

Q. WHAT TIME PERIOD HAVE YOU USED IN MAKING YOUR DETERMINATION OF PECO'S REVENUE REQUIREMENTS ON THE AS-FILED COST OF SERVICE?

A. I used the FPFTY ending June 30, 2022, as filed by PECO, as the basis for determining its rate year revenue requirements.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. First, I will address the reasons why the cost of service as filed by PECO is not representative of the operations during the FPFTY. I will explain why relying on the financial data contained in the rate case filing would lead to inaccurate results and rates that are not just and reasonable.

In the remainder of my testimony, I document and explain each of the adjustments to the as-filed rate base and operating income that I have made to arrive at the rate year revenue requirement shown on Schedule LKM-1. My discussion of these adjustments is organized into sections corresponding to the issue being addressed. These sections are set forth in the Table of Contents for this testimony.

PART I: <u>PECO'S FPFTY COST OF SERVICE IS NOT REASONABLE</u>

Q. HOW HAS PECO CALCULATED ITS COST OF SERVICE FOR THE FPFTY?

A. From a revenue requirements perspective, the cost of service is composed of the rate base and the components of the net operating income (i.e., revenues, operation and maintenance expenses, depreciation and amortization expense, and taxes). According to Company witness Trzaska, the data for the FPFTY and FTY cost of service were derived from PECO's capital and operating budgets for the twelve months ending June 30, 2022 and June 30, 2021.

Q. PLEASE EXPLAIN PECO'S BUDGETING PROCESS.

A. PECO claims that the annual budgeting and planning process is designed "to integrate and align PECO's operational, regulatory, and financial plans."[2] Accordingly, PECO claims that the spending targets in the financial plan are set to achieve operational goals, comply with regulatory requirements, and manage O&M expense increases at a rate lower than the rate of inflation. Company witness Stefani states:

> The planning process starts with a review and update of PECO's operational and regulatory goals and initiatives to determine if changes are required for the future. Any significant changes in such goals and initiatives are taken into consideration when updating the Company's financial Long Range Plan ("LRP"). The LRP is a five-year outlook and is updated with key assumptions (e.g., inflation rates, interest rates) and with detailed input provided by "responsibility areas." Each responsibility area reviews its historic expense levels, current and anticipated employee staffing levels,

[2] Direct Testimony of Robert J. Stefani at page 10, lines 12 and 13.

> performance assessments, regulatory requirements, operational goals, specific projects, and other factors.
>
> The individual responsibility areas of LRPs are typically submitted to PECO's finance group in June of each year and are carefully analyzed for consistency, completeness and appropriateness. The responsibility area LRPs are then consolidated and delivered to PECO's senior management (i.e., the Chief Executive Officer, Chief Operating Officer, and Chief Financial Officer) for review and approval in September.
>
> Once the LRP has been updated and approved, data are used to formulate a detailed two-year budget. The two-year budget is "built up" by responsibility area, similar to the LRP process described above. The financing plan is then developed to ensure PECO can maintain investment grade credit ratings. Based on that plan, PECO determines the amount it can borrow to fund its spending plans and the dividend levels that will achieve its targeted capital structure.
>
> The final consolidated budget is then submitted to PECO's senior management for review and approval.[3]

To simplify the chronology, the budgeting process begins with a review and update of the LRP in June, and the LRP is reviewed and approved in September. It is after September that a detailed two-year budget is formulated. At that point, the budget is not finalized because a financing plan must be developed. The financing plans are then used to determine the funding for spending plans. It is after that point that the budget is finalized and submitted to senior management for approval. Based upon this chronology, I believe that to fully develop a budget that is representative of PECO's operational, regulatory, and financial plans, and for it to be reasonable, it would require the 4 months (or more) that the company has described. Accordingly, I would expect budget planning that started in July to be completed in November.

Q. WHEN WERE THE FPFTY AND FTY BUDGETS PREPARED?

[3] Direct Testimony of Robert. J. Stefani at page 11, line 2 to page 12, line 3.

A. According to the response to OCA-II-2, PECO's FPFTY and FTY capital and operating budgets for the twelve months ending June 30, 2022 and 2021 were prepared beginning in July 2020 and finalized in August 2020.

Q. WHY IS THE BUDGET PREPARATION DATE IMPORTANT?

A. The budget preparation date is critical because the events, circumstances and related data from that period affects the judgement and decision making while preparing the budget. For example, during April and May 2020, there were very dramatic changes in the US economy. In April, sales of existing homes dropped by 17.8 percent. The National Association of Home Builders (NAHB) Housing Market Index (HMI) [4] dropped from 72 to 30 and 37 for April and May, respectively. Unemployment surged in April to 14.7 percent from 4.4 percent in March. These data points began to recover in June, and the Company indicates it developed the FTY and FPFTY budget during this period when the economy was very volatile. These rapid changes in the housing sector are very relevant to gas operation because it affects capital expenditures, especially since capital expenditures related to New Business Connection forms 12.9 percent of PECO's FPFTY plant projection activity. New Business Connections also affects the revenue projections. It is doubtful that one can accurately project customer growth with the volatility in the housing market and business closures.

Another reason to have concerns over the Company's budget is related to the spike in unemployment and the moratorium placed on service disconnection and late payment fees. These factors had the effect of increasing uncollectible expense and reducing revenues from late payment fees. Keeping in mind that the events were

[4] The National Association of Home Builders (NAHB) Housing Market Index (HMI) is a measure of builders opinion on the relative level of current and future single-family home sales. It is a diffusion index, which means that a reading above 50 indicates a favorable outlook on home sales; below 50 indicates a negative outlook.

unprecedented, the ability of the Company to accurately forecast two years into the future amidst the uncertainty is questionable, especially given the rapid pace of the budget preparation.

Q. DO YOU BELIEVE THE BUDGET USED FOR THE FTY AND FPFTY COST OF SERVICE IS REASONABLE?

A. No. As I have explained above, the Company appears to have used an abbreviated approach to the development of the O&M and Capital budgets. By the Company's own admission, the normal budgeting process takes four months, at best. Yet the Company claims to have produced a reliable budget in two months. It is more doubtful that the budget is reasonable when one considers that the abbreviated budget was prepared while the U.S. economy is experiencing significant volatility, negative growth, and high unemployment.

This abbreviated approach may be the cause for the inconsistencies and inadequate data supporting the rate increase request. For instance, the Company has been unable to provide detailed support for its plant in service additions and, in some instances, the total plant additions during the FTY and FPFTY are not the same amount where comparing different source documents with data request responses.

In data request OCA-XI-5, the Company states the 11.5 miles of gas main (related to a reliability project) is on schedule to be installed by the end of 2021, but in Attachment IE-RB-4-D(a), the Company states that project will be completed in June 2023.

The number of employees presented in Public Attachment IE-RE-8-D(a) clearly shows the number of employees increased in October 2020 by approximately 35 employees, yet in the response to OCA-IX-10, the Company claims that the increase in the number of employees occurred during the HTY and does not provide information on allocated employees from affiliates.

In several instances, the Company explains its increases in expenses by stating that the increase in the expense is generally due to inflation adjustments.[5] General inflation escalation adjustments do not accomplish the Company's goal to integrate and align PECO's operational, regulatory, and financial plans because they are not specific to the Company nor do they reflect planned activities. Moreover, I do not believe that the intent of Act 11, which allowed the use of a FPFTY, was for utilities to develop the FPFTY amount by just escalating for inflation. Therefore, I recommend that the Commission not accept the increases based on inflation escalation.

Q. HOW WAS PECO'S OPERATIONS AFFECTED BY THE COVID-19 PANDEMIC?

A. In the response to OCA-II-66, PECO explained that its gas operations construction activities were delayed as a result of the COVID-19 pandemic beginning in March 2020. As a result, construction work scheduled in the first half of 2020 was shifted to the second half of 2020. Even though PECO does not explicitly state construction activities were suspended, it admits that construction activities resumed in June 2020, implying that there was a suspension period. The Company also states that during "the period of delay", it carried out some main construction installation activities, but work that required entry into existing customer properties was restricted. According to the Company, COVID-19- related restrictions mostly limited construction involving main retirement and bare steel service replacements. According to the

[5] See PECO's response to IE-RE-50-D, IE-RE-16-D (e) & (f), IE-RE-15-D(c), IE-RE-15-D(e), Attachment IE-RE-65-D(a).

Company, the timing and shift of the construction workplan from the first half of 2020 to the second half of 2020 resulted in expenditures moving from the HTY to the FTY.

Yet, in the response to OCA-II-69, PECO argues that "[t]here have been no delays, cancellations or rescheduling affecting the FY2021 and FY2022 capital and operation and maintenance projects resulting from the Company's response to the COVID-19 pandemic." These two responses are inconsistent. Clearly the response to OCA-II-69 is not accurate given the response to OCA-II-66. The responses imply that the abbreviated budgets lack the detail to adequately respond.

If, as PECO indicates, construction work scheduled in the first half of 2020 was shifted to the second half of 2020, then some construction work planned for the second half 2020 will be shifted to first half of 2021 and so forth.

Q. HOW DO THESE DELAYS AFFECT THE FPFTY COST OF SERVICE?

A. Perhaps, one area that is impacted the most by the delays is rate base. The costs in rate base for the FPFTY are cumulative. Therefore, the FPFTY rate base assumes the planned plant additions for the FTY occurred. However, if planned construction projects did not occur in the FTY due to delays and are shifted to FPFTY, some of the FPFTY projects are likely to be shifted to the future because the Company's capacity to work on projects are not unlimited. Realistically, it cannot be assumed that the projects that are carried over will be completed in addition to previously planned projects. The problem is that construction work takes time, and some phases of projects need to occur before further work can be done in a subsequent period. Hence, one cannot simply assume that projects that did not get completed in one year will be completed in the next year along with all the other planned work. Complicating this further is the contribution of suppliers and subcontractors. If suppliers have shut down operations due to the pandemic, the materials and supplies may not be available instantly when the planned work resumes. Subcontractors may be regrouping themselves from COVID-related disruption. There is a whole supply chain that must be operating and functioning well to resume full construction activity. Consequently, some FTY & FPFTY construction work will inevitably be postponed.

Since the Company does not have unlimited resources, coupled with the possibility of decreased cash flow from the loss of customers and the loss of small businesses, it would not be reasonable to assume that all postponed FTY construction work and planned FPFTY construction work will be done during the FPFTY, especially those forecasts related to New Business Connections. This would mean that work scheduled for the FPFTY may not occur or may be postponed to the future.

As I have explained, the Commission cannot rely on the Company's FPFTY data as filed. OCA witness Scott Rubin provides further discussion on the effect of COVID-19 and why the Commission should not grant a rate increase at this time.

PART II: <u>OCA ADJUSTMENTS TO PECO'S TEST YEAR</u>

Q. IF THE COMMISSION ACCEPTS PECO'S COST OF SERVICE FOR RATEMAKING IN THIS PROCEEDING, WHAT DO YOU RECOMMEND?

A. As stated above, the Commission cannot rely on the Company's projections and data regarding its test year revenue requirement. As a matter of prudence, however, I have examined the FPFTY data presented by the Company as the basis for future rates and made adjustments where I found costs to be inappropriate for inclusion, uncertain and unreasonable. I discuss each of those adjustments in the following section of my testimony.

Plant in Service

Q. PLEASE EXPLAIN THE COMPANY'S ADJUSTMENT TO PLANT IN SERVICE.

A. According to the Company, the FPFTY plant in service claim was derived based on the utility plant in service at June 30, 2020, plus budgeted capital expenditures estimated to be closed to plant in service during the FTY and FPFTY and less the estimated retirements during the FTY and FPFTY.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE BUDGETED DATA SUPPORTING THE ADJUSTMENT TO PLANT IN SERVICE?

A. Yes. Although I made several attempts to get detailed budget data, the Company was unable to provide the detailed data supporting its plant in service claim. In my initial data request, OCA-II-3 sought detailed information that would provide a description of the project, the initial estimated completion dates and any revised completion date; current status of each project, etc. The Company provided general categories rather than the data requested. The OCA contacted the Company in an attempt to obtain the data that was sought. The OCA submitted OCA-XIII-3 and OCA-XIII-4 as a result of our conversation with hopes of obtaining the data we sought. Again, the Company provided general and summary data rather than the data sought.

Even the data we received contained inconsistencies. The plant in-service dates provided in the response to OCA-II-3, differed from the in-service dates presented on OCA-XIII-3, and the in-service dates on both of those documents were different than the in-service dates presented on IE-RB-4-D. The differing data does not provide much confidence about the accuracy of the Company's claim.

Even when I attempted to gain better understanding of the budgeting process based on previous responses to the OCA's interrogatories, the Company's response was not clear.[6] I attempted to seek other means to assure myself that the plant in service data was reliable but was not successful. I sought to obtain the budget preparation instructions that is often used by Companies at the beginning of their budget process. PECO did not provide the information.[7]

Q. WHAT ADJUSTMENT HAVE YOU MADE TO PLANT IN SERVICE?

A. Since I do not have a high degree of confidence in the plant data I reviewed, it is difficult for me to accept the FPFTY plant in service data as presented by the Company. In short, the project groupings and completion dates have changed with each data request response. Attempts to gain additional understanding of the basis of the projections have also failed. Yet, it is reasonable to assume that since the end of the HTY additional plant has been added.

Therefore, as a compromise, I determined that using the FTY plant additions would be a reasonable approach to determine rates in this proceeding. Hence, for the FPFTY, I have adjusted the plant-related components in rate base to reflect the FTY level of costs. The use of the FTY plant-related amounts has resulted in a decrease to rate base of $271 million. This adjustment is presented on Schedule LKM-4, pages 1 through 5.

Pension Asset

Q. PLEASE EXPLAIN THE PENSION ASSET INCLUDED IN RATE BASE.

A. In simple terms, the Pension Asset represents the cumulative portion of the contribution by PECO to the pension plan trust fund that exceeds the pension costs that is recognized for financial reporting purposes pursuant to the Financial Accounting Standards Board (FASB) Accounting Standards Codification 715-30

[6] See PECO’s response to OCA-XV-12
[7] See PECO’s response toOCA-XIII-2

(ASC 715). The contribution to the pension plan trust fund and the pension costs recognized for financial reporting purposes are determined differently. The costs determined pursuant to ASC 715 is based upon an actuarial process that considers the expected increase in pension liability due to active participants, interest costs, the return on plan assets and amortization of prior service costs. On the other hand, the pension contribution is determined from the Employee Retirement Income Security Act of 1974 (ERISA) requirements, the Pension Protection Act of 2006, the tax deductibility of contributions to the plan and target funding percentages. Over the years, PECO's accumulated contributions to the plan has exceeded the ASC 715 costs to create the current pension asset.

Q. WHY IS THE COMPANY SEEKING TO INCLUDE THE PENSION ASSET IN RATE BASE?

A. The Company states that it believes "that it is appropriate and necessary to include the pension asset in its rate base in order to adhere to the Commission's policy and practice on pension expense recovery while also properly recognizing the amount of pension costs that, for ratemaking purposes, has not been recovered as an expense or capitalized to plant in service…" In PECO Statement No. 3, at pages 22 to 24, Witness Trzaska states:

> The asset represents the portion of the Company's net aggregate total of pension costs to be incurred at the end of the FPFTY, calculated in the manner required for ratemaking purposes, that was not, and will not be, recovered in operating expenses and was also not, and will not be, capitalized to its plant accounts. This asset represents the difference between the manner in which pension expense is calculated for ratemaking purposes and the manner in which pension costs are determined for purposes of calculating the labor loading rate used to capitalize a portion of pension costs under applicable Generally Accepted Accounting Principles ("GAAP"). Specifically, for ratemaking purposes, consistent with Commission policy and practice, PECO has historically claimed for recovery its cash

> contributions to its pension fund. However, also consistent with Commission policy and practice, the amount of the total cash contribution included in operating and maintenance expenses was determined by reducing the total cash contribution by the capitalization rate used for ratemaking purposes. In that way, labor-related costs are separated between amounts that are expensed and amounts assigned, on a pro forma basis, to capital.

Q. DO YOU AGREE THAT IT IS APPROPRIATE AND NECESSARY TO INCLUDE THE PENSION ASSET IN ITS RATE BASE IN ORDER TO ADHERE TO THE COMMISSION'S POLICY?

A. No. In fact, the opposite is true. Under past Commission ruling, no return is allowed to be earned on expenses, only on capital investments. Expenses are recovered on a dollar-for-dollar basis without profit. Hence, the attempt by the Company to include the Pension Asset in rate base is an attempt to earn a return on expenses and violate Commission rules.

Q. MR. TRZASKA STATES THAT PECO IS NOT PROPERLY RECOGNIZING THE AMOUNT OF PENSION COSTS THAT, FOR RATEMAKING PURPOSES, HAS NOT BEEN RECOVERED AS AN EXPENSE OR CAPITALIZED TO PLANT IN SERVICE. DO YOU AGREE?

A. No. Mr. Trzaska is conflating the ratemaking and financial reporting concepts. For ratemaking purposes, the pension expense for PECO has been based upon the amount contributed to the pension plan instead of the amount reported for financial reporting (the ASC 715 amount). The rationale for using the pension plan contribution as the pension expense recovery in rates is to allow the Company recovery of the cash outflows instead of the ASC 715 expense, which has generally been lower than the pension contribution. As stated above, the annual pension contribution amount is determined from ERISA and the Pension Protection Act requirements and the tax deductibility of contributions. Following these criteria, prevents the Company from underfunding its pension plan. Given that the excess pension contribution over the expense can be significant, allowing the Company to recover pension contributions in current rates prevents the Company from using cash raised from investor sources to fund its pension obligations. So, from a ratemaking perspective, the amount contributed has been provided through rates because the expense in the cost of service equals the contribution amount.

For financial reporting, as stated above, the expense is based on the actuarial study as prescribed by ASC 715. Since the ASC 715 cost is the basis of the expense for financial reporting, if the pension contribution exceeds the ASC 715 costs, the excess contribution over the ASC 715 cost will be charged to the pension asset. However, it is important to keep in mind that the excess that is charged to the pension assets has been collected in rates. So, it does not reflect an outlay of cash contributions that has not been collected from ratepayers (which may make it subject to earning a return by inclusion in rate base). Therefore, the pension asset reflects the difference between the expense for financial purposes and the contribution to the pension plan. Again, this, in itself, does not make it eligible for inclusion in rate base since the contributions have been collected in rates. Therefore, Mr. Trzaska's argument is flawed because it fails to recognize that the contribution to the pension fund has already been provided in rates.

Q. FROM ANOTHER PERSPECTIVE, THE PENSION ASSET ADJUSTMENT PRESENTED ON EXHIBIT MJT-1, SCHEDULE C-5, PAGE 32, APPEARS TO IMPLY THAT THE COMPANY IS SEEKING TO INCLUDE THE CAPITALIZED PORTION OF THE AMOUNT THAT HAS

BEEN ALLOWED IN EXPENSES. DO YOU THINK THIS IS REASONABLE?

A. No. The Company's proposal would overstate rate base because the pension asset does not get amortized. In the response to OCA-II-26, PECO stated:

> The pension asset on PECO's balance sheet represents cumulative cash contributions made by PECO in excess of PECO's cumulative pension cost and does not get amortized to expense. The change in the pension asset represents annual contributions paid by PECO to the pension trust and annual pension cost accounted for in accordance with ASC 715.

Based on the above quote, the pension asset would be reduced only when the pension expense for financial reporting exceeds the pension contribution. However, some of the capital projects to which PECO is attempting to attribute the pension asset have already begun depreciation. Under the Company's proposal, since the pension asset is not amortized (or depreciated), the pension asset amount (that was attributed to those projects) would remain virtually constant, while the actual net balance (plant minus accumulated depreciation) of those projects will decrease over time. The return earned on the unchanging balance will result in an over-recovery of the return if the Commission allows the Pension Asset in rate base.

On Schedule LKM-5, I present my adjustment to remove the total plant not eligible for rate base inclusion. This adjustment reduces rate base by $35,059,000.

<u>Allowance for Cash Working Capital</u>

Q. HOW DO YOU DEFINE CASH WORKING CAPITAL?

A. For ratemaking purposes, cash working capital is the investment that a utility needs to have on hand to fund its day-to-day operations. Positive cash working capital represents funds provided by investors that should be included in rate base so that the utility earns a return on it. Negative cash working capital represents funds supplied by ratepayers that should be recognized as a rate base offset to reflect funds advanced for operations by ratepayers.

Q. HOW DID THE COMPANY REFLECT CASH WORKING CAPITAL IN ITS FILING?

A. The Company's cash working capital allowance is calculated based upon the results of a lead/lag study. A lead/lag study is an in-depth analysis that measures the difference between the lapse of time when a company receives revenue for the provision of service and the lapse of time when a company pays for the costs of providing service. This difference is expressed as a number of days and is used to calculate the level of investor-supplied funds advanced for operations, or the funds advanced by customers for operations.

Q. WHAT CHANGES HAVE YOU MADE TO THE ALLOWANCE FOR CASH WORKING CAPITAL?

A. I have made an adjustment to cash working capital to reduce rate base by $332,000 on Schedule LKM-6. This adjustment is the result of reflecting the adjustments I have recommended be made to O&M expenses and taxes in the lead/lag study. The operating expenses (O&M expenses and taxes) are the bases on which the lead/lag working capital is calculated. Therefore, when deriving the allowance for cash working capital, any adjustment made to operating expenses or taxes in the cost of service should also be incorporated in the lead/lag study.

In addition, I have adjusted the total prepaid expenses component of the lead/lag study to reflect the most recent month actual balances that were provided by PECO. In PECO's presentation of the prepaid expenses, the Company used the HTY monthly balances for FPFTY balances. However, since more recent data is available, they should be used.

Gas Stored Underground

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE GAS STORED UNDERGROUND.

A. The average balance of Gas Stored Underground included in PECO's rate base is based upon the 13-month average balance as of June 30, 2020. I requested and received more recent monthly data from the Company through October 2020. Given that the test year used for ratemaking is the FPFTY, it is appropriate to use the most recent data in the cost of service. Therefore, the gas stored underground balance should be adjusted.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE GAS STORED UNDERGROUND BALANCE?

A. On Schedule LKM-7, I present my adjustment which updates the Gas Stored Underground balance to reflect the 13-month average balance as of September 2020. The resulting average of $31.1 million was compared to the Company's claim of $30.9 million. This results in an adjustment of $286,000 to rate base.

Customer Deposits

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO CUSTOMER DEPOSITS.

A. This adjustment is similar to the adjustment I recommended for Gas Stored Underground. The Customer Deposits balance included in PECO's rate base is based upon the 13-month average balance as of June 2020. I requested and received more recent monthly data from the Company through September 2020. Given that the test year used for ratemaking is the FPFTY, it is appropriate to use the most recent data in the cost of service. Therefore, the Customer Deposits balance should be adjusted.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE CUSTOMER DEPOSITS?

A. On Schedule LKM-8, I present my adjustment which updates the Customer Deposits balance to reflect the 13-month average balance as of September 2020. The resulting average of $13.401 million was compared to the Company's claim of $13.418 million. This results in an adjustment which decreases rate base by $17,000.

Materials and Supplies

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO MATERIALS AND SUPPLIES.

A. I am recommending an adjustment that is similar to the adjustment I recommended for Gas Stored Underground. The Materials and Supplies balance included in PECO's rate base is based upon the 13-month average balance as of June 2020. I requested and received more recent actual monthly data from the Company through September 2020. Given that the test year used for ratemaking is the FPFTY, it is appropriate to use the most recent data in the cost of service. Therefore, the Materials and Supplies balance should be adjusted.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE MATERIALS AND SUPPLIES BALANCE?

A. On Schedule LKM-9, I present my adjustment to Materials and Supplies to reflect the 13-month average balance as of September 2020. The resulting average of $294,000 was compared to the Company's claim of $489,000. This results in an adjustment which decreases rate base by $195,000.

Customer Advances

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO CUSTOMER ADVANCES.

A. I am recommending an adjustment that is similar to the adjustment I recommended for Materials and Supplies. The Customer Advances balance included in PECO's rate base is based upon the 13-month average balance as of June 2020. I requested and received more recent actual monthly data from the Company through September 2020. Given that the test year used for ratemaking is the FPFTY, it is appropriate to use the most recent data in the cost of service. Therefore, the Customer Advances balance should be adjusted.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE CUSTOMER ADVANCES BALANCE?

A. On Schedule LKM-10, I present my adjustment to Customer Advances. The first part of the adjustment updates the Customer Advances balance to reflect the 13-month average balance as of September 2020. The resulting average of $1,255,000 was compared to the Company's claim of $1,334,000. This results in an adjustment which decreases rate base by $79,000.

<u>Payroll Expense</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PAYROLL EXPENSE.

A. The Company's FPFTY payroll expense was calculated to annualize budgeted payroll expense to reflect the number of employees at the end of the FPFTY and reflect a 2.5% wage increase for both union and non-union employees forecasted to be effective on January 1, 2022 and March 1, 2022, respectively. The Company's payroll adjustment also normalized, over a 6-year period, a one-time cash payment to union employees made in connection with the ratification of current union contracts. Finally, the Company adjusted its payroll expense to increase its employee headcount by 1 position to include 639 positions in the payroll expense. The adjustment that I am recommending reduces the number of employees to the most recent actual number of employees and removes the normalization of the one-time cash payment for ratification of the union contract.

Q. WHY HAVE YOU REDUCED THE NUMBER OF EMPLOYEES FROM 639 POSITIONS TO 604 POSITIONS?

A. I have reduced the number of employees because the Company has not adequately supported the increase in the number of positions for the FPFTY. According to the Company, it developed its FPFTY payroll on the average number of employees during the FPFTY of 638. In Public Attachment IE-RE-8-D(a), the Company showed that at the beginning of the HTY, there were 585 employees and 602 employees at the end of the HTY. That attachment showed that the projected increase of 35 employees did not occur until October 2020. Clearly, the increase in the number of employees were projected to occur during the FTY according to Public Attachment IE-RE-8-D(a) and the response to OCA-II-47 (a).

I requested that the Company provide a list of each of the 37 new positions, showing the annual salaries and wages; date hired, if hired or the expected hiring date; and date terminated, if terminated during the HTY or FTY. The Company responded stating that 30 positions were hired during the HTY, and the remaining 7 positions were for positions that were allocated. Based on the response from the Company, these were not the support for the projected increase in the number of positions that occurred during the FTY. Consequently, I have not seen any support, including management authorization for the projected increase in the number of employees. In other words, there is no documentation that the new positions were authorized. There also is no support for the salary and wages, hire dates, or a description of the positions. Therefore, the costs related to the additional position should not be allowed.

Q. WHY HAVE YOU REMOVED THE COSTS RELATED TO THE ONE-TIME PAYMENT FOR RATIFICATION OF THE UNION CONTRACT?

A. On January 6, 2015, each bargaining-unit member of Local 614 was to be paid a ratification bonus of $1,000 for ratification of the then new union contract. There were no future obligations, services or tasks that were expected from the employees. Employees were free to voluntarily leave the company or retire. Any employee who left after the payment of the one-time bonus was not required to repay the $1,000. Five years after the payment of the one-time bonus, the Company is seeking to recover the cost of the one-time bonus over a 6-year period.

I am recommending an adjustment to remove the recovery of the one-time bonus because it is a prior period cost, and recovery would constitute retroactive ratemaking and violate normal ratemaking principles. The bonus was paid in exchange for ratification of the union contract on or before December 31, 2014. Thus, the bonus was compensation for the action the workers took in December 2014. There also was no authorization from the Commission to defer those costs for future recovery. As a result, these costs are not eligible for recovery.

Based on the foregoing explanations, on Schedule LKM-11, I present my adjustment which reduces payroll expenses by $2,447,000.

<u>Employee Benefits Expense</u>

Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE EMPLOYEE BENEFITS EXPENSE?

A. The Company explains that it annualized the non-pension employee benefits expense to reflect the full year's level of costs associated with the number of employees during the FPFTY. The Company then annualized the adjustment to reflect an increase of 1 employee. The Company then added the pension cost and the postretirement benefits costs to derive the total employee benefits expense.

I am adjusting the employee benefit costs to reflect the reduction in the number of employees that I have recommended in my adjustment to payroll expense. Hence, I have adjusted employee benefits expense to reflect 604 employees as compared to the Company's 639 employees. On Schedule LKM-12, I present my adjustment which reduces employee benefits expense by $315,000.

Postretirement Benefits Expense

Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE POSTRETIREMENT BENEFITS EXPENSE?

A. The Company has claimed a postretirement benefits expense of $1,050,000 for the FPFTY. This amount represents a significant increase in the postretirement benefits cost when compared to the historical average for the most recent actual 3-year average. When queried about the significant increase, the Company stated that:

> The increase in projected OPEB cost from 2021 to 2022 is a result of expiring prior service credit amortization in the East plan in which PECO participates. The prior service credit amortization is a result of a plan design change made in 2014 that is amortized into pension cost over the average remaining service period of active participants.[8]

However, according to the actuarial report: [BEGIN CONFIDENTIAL]

> [redacted]

[END CONFIDENTIAL] With respect to OPEB specifically, the actuarial report stated: [BEGIN CONFIDENTIAL]

> [redacted]

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[8] PECOs response to OCA-IX-7.
[9] Confidential Attachment III-A-21(b), page 1.

[redacted]

[redacted]

[END CONFIDENTIAL] Based on these quotes, cost increases do not seem to be imminent. Moreover, I could not locate any support in the actuarial reports to support the Company's $1,050,000 claim. Therefore, I have adjusted OPEB expense to reflect the most recent actual 3-year average. This adjustment reduces OPEB by $1,085,000 and is presented on Schedule LKM-13.

<u>Pension Expense</u>

Q. WHAT ADJUSTMENT HAVE YOU MADE TO PENSION EXPENSE?

A. The Company has adjusted pension expense to reflect the 5-year average of contributions to the pension plan. However, the Company has indicated that there was an error in the calculation of the adjustment. I am recommending an adjustment to pension expense to reflect the correction of the error.[12] This results in an adjustment of which decreases pension expense by $448,000. This adjustment is presented on Schedule LKM-14.

<u>MGP Remediation Expense</u>

Q. PLEASE EXPLAIN PECO'S ADJUSTMENT TO ENVIRONMENTAL REMEDIATION EXPENSE.

A. PECO has proposed an adjustment to recover costs to remediate former manufactured gas plant ("MGP") sites at an annual cost of $804,000. This amount was derived based upon a 9-year recovery of an estimated total of $7.2 million to remediate

[10] ibid
[11] Confidential Attachment III-A-21(b), page 2.
[12] PECO's response to OCA-XIII-16(a).

former MGP sites. According to the Company, it has eight remaining sites with an overall estimated liability of $21.5 million to remediate. Of that amount, it has not recovered $7.237 million.

Q. PLEASE EXPLAIN HOW THE 9-YEAR RECOVERY PERIOD WAS DETERMINED.

A. According to the company, "[t]he nine-year amortization period is based on recovery of the unrecovered MGP remediation costs over three future rate cases as PECO expects to file a base rate case every three years."[13]

Q. PLEASE EXPLAIN HOW PECO PARTIALLY RECOVERED THE MGP REMEDIATION COSTS.

A. In Docket Nos. R-2008-2028394 and R-2010-2161592, the Company and the intervening parties reached settlements that included a recovery mechanism for MGP remediation costs. The MGP recovery mechanism designated annual recovery of MGP remediation. Based on this annual recovery, the Company determined that out of the $21.5 million to remediate the remaining sites, it had pre-collected $14.3 million, resulting in an unrecovered amount of $7.2 million.

Q. FROM A RATEMAKING PERSPECTIVE, WHAT DOES THIS $14.3 MILLION REPRESENT.

A. This $14.3 million represents an over-collection of ratepayer funds that is being held by the Company, which can be used for general corporate purposes until it is needed for MGP remediation.

Q. ARE RATEPAYERS BEING PROVIDED A CARRYING COST ON THE $14.3 MILLION THAT THE COMPANY RETAINS?

[13] PECO's response to I&E-RE-45-D(g).

A. To my knowledge, the answer is no. From the analyses that the Company has provided with respect to the MGP remediation, I have not observed any carrying charge being credited to ratepayers.

Q. SHOULD THE COMPANY BE ALLOWED TO RECOVER THE $7.2 MILLION OVER A NINE-YEAR PERIOD AS IT PROPOSES?

A. No. The settlement language in Docket No. R-2010-2161592, was specific as to the recovery of the MGP remediation costs in this base rate proceeding. The settlement stated:

> The Joint Petitioners further agree that, in PECO's next general gas base rate case, the Company's MGP remediation expense allowance will be reset based on: (1) **a normalized annual level of MGP remediation costs to be incurred over the remainder of its MGP remediation program**, and (2) the difference between (a) $5.982 million per year times the number of years (including partial years as a fraction) that the Settlement Rates are in effect, and (b) the actual, prudently-incurred MGP remediation costs, net of insurance recoveries, experienced during that same period.[14]

Based on the Company's response to OCA-XIII-18, the remediation is expected to extend through 2034 (14 years from this year). Therefore, I am recommending the $7.2 million be recovered through 2034, consistent with the settlement instead of the 9 years proposed by the Company.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR MGP REMEDIATION EXPENSES.

A. As I have explained, the Company should be required to recover the remaining remediation cost over a 14-year period consistent with the settlement in Docket No. R-2010-2161592. Collection over that period would result in an annual recovery of

[14] Docket No. R-2010-2161592, Joint Petition for Settlement, pages 4-5 (emphasis added).

$517,000. This amount will result in an adjustment that reduces O&M expenses by $287,000. This adjustment is presented on Schedule LKM-15.

I am also recommending that the Company be required to impute carrying costs on the over-collected MGP remediation cost that is held by the Company. As I have stated, the $14.5 million over-collection represents ratepayer funds that is being held by the Company which can be used for general corporate purposes until it is needed for MGP remediation. Ratepayers should not be in the position of providing cost-free capital to the Company.

Injuries and Damages Expense

Q. PLEASE EXPLAIN THE COMPANY'S ADJUSTMENT TO INJURIES AND DAMAGES EXPENSE.

A. In the cost of service, PECO proposed to include FPFTY budget amount for Injuries and Damages. However, the amount included in the cost of service for Injuries and Damages is significantly higher than previous years. The nature of Injuries and Damages is one that fluctuates from year to year. Hence, no single year is representative of the normal level of this expense. Therefore, it is appropriate to normalize the Injuries and Damages expenses to avoid an over-recovery of costs.

On Schedule LKM-16, I have normalized Injuries and Damages based upon the most recent 3 years of actual expenses. This results in a decrease in expenses of $464,000.

Rate Case Expense

Q. WHAT ADJUSTMENT HAVE YOU MADE TO RATE CASE EXPENSE?

A. PECO's rate case expense claim is based upon the inclusion of the fees for legal services and consultants to prepare and adjudicate this case. The Company has projected approximately $1.5 million as the cost of this proceeding. That amount has been normalized by the Company over a 3-year period to derive an annual expense of $520,000.

I am recommending an adjustment to normalize the rate case expense over a 5-year period. I chose a 5-year period based on the Company's history of the frequency of rate case filings. The Company's last rate case filing was approximately 10 years ago. In general, it is preferred that rate case expenses be recovered over a period of time that reflects the frequency of rate case filings so that costs can be recovered between rate cases.

Additionally, the estimated costs are comparable to the costs incurred recently by the Company's electric division for its rate case. That case was adjudicated under the normal approach that included travel for hearings, document reproduction, etc. This proceeding is being done virtually, for the most part. Therefore, it is possible that there may be some cost savings. Rather than estimate those savings, the annual cost reduction brought about by the 5-year normalization will also serve to reflect the potential savings derived from the decreased travel and document reproduction. On Schedule LKM-17, I present my adjustment to rate case expenses. On this schedule I reduce rate case expenses by $208,000.

Regulatory Initiative Costs

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE COMPANY'S CLAIM FOR REGULATORY INITIATIVE COSTS.

A. PECO has included $753,000 in O&M expenses for costs incurred prior to the FPFTY associated with implementing certain regulatory programs for which it claims it has not fully recovered. These costs are related to the initiative to establish and implement a Gas Procurement Charge (GPC) and Merchant Function Charge (MFC) pursuant to the Commission's Order in Docket No. P-2012-2328614 and the implementation of the Neighborhood Gas Pilot program which was approved by the Commission in Docket No. P-2014-2451772. The total amount presented for recovery

Gas Unbundling of GPC/MFC		
Capital Costs	$129,249	
O&M Expenses	20,570	
	$149,819	*
Gas Neighborhood Pilot Program		
Capital Costs	$1,802,831	
O&M Expenses	314,507	
	$2,117,338	

** The Company claimed $141,000 for the Gas Unbundling Program instead of the $149,819.*

is presented below:

PECO requested to amortize these costs over a 3-year period, resulting in an annual cost of $753,000. The Company also stated that there were no depreciation expense and no operating expense included in the FPFTY for these programs. PECO also stated that the capital costs were software costs.

With respect to the Gas Procurement Charge and Merchant Function Charge, Paragraph 39 of the Joint Settlement in Docket No. P-2012-2328614 included the following statement which was approved by the Commission:

> Implementing the proposed PTC revisions will require changes to PECO's operations and systems, including IT modifications to PECO's billing system and bill format. PECO may defer such costs on its books, and once determined, seek recovery in its next gas base rate case.

This statement, approved by the Commission, is clear that IT modifications (capitalized software) could be recovered in this proceeding. Consistent with the Commission's Order, I have allowed the recovery of the capital costs, but removed the O&M expenses from the costs eligible for recovery.

With respect to the Neighborhood Gas Pilot program costs that the Company is seeking to recover, the Commission's Order in Docket No. P-2014-2451772 does not authorize future recovery. Paragraph 16 of the joint settlement states:

> In its next general base rate case filing, PECO will assign all Neighborhood Gas Pilot Program related investment cost and associated revenues to the appropriate rate classes.

This paragraph means that to the extent there are current Neighborhood Gas Pilot Program costs in the cost of service, those costs should be assigned to the appropriate class. It does not authorize deferral of any cost for future recovery. In the response to OCA-II-54, the Company clearly stated that no depreciation or O&M expenses were included in the cost of service relating to these programs. Therefore, there were no current costs to recover. The attempt by the Company to include the Neighborhood Gas Pilot Program costs in rate should not be allowed because it is a prior period cost and inclusion would be retroactive ratemaking which is prohibited in accepted ratemaking practice. Since there was no order, by the Commission, to defer these costs, they are not eligible for recovery.

On Schedule LKM-18, I am recommending my adjustment to regulatory initiative costs which removes the $746,000 from the cost of service.

<u>Cost to Achieve</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE COMPANY'S CLAIM FOR RECOVERY OF THE COST TO ACHIEVE THE MERGER SAVINGS.

A. PECO is attempting to recover the costs to achieve the merger savings that were to be produced by the merger of PECO's parent, Exelon Corporation, with Pepco Holdings, Inc. in 2016. These costs, totaling $1,111,000, were incurred during 2016, 2017 and

2018. The Company states that because PECO and its customers receive the benefit of PECO's allocable share of merger savings, it is appropriate that PECO should bear the costs to achieve those savings. PECO seeks to recover these costs over a 3-year period which results in a $370,000 increase in O&M expenses.

The attempt by the Company to include the Cost to Achieve costs in rates should not be allowed because it is a prior period cost and inclusion would be retroactive ratemaking which is prohibited in accepted ratemaking practice. The Commission did not authorize deferral of these costs, so they are not eligible for recovery.

Q. DID PECO SEEK AUTHORIZATION FROM THE COMMISSION TO DEFER THESE COSTS?

A. No. In the response to IE-RE-47-D(b), PECO stated:

> PECO Energy did not request permission to "defer" for accounting purposes its share of the costs to achieve the merger savings that it is realizing, nor is it PECO Energy's position that permission to record an accounting deferral is necessary to make or substantiate its claim. Because the costs to achieve merger savings were incurred before the merger-related savings could be fully realized and because a full annual level of merger savings was reflected in developing the Company's revenue requirement in this case, it is proper to reflect, by amortization over a reasonable prospective period, the costs-to-achieve associated with the merger savings so that only an appropriate level of net merger savings is flowed-through to customers. Otherwise, customers would receive merger savings, which substantially exceed the costs to achieve the merger, but not bear any of the costs that were incurred to obtain those savings.

PECO is wrong in some of its assertions. According to the 2018 Edition of <u>A Guide to Ratemaking</u> by James H. Cawley and Norman J. Kennard at page 125:

> Accounting Standards Codification (ASC) 980 acknowledges that, for regulatory accounting purposes, regulators sometimes include the recovery of costs in periods other than the period in which costs

> would otherwise be charged to expense in GAAP financial statements if the company were not regulated.
>
> That is, regulators sometimes find it necessary to allow regulated entities to establish a regulatory asset on their books for certain types of costs that would otherwise require expense treatment in the current period. The regulatory asset is established to allow a utility to recover costs from ratepayers over future periods. The regulatory asset accounts may or may not be included in rate base, depending on the circumstances.
>
> ASC 980-340-25-1 states that an entity should defer all or part of an incurred cost that would otherwise be charged to expense if it is probable that the specific cost is subject to recovery in future revenues. The regulatory asset is initially measured as the amount of incurred cost. Recovery should be tied to a specific item. If a specific cost is determined not to meet criteria for deferral at the date incurred, it should be expensed; a regulatory asset may be established later when criteria for recognition are met.

The normal course of action before this Commission (and other Commissions nationwide) with regard to the recovery of prior period costs is that costs that are being held for future recovery in rates must be deferred pursuant to a Commission order.

Q. MR. TRZASKA ARGUES THAT PECO AND ITS CUSTOMERS RECEIVE THE BENEFIT OF PECO'S ALLOCABLE SHARE OF MERGER SAVINGS, SO IT IS APPROPRIATE THAT PECO SHOULD BEAR THE COSTS TO ACHIEVE THOSE SAVINGS. DO YOU AGREE?

A. No. PECO's rates were not changed to flow through costs savings to its customers. This is the Company's first rate case since 2010. Therefore, any cost savings that were achieved, were passed through to PECO's parent company and shareholders. Therefore, it would be unfair and inappropriate to pass the Cost to Achieve to Pennsylvania customers.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENT.

A. As I have explained above, I am recommending an adjust to remove the Company's claim on Schedule LKM-19. This adjustment reduces O&M Expenses by $370,000.

EBSC Charges

Q. WHAT ADJUSTMENT HAVE YOU MADE TO EBSC CHARGES?

A. PECO increased FPFTY EBSC charges by approximately $1,600,000 over the HTY. The Company could not provide a specific reason to attribute the cause of the increase. When asked to explain the cause of the increase, the company responded by stating that "[b]udgeted increases in the relevant line item of the allocated expenses are generally due to inflation and any MMF rate adjustments." It is unknown what the MMF rate adjustment could be because the Company did not provide the information requested. The lack of data here (as well as for other expenses) is part of the reason I have concluded that the Company has used an abbreviated approach to develop the FPFTY expenses.

I disagree with the use of adjustments based on inflation escalations because they are not actually known and measurable. They do not reflect the anticipated cost of expenses and are inconsistent with the Company's claim that the annual budgeting and planning process is designed "to integrate and align PECO's operational, regulatory, and financial plans." Inflation adjustments are typically blanket adjustments or increases which do not directly relate to actual costs expected to be incurred by the Company in the period in which rates are to be set. Instead, costs should be based upon evidence or documentation that supports the Company's adjustments. I do not believe the determination of expenses for the FPFTY was envisioned to be simply applying an inflation rate to expenses. Therefore, I am recommending an adjustment to reflect the most recent 3-year average EBSC expense. This results in an adjustment to reduce O&M expenses by $997,000 on Schedule LKM-20.

R&D Expenses

Q. WHAT ADJUSTMENT HAVE YOU MADE TO R&D EXPENSES?

A. PECO projected the FPFTY R&D Expenses to be $280,000. However, when reviewed in conjunction with previous years, the FPFTY amount appeared to be abnormally high. The Company could not provide a specific reason to attribute the cause of the increase. When asked to explain the cause of the increase, the company responded by stating that:

> The projected increase in R&D compared to the historical R&D expenditures is due to: (1) the overall management of Gas O&M; and (2) the R&D programs from NYSearch in which the Company participates. Relating to the overall O&M management, historically, we have used R&D funding to offset higher priority needs to manage to the total O&M expenditures in Gas. We also review the NYSearch R&D programs throughout the year to determine which programs are in our best interest and can be funded from our R&D budget.

Again, the lack of data here (as well as for other expenses) is part of the reason I have concluded that the Company has used an abbreviated approach to develop the FPFTY expenses.

Essentially, the Company admits, in the quote above, that it does not expect to incur R&D expenses at the level it has projected. Therefore, PECO's budgeted R&D expense does not reflect the anticipated expenses and are inconsistent with the Company's claim that the annual budgeting and planning process is designed "to integrate and align PECO's operational, regulatory, and financial plans." Therefore, I am recommending an adjustment to reflect the most recent 3-year average R&D expense. This results in an adjustment to reduce O&M expenses by $138,000 on Schedule LKM-21.

Regulatory Commission Expenses

Q. WHAT ADJUSTMENT HAVE YOU MADE TO REGULATORY COMMISSION EXPENSES?

A. PECO increased FPFTY Regulatory Commission expense by approximately $462,000 over the HTY. The Company could not provide a specific reason to attribute the cause of the increase. When asked to explain the cause of the increase, the company responded by stating that "[t]he projected increases in regulatory commission expense are generally due to inflation adjustments." The specifics of the inflation adjustment are unknown because the Company did not provide the information requested. The Company's use of an abbreviated approach to develop the FPFTY expenses appears to contribute to the lack of data here.

I disagree with the use of adjustments based on inflation escalations because they are not actually known and measurable. They do not reflect the anticipated cost of expenses and are inconsistent with the Company's claim that the annual budgeting and planning process is designed "to integrate and align PECO's operational, regulatory, and financial plans." Inflation adjustments are typically blanket adjustments or increases which do not directly relate to actual costs expected to be incurred by the Company in the period in which rates are to be set. Instead, projected costs should be based upon evidence or documentation that show the specific actions and program that underlie the Company's adjustments. I do not believe that, when Act 11 was implemented, the determination of expenses for the FPFTY was envisioned to be simply applying an inflation rate to expenses. Therefore, I am recommending an adjustment to reflect the HTY level of regulatory commission expense. This results in an adjustment to reduce O&M expenses by $462,000 on Schedule LKM-22.

Contracting Expenses

Q. WHAT ADJUSTMENT HAVE YOU MADE TO CONTRACTING EXPENSES?

A. PECO increased the FPFTY Contracting Services expense and Contracting Professional expense by approximately $400,000 over the HTY amount in the aggregate. The Company could not provide a specific reason to attribute the cause of the increase. When asked to explain the cause of the increase, the company responded by stating that:

> The increases in contracting professional expense are generally due to inflation adjustments. PECO does not budget by FERC account. For further detail pertaining to the FPFTY and FTY budgets by FERC account, refer to Exhibit MJT-1 and MJT-2, respectively.
>
> and
>
> The increases in contracting services expense are generally due to inflation adjustments. PECO does not budget by FERC account. For further detail pertaining to the FPFTY and FTY budgets by FERC account, refer to Exhibit MJT-1 and MJT-2, respectively.

The specifics of the inflation adjustment are unknown because the Company did not provide the information requested. The lack of data here (as well as for other expenses) is part of the reason I have concluded that the Company has used an abbreviated approach to developing the FPFTY expenses.

I disagree with the use of adjustments based on inflation escalations because they are not actually known and measurable. They do not reflect the anticipated cost of expenses and are inconsistent with the Company's claim that the annual budgeting and planning process is designed "to integrate and align PECO's operational, regulatory, and financial plans." Inflation adjustments are typically blanket adjustments or increases which do not directly relate to actual costs expected to be incurred by the Company in the period in which rates are to be set. Instead, projected costs should be based upon evidence or documentation that show the specific actions and program that underlie the Company's adjustments. I do not believe that, when Act 11 was implemented, the determination of expenses for the FPFTY was envisioned to be simply applying an inflation rate to expenses. Therefore, I am recommending an adjustment to reflect the most recent actual 3-year average level of contracting expenses. This results in an adjustment to reduce O&M expenses by $367,000 on Schedule LKM-23.

<u>Employee Activity Expenses</u>

Q. WHAT ADJUSTMENT HAVE YOU MADE TO EMPLOYEE ACTIVITY EXPENSES?

A. PECO increased the FPFTY Employee Activity Expense by approximately $71,000 over the HTY amount. According to the Company, the increase in employee activity costs from the HTY to the FPFTY is attributable to abnormally low spending during the HTY resulting from COVID-19 and many employees working remotely rather than from PECO facilities. Therefore, the Company has attempted to estimate the FPFTY at a level this more indicative of normal spending levels.

Because of the uncertainty of the COVID-19 pandemic, it is nearly impossible to forecast costs such as employee activity because it is unknown what and when the new normal will be. Rather, than base the level of expense on a forecast determined from 2018 and 2019 activity, I have adjusted the employee activity expense to reflect the HTY level of expense. This results in an adjustment to reduce O&M expenses by $71,000 on Schedule LKM-24.

<u>Employee Travel Expenses</u>

Q. WHAT ADJUSTMENT HAVE YOU MADE TO EMPLOYEE ACTIVITY EXPENSES?

A. Employee Travel Expense has been impacted in a manner similar to Employee Activity Expense. Because of the uncertainty of the COVID-19 pandemic, it is nearly impossible to forecast costs such as employee travel activity because it is unknown what and when the new normal will be. Rather, than base the level of expense on a forecast determined from 2018 and 2019 activity, I have adjusted the employee activity expense to reflect the HTY level of expense. This results in an adjustment to reduce O&M expenses by $178,000 on Schedule LKM-25.

Energy Efficiency and Conservation Program Costs

Q. WHAT ADJUSTMENT HAVE YOU MADE TO ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS?

A. Based on the recommendation of OCA witness Geoff Crandall, I have adjusted the Energy Efficiency Costs to reflect the current funding level of $2,008,000. This adjustment is presented on Schedule LKM-26.

Depreciation Expense

Q. WHAY HAVE YOU ADJUSTED DEPRECIATION EXPENSE?

A. Based on my adjustment to Plant in Service, as I have explained, I recommending an adjustment to depreciation expense to be consistent with the plant in service adjustment I am recommending. This adjustment reduces depreciation expense by $7,827,000 and is presented on Schedule LKM-27.

Property Taxes

Q. WHAT ADJUSTMENT HAVE YOU MADE TO PROPERTY TAXES?

A. According to PECO the FPFTY real estate tax is based on the FTY real estate tax including a 2.5% inflation rate escalation. I disagree with the use of adjustments based on inflation escalations because they are not actually known and measurable. They do not reflect the anticipated cost of expenses and are inconsistent with the

Company's claim that the annual budgeting and planning process is designed "to integrate and align PECO's operational, regulatory, and financial plans." Inflation adjustments are typically blanket adjustments or increases which do not directly relate to actual costs expected to be incurred by the Company in the period in which rates are to be set. Instead, costs should be based upon evidence or documentation that supports the Company's adjustments. I do not believe the determination of expenses for the FPFTY was envisioned to be simply applying an inflation rate to expenses. Therefore, I am recommending an adjustment to remove the effect of the inflation escalation on the property tax expense. This results in an adjustment to reduce Taxes Other Than Income by $112,000 on Schedule LKM-28.

<u>Payroll Taxes</u>

Q. WHAT ADJUSTMENT HAVE YOU MADE TO PAYROLL TAXES?

A. Earlier I discussed the adjustment I am recommending to Payroll expense. Since payroll Expense is being reduced, there is a corresponding effect on payroll taxes since payroll taxes are calculated as a percentage of payroll. As a result, I have applied the FICA and Medicare tax rate to the decrease in payroll to derive my adjustment which reduces payroll taxes by $187,000 on Schedule LKM-29.

<u>Interest Synchronization</u>

Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION ADJUSTMENT.

A. To determine the tax deductible interest for ratemaking, I have multiplied the OCA's recommended rate base by the weighted cost of debt included in the capital structure recommended by OCA witness Mr. O'Donnell. This procedure synchronizes the interest deduction for tax purposes with the interest component of the return on rate base to be recovered from ratepayers. As shown at the bottom of Schedule LKM-30, this adjustment decreases the interest deduction by $4,159,000 compared to the interest deduction recognized by PECO. This increases state and federal income taxes by $415,000 and $786,000, respectively.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

301279

OCA Statement No. 2

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	**Docket No. R-2020-3018929**
v.	)	
	)	
PECO Energy Company - Gas Division	)	

SCHEDULES ACCOMPANYING THE DIRECT TESTIMONY

OF

LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

December 22, 2020

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

PECO Energy Company - Gas Division

Summary of Operating Income
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Company Amounts at Present Rates	OCA Adjustments	Amounts After OCA Adjustments	Pro Forma Change in Revenues	Amounts After Change in Revenues
	Operating Revenues					
1	Base Customer Charges	$ 361,541	$ -	$ 361,541	$ -	$ 361,541
2	Supply Cost Revenue	226,710	-	226,710	-	226,710
3	Other Operating Revenue	1,528	-	1,528	-	1,528
4	Revenue Increase	-	-	-	(24,930)	(24,930)
5	Total Operating Revenues	$ 589,779	$ -	$ 589,779	$ (24,930)	$ 564,849
6						
7	Operating Revenue Deductions					
8	O&M Expenses	$ 371,101	$ (11,075)	$ 360,026	(87)	359,939
9	Depreciation & Amortization	86,146	(7,827)	78,319	-	78,319
10	Amortization of Regulatory Expense	2,812	-	2,812	-	2,812
11	Taxes Other Than Income Taxes	7,545	(299)	7,246	(77)	7,169
12	Total Operating Revenue Deductions	467,604	(19,201)	448,403	(164)	448,239
13						
14	Operating Income Before Income Taxes	122,175	19,201	141,376	(24,766)	116,610
15						
16	Income Taxes @ Effective Tax Rates	(18,784)	6,747	(12,037)	(7,155)	(19,192)
17	Income Taxes @ Statutory Tax Rates	-	-	-	-	-
18						
19	Net Operating Income	$ 140,959	$ 12,454	$ 153,413	$ (17,611)	$ 135,802
20						
21	Rate Base	$ 2,461,939		$ 2,155,587		$ 2,155,587
22						
23	Return On Rate Base	5.73%		7.12%		6.30%

PECO Energy Company - Gas Division

Summary of Revenue Increase at OCA Rate of Return
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description			Amount	Source
1	Adjusted Rate Base		$	2,155,587	Schedule LKM-2, Page 2
2	Required Rate of Return			6.300%	Per OCA Witness O'Donnell
3					
4	Net Operating Income Required		$	135,802	
5	Net Operating Income at Present Rates			153,413	Schedule LKM-1, Page 1
6					
7	Income Deficiency/(Surplus)		$	(17,611)	
8	Revenue Multiplier			1.415588	
9					
10	Required Change in Company Revenue		$	(24,930)	
11					
12	Proposed Revenue Change		$	(24,930)	
13	Less: Uncollectibles	0.3472%		(87)	0.001288339
14	Revenues After Uncollectibles			(24,843)	
15	Less: PUC Assessments	0.3080%		(77)	
16					
17	Income Before State Taxes		$	(24,766)	
18	State Income Tax Effect Tax Rate	9.9900%			
19	Less: State Income Tax			(2,474)	
20					
21	Income Before Federal Taxes		$	(22,292)	
22	Federal Income Tax	21.0000%		(4,681)	
23					
24	Net Income Surplus/(Deficiency)		$	(17,611)	

PECO Energy Company - Gas Division

Summary of Rate Base
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount per Company Filing	OCA Rate Base Adjustments	Amount After OCA Adjustments
1	Utility Plant	$ 3,537,669	$ (305,555)	$ 3,232,114
2	Accumulated Depreciation	(893,447)	41,453	(851,994)
	Common Plant	136,770	(8,323)	128,447
3	Net Plant in Service	$ 2,780,992	$ (272,424)	$ 2,508,568
4				
5	Working Capital	$ 3,223	$ (318)	$ 2,905
6	Pension Asset/(Liabilities)	35,059	(35,059)	-
7	Accumulated Deferred Income Taxes	(247,620)	3,570	(244,050)
8	Customer Deposits	(13,418)	(17)	(13,435)
9	Customer Advances for Construction	(1,334)	(79)	(1,413)
10	Materials & Supplies	489	(195)	294
11	ADIT - Reg Liability	(126,322)	(2,115)	(128,437)
	Gas Storage	30,870	286	31,156
	Total Rate Base	$ 2,461,939	$ (306,352)	$ 2,155,587

PECO Energy Company - Gas Division

Summary of Rate Base Adjustments
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Source		Amount
1	Rate Base per Company Filing	Schedule LKM-2, Page 1	$	2,461,939
2				
3	OCA Adjustments:			
4				
5	Adjustment to Plant in Service	Schedule LKM- 4		(270,970)
6	Remove Pension Asset from Rate Base	Schedule LKM- 5	$	(35,059)
7	Cash Working Capital	Schedule LKM- 6		(318)
8	Average Gas Inventory Balance	Schedule LKM- 7		286
9	Average Customer Deposits	Schedule LKM- 8		(17)
10	Average Materials & Supplies	Schedule LKM- 9		(195)
11	Average Customer Advances	Schedule LKM- 10		(79)
12	Total Ratemaking Adjustments		$	(306,352)
13				
14	Adjusted Rate Base per OCA		$	2,155,587

PECO Energy Company - Gas Division

Summary of Adjustments to Income Before Income Taxes
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.		Amount	Source
1	Operating Income per Company	$ 140,959	Schedule LKM-
2			
3	OCA Adjustments:		
4	Annualize FPFTY Payroll	$ 1,740	Schedule LKM- 11
5	Revise Benefits Expense	224	Schedule LKM- 12
6	Annualize Postretirement Benefits Expense	772	Schedule LKM- 13
7	Annualize Pension Expense	319	Schedule LKM- 14
8	Remove Advance Recovery of MGP Remediation	204	Schedule LKM- 15
9	Normalize Injuries and Damages Expense	330	Schedule LKM- 16
10	Normalize Rate Case Expenses	148	Schedule LKM- 17
11	Normalize Regulatory Initiative Costs	530	Schedule LKM- 18
12	Remove Recovery of Cost to Achieve	263	Schedule LKM- 19
13	Normalize EBSC Charges	709	Schedule LKM- 20
14	Adjustment to Normalize R&D Expense	98	Schedule LKM- 21
15	Reflect Annual Regulatory Commission Expense	329	Schedule LKM- 22
16	Normalize Contracting Expenses	261	Schedule LKM- 23
17	Annualize Employee Activity Expenses	50	Schedule LKM- 24
18	Annualize Travel Meals & Entertainment Expense	127	Schedule LKM- 25
19	Remove Increase in Energy Efficiency Costs	1,772	Schedule LKM- 26
20	Annualize Depreciation Expense	5,566	Schedule LKM- 27
21	Remove Inflation Escalation From Property Taxes	80	Schedule LKM- 28
22	Remove Inflation Escalation From Payroll Taxes	133	Schedule LKM- 29
23	Interest Synchronization	(1,201)	Schedule LKM- 30
24			
25	Total OCA Adjustments	12,454	
26			
27	Total OCA Adjustments	$ 153,413	

PECO Energy Company - Gas Division

Summary of Adjustments to Income Before Income Taxes
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.		Operating Revenues	O&M Expenses	Depreciation & Amortization	Regulatory Expense Amortization	Taxes Other Than Income	Income Taxes	Operating Income Before Income Taxes
1	Amount per Company	$ 589,779	$ 371,101	$ 86,146	$ 2,812	$ 7,545	$ (18,784)	$ 140,959
2								
3	OCA Adjustments:							
4	Annualize FPFTY Payroll	$ -	$ (2,447)	$ -	$ -	$ -	$ 707	$ 1,740
5	Revise Benefits Expense	-	(315)	-	-	-	91	224
6	Annualize Postretirement Benefits Expense	-	(1,085)	-	-	-	313	772
7	Annualize Pension Expense	-	(448)	-	-	-	129	319
8	Remove Advance Recovery of MGP Remediation	-	(287)	-	-	-	83	204
9	Normalize Injuries and Damages Expense	-	(464)	-	-	-	134	330
10	Normalize Rate Case Expenses	-	(208)	-	-	-	60	148
11	Normalize Regulatory Initiative Costs	-	(746)	-	-	-	216	530
12	Remove Recovery of Cost to Achieve	-	(370)	-	-	-	107	263
13	Normalize EBSC Charges	-	(997)	-	-	-	288	709
14	Adjustment to Normalize R&D Expense	-	(138)	-	-	-	40	98
15	Reflect Annual Regulatory Commission Expense	-	(462)	-	-	-	133	329
16	Normalize Contracting Expenses	-	(367)	-	-	-	106	261
17	Annualize Employee Activity Expenses	-	(71)	-	-	-	21	50
18	Annualize Travel Meals & Entertainment Expense	-	(178)	-	-	-	51	127
19	Remove Increase in Energy Efficiency Costs	-	(2,492)	-	-	-	720	1,772
20	Annualize Depreciation Expense	-	-	(7,827)	-	-	2,261	5,566
21	Remove Inflation Escalation From Property Taxes	-	-	-	-	(112)	32	80
22	Remove Inflation Escalation From Payroll Taxes	-	-	-	-	(187)	54	133
23	Interest Synchronization	-	-	-	-	-	1,201	(1,201)
24								
25	Total OCA Adjustments	$ -	$ (11,075)	$ (7,827)	$ -	$ (299)	$ 6,747	$ 12,454
26								
27	Total Adjusted Income Before Income Taxes	$ 589,779	$ 360,026	$ 78,319	$ 2,812	$ 7,246	$ (12,037)	$ 153,413

PECO Energy Company - Gas Division

Adjustment to Plant in Service
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description		FPFTY Amount	FTY Amount	Adjustment
	Intangible Plant				
1	G302 - Franchises & Consents		$ 50	$ 50	$ -
2	G303 - Intangible Property		18,179	18,487	307
3		Subtotal	18,229	18,537	307
4	**Manufactured Gas Production Plant**				
5	G305 - Structures and Improvements		1,206	1,215	10
6	G311 - Liquefied Petroleum Gas Equip.		14,334	14,334	-
7		Subtotal	15,539	15,549	10
8	**Other Storage Plant**				
9	G360 - Land and Land Rights		16	16	-
10	G361 - Structures & Improvements		14,919	14,883	(36)
11	G362 - Gas Holders		7,084	7,084	-
12	G363 - Gas Storage Equipment		50,409	44,519	(5,890)
13		Subtotal	72,428	66,502	(5,926)
14	**Distribution Plant**				
15	G374 - Land and Land Rights		3,637	3,716	79
16	G375 - Structures and Improvements		15,745	15,006	(739)
17	G376 - Gas Mains		1,771,990	1,614,315	(157,675)
18	G378 - Measure & Regulate Sta Equip		24,652	22,324	(2,328)
19	G379 - City Gate Station		77,160	67,136	(10,024)
20	G380 - Services		1,111,048	1,008,483	(102,565)
21	G381 - Meters		164,090	158,421	(5,668)
22	G382 - Meter Installations		221,083	204,996	(16,087)
23	G387 - Other Equipment		2,118	2,118	-
24	G388 - ARO Costs Distribution Plt		1,454	1,456	2
25		Subtotal	3,392,977	3,097,970	(295,007)
26	**General Plant**				
27	G390 - Structures & Improvements		10,387	9,321	(1,065)
28	G391 - Office Furniture & Equipment		6,858	5,097	(1,761)
29	G394 - Tools, Shop & Garage Equip		16,155	14,156	(1,999)
30	G397 - Communication Equipment		4,872	4,740	(133)
31	G398 - Miscellaneous Equipment		107	119	12
32	G399.1 - ARO Costs General Plt		116	123	7
33		Subtotal	38,495	33,556	(4,939)
34					
35	**Total**		$ 3,537,669	$ 3,232,114	$ (305,555)

PECO Energy Company - Gas Division

Adjustment to Accumulated Depreciation
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	FPFTY Amount	FTY Amount	Adjustment
	Intangible Plant			
1	G302 - Franchises & Consents	$ -	$ -	$ -
2	G303 - Intangible Property	16,737	15,334	(1,403)
3	Subtotal	16,737	15,334	(1,403)
4	**Manufactured Gas Production Plant**			
5	G305 - Structures and Improvements	798	786	(12)
6	G311 - Liquefied Petroleum Gas Equip.	12,423	12,329	(94)
7	Subtotal	13,221	13,115	(106)
8	**Other Storage Plant**			
9	G360 - Land and Land Rights	-	-	-
10	G361 - Structures & Improvements	7,292	6,957	(336)
11	G362 - Gas Holders	6,900	6,881	(18)
12	G363 - Gas Storage Equipment	17,080	17,117	37
13	Subtotal	31,273	30,955	(317)
14	**Distribution Plant**			
15	G374 - Land and Land Rights	(158)	(79)	79
16	G375 - Structures and Improvements	6,022	5,715	(307)
17	G376 - Gas Mains	365,491	348,477	(17,014)
18	G378 - Measure & Regulate Sta Equip	8,285	7,964	(321)
19	G379 - City Gate Station	24,867	23,497	(1,370)
20	G380 - Services	262,159	251,526	(10,632)
21	G381 - Meters	71,646	66,641	(5,005)
22	G382 - Meter Installations	75,793	72,340	(3,453)
23	G387 - Other Equipment	1,428	1,295	(133)
24	G388 - ARO Costs Distribution Plt	555	478	(77)
25	Subtotal	816,087	777,853	(38,234)
26	**General Plant**			
27	G390 - Structures & Improvements	3,347	3,134	(213)
28	G391 - Office Furniture & Equipment	2,781	2,247	(534)
29	G394 - Tools, Shop & Garage Equip	5,373	4,877	(497)
30	G395 - Laboratory Equipment	-	-	-
31	G397 - Communication Equipment	4,583	4,428	(155)
32	G398 - Miscellaneous Equipment	29	33	4
33	G399.1 - ARO Costs General Plt	18	21	(1,394)
34	Subtotal			
35	**Total**	$ 893,447	$ 851,997	$ (41,453)

PECO Energy Company - Gas Division

Adjustment to Common Plant
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	FPFTY Total	FTY Total	Adjustment
1	**Common Plant in Service:**			
2	Land	$ 7,057	$ 6,920	$ (137)
3	Organization	677	677	-
4	Software	365,156	338,268	(26,888)
5	General Plant	734,696	671,511	(63,185)
6	Other	-	-	-
7				
8	Subtotal	$ 1,107,586	$ 1,017,376	$ (90,210)
9				
10	**Common Plant Accumulated Depreciation:**			
11	Land	$ -	$ -	$ -
12	Organization	-	-	-
13	Software	280,592	251,288	(29,304)
14	General Plant	233,117	208,349	(24,767)
15	Other	-	-	-
16	Subtotal	$ 513,709	$ 459,637	$ (54,072)
17				
18	Net Common Plant	$ 593,877	$ 557,739	$ (36,138)
19				
20	Allocation Factor	23.030%	23.030%	23.030%
21				
22	Common Plant in Service to Utility	$ 255,077	$ 234,302	$ (20,775)
23	Common Plant Accumulated Depreciation to Utility	118,307	105,854	(12,453)
24	Net Common Plant to Utility	$ 136,770	$ 128,447	$ (8,323)

PECO Energy Company - Gas Division

Adjustment to ADIT
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Utility Amount	Percent to Distribution	Distribution Amount
	HTY			
1	ADIT - CIAC	$ (10,667)	100.00%	$ (10,667)
2	ADIT - Common Plant	6,582	100.00%	6,582
3	ADIT - Gas Distribution	242,089	100.00%	242,089
4	Sub-Total	238,004		238,004
5	**FTY**			
6	DIT - CIAC	(1,771)	100.00%	(1,771)
7	DIT - Common Plant	-	100.00%	-
8	DIT - Gas Distribution	7,816	100.00%	7,816
9	Sub-Total	6,046		6,046
10	FTY ADIT	244,050		244,050
11	**FPFTY**			
12	DIT - CIAC	(1,994)	100.00%	(1,994)
13	DIT - Common Plant	-	100.00%	-
14	DIT - Gas Distribution	5,564	100.00%	5,564
15	Sub-Total	3,570		3,570
16				
17	Total	$ 247,620		$ 247,620
18				
19	FPFTY to FTY Adjustment			

PECO Energy Company - Gas Division

Adjustment to Regulatory Liability ADIT
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Utility Amount	Percent to Distribution	Distribution Amount
	HTY			
1	ADIT - Distribution	$ 136,680	100.00%	$ 136,680
2	ADIT - CIAC	(3,547)	100.00%	(3,547)
3	Subtotal HTY	133,133		133,133
4	**FTY**			
5	DIT - Distribution	(5,780)	100.00%	(5,780)
6	DIT - CIAC	1,085	100.00%	1,085
7	Subtotal FTY	(4,695)		(4,695)
8				128,438
9	**FPFTY**			
10	DIT - Distribution	(3,100)	100.00%	(3,100)
11	DIT - CIAC	985	100.00%	985
12	Subtotal FPFTY	(2,115)		(2,115)
13				
14	**Total**	$ 126,322		$ 126,322
15				
16	FPFTY to FTY Adjustment			$2,115

PECO Energy Company - Gas Division

Adjustment to Remove Pension Asset from Rate Base
For the Rate Year Ending September 30, 2021
($ in Thousands)

Line No.	Description	Amount
1	Gas Distribution Pension Asset	$ 35,059
2		
3	Adjustment to Rate Base	$ (35,059)

[1/] Exhibit MJT-1, Schedule C-5, Page 32.

PECO Energy Company - Gas Division

Adjustment to Cash Working Capital
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	FPFTY Expenses	OCA Adjustments	FPFTY Expenses After OCA Adjustments	(Lead)/Lag Days	Dollar-Days
1	**Working Capital Requirement**					
3	Revenue Lag Days				43.17	
4						
5	Expense Lag					
6	Payroll (Dist Only)	$ 42,209	$ (2,447)	$ 39,762	13.67	$ 543,551
7	Pension Expense	2,513	(448)	2,065	14.00	28,910
8	Commodity Purchased - Gas	226,710	-	226,710	36.51	8,277,182
9	Payment to Suppliers	63,454	-	63,454	56.21	3,566,749
10	Other Expenses	97,084	(8,180)	88,903	37.54	3,337,430
11	Total O&M and POR Payments	431,970	(11,075)	420,895		15,753,823
12						
13	O&M Expense / POR Payment Lag Days				37.43	
14						
15	Net (Lead)/Lag Days				5.74	
17	Days in Current Year				365	
18						
19	Operating Expenses Per Day			1,153.14		
20						
21	Working Capital for O&M Expense			6,619.72		
22						
23	Average Prepayments			2,091		
24	Accrued Taxes			189		
25	Interest Payments			(5,995)		
26						
27	Total Working Capital Requirement Per OCA			2,905		
	Total Working Capital Requirement Per PECO			3,223		
	Adjustment			$ (318)		
28						
29	Pro Forma O&M Expense	371,101.00				
30	Uncollectible Expense	2,585.42				
31	Pro Forma Cash O&M Expense	368,515.58				

PECO Energy Company - Gas Division

Calculation of Prepaid Expenses
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	AGA Membership Dues	EAP Membership Dues	NGA Membership Dues	PUC Assessment Gas	Maintenance	IT License & Maintenance	Prepaid Rent	VEBA Adjust	Facilities Contracts	IT License & Maintenance	Fleet Activities	IT License & Maintenance	Customer Experience	Postage
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	September	$ 98	$ -	$ -	$ 1,301	$ 15	$ 500	$ 86	$ -	$ 23	$ 488	$ 237	$ 836	$ 100	$ 719
2	October	98	(20)	(9)	1,156	15	437	70	-	(4)	792	298	594	56	537
3	November	33	10	5	1,012	15	364	90	-	(31)	680	323	759	46	659
4	December	1	(1)	-	867	15	297	74	135	-	339	337	516	17	595
5	January	371	114	-	723	15	201	58	135	175	441	339	586	258	743
6	February	337	104	-	578	15	134	77	135	159	397	339	382	226	588
7	March	303	93	41	434	10	67	54	120	143	376	359	185	218	698
8	April	270	83	37	289	10	22	38	120	127	444	364	645	209	618
9	May	236	73	32	144	10	729	57	120	111	355	354	467	168	808
10	June	202	62	28	0	10	662	41	1,174	95	306	356	620	148	720
11	July	168	52	23	930	10	595	25	1,174	79	265	360	772	174	886
12	August	135	41	18	764	10	527	12	1,174	64	172	302	597	130	628
13	September	101	31	14	1,517	10	460	31	2,152	48	96	328	432	88	813
14															
15	Total SUM L1 to L13	$ 2,353	$ 642	$ 189	$ 9,715	$ 160	$ 4,995	$ 713	$ 6,439	$ 989	$ 5,151	$ 4,296	$ 7,391	$ 1,838	$ 9,012
16															
17	Distribution Percentage	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	23.03%	23.03%	23.03%	23.03%	24.84%	24.84%	24.84%
18															
19	Distribution Amount L15 * L17	$ 2,353	$ 642	$ 189	$ 9,715	$ 160	$ 4,995	$ 713	$ 1,483	$ 228	$ 1,186	$ 989	$ 1,836	$ 456	$ 2,238
20															
21	Number of Months	13	13	13	13	13	13	13	13	13	13	13	13	13	13
22															
23	Monthly Average L19 / L21	$ 181	$ 49	$ 15	$ 747	$ 12	$ 384	$ 55	$ 114	$ 18	$ 91	$ 76	$ 141	$ 35	$ 172
24															
25														Total Prepayment per OCA	$2,091

Source:
Exhibit MJT-1, Schedule C-5, Page 32.

PECO Energy Company - Gas Division

Adjustment to Average Gas Inventory Balance
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description		Amount	
1	13-Month Average Gas Stored Underground per OCA	$	31,156	1/
2				
3	13-Month Average Gas Stored Underground per PECO		30,870	2/
4				
5	Adjustment to Rate Base	$	286	
6				

Notes:
1/ Schedule LKM 7, Page 2.
2/

PECO Energy Company - Gas Division

Calculation of 13-Month Average Gas Inventory Balances
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount [1/]
1	September, 2019	$ 40,231
2	October	44,365
3	November	43,166
4	December	36,910
5	January, 2020	29,780
6	February	23,132
7	March	20,887
8	April	20,142
9	May	23,136
10	June	26,087
11	July	29,262
12	August	32,372
13	September	35,558
14		
15	13-Month Average Gas Stored Underground	$ 31,156

Notes:
1/ Response to IE-RB-7-D(a)

PECO Energy Company - Gas Division

Adjustment to 13-Month Average Customer Deposits
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount	
1	13-Month Average Customer Deposits per OCA	$ 13,401	1/
2			
3	13-Month Average Customer Deposits per PECO	13,418	2/
4			
5	Adjustment to Rate Base	$ (17)	

Notes:
1/ Schedule LKM 8, Page 2.

PECO Energy Company - Gas Division

Calculation of 13-Month Average Customer Deposits Balances
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount [1/]
1	September, 2019	$ 12,994
2	October	13,033
3	November	13,029
4	December	13,058
5	January, 2020	14,034
6	February	14,014
7	March	14,066
8	April	13,916
9	May	13,711
10	June	13,488
11	July	13,226
12	August	12,971
13	September	12,667
14		
15	13-Month Average Customer Deposits	$ 13,401

Notes:
1/ Attachment I&E-RB-3-D.

PECO Energy Company - Gas Division

Adjustment to 13-Month Average Materials & Supplies
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount	
1	13-Month Average Materials & Supplies per OCA	$ 294	1/
2			
3	13-Month Average Materials & Supplies per PECO	489	2/
4			
5	Adjustment to Materials & Supplies to Reflect Updated 13-Month Average	$ (195)	

Notes:
1/ Schedule LKM 9, Page 2.

PECO Energy Company - Gas Division

Calculation of 13-Month Average Materials & Supplies Balances
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Materials& Supplies [1/]	Undistributed Stores Expense	Total
1	September, 2019	$ 602	$ -	$ 602
2	October	595	(670)	(75)
3	November	590	(664)	(74)
4	December	592	-	592
5	January, 2020	443	107	550
6	February	434	151	585
7	March	453	-	453
8	April	461	(6)	455
9	May	434	(32)	402
10	June	436	(242)	194
11	July	464	(209)	255
12	August	450	(486)	(36)
13	September	398	(478)	(80)
14				
15	13-Month Average Materials & Supplies	$ 489	$ (195)	$ 294

Notes:

1/ Attachment I&E-RB-6-D.

PECO Energy Company - Gas Division

Adjustment to 13-Month Average Customer Advances
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	13-Month Average Customer Advances per OCA	$ 1,255 [1/]
2		
3	13-Month Average Customer Advances per PECO	1,334 [2/]
4		
5	Adjustment to Rate Base	$ (79)

Notes:
1/ Schedule LKM 10, Page 2.
2/ Exhibit MJT-1, Schedule C-9, Page 36.

PECO Energy Company - Gas Division

Calculation of 13-Month Average Customer Advances
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount [1/]
1	September, 2019	$ 1,429
2	October	1,901
3	November	1,879
4	December	1,082
5	January, 2020	1,319
6	February	1,355
7	March	1,198
8	April	1,228
9	May	1,032
10	June	1,004
11	July	983
12	August	1,000
13	September	899
14		
15	13-Month Average Customer Advances	$ 1,255

Notes:
1/ Attachment I&E-RB-53-D.

PECO Energy Company - Gas Division

Adjustment to Annualize FPFTY Payroll
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Union		Non-Union		Total	
1	Total Payroll					$ 283,336	1/
2	O&M Ratio					61.7%	2/
3							
4	O&M Payroll					$ 174,818	
5	Gas Allocator					20.22%	1/
6							
7	Base Labor					$ 35,348	
8	Overtime Labor					5,548	6/
9							
10	FPFTY Annualized Salaries and Wages Before Adjustment					$ 40,896	
11	FPFTY Average Number of Employees					638	3/
12							
13	Average Salary & Wages per Employee					$ 64	
14	Number of Employees at September 2020					604	4/
15							
16	FPFTY Annualized Salaries & Wages based on Actual Number of Customers	$ 20,144		$ 18,512		$ 38,656	
17	Number of Months TY	6	5/	8	5/		
18	Rate for Increase TY	2.50%	5/	2.50%	5/		
19	Total Wage Increase TY	$ 252		$ 309		560	
20	Other Payroll Premium					546	6/
21	Total Payroll per OCA					$ 39,762	
22	Total Payroll per Company					42,209	3/
23							
24	Adjustment to O&M Expenses					$ (2,447)	

Notes
[1] Attachment OCA-IX-2(a).
[2] Public Attachment IE-8-D(a).
[3] Exhibit MJT-1, Schedule D-6, Page 65.
[4] Response to OCA-II-47(a).
[5] Exhibit MJT-1, Schedule D-6, Page 64.
[6] Attachment OCA-IX-1(a).

PECO Energy Company - Gas Division

Adjustment to Revise Benefits Expense for Change in Number of Employees
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Total Benefits Costs [1]	Benefits Capitalized [1]	Benefits Expense	Benefits Expense per Employee	Benefits Expense Using HTY Employees
1	Medical	$ 6,100	$ 2,158	$ 3,942	$ 6.18	$ 3,732
2	Dental	366	120	246	0.39	233
3	Other Benefit Plan	109	(32)	141	0.22	133
4	401K Plan	2,210	960	1,250	1.96	1,183
5	ESPP	205	131	74	0.12	70
6	Disability Plan	133	26	107	0.17	101
7	Excess Benefits Saving Plan	12	5	7	0.01	7
8	Workers Comp	239	101	138	0.22	131
9	Pension	-	-	-	-	-
10	OPEB	-	-	-	-	
11						
12	Subtotal	$ 9,374	$ 3,469	$ 5,905		$ 5,590
13						
14	Unadjusted Benefits Expense				5,905	
15	Company's Adjustment to Include Additional Employee				11 [2]	
16	Total Benefits Expense per Company					5,916
17						
18	Adjustment to Benefits Expense					$ (315)
19						

Notes:

[1] Attachment IE-RE-9-D(a)

[2] Exhibit MJT-1, Schedule D-8, Page 69.

PECO Energy Company - Gas Division

Adjustment to Annualize Postretirement Benefits Expense
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	3 Year Average OPEB Expense	$ (35) [1/]
2	FPFTY OPEB Expense	1,050 [2/]
3		
4	Adjustment to O&M Expenses	$ (1,085)
5		

Notes:
[1/] Attachment OCA-IX-7(b).
[2/] Attachment SDR-OM-34.

PECO Energy Company - Gas Division

Adjustment to Annualize Pension Expense
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	FPFTY Expense Portion of Pension Contribution	$ 2,525 [1/]
2	FPFTY Expense Portion of ASC 715 Pension Costs	563 [1/]
3		
4	Adjustment to Pension Expense	$ 1,962
5	Reversal of Company's Adjustment	(2,410) [2/]
6		
7	Adjustment to O&M Expenses	$ (448)

Notes:
[1/] Attachment OCA-XIII-16(a)
[2/] Exhibit MJT-1, Schedule D-9, Page 70.

PECO Energy Company - Gas Division

Adjustment to Remove Advance Recovery of MGP Remediation
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	Regulatory Asset for Unrecovered MGP Remediation Liability	$ 7,237 [1/]
2	Normalization Period	14
3		
4	Annual Recovery of MGP Liability	$ 517
5	Annual Recovery of Claimed by PECO	804
6		
7	Adjustment to O&M Expenses	$ (287)

Notes:
[1/] Exhibit MJT-1, Schedule D-13, Page 74.

PECO Energy Company - Gas Division

Adjustment to Normalize Injuries and Damages Expense
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount [1/]
1		
2	2018 Injuries and Damages Expense	$ 301
3	2019 Injuries and Damages Expense	(9)
4	2020 Injuries and Damages Expense	231
5		
6	3-Year Average Injuries and Damages Expense	$ 174
7	FPFTY Injuries and Damages Expense	638
8		
9	Adjustment to Injuries and Damages	$ (464)

Notes:
[1/] Company's Response to I&E-RE-7.

PECO Energy Company - Gas Division

Adjustment to Normalize Rate Case Expenses
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
	Total Rate Case Expense	$ 1,559
1	Normalization Period	5
2		
3	Annual Normalization Amount	$ 312
	Amount per Company	520
	Adjustment to O&M Expenses	$ (208)

Notes:

PECO Energy Company - Gas Division

Adjustment to Normalize Regulatory Initiative Costs
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	Gas Unbundling of GPC/MFC Expense Portion	$ 21 [1/]
2	Gas Neighborhood Pilot Program Expense	-
3		
4	Authorized Deferred Costs	$ 21
5	Normalization Period	3 [2/]
6		
7	Normalization of Deferred Costs	$ 7
8	Annual Cost Recovery Sought by PECO	753 [1/]
9		
10	Adjustment to O&M Expenses	$ (746)

Notes:
[1/] Company's Response to OCA-II-54.
[2/] Exhibit MJT-1, Schedule D-14, Page 75.

PECO Energy Company - Gas Division

Adjustment to Remove Recovery of Cost to Achieve
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	Cost to Achieve Cost Recovery Included in O&M Expenses	$ 370 [1/]
2		
3	Adjustment to O&M Expenses	$ (370)

Notes:
[1/] Exhibit MJT-1, Schedule D-15, Page 76.

PECO Energy Company - Gas Division

Adjustment to Normalize EBSC Charges
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	7/1/2019 - 6/30/2020 Amount [1]	7/1/2018 - 6/30/2019 Amount [2]	7/1/2017 - 6/30/2018 Amount [2]	Average
1	Communication	$ 329	$ 303	$ 386	$ 339
2	Executives	1,074	1,897	1,238	1,403
3	Exelon Utilities	989	1,516	1,069	1,191
4	Finance	2,239	2,643	2,343	2,408
5	Government Affairs	56	138	160	118
6	Human Resource	978	1,036	905	973
7	Legal Governance	1,025	970	1,019	1,005
8	Security	1,080	1,038	1,007	1,042
9	Supply	199	195	181	192
10	Other EBSC Services	127	52	-	60
11					
12	Total	$ 8,096	$ 9,788	$ 8,308	8,731
13	FPFTY Amount per Company				9,728
14					
15	Adjustment to O&M Expenses				$ (997)

Notes:
[1] Attachment III-A-22(a)
[2] Attachment IE-RE-11-D(a), Page 2.

PECO Energy Company - Gas Division

Adjustment to Normalize R&D Expense
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount [1/]
1	7/1/2017 - 6/30/2018 Expense Amount	$ 59
2	7/1/2018 - 6/30/2019 Expense Amount	113
3	7/1/2019 - 6/30/2020 Expense Amount	253
4		
5	Average Annual R&D Expense	142
6	FPFTY R&D Expense	280 [2/]
7		
8	Adjustment to O&M Expenses	(138)

Notes:
[1/] Company's Response to I&E -17-D.
[2/] Company's Response to OCA-V-22.

PECO Energy Company - Gas Division

Adjustment to Reflect Annual Regulatory Commission Expense
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	HTY Regulatory Commission Expense	$ 1,735 [1/]
2	FPFTY Regulatory Commission Expense Claimed by Company	2,197 [2/]
3		
4	Adjustment to O&M Expenses	$ (462)

Notes:
[1/] Exhibit MJT-1, Schedule D-9, Page 70.
[2/] Company's Response to OCA-II-27.

PECO Energy Company - Gas Division

Adjustment to Normalize Contracting Expenses
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	7/1/2019 - 6/30/2020 Amount [1/]	7/1/2018 - 6/30/2019 Amount [1/]	7/1/2017 - 6/30/2018 Amount [1/]	Average
1	Contracting Professional	$ 715	$ 784	$ 534	$ 678
2					
3	Contracting Services	548	552	781	627
4					
5	Total	$ 1,263	$ 1,336	$ 1,315	1,305
6					
7	FPFTY Amount per Company				1,672 [2/]
8					
9	Adjustment to O&M Expenses				$ (367)

Notes:
[1/] Attachment OCA-V-18(a)
[2/] Attachment III-A-28(a)

PECO Energy Company - Gas Division

Adjustment to Annualize Employee Activity Expenses
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	HTY Amount [1]	FPFTY Amount [2]	Adjustment
1	Employee Recognition Awards	$ 7	$ 36	$ (29)
2				
3	Employee Service Awards	12	21	(9)
4				
5	Employee Picnic, Celebration, Other Employee Compact Expenses	48	81	(33)
6				
7	Employee Network Groups	1	1	-
8				
9	Adjustment to O&M Expenses			$ (71)

Notes:
[1] Attachment IE-RE-26-D(a).

PECO Energy Company - Gas Division

Adjustment to Annualize Travel Meals & Entertainment Expense
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount [1/]
1	HTY Travel Meals & Entertainment Expense	$ 165
2	FPFTY Travel Meals & Entertainment Expense	343
3		
4	Adjustment to O&M Expenses	$ (178)

Notes:
[1/] Attachment OCA-XIII-23(a).

PECO Energy Company - Gas Division

Adjustment to Remove Increase in Energy Efficiency Costs
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	Remove Energy Efficiency Costs	$ 2,492 [1/]
2		
3	Adjustment to O&M Expenses	$ (2,492)

Notes:
[1/] Exhibit MJT-1, Schedule D-11, Page 72.

PECO Energy Company - Gas Division

Adjustment to Depreciation Expense
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	FTY Depreciation Expense	$ 78,320 [1/]
2	FPFTY Depreciation Expense	86,146 [2/]
3		
4	Adjustment to O&M Expenses	$ (7,827)

Notes:
[1/] Exhibit MJT-2, Schedule D-1, Page 40.
[2/] Exhibit MJT-1, Schedule D-1, Page 40.

PECO Energy Company - Gas Division

Adjustment to Remove Inflation Escalation From Property Taxes
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	FTY Property Taxes	$ 3,594 [1/]
2	Inflation factor	102.500% [2/]
3		
4	Property Taxes before Inflation	$ 3,506
5	FPFTY Property Taxes	3,618 [1/]
6		
7	Adjustment to Taxes Other Than Income	$ (112)

Notes:
[1/] Attachment IE-RE-19-D(a)
[2/] Response to IE-RE-50-D(a).

PECO Energy Company - Gas Division

Adjustment to Annualize Payroll Taxes
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	FTY Property Taxes	$ (2,447) [1/]
2	Payroll Tax Rate	7.650%
3		
4	Adjustment to Taxes Other Than Income	$ (187)

PECO Energy Company - Gas Division

Interest Synchronization Adjustment
For the Fully Projected Future Test Year Ending June 30, 2022

Line No.	Description		Amount	
1	Company Rate Base	$	2,155,587	1/
2	Weighted Cost of Debt		1.920%	
3				
4	Adjusted Interest Deduction	$	41,387	
5	Interest Deduction Per Company		45,546	2/
6				
7	Adjustment to Synchronize Interest Expense	$	(4,159)	
8	Effective State Income Tax Rate		9.99%	
9				
10	Adjustment to State Income Taxes	$	415	
11				
12	Federal Income Tax Base	$	(3,744)	
13	Federal Income Tax Rate		21.00%	
14				
15	Adjustment to Federal Income Taxes	$	786	

Notes:
1/ Schedule LKM-2, Page 1.
2/ Exhibit MJT-1,Schedule D-18, Page 91.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-2020-3018929**
	)	
PECO Energy Company - Gas Division	)	

Appendix A

LAFAYETTE K. MORGAN, JR.

Mr. Morgan is an independent regulatory consultant focusing in the area of the analysis of the operations of public utilities with particular emphasis on rate regulation. He has reviewed and analyzed utility rate filings, focusing primarily on revenue requirements determination, accounting and regulatory policy and cost recovery mechanisms. This work has included natural gas, water, electric, and telephone utilities.

Education and Qualifications

B.B.A. (Accounting) – North Carolina Central University, 1983

M.B.A. (Finance) – The George Washington University, 1993

C.P.A. – Licensed in the State of North Carolina (Inactive status)

Previous Employment

1993-2010 Senior Regulatory Analyst
Exeter Associates, Inc.
Columbia, MD

1990-1993 Senior Financial Analyst
Potomac Electric Power Company
Washington, D.C.

1984-1990 Staff Accountant
North Carolina Utilities Commission – Public Staff
Raleigh, NC

Professional Experience

As a Staff Accountant with the North Carolina Utilities Commission – Public Staff, Mr. Morgan was responsible for analyzing testimony, exhibits, and other data presented by parties before the Commission. In addition, he performed examinations of the books and records of utilities involved in rate proceedings and summarized the results into testimony and exhibits for presentation before the Commission. Mr. Morgan also participated in several policy proceedings and audits involving regulated utilities.

As a Senior Financial Analyst with Potomac Electric Power Company, Mr. Morgan was a lead analyst and was involved in the preparation of the cost of service, rate base, and ratemaking adjustments supporting the Company's request for revenue increases in its retail jurisdictions.

As a Senior Regulatory Analyst with Exeter Associates, Inc., Mr. Morgan has been involved in the analysis of the operations of public utilities with particular emphasis on rate regulation. He has reviewed and analyzed utility rate filings, focusing primarily on revenue requirements determination, accounting and regulatory policy and cost recovery mechanisms. This work included natural gas, water, electric, and telephone utilities.

Expert Testimony

of Lafayette K. Morgan, Jr.

Kings Grant Water Company (North Carolina Utilities Commission, Docket No. W-250, Sub 5), 1984. Presented testimony on rate base, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

Northwood Water Company (North Carolina Utilities Commission, Docket No. W-690, Sub 1), 1985. Presented testimony on rate base, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

Emerald Village Water System (North Carolina Utilities Commission, Docket No. W-184, Sub 3), 1985. Presented testimony on rate base, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

General Telephone Company of the South (North Carolina Utilities Commission, Docket No. P-19, Sub 207), July 1986. Presented testimony on the level of cash working capital allowance on behalf of the North Carolina Utilities Commission – Public Staff.

Heins Telephone Company (North Carolina Utilities Commission, Docket No. P-26, Sub 93), November 1986. Presented testimony on rate base, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

Carolina Power and Light Company (North Carolina Utilities Commission, Docket No. E-2, Sub 537), March 1988. Presented testimony on rate base, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

Public Service Company of North Carolina, Inc. (North Carolina Utilities Commission, Docket No. G-5, Sub 246), August 1989. Presented testimony on rate base, cash working capital allowance, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

Conestoga Telephone and Telegraph Company (Pennsylvania Public Utility Commission, Docket No. I-00920015), September 1993. Presented testimony on cost of service on behalf of the Pennsylvania Office of Consumer Advocate.

Louisiana Power and Light Company (Louisiana Public Service Commission, Docket No. U-20925), February 1995. Presented testimony on rate base and working capital issues on behalf of the Louisiana Public Service Commission Staff.

South Central Bell Telephone Company – Louisiana (Louisiana Public Service Commission, Docket No. U-17949, Subdocket E), June 1995. Presented testimony on rate base and working capital issues on behalf of the Louisiana Public Service Commission Staff.

Expert Testimony

of Lafayette K. Morgan, Jr.

Apollo Gas Company (Pennsylvania Public Utility Commission, Docket No. R-00953378), August 1995. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Carnegie Natural Gas Company (Pennsylvania Public Utility Commission, Docket No. R-00953379), August 1995. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Tennessee Gas Pipeline Company (Federal Energy Regulatory Commission, Docket No. RP95-112), September 1995. Presented testimony rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Virginia-American Water Company (Virginia State Corporation Commission, Case No. PUE-950003), March 1996. Presented testimony on rate base and cost of service issues on behalf of the City of Alexandria.

GTE North, Inc. Interconnection Arbitration (Pennsylvania Public Utility Commission, Docket No. A-310125F0002), September 1996. Presented testimony on the determination of the appropriate resale discount on behalf of the Pennsylvania Office of Consumer Advocate.

United Cities Gas Company (Georgia Public Service Commission, Docket No. 6691-U), October 1996. Presented testimony on rate base and cost of service issues on behalf of the Office of Governor, Consumer Utility Counsel Division.

GTE North, Inc. (Pennsylvania Public Utility Commission, Docket Nos. R-00963666 and R-00963666C001), February 1997. Presented testimony on the determination of the appropriate resale discount on behalf of the Pennsylvania Office of Consumer Advocate.

Consumers Maine Water Company (Maine Public Utilities Commission, Docket No. 96-739), May 1997. Presented testimony on rate base, cost of service, and rate of return issues on behalf of the Maine Office of the Public Advocate.

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission, Docket No. R-00973944), July 1997. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Pennsylvania-American Water Company – Wastewater Operations (Pennsylvania Public Utility Commission, Docket No. R-00973973), July 1997. Presented testimony on rate base, cost of service, depreciation, and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

Expert Testimony

of Lafayette K. Morgan, Jr.

Jackson Purchase Electric Cooperative Corporation (Kentucky Public Service Commission, Case No. 97-224), December 1997. Presented testimony on rate base and cost of service issues on behalf of the Kentucky Office of the Attorney General.

Henderson Union Electric Cooperative Corporation (Kentucky Public Service Commission, Case No. 97-220), January 1998. Presented testimony on the return of patronage capital on behalf of the Kentucky Office of the Attorney General.

Green River Electric Corporation (Kentucky Public Service Commission, Case No. 97-219), January 1998. Presented testimony on the return of patronage capital on behalf of the Kentucky Office of the Attorney General.

Western Kentucky Gas Company (Kentucky Public Service Commission, Case No. 99-070), November 1999. Presented testimony on rate base and cost of service issues on behalf of the Kentucky Office of the Attorney General.

American Broadband, Inc. (Rhode Island Public Utilities Commission, Docket No. 2000-C-3), June 2000. Presented report and testimony on the Company's financing plan on behalf of the Rhode Island Division of Public Utilities and Carriers.

PPL Utilities (Pennsylvania Public Utility Commission, Docket No. R-00005277), October 2000. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

T.W. Phillips Oil and Gas Company (Pennsylvania Public Utility Commission, Docket No. R-00005459), October 2000. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Pike County Light & Power Company (Pennsylvania Public Utility Commission, Docket No. P-00011872), May 2001. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Vermont Gas Systems, Inc. (Vermont Public Service Board, Docket No. 6495), June 2001. Presented testimony on rate base and cost of service issues on behalf of the Vermont Public Service Department.

Community Service Telephone Company (Maine Public Utilities Commission, Docket No. 2001-249), July 2001. Presented joint testimony on rate base and cost of service issues on behalf of the Maine Office of the Public Advocate.

Expert Testimony

of Lafayette K. Morgan, Jr.

West Virginia-American Water Company (Public Service Commission of West Virginia, Docket No. 01-0326-W-42-T), August 2001. Presented testimony on rate base and cost of service issues on behalf of the Consumer Advocate Division.

Philadelphia Suburban Water Company (Pennsylvania Public Utility Commission, Docket No. R-00016750) February 2002. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Illinois-American Water Company (Illinois Commerce Commission, Docket No. 02-0690) January 2003. Presented testimony on cost of service issues on behalf of Citizens Utility Board.

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission, Docket No. R-00027983), February 2003. Presented testimony addressing surcharge mechanism to recover security costs on behalf of the Pennsylvania Office of Consumer Advocate.

FairPoint New England Telephone Companies (Maine Public Utilities Commission, Docket Nos. 2002-747, 2003-34, 2003-35, 2003-36, and 2003-37), June 2003. Presented testimony on rate base and cost of service issues on behalf of the Maine Office of the Consumer Advocate.

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission, Docket No. R-00038304), August 2003. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

PPL Electric Utilities Corporation (Pennsylvania Public Utility Commission, Docket No. R-00049255), June 2004. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Entergy Louisiana, Inc. (Louisiana Public Service Commission, Docket No. U-20925 RRF 2004), August 2004. Presented testimony on rate base and cost of service issues on behalf of the Louisiana Public Service Commission Staff.

Vectren Energy Delivery of Indiana (Indiana Utility Regulatory Commission, Cause No. 42598), September 2004. Presented testimony on O&M expense issues on behalf of the Indiana Office of Utility Consumer Counselor.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission, Docket No. R-00049656), December 2004. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Expert Testimony

of Lafayette K. Morgan, Jr.

Block Island Power Company (Rhode Island Public Utilities Commission, Docket No. 3655), April 2005. Presented testimony on cash working capital on behalf of the Rhode Island Division of Public Utilities & Carriers.

Verizon New England, Inc. (Maine Public Utilities Commission, Docket No. 2005-155), September 2005. Presented joint testimony with Thomas S. Catlin on rate base and cost of service issues on behalf of the Maine Office of the Public Advocate.

T.W. Phillips Oil and Gas Company (Pennsylvania Public Utility Commission, Docket No. R-00051178), May 2006. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Duquesne Light Company (Pennsylvania Public Utility Commission, Docket No. R-00061346), July 2006. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

National Fuel Gas Distribution Company (Pennsylvania Public Utility Commission, Docket No. R-00061493), September 2006. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Southern Indiana Gas & Electric Co. (Indiana Utility Regulatory Commission, Cause No. 43112), January 2007. Presented testimony on rate base and cost of service issues on behalf of the Indiana Office of Utility Consumer Counsel.

PPL Electric Utilities (Pennsylvania Public Utility Commission, Docket No. R-00072155), July 2007. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Aqua Pennsylvania, Inc. (Pennsylvania Public Utility Commission, Docket No. R-00072711), February 2008. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Gas Company (Pennsylvania Public Utility Commission, Docket No. R-2008-2029325), October 2008. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

The Narragansett Bay Commission (Rhode Island Public Utilities Commission, Docket No. 4026), April 2009. Presented testimony on rate base and cost of service issues on behalf of the Rhode Island Division of Public Utilities and Carriers.

Expert Testimony

of Lafayette K. Morgan, Jr.

Maryland-American Water Company (Maryland Public Service Commission, Case No. 9187), July 2009. Presented testimony on rate base and cost of service issues on behalf of the Maryland Office of People's Counsel.

Monongahela Power Company & The Potomac Edison Company, both d/b/a Allegheny Power Company (West Virginia Public Service Commission, Case No. 09-1352-E-42T), February 2010. Presented testimony on rate base and cost of service issues on behalf of the West Virginia Consumer Advocate Division.

PPL Electric Utilities (Pennsylvania Public Utility Commission, Docket No. R-2010-2161694), June 2010. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Pawtucket Water Supply Board (Rhode Island Public Utilities Commission, Docket No. 4550), June 2015. Presented testimony on revenue requirements issues on behalf of the Rhode Island Division of Public Utilities and Carriers.

Columbia Gas of Pennsylvania (Pennsylvania Public Utility Commission, Docket No. R-2015-2468056), June 2015. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Indianapolis Power and Light Company (Indiana Utility Regulatory Commission, Cause No. 44576/44602), July 2015. Presented testimony on revenue requirements issues on behalf of the Indiana Office of Utility Consumer Counselor.

Public Service Company of Oklahoma (Corporation Commission of Oklahoma, Cause No. PUD 201500208), October 2015. Presented testimony on revenue requirements and environmental compliance rider issues on behalf of the United States Department of Defense and the Federal Executive Agencies.

Northern Indiana Public Service Company (Indiana Utility Regulatory Commission, Cause No. 44688), January 2016. Presented testimony on the company's electric division operating revenues, operating expenses and income taxes issues on behalf of the Indiana Office of Utility Consumer Counselor.

Philadelphia Water Department (Philadelphia Water, Sewer And Storm Water Rate Board, FY2017-2018 Rate Proceeding), March 2016. Presented testimony on revenue requirements issues on behalf of the Public Advocate.

Columbia Gas of Maryland (Public Service Commission of Maryland, Case No. 9417), June 2016. Presented testimony on rate base and cost of service issues on behalf of the Office of People's Counsel.

Expert Testimony

of Lafayette K. Morgan, Jr.

Chesapeake Utilities Corporation (Delaware Public Service Commission, PSC Docket No. 15-1734), August 2016. Presented testimony on rate base and cost of service issues on behalf of the Staff of the Delaware Public Service Commission.

Kent County Water Authority (Public Service Commission of Rhode Island, Docket No. 4611), September 2016. Presented testimony on rate base and cost of service issues on behalf of the Division of Public Utilities and Carriers.

Northern Utilities, Inc. (Maine Public Utilities Commission, Docket No. 2017-00065), August 2017. Assisted the Maine Office of Public Advocate (OPA) with Northern Utilities application for an increase in rates. Mr. Morgan provided testimony, on behalf of the OPA, on accounting issues including test year revenue requirements, the utility's request to renew and modify its alternative rate plan, and its Targeted Infrastructure Replacement Adjustment.

Indiana Michigan Power Company (Indiana Utility Regulatory Commission, Cause No. 44967), November 2017. Presented testimony on rate base, operating revenues and operating expenses issues on behalf of the Indiana Office of Utility Consumer Counselor.

Emera Maine (Maine Public Utilities Commission, Docket No. 2017-00198), December 2017. Assisted the Maine Office of Public Advocate (OPA) with Emera Maine's application for an increase in rates. Mr. Morgan provided testimony, on behalf of the OPA, on accounting issues including test year revenue requirements, the utility's request to reflect the changes brought about by the Tax Change and Jobs Act of 2017.

UGI-Electric (Pennsylvania Public Utility Commission, Docket No. R-2017-2640058), April 2018. Assisted the Pennsylvania Office of Consumer Advocate (OCA) with UGI-Electric's application for an increase in rates. Mr. Morgan provided testimony, on behalf of the OCA, on accounting issues including test year revenue requirements, the utility's request to reflect the changes brought about by the Tax Change and Jobs Act of 2017.

Philadelphia Water Department (Philadelphia Water, Sewer And Storm Water Rate Board, FY2019-2020 Rate Proceeding), April 2018. Presented testimony on revenue requirements and the Department's three-year rate plan issues on behalf of the Public Advocate.

Westar Energy, Inc. (Westar Energy) and Kansas Gas and Electric Company (KGE), (Kansas State Corporation Commission, Docket No. 18-WSEE-328-RTS), May 2018. Presented testimony on revenue requirements on behalf on behalf of the Federal Executive Agencies.

Expert Testimony

of Lafayette K. Morgan, Jr.

Duquesne Light Company (Pennsylvania Public Utility Commission, Docket No. R-2018-3000124), June 2018. Assisted the Pennsylvania Office of Consumer Advocate (OCA) with UGI-Electric's application for an increase in rates. Presented testimony, on behalf of the OCA, on accounting issues including test year revenue requirements, the utility's request to reflect the changes brought about by the Tax Change and Jobs Act of 2017.

Bangor Natural Gas Company (Maine Public Utilities Commission, Docket No. 2018-00007), June 2018. Assisted the Maine Office of Public Advocate (OPA) Presented testimony, on behalf of the OPA, on the changes brought about by the Tax Change and Jobs Act of 2017.

SUEZ Water Pennsylvania, Inc. (Pennsylvania Public Utility Commission, R-2018-3000834), July 2018. Assisted the Pennsylvania Office of Consumer Advocate (OCA) with SUEZ Water's application for an increase in rates. Presented testimony, on behalf of the OCA, on accounting issues including Rate Base, Operating Income, Inclusion of Costs Related to Expansion Territories and the utility's request to reflect the changes brought about by the Tax Change and Jobs Act of 2017.

Woonsocket Water Division (Public Service Commission of Rhode Island, Docket No. 4879), January 2019. Presented testimony on cost of service issues on behalf of the Division of Public Utilities and Carriers.

Central Maine Power Company (Maine Public Utilities Commission, Docket No. 2018-00194), January 2019. Assisted the Maine Office of Public Advocate (OPA) with Central Maine Power's application for an increase in rates. Mr. Morgan provided testimony, on behalf of the OPA, on accounting issues including test year revenue requirements, the utility's request to reflect the changes brought about by the Tax Change and Jobs Act of 2017.

Newport Water Department (Public Service Commission of Rhode Island, Docket No. 4933), July 2019. Presented testimony on cost of service issues on behalf of the Division of Public Utilities and Carriers.

UGI-Gas (Pennsylvania Public Utility Commission, Docket No. R-2018-3006814), April 2019. Assisted the Pennsylvania Office of Consumer Advocate (OCA) with UGI-Gas' application for an increase in rates. Mr. Morgan provided testimony, on behalf of the OCA, on accounting issues including Rate Base and Net Operating Income.

Columbia Gas of Maryland (Public Service Commission of Maryland, Case No. 9609), August 2019. Presented testimony on rate base and cost of service issues on behalf of the Office of People's Counsel.

Expert Testimony

of Lafayette K. Morgan, Jr.

Public Service Company of Colorado (Colorado Public Utility Commission, Proceeding No. 19AL-0268E), September 2019. Mr. Morgan provided testimony, on behalf of the Department of Energy and the Federal Executive Agencies, on accounting issues including test year revenue requirements, Rate Base and Net Operating Income.

Northern Utilities, Inc. (Maine Public Utilities Commission, Docket No. 2019-00092), September 2019. Assisted the Maine Office of Public Advocate (OPA) with Northern Utilities application for an increase in rates. Mr. Morgan provided testimony, on behalf of the OPA, on accounting issues including test year revenue requirements and the utility's request to institute a Capital Investment Recovery Mechanism.

Citizens' Electric Company of Lewisburg (Pennsylvania Public Utility Commission, Docket No. R-2019-3008212), October 2019. Provided testimony on Plant in Service, Construction Work in Progress, Materials and Supplies, Customer Deposits, Depreciation Expense, Growth Factor, and The Tax Cuts and Jobs Act. Mr. Morgan provided testimony, on behalf of the Pennsylvania Office of Consumer Advocate (OCA).

Valley Energy, Inc. (Pennsylvania Public Utility Commission, Docket No. R-2019-3008209), October 2019. Provided testimony on Plant in Service, Construction Work in Progress, Materials and Supplies, Customer Deposits, Depreciation Expense, Growth Factor, and The Tax Cuts and Jobs Act. Mr. Morgan provided testimony, on behalf of the Pennsylvania Office of Consumer Advocate (OCA).

Wellsboro Electric Company (Pennsylvania Public Utility Commission, Docket No. R-2019-3008208), October 2019. Provided testimony on Plant in Service, Construction Work in Progress, Materials and Supplies, Customer Deposits, Depreciation Expense, Growth Factor, and The Tax Cuts and Jobs Act. Mr. Morgan provided testimony, on behalf of the Pennsylvania Office of Consumer Advocate (OCA).

Blue Granite Water Company (Public Service Commission of South Carolina, (Docket No. 2019-290-WS), January 2020. Assisted the South Carolina Department of Consumer Affairs. Presented testimony on accounting policy issues including test year revenue requirements.

UGI-Gas (Pennsylvania Public Utility Commission, Docket No. R-2019-3015162), May 2020. Assisted the Pennsylvania Office of Consumer Advocate (OCA) with UGI-Gas' application for an increase in rates. Mr. Morgan provided testimony, on behalf of the OCA, on accounting issues including Rate Base and Net Operating Income.

Special Projects

Developed a Uniform System of Accounts and Financial Data Collection Template for five countries participating in the National Association of Regulatory Utility Commissioners (NARUC)/East Africa Regional Energy Regulatory Partnership. Also conducted training seminars and participated as a panel member addressing issues in the utility industry from the perspective of the regulator. This work was conducted by NARUC) and the United States Agency for International Development (USAID).

Other Projects

Texas Gas Transmission Corporation (Federal Energy Regulatory Commission, Docket No. RP93-106). Technical analysis and participation in settlement negotiations on cost of service, invested capital, and revenue deficiency on behalf of the Indiana Office of Utility Consumer Counselor.

Natural Gas Pipeline Company of America (Federal Energy Regulatory Commission, Docket No. RP93-36). Technical analysis and participation in settlement negotiations on cost of service, invested capital, and revenue deficiency on behalf of the Indiana Office of Utility Consumer Counselor.

Texas Gas Transmission Company (Federal Energy Regulatory Commission, Docket No. RP94-423). Technical analysis and participation in settlement negotiations on cost of service, invested capital, and revenue deficiency on behalf of the Indiana Office of Utility Consumer Counselor.

Lafourche Telephone Company (Louisiana Public Service Commission, Docket No. U-21181). Analysis and investigation of earnings and appropriate rate of return on behalf of the Louisiana Public Service Commission Staff.

Natural Gas Pipeline Company of America (Federal Energy Regulatory Commission, Docket No. RP95-326). Technical analysis and participation in settlement negotiations on cost of service, invested capital, and revenue deficiency on behalf of the Indiana Office of Utility Consumer Counselor.

Pymatuning Independent Telephone Company (Pennsylvania Public Utility Commission, Docket No. R-00953502). Technical analysis and development of settlement position in the Company’s rate case on behalf of the Pennsylvania Office of Consumer Advocate.

Illinois Bell Telephone Company (Illinois Commerce Commission, Docket No. 96-0172). Technical analysis of the Company’s annual rate filing pursuant to its Price Cap Plan on behalf of Citizens Utility Board.

Illinois Bell Telephone Company (Illinois Commerce Commission, Docket No. 97-0157). Technical analysis of the Company's annual rate filing pursuant to its Price Cap Plan on behalf of Citizens Utility Board.

TDS Telecom (Pennsylvania Public Utility Commission, Docket Nos. R-00973892 and R-00973893). Technical analysis regarding rate base, cost of service, rate design, and rate of return, and assistance in settlement negotiations in the Company's rate case and alternative regulatory filing on behalf of the Pennsylvania Office of Consumer Advocate.

Appalachian Power Company (Virginia State Corporation Commission, Case No. PUE 960301). Technical analysis regarding rate base and cost of service and assistance in settlement negotiations in the Company's rate case and alternative regulatory filing on behalf of the Virginia Office of the Attorney General.

Central Maine Power Company (Maine Public Utilities Commission, Docket No. 97-580). Technical analysis regarding attrition and accounting issues in the Company's Transmission and Distribution unbundling proceeding on behalf of the Maine Public Utilities Commission Staff.

Illinois Bell Telephone Company (Illinois Commerce Commission, Docket No. 98-0259). Technical Analysis of the Company's annual rate filing pursuant to its Price Cap Plan on behalf of Citizens Utility Board.

Maine Public Service Company (Maine Public Utilities Commission, Docket No. 98-577). Technical analysis regarding attrition and accounting issues in the Company's Transmission and Distribution unbundling proceeding on behalf of the Maine Public Utilities Commission Staff.

Bangor Hydro-Electric Company (Maine Public Utilities Commission, Docket No. 97-596). Technical analysis regarding attrition and accounting issues in the Company's Transmission and Distribution unbundling proceeding on behalf of the Maine Public Utilities Commission Staff.

TDS Telecom (Maine Public Utilities Commission, Docket Nos. 98-894, 98-895, 98-904, 98-906, 98-911, and 98-912). Technical analysis regarding accounting issues and access rate changes on behalf of the Maine Office of the Public Advocate.

Mid-Maine Telecom (Maine Public Utilities Commission, Docket No. 2000-810). Technical analysis regarding accounting issues and access rate changes on behalf of the Maine Office of the Public Advocate.

Unitel, Inc. (Maine Public Utilities Commission, Docket No. 2000-813). Technical analysis regarding accounting issues and access rate changes on behalf of the Maine Office of the Public Advocate.

Hydraulics International, Inc. (Armed Services Board of Contract Appeals, ASBCA No. 51285). Technical analysis and support relating to the Economic Adjustment Clause claim on behalf of the Air Force Materiel Command.

Tidewater Telecom and Lincolnville Telephone Company (Maine Public Utilities Commission, Docket Nos. 2002-100 and 2002-99). Technical analysis regarding accounting issues and access rate changes on behalf of the Maine Office of the Public Advocate.

TDS Telecom (Vermont Public Service Board, Docket No. 6576). Technical analysis regarding rate base, cost of service, and depreciation expense on behalf of the Vermont Department of Public Service.

CenterPoint Energy-Entex (Louisiana Public Service Commission, Docket No. U-26720, Subdocket A). Technical analysis regarding rate base and cost of service on behalf of the Louisiana Public Service Commission Staff.

CenterPoint Energy-Arkla (Louisiana Public Service Commission, Docket No. U-27676). Technical analysis regarding rate base and cost of service on behalf of the Louisiana Public Service Commission Staff.

Provided technical analysis and support on behalf of the Louisiana Public Service Commission Staff relating to CLECO Power LLC Rate Stabilization Plan.

Provided technical analysis and support on behalf of the Louisiana Public Service Commission Staff relating to CLECO Power LLC post-Katrina power purchases.

Provided technical analysis and support on behalf of the Louisiana Public Service Commission Staff relating to Entergy Louisiana LLC recovery of storm damage costs.

Westar Energy, Inc. (Westar Energy) and Kansas Gas and Electric Company (KGE), (Kansas State Corporation Commission, Docket No. 17-WSEE-147-RTS). Technical analysis regarding rate base and cost of service on behalf of the Federal Executive Agencies.

Westar Energy, Inc. (Westar Energy) and Kansas Gas and Electric Company (KGE), (Kansas State Corporation Commission, Docket No. 17-WSEE-147-RTS). Technical analysis regarding rate base and cost of service on behalf of the Federal Executive Agencies.

OCA Statement No. 2

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-2020-3018929**
	)	
PECO Energy Company - Gas Division	)	

Appendix B

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set II

Response Date: 11/13/2020

OCA-II-2

According to Mr. Trzaska's testimony beginning at page 3, line 2, the base data for the FPFTY that was used to develop PECO's FPFTY and FTY were derived from PECO's capital and operating budgets for the twelve months ending June 30, 2022 and 2021, respectively. Please indicate when these budgets were originally prepared.

RESPONSE:

The base data for the FPFTY and FTY that was used to develop PECO's capital and operating budgets for the twelve months ending June 30, 2022 and 2021 respectively were prepared in July 2020 and finalized in August 2020.

Responsible Witness: Robert J. Stefani

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set II

Response Date: 11/13/2020

OCA-II-3

Please provide a copy of the capital budget by plant account for the FTY and the FPFTY. Provide these data in electronic (Excel) format with the formulae intact. Separately list all projects expected to be completed in the FTY and the FPFTY. For each project in your response:

(a) provide a description of the project, the initial estimated completion dates and any revised completion date;

(b) provide the current status of each project. Where applicable, indicate whether the project was suspended or cancelled and include the date such action occurred; and,

(c) identify any new project included after the budget was approved.

RESPONSE:

a) See Attachment OCA-II-3(a).
b) See Attachment OCA-II-3(a).
c) No additional projects have been added to the budget.

Responsible Witness: Robert J. Stefani

Attachment OCA-II-3(a)
Page 1 of 1

Capital Spend Category / Program	Description	Current Status	Estimated Completion Date	FTY Jul 2020 - Jun 2021	FPFTY Jul 2021 - Jun 2022
Projects Closing Beyond FTY & FPFTY:					
Main Replacement Program	Replacement of all outmoded mains	In Progress	Dec-35	$ 158,062,274	$ 152,478,114
Bare Steel Service Replacement	Replacement of all bare steel services	In Progress	Dec-22	$ 26,822,556	$ 21,452,034
New Business	Annual Budget for New Business Projections	In Progress	Annually	$ 37,705,884	$ 36,885,030
Facility Relocation	Annual Budget for Facility Relocation work	In Progress	Annually	$ 10,412,933	$ 8,085,461
Natural Gas Reliability	New Gas Supply Line from West Conshohocken Gas Plant to Broomall	In Progress	Jun-23	$ 58,982,240	$ 43,962,622
HP Service Regulator Replacement	Replace 3/16” B42 Service Regulators installed on HP systems post-1998	In Progress	Jun-25	$ 4,104,965	$ 7,964,269
Bolt On Tee Replacement	Program to replace bolt-on tees	In Progress	TBD	$ 516,909	$ 1,000,000
Tier 2 & 3 Security Upgrades	Facility Security Enhancement Program	In Progress	Dec-24	$ 546,612	$ 4,347,548
Corrective Maintence	Includes reactive capital replacements impacting services and valves	In Progress	Annually	$ 7,750,131	$ 7,663,604
Gas Plant Improvements - Gas Winter Critical	Project improvements to improve winter readiness	In Progress	Annually	$ 4,467,997	$ 2,741,255
Sub-Total				$ 309,372,503	$ 286,579,937
Projects Closing During FTY & FPFTY:					
New Business - Kimberly Clark	Construct necessary facilities to provide gas to the Kimberly Clark mill in Chester for a proposed gas-fired cogeneration facility	Completed	Oct 2020	$ 459,866	$ -
LNG Tank Boil-Off Compressors	Replacement of two boil-off compressors	In Progress	Dec-21	$ 2,807,184	$ 850,526
Sub-Total				$ 3,267,050	$ 850,526
All Other Anr Real Estate			Annually	$ 7,827,461	$ 5,741,095
IT			Annually	$ 3,555,341	$ 7,912,440
Back Office			Annually	$ 4,552,092	$ 2,280,078
Other				$ 9,476,941	$ 9,755,866
Sub-Total				$ 25,411,834	$ 25,689,479
Total Capital				$ 338,051,386	$ 313,119,942

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

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Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set II

Response Date: 11/13/2020

OCA-II-12

Reference Exhibit MJT-1, Schedule C-4, Page 30 (Fully Projected Future Test Year).

(a) Please indicate what "EAP" and "NGA" stand for.

(b) Please indicate how frequently these dues are paid.

(c) Please explain why the pattern of the monthly balances for EAP and NGA differ from the AGA dues. In other words, why doesn't the prepaid monthly balances appear to be an annual amount that is amortized monthly (i.e., a high balance that decreases monthly during the year)?

(d) Please explain how, in the lead/lag study, these prepayments were removed from the "Other Expenses" amount to which the 37.54 days were applied.

RESPONSE:

(a) "EAP" means The Energy Association of Pennsylvania and "NGA" means the Northeast Gas Association.

(b) The dues are paid annually.

(c) With regards to EAP and NGA, PECO utilized historical data from July 2019 to June 2020 for the prepaid balances for the FPFTY. However, the historical data included accounting adjustments that created inconsistencies on a monthly basis but did not impact the 13-month average monthly balances which are properly reflected in Exhibit MJT-1.

(d) The prepayments were not removed from the "Other Expenses" amount in the lead/lag study.

Responsible Witness: Michael J. Trzaska

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set II

Response Date: 11/13/2020

OCA-II-13

Reference Exhibit MJT-1, Schedule C-4, Page 30 (Fully Projected Future Test Year).

(a) Please explain the nature of the "Maintenance" that is presented in Column (6).

(b) Please explain why the monthly balance stays unchanged for most of the 13-month period.

(c) Please provide the level of these specific maintenance expense that is included in O&M expenses.

(d) Please explain how, in the lead/lag study, these maintenance expenses were removed from the "Other Expenses" amount to which the 37.54 days were applied.

RESPONSE:

(a) Item refers to a maintenance service agreement related to Automated External Defibrillators.

(b) Maintenance service agreement costs are amortized on a straight-line basis over the life of the agreement.

(c) These specific maintenance expenses are not included in O&M expenses for the FPFTY.

(d) N/A. See the responses above.

Responsible Witness: Michael J. Trzaska

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set II

Response Date: 11/13/2020

OCA-II-18

Reference Exhibit MJT-1, Schedule C-4, Page 30 (Fully Projected Future Test Year).

(a) Please explain the nature of the "VEBA Adjust" that is presented in Column (9).

(b) Please provide the level of the VEBA Adjust expenses that are included in the O&M expenses.

(c) Please explain how, in the lead/lag study, the VEBA Adjust expenses were removed from the "Other Expenses" amount to which the 37.54 days were applied.

RESPONSE:

(a) VEBA Adjust refers to the Voluntary Employees' Beneficiary Association (VEBA) plan which provides benefits including medical, dental, vision, hearing, prescription drugs, and wellness programs to employees.

(b) The level of VEBA Adjust expenses that are included in the O&M expense for the FPFTY is $141,000.

(c) The expenses were not removed from the "Other Expenses" amount in the lead/lag study.

Responsible Witness: Michael J. Trzaska

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set II

Response Date: 11/13/2020

OCA-II-19

Reference Exhibit MJT-1, Schedule C-4, Page 30 (Fully Projected Future Test Year).

(a) Please explain the nature of the "Fleet Activities" that is presented in Column (12).

(b) Please provide the level of the Fleet Activities expenses that are included in O&M expenses.

(c) Please explain how, in the lead/lag study, the Fleet Activities expenses were removed from the "Other Expenses" amount to which the 37.54 days were applied.

RESPONSE:

(a) Fleet Activities refers to vehicle licenses and registrations.

(b) The Company budgets its Fleet expenses at a total level, utilizing a vehicle rate that includes license and registration fees, among other expenses. A more detailed budget specific to licenses and registrations is not readily available.

(c) The expenses were not removed from the "Other Expenses" amount in the lead/lag study.

Responsible Witness: Michael J. Trzaska

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set II

Response Date: 11/13/2020

OCA-II-20

Reference Exhibit MJT-1, Schedule C-4, Page 30 (Fully Projected Future Test Year).

(a) Please explain the nature of the "Customer Experience" that is presented in Column (14).

(b) Please provide the level of the Customer Experience expenses that are included in O&M expenses.

(c) Please explain how, in the lead/lag study, the Customer Experience expenses were removed from the "Other Expenses" amount to which the 37.54 days were applied.

RESPONSE:

(a) Customer Experience refers to prepaid expenses for eChannel vendors offering support toward the customer experience initiative including support for web and mobile browser, mobile apps, social media, and analytics.

(b) The level of Customer Experience expenses that are included in O&M expenses in the FPFTY is $84,000.

(c) The expenses were not removed from the "Other Expenses" amount in the lead/lag study.

Responsible Witness: Michael J. Trzaska

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set II

Response Date: 11/13/2020

OCA-II-26

Please explain how the pension asset is amortized to expenses and show where it is recorded on the Company's books.

RESPONSE:

The pension asset on PECO's balance sheet represents cumulative cash contributions made by PECO in excess of PECO's cumulative pension cost and does not get amortized to expense. The change in the pension asset represents annual contributions paid by PECO to the pension trust and annual pension cost accounted for in accordance with ASC 715.

Responsible Witness: Caroline Fulginiti

Pennsylvania Public Utility Commission
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PECO Energy Company – Gas Division

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Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set II

Response Date: 11/13/2020

OCA-II-27

According to Mr. Trzaska, for the FPFTY ending June 30, 2022, the amount of pension cost capitalized would be $0.1 million.

(a) lease provide the actuarial study that provides the pension cost from which the $0.1 million amount was calculated.

(b) Please show the calculation of the $0.1 million amount. Confirm that this is the amount consistent with ASC 715. If not, explain why it would be different.

(c) Please provide the FPFTY ASC 715 pension expense for the FPFTY.

RESPONSE:

a. Refer to Confidential Attachment OCA-II-27(a).

b. The Gas portion of ASC 715 pension expense is $562,614. The calculation of this amount is based on applying a rate per dollar of labor expense. The rate is developed by dividing total Pension cost by total budgeted Regular Time Labor. Please note that the $562,614 does not agree with the amount shown in MJT-1. The $0.1 million amount on MJT-1 was incorrect as it did not include the total ASC-715 expense.

c. Total ASC 715 Pension Expense for the FPFTY is $562,614.

THE CONFIDENTIAL ATTACHMENT TO THIS RESPONSE IS BEING PROVIDED ONLY SUBJECT TO THE EXECUTION OF A SUITABLE STIPULATED PROTECTIVE AGREEMENT WITH THE RECIPIENT PENDING THE ISSUANCE OF A PROTECTIVE ORDER IN THIS CASE. PECO WILL PROVIDE A STIPULATED PROTECTIVE AGREEMENT DEEMED SUITABLE TO THE COMPANY FOR

EXECUTION, WHICH IS SIMILAR TO THE STIPULATED PROTECTIVE AGREEMENT EMPLOYED IN PECO'S PRIOR BASE RATE CASE.

Responsible Witness: Robert J. Stefani

Pennsylvania Public Utility Commission
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PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set II

Response Date: 11/13/2020

OCA-II-47

Please provide the actual monthly number of employees for the twelve months ended June 30, 2017, 2018, 2019, and 2020 through the most recent month available.

RESPONSE:

Please see Attachment OCA-II-47(a) for headcount information.

Responsible Witness: Robert J. Stefani

OCA-II-47 (a)

PECO Headcount

Month/YR	Gas - Regular	Gas - Temporary
Jul-16	534	30
Aug-16	533	25
Sep-16	531	19
Oct-16	530	21
Nov-16	532	21
Dec-16	548	19
Jan-17	562	19
Feb-17	561	18
Mar-17	562	14
Apr-17	570	21
May-17	571	22
Jun-17	571	28
Jul-17	570	29
Aug-17	570	37
Sep-17	573	17
Oct-17	576	17
Nov-17	573	17
Dec-17	573	17
Jan-18	556	15
Feb-18	569	15
Mar-18	564	9
Apr-18	561	20
May-18	558	18
Jun-18	558	26
Jul-18	557	27
Aug-18	563	17
Sep-18	564	17
Oct-18	581	17
Nov-18	585	18
Dec-18	584	17
Jan-19	600	18
Feb-19	587	17
Mar-19	585	12
Apr-19	584	21
May-19	595	22
Jun-19	592	31
Jul-19	585	30
Aug-19	582	25
Sep-19	604	22
Oct-19	606	17
Nov-19	605	18
Dec-19	601	17
Jan-20	599	17
Feb-20	605	17
Mar-20	603	14
Apr-20	603	14
May-20	599	17
Jun-20	602	24
Jul-20	603	24
Aug-20	602	20
Sep-20	604	22

Note: Temporary headcount is not included in the Company's official headcount.
BSC support employees are not included in company headcount as they are allocated to the utility according to the MMF rate.

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OCA-II-54

Reference Exhibit MJT-1, Schedule D-14, Page 75 (Fully Projected Future Test Year).

(a) Please provide a breakdown of the costs that make up Gas Unbundling of GPC/MFC Charge Expense by year.

(b) Please provide a breakdown of the costs that make up Gas Neighborhood Pilot Program Expense by year.

(c) Please show where the depreciation expense relating to the programs is included.

(d) Please identify the assets related to the claimed depreciation expense and indicate where they are recorded. In your response, please indicate whether any of these assets have been fully recovered.

(e) If there is any ongoing depreciation expense related to the assets used for these programs, please explain how they are included in the cost of service.

RESPONSE:

(a) The Gas Unbundling project costs included $129,249 of capital and $20,570 of expense. The capital portion reflects software costs.

(b) The Gas Neighborhood Pilot project costs included $1,802,831 of capital and $314,507 of expense. The capital portion reflects software costs.

(c) There is no depreciation included in the FPFTY for the referenced programs.

(d) The assets related to the claimed depreciation are as follows:

Project	Amount	Utility Account
Gas Unbundling Software	$ 129	PECO Gas 303 - Intangible Property
On Bill Payment Software	$ 1,803	PECO Gas 303 - Intangible Property

(e) There is no ongoing expense in the FPFTY.

Responsible Witness: Michael J. Trzaska

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OCA-II-66

Please explain how the COVID-19 pandemic has affected the Company's construction activities and quantify, in terms of expenditures, the effect of the virus in meeting capital expenditure goals as reflected in the FY 2021 and FY 2022 capital budgets.

RESPONSE:

Beginning in March 2020, PECO's Gas Operations construction activities were delayed as a result of the COVID-19 pandemic. As a result, construction work scheduled in the first half of 2020 was shifted to the second half of 2020 and resumed in June 2020. During the period of delay, PECO was able to maintain some main construction installation activities and similar work, but work that required entry into existing customer properties was restricted. COVID-19-related restrictions mostly limited construction involving main retirement and bare steel service replacements.

The timing and shift of the construction workplan from the first half of 2020 to the second half of 2020 resulted in expenditures moving from the Historic Test Year (FY 2020) to the Future Test Year (FY 2021), including $23.5M associated with main replacement and $5.8M for bare steel service replacements. To date, there is no impact to the Fully Projected Future Test Year (FY 2022).

Responsible Witness: Ronald A. Bradley

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Response Date: 11/13/2020

OCA-II-69

To the extent that there are delays, cancellations and rescheduling affecting the FY 2021 and FY 2022 capital and operation and maintenance projects resulting from the Company's response to the COVID-19 pandemic, please identify on a project by project basis, the new deadlines, in-service dates and other planned changes.

RESPONSE:

There have been no delays, cancellations or rescheduling affecting the FY2021 and FY2022 capital and operation and maintenance projects resulting from the Company's response to the COVID-19 pandemic.

Responsible Witness: Ronald A. Bradley

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OCA Set IX

Response Date: 12/04/2020

OCA-IX-7

Regarding Item (f)–Employee Benefits–presented on Confidential Attachment III-A-21(a),

(a) please provide supporting documentation for each of the components of Employee Benefits for the FPFTY;

(b) please provide a schedule similar to Item (f) showing the amount for each of the employee benefits for the 12 months ended June 30, 2018, 2019 and 2020;

(c) please explain the cause of the change in the amount for Pension for the FPFTY;

(d) please explain the cause of the change in the amount for OPEB for the FPFTY; and

(e) please provide the actuarial studies supporting the FPFTY amounts for Pension and OPEB.

RESPONSE:

(a) Refer to Confidential Attachment OCA-IX-7(a).

(b) Refer to Attachment OCA-IX-7(b).

(c) The decrease in projected pension cost from 2021 to 2022 is mainly attributed to the contributions being made to the pension trust which increase the asset base on which the pension receives a return.

(d) The increase in projected OPEB cost from 2021 to 2022 is a result of expiring prior service credit amortization in the East plan in which PECO participates. The prior service credit amortization is a result of a plan design change made in 2014 that is amortized into pension cost over the average remaining service period of active participants.

(e) Refer to Confidential Attachment III-A-21(b).

THE ATTACHMENTS ARE CONFIDENTIAL AND ARE PROVIDED ONLY TO THOSE WHO HAVE EXECUTED NON-DISCLOSURE AGREEMENTS UNDER PROTECTIVE ORDER.

Responsible Witness: Robert J. Stefani

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Response Date: 12/04/2020

OCA-IX-10

Reference Exhibit MJT-1, Schedule D-6, Page 65 (Fully Projected Future Test Year). Please provide a list of each of the 37 new positions, showing the annual salaries and wages; date hired, if hired or the expected hiring date; and date terminated, if terminated during the HTY or FTY.

RESPONSE:

Please see Confidential Attachment OCA-IX-10(a) for details on 30 positions hired during the HTY. The remaining seven positions reflect employees that partially support the Gas function as a result of allocation and those positions are Energy Technicians in the Company's Distribution Service Organization.

THE ATTACHMENTS ARE CONFIDENTIAL AND ARE PROVIDED ONLY TO THOSE WHO HAVE EXECUTED NON-DISCLOSURE AGREEMENTS UNDER PROTECTIVE ORDER.

Responsible Witness: Robert J. Stefani

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Response of PECO Energy Company
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OCA Set XI

Response Date: 12/11/2020

OCA-XI-5

Reference PECO Gas St. 1 (Bradley direct), at page 17, lines 11-15. Provide an update regarding the natural gas reliability project in Delaware and Montgomery counties. What is the Company's schedule for installing the natural gas reliability station? Has this schedule changed since the Company made its rate filing? Explain.

RESPONSE:

The 11.5 miles of gas main is on schedule to be installed by the end of 2021.
The gas reliability station is now projected to complete construction by Q2 of 2022.
The required upgrades to PECO's natural gas plant are on track to be in service by the end of 2022. The station property did not receive zoning approval as expected, which has delayed the original schedule.

Responsible Witness: Ronald A. Bradley

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OCA-XIII-2

Please provide management's budget guidelines/instructions issued for development of the O&M and Capital budgets for the periods applicable to the FTY and FPFTY.

RESPONSE:

Refer to PECO Statement No. 2 (Direct Testimony of Robert Stefani), pp. 10-12 for a description of the Company's budgeting process, which was utilized for the development of the O&M and Capital budgets for the periods applicable to the FTY and FPFTY.

Responsible Witness: Robert J. Stefani

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Response Date: 12/14/2020

OCA-XIII-3

Please provide a detailed project listing for each of the categories presented on Attachment OCA-II-3(a) showing the projected in-service dates, current status of each project, and identify any project that has been suspended, delayed or cancelled.

RESPONSE:

Please see the below list of Programs/Projects. PECO budgets for certain projects at the program level. Where the "In-Service" column shows "various" and the "Project Status" column shows "N/A", it is because the line item is a program that consists of multiple projects that has been budgeted at the program level (and not the project level). All of the projects under such programs will have in-service dates throughout the FTY and FPFTY. None of the projects or programs listed below have been suspended, delayed, or cancelled.

Project Type	Project Description	Short Description	Additions to Capital per Schedule C-2 for the FTY	Additions to Capital per Schedule C-2 for the FPFTY	In-service	Project Status
Baseline	NB Gas GAMs by contractor	NB Gas along the Mains by Contractor (provide Gas to customers that have a main in front of the homes	10,807,829	10,029,684	Various	N/A
	NB Gas C&I	New Business Commercial and Industrial	7,144,627	8,071,115	Various	N/A
	NRCG Gas Residential Inside Developments	New Residential Construction	4,788,413	5,750,396	Various	N/A
	Public Relo GAS Baseline Work PADOT Requ	Public Relocation Baseline Work Pennsylvania Department of Transportation	5,607,132	4,537,663	Various	N/A
	Plant Improvements - Gas Winter Critical	Additions associated with Gas Winter Critical program	4,467,997	2,741,255	Various	N/A
	Winter Critical Capacity Upgrades Baseline	Winter Critical Capacity Upgrades Baseline Work	3,855,239	2,625,810	Various	N/A
	Locate & repair #1 & #2A Leaks - Services	Locate & repair #1 & #2A Leaks - Services Only	2,501,026	2,621,749	Various	N/A
	Locate & Repair #2B Leaks - Services	Locate & Repair Non Critical Gas Leaks #2B Leaks - Services Only	2,551,336	2,522,690	Various	N/A
	NB Gas NRCG Approach Mains	NB Gas NRCG Approach Mains (Extension of Gas Facilities to new development	1,516,527	2,003,909	Various	N/A
	Gas- Service Maintenance	Gas- Service Maintenance	2,170,987	1,970,112	Various	N/A
	NB Gas Residential	NB Gas Residential (not included in New Residential Construction)	2,708,789	1,888,999	Various	N/A
	Regulatory (Gas) Plant Additions	Additions associated with Regulatory required spend	1,705,801	1,594,199	Various	N/A
	Purchase Gas Meters for Residential NB	Purchase Gas Meters for Residential New Business Replacement	1,082,318	1,590,631	Various	N/A
	Gas- Once-cathodically protected BS Main Re	Gas- Once-cathodically protected Bare Steel Main Replacement Program	1,117,373	1,340,787	Various	N/A
	Abandonment of Inactive Gas services.	Abandonment of Inactive Gas services.	1,248,351	1,292,689	Various	N/A
	Regulator Station Upgrades	General Work - Sealing of underground Regulator Station Vaults	1,706,517	846,367	Various	N/A
	Capital Tools Corrosion/Leak Survey/Regula	Capital Tools Corrosion/Leak Survey/Regulatory Equipment necessary for regulatory required surveys	1,018,001	817,157	Various	N/A
	PECO Capital Overhead- Gas	The capitalization of Overhead costs	891,502	526,098	Various	N/A
	Purchase Gas Meters for Plant Replacement	Purchase Gas Meters for Plant Replacement	195,910	269,815	Various	N/A
	Replace Nonoperable Valves Identified by In	Replace Nonoperable Valves Identified by Inspection Program	307,074	259,129	Various	N/A
	Gas Cathodic Protection Reg. Work & OIR's	Gas Cathodic Protection Regulatory Work	213,390	245,777	Various	N/A
	Gas Meter & House Regulator Maint.	Gas Meter & House Regulator Maintanance	145,728	127,840	Various	N/A
Baseline Total			**57,751,868**	**53,673,870**		
Programmatic	Accelerated Mod - Cast Iron	Part of Gas Modernization Program. Accelerate Cast Iron replacement.	86,226,793	70,886,989	Various	N/A
	Main Replacements - Large Diameter	Large Diameter main replacements	46,391,845	31,614,529	Various	N/A
	Restoration Blanket for AGIMP	This is the restoration/paving required on any AGIMP construction project that requires a specific ITN.	19,775,908	21,565,364	Various	N/A
	Replace (Leaking) Bare Steel Mains (Optimai	Replace (Leaking) Bare Steel Mains (Optimain)	25,906,596	20,971,247	Various	N/A
	Accelerated Mod - Bare Steel Services	Part of Gas Modernization Program. Accelerate Bare Steel Services replacement.	24,841,450	17,579,226	Various	N/A
	Residential HP Regulator Replacement	HP residential regulators could cause build-up pressures of > 2 psig under failure conditions per ANSI standard B109.4. This is the plan to replace 35k-40k regulators installed after 1998.	4,104,965	7,964,269	Various	N/A
	NB Neighborhood Gas Program	NB Neighborhood Gas Program	9,028,722	7,502,347	Various	N/A
	Bare Steel Service Replacement Program	Bare Steel Service Replacement Program- utilizing graphical leak analysis	1,981,106	3,872,808	Various	N/A
	Replacement Cast Iron Mains	Replacement Cast Iron Mains	3,993,163	3,473,387	Various	N/A
	FEP - Tier 2 Gas	Facility Enhancement Program - Security Upgrade	282,670	1,903,652	Various	N/A
	Bolt-On Tee Replacements	Bolt-On tees have failed in the industry. PECO used these tees from mid 1990s-2004. The PUC requirement is to remove any bolt-on tees when identified.	516,909	1,000,000	Various	N/A
	Relocate Indoor Gas Meters	Relocate Indoor Gas Meters to Outdoor	1,280,105	820,636	Various	N/A
Programmatic Total			**224,330,232**	**189,154,454**		
Specific Project	Natural Gas Reliability		-	82,481,428	December 2021	Still Open
	FR - Rte 202 - Section 61N		4,853,370	3,547,125	May 2022	Still Open
	EU Analytics - Advanced Metering Infrastructure (AMI)		-	1,113,070	October 2021	Still Open
	LNG Plant BOC		2,807,184	807,114	December 2021	Still Open
	2020 AGIMP – Abington Twp. Small Diameter		-	752,064	December 2021	Closed
	2020 AGIMP – Springfield Twp. Small Diameter		-	480,559	January 2022	Still Open
	Oracle Implementation		-	101,116	December 2021	Still Open
	2020 AGIMP- Conshy St Phase 1 Large Diameter		1,987,165	-	December 2020	Closed
	2020 AGIMP – Folcroft Boro Small Diameter		1,531,420	-	December 2020	Closed
	2020 AGIMP- Del/Chester Large Diameter		1,262,057	-	December 2020	Still Open
	2020 AGIMP – Cheltenham Twp. Small Diameter		1,154,741	-	December 2020	Closed
	2020 AGIMP – Upper Darby Twp. Small Diameter		1,021,405	-	December 2020	Closed
	2019 AGIMP - Bucks/Mont Large Diameter		871,121	-	December 2020	Still Open
	2020 AGIMP – Radnor Twp. Small Diameter		838,457	-	December 2020	Closed
	2020 AGIMP – Haverford Twp. Small Diameter		776,304	-	December 2020	Closed
	2020 AGIMP- Bux/Mont Large Diameter		563,337	-	December 2020	Still Open
	Kimberly Clark NB C&I		459,866	-	December 2020	Closed
	2020 AGIMP – Misc. Twp. Small Diameter		358,082	-	December 2020	Closed
	Portable LNG Vaporizer		356,692	-	December 2020	Still Open
	2019 AGIMP – Upper Darby Twp. Small Diameter		297,243	-	December 2020	Still Open
	2019 AGIMP – Abington Twp. Small Diameter		171,151	-	July 2020	Closed
	2020 AGIMP- Upper Darby SEPTA J&B Large Diameter		142,441	-	March 2021	Still Open
	2021 AGIMP SD SPRINGFIELD (D)		118,210	-	December 2021	Still Open
	OPT Washington		117,573	-	July 2020	Closed
	PECO Gas Service Regulators for GFR and AS8		115,367	-	July 2020	Closed
	2019 AGIMP – Springfield (D) Twp. Small Diameter		90,536	-	January 2021	Still Open
	2020-CE-Noble St.		54,110	-	December 2020	Closed
	2019 AGIMP – Tredyffrin Twp. Small Diameter		29,316	-	December 2020	Closed
	OPBS - Olive Street		27,967	-	July 2020	Closed
	RNG Springton Pointe, Newtown Square		268	-	July 2020	Closed
Specific Project Total			**20,005,382**	**89,282,476**		
		Gross Plant Additions	**302,087,482**	**332,110,800**		
		Calculated Cost of Removal	**(9,964,378)**	**(9,964,378)**		
		Plant Additions	**292,123,104**	**322,146,422**		

Responsible Witness: Robert J. Stefani

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To Interrogatories of the
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Response Date: 12/14/2020

OCA-XIII-4

Please reconcile the budgeted FTY and FPFTY plant additions provided in Attachment OCA-II-3(a) with the plant additions provided in Exhibit MJT-1, Schedule C-2, page 16 and Exhibit MJT-2, Schedule C-2, Page 16.

RESPONSE:

The submission of OCA-II-3(a) provided Capital Expenditures and not Capital Additions. Attachment OCA-XIII-4(a) reflects the details of the Capital Additions included in MJT-1 and MJT-2. There are several classifications of assets included on MJIT exhibits Schedule C-2: Baseline, Program, and Specific Projects. Baseline Projects are typical work that is short in duration and is capitalized on a monthly or quarterly basis. Program work are work programs that have a defined period of time but are longer in duration (6 months to 1 year). Once detailed program work is identified, costs are assigned to specific projects. The Specific projects have a beginning and end date associated with them.

Responsible Witness: Robert J. Stefani

PECO Energy Company

Attachment OCA-XIII-4(a)
Page 1 of 1

Project Type	Project Description	Short Description	Additions to Capital per Schedule C-2 for the FTY	Additions to Capital per Schedule C-2 for the FPFTY
Baseline	NB Gas GAMs by contractor	NB Gas along the Mains by Contractor (provide Gas to customers that have a main in front of the homes	10,807,829	10,029,684
	NB Gas C&I	New Business Commercial and Industria	7,144,627	8,071,115
	NRCG Gas Residential Inside Developments	New Residential Construction	4,788,413	5,750,396
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	Winter Critical Capacity Upgrades Baseline	Winter Critical Capacity Upgrades Baseline Work	3,855,239	2,625,810
	Locate & repair #1 & #2A Leaks - Services	Locate & repair #1 & #2A Leaks - Services Only	2,501,026	2,621,749
	Locate & Repair #2B Leaks - Services	Locate & Repair Non Critical Gas Leaks #2B Leaks - Services Only	2,551,336	2,522,690
	NB Gas NRCG Approach Mains	NB Gas NRCG Approach Mains (Extension of Gas Facilities to new developmen	1,516,527	2,003,909
	Gas- Service Maintenance	Gas- Service Maintenance	2,170,987	1,970,112
	NB Gas Residential	NB Gas Residential (not included in New Residential Constructior	2,708,789	1,888,999
	Regulatory (Gas) Plant Additions	Additions associated with Regulatory required spenc	1,705,801	1,594,199
	Purchase Gas Meters for Residential NE	Purchase Gas Meters for Residential New Business Replacemen	1,082,318	1,590,631
	Gas- Once-cathodically protected BS Main Re	Gas- Once-cathodically protected Bare Steel Main Replacement Prograr	1,117,373	1,340,787
	Abandonment of Inactive Gas services	Abandonment of Inactive Gas services	1,248,351	1,292,689
	Regulator Station Upgrades	General Work - Sealing of underground Regulator Station Vault	1,706,517	846,367
	Capital Tools Corrosion/Leak Survey/Regula	Capital Tools Corrosion/Leak Survey/Regulatory Equipment necessary for regulatory required surveys	1,018,001	817,157
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	Gas Meter & House Regulator Maint.	Gas Meter & House Regulator Maintanance	145,728	127,840
Baseline Total			**57,751,868**	**53,673,870**
Programmatic	Accelerated Mod - Cast Iron	Part of Gas Modernization Program. Accelerate Cast Iron replacement	86,226,793	70,886,989
	Main Replacements - Large Diameter	Large Diameter main replacements	46,391,845	31,614,529
	Restoration Blanket for AGIMP	This is the restoration/paving required on any AGIMP construction project that requires a specific ITN.	19,775,908	21,565,364
	Replace (Leaking) Bare Steel Mains (Optima	Replace (Leaking) Bare Steel Mains (Optimain)	25,906,596	20,971,247
	Accelerated Mod - Bare Steel Services	Part of Gas Modernization Program. Accelerate Bare Steel Services replacement	24,841,450	17,579,226
	Residential HP Regulator Replacement	HP residential regulators could cause build-up pressures of > 2 psig under failure conditions per ANS standard B109.4. This is the plan to replace 35k-40k regulators installed after 1998.	4,104,965	7,964,269
	NB Neighborhood Gas Program	NB Neighborhood Gas Program	9,028,722	7,502,347
	Bare Steel Service Replacement Program	Bare Steel Service Replacement Program- utilizing graphical leak analysi	1,981,106	3,872,808
	Replacement Cast Iron Mains	Replacement Cast Iron Mains	3,993,163	3,473,387
	FEP - Tier 2 Gas	Facility Enhancement Program - Security Upgrade	282,670	1,903,652
	Bolt-On Tee Replacements	Bolt-On tees have failed in the industry. PECO used these tees from mid 1990s-2004. The PUC requirement is to remove any bolt-on tees when identified.	516,909	1,000,000
	Relocate Indoor Gas Meters	Relocate Indoor Gas Meters to Outdoor	1,280,105	820,636
Programmatic Total			**224,330,232**	**189,154,454**
Specific Project	Natural Gas Reliability		-	82,481,428
	FR - Rte 202 - Section 61N		4,853,370	3,547,125
	EU Analytics - Advanced Metering Infrastructure (AMI		-	1,113,070
	LNG Plant BOC		2,807,184	807,114
	2020 AGIMP – Abington Twp. Small Diameter		-	752,064
	2020 AGIMP – Springfield Twp. Small Diameter		-	480,559
	Oracle Implementation		-	101,116
	2020 AGIMP- Conshy St Phase 1 Large Diameter		1,987,165	-
	2020 AGIMP – Folcroft Boro Small Diameter		1,531,420	-
	2020 AGIMP- Del/Chester Large Diameter		1,262,057	-
	2020 AGIMP – Cheltenham Twp. Small Diameter		1,154,741	-
	2020 AGIMP – Upper Darby Twp. Small Diameter		1,021,405	-
	2019 AGIMP - Bucks/Mont Large Diameter		871,121	-
	2020 AGIMP – Radnor Twp. Small Diameter		838,457	-
	2020 AGIMP – Haverford Twp. Small Diameter		776,304	-
	2020 AGIMP- Bux/Mont Large Diameter		563,337	-
	Kimberly Clark NB C&I		459,866	-
	2020 AGIMP – Misc. Twp. Small Diameter		358,082	-
	Portable LNG Vaporizer		356,692	-
	2019 AGIMP – Upper Darby Twp. Small Diameter		297,243	-
	2019 AGIMP – Abington Twp. Small Diameter		171,151	-
	2020 AGIMP- Upper Darby SEPTA J&B Large Diameter		142,441	-
	2021 AGIMP SD SPRINGFIELD (D)		118,210	-
	OPT Washington		117,573	-
	PECO Gas Service Regulators for GFR and ASE		115,367	-
	2019 AGIMP – Springfield (D) Twp. Small Diameter		90,536	-
	2020-CE-Noble St.		54,110	-
	2019 AGIMP – Tredyffrin Twp. Small Diameter		29,316	-
	OPBS - Olive Street		27,967	-
	RNG Springton Pointe, Newtown Square		268	-
Specific Project Total			**20,005,382**	**89,282,476**
		Gross Plant Additions	**302,087,482**	**332,110,800**
		Calculated Cost of Removal	**(9,964,378)**	**(9,964,378)**
		Plant Additions	**292,123,104**	**322,146,422**

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Response of PECO Energy Company
To Interrogatories of the
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OCA Set XIII

Response Date: 12/14/2020

OCA-XIII-18

According to the Company's response to OCA II-52, there are eight sites that remain active with an overall estimated liability of $21.5 million to remediate. Please provide the estimated remediation cost for each of the remaining sites and the date each site is expected to be completed.

RESPONSE:

Refer to the table below.

Active MGP Sites	**Cost to Remediate***	**Estimated Date of Completion/Comments**
Ardmore (Lancaster Ave)	$3,433,290	2030 based upon future site development and removal action
Bristol	$6,204,445	EOY 2023
Chester Crosby	$43,272	EOY 2021
Coatesville	$3,382,483	2033, based on achieving access in 2030
Darby B	$108,240	EOY 2021
Fort Washington	$54,720	EOY 2021
Langhorne	$4,390,614	2033 based on achieving access by 2030
West Conshohocken	$1,091,290	EOY 2023
Total (active sites)	**$18,708,354**	
Other MGP Costs	**Costs**	**Comments**
18 Closed Sites	$261,776	Costs for annual reporting, etc. through 2026
Contracted MGP General Services	$2,592,204	Programmatic Costs through 2034
Overall Total	**$21,562,334**	

Responsible Witness: Michael J. Trzaska

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set XV

Response Date: 12/17/2020

OCA-XV-12

According to the response to OCA II-2, "[t]he base data for the FPFTY and FTY that was used to develop PECO's capital and operating budgets for the twelve months ending June 30, 2022 and 2021 respectively were prepared in July 2020 and finalized in August 2020." However, according to page 11, lines 3 through 20 of Mr. Stefani's testimony, the budget preparation begins with a planning process that starts in June that reviews and updates the Company's financial Long-Range Plan (LRP). That process is concluded/approved in September, before work on a two-year detailed budget can begin.

a. If work begins on the two-year detailed budget after the LRP process concludes in September, when is the two-year detailed budget completed?

b. Is it true that, based on the foregoing, the budget on which the FPFTY is based is not the corporate budget that was formerly adopted by management for the 12-month period ended June 30, 2022? If no, please explain and provide documentation showing that the data in the FPFTY corresponds to the approved budget data for the 12-month period ending June 30, 2022.

RESPONSE:

a. The two-year detailed, calendar-year budget is completed in January.
b. No. The budget on which the FPFTY is based was approved by PECO's senior management in January 2020. The FPFTY budget was then prepared in July 2020 and finalized in August 2020 for alignment with the fiscal year ending June 30, 2022.

Responsible Witness: Robert Stefani

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Bureau of Investigation and Enforcement
IE Set VIII

Response Date: 12/04/2020

IE-RB-4-D

Reference PECO Exhibit MJT-1, Schedule C-2, p. 16 regarding Additions to Plant. For each plant addition listed, please provide the following:

A. Brief description;

B. Start date;

C. Amount spent to date;

D. Anticipated completion date;

E. Estimation of percent completion.

RESPONSE:

There are several classifications of assets included on Schedule C-2: Baseline, Program, and Specific Projects. Baseline Projects are typical work that is short in duration and is capitalized on a monthly or quarterly basis. Program work are work programs that have a defined period of time but are longer in duration (6 months to 1 year). Once detailed program work is identified, costs are assigned to specific projects. In both Program and Baseline, the costs incurred today are generally not in the FPFTY Capital Additions as these costs would be placed into service in the FTY. The Specific projects have a beginning an end date associated with them.

Refer to Attachment IE-RB-4-D(a) for the project information.

Responsible Witness: Robert Stefani

PECO Energy Company

ATTACHMENT IE-RB-4-D(a)

Project Type	Project Description	Short Description	Additions to Capital per Schedule C-2 for the FPFTY	Start Date	Completion Date	Spend to Date	% of Completion
Baseline	NB Gas GAMs by contractor	NB Gas along the Mains by Contractor (provide Gas to customers that have a main in front of the homes	10,029,684	Various	Various	N/A	N/A
	NB Gas C&I	New Business Commercial and Industrial	8,071,115	Various	Various	N/A	N/A
	NRCG Gas Residential Inside Developments	New Residential Construction	5,750,396	Various	Various	N/A	N/A
	Public Relo GAS Baseline Work PADOT Requ	Public Relocation Baseline Work Pennsylvania Department of Transportation	4,537,663	Various	Various	N/A	N/A
	Plant Improvements - Gas Winter Critical	Additions associated with Gas Winter Critical program	2,741,255	Various	Various	N/A	N/A
	Winter Critical Capacity Upgrades Baseline	Winter Critical Capacity Upgrades Baseline Work	2,625,810	Various	Various	N/A	N/A
	Locate & repair #1 & #2A Leaks - Services	Locate & repair #1 & #2A Leaks - Services Only	2,621,749	Various	Various	N/A	N/A
	Locate & Repair #2B Leaks - Services	Locate & Repair Non Critical Gas Leaks #2B Leaks - Services Only	2,522,690	Various	Various	N/A	N/A
	NB Gas NRCG Approach Mains	NB Gas NRCG Approach Mains (Extension of Gas Facilities to new development	2,003,909	Various	Various	N/A	N/A
	Gas- Service Maintenance	Gas- Service Maintenance	1,970,112	Various	Various	N/A	N/A
	NB Gas Residential	NB Gas Residential (not included in New Residential Construction)	1,888,999	Various	Various	N/A	N/A
	Regulatory (Gas) Plant Additions	Additions associated with Regulatory required spend	1,594,199	Various	Various	N/A	N/A
	Purchase Gas Meters for Residential NB	Purchase Gas Meters for Residential New Business Replacement	1,590,631	Various	Various	N/A	N/A
	Gas- Once-cathodically protected BS Main Re	Gas- Once-cathodically protected Bare Steel Main Replacement Program	1,340,787	Various	Various	N/A	N/A
	Abandonment of Inactive Gas services.	Abandonment of Inactive Gas services.	1,292,689	Various	Various	N/A	N/A
	Regulator Station Upgrades	General Work - Sealing of underground Regulator Station Vaults	846,367	Various	Various	N/A	N/A
	Capital Tools Corrosion/Leak Survey/Regula	Capital Tools Corrosion/Leak Survey/Regulatory Equipment necessary for regulatory required surveys	817,157	Various	Various	N/A	N/A
	PECO Capital Overhead- Gas	The capitalization of Overhead costs	526,098	Various	Various	N/A	N/A
	Purchase Gas Meters for Plant Replacement	Purchase Gas Meters for Plant Replacement	269,815	Various	Various	N/A	N/A
	Replace Nonoperable Valves Identified by In	Replace Nonoperable Valves Identified by Inspection Program	259,129	Various	Various	N/A	N/A
	Gas Cathodic Protection Reg. Work & OIR's	Gas Cathodic Protection Regulatory Work	245,777	Various	Various	N/A	N/A
	Gas Meter & House Regulator Maint.	Gas Meter & House Regulator Maintanance	127,840	Various	Various	N/A	N/A
Baseline Total			**53,673,870**				
Programmatic	Accelerated Mod - Cast Iron	Part of Gas Modernization Program. Accelerate Cast Iron replacement.	70,886,989	Apr-11	Apr-35	N/A	N/A
	Main Replacements - Large Diameter	Large Diameter main replacements	31,614,529	Jan-18	Dec-35	N/A	N/A
	Restoration Blanket for AGIMP	This is the restoration/paving required on any AGIMP construction project that requires a specific ITN.	21,565,364	Apr-11	Apr-35	N/A	N/A
	Replace (Leaking) Bare Steel Mains (Optimai	Replace (Leaking) Bare Steel Mains (Optimain)	20,971,247	Apr-11	Dec-22	N/A	N/A
	Accelerated Mod - Bare Steel Services	Part of Gas Modernization Program. Accelerate Bare Steel Services replacement.	17,579,226	Apr-11	Dec-22	N/A	N/A
	Residential HP Regulator Replacement	HP residential regulators could cause build-up pressures of > 2 psig under failure conditions per ANSI standard B109.4. This is the plan to replace 35k-40k regulators installed after 1998.	7,964,269	Jan-20	Apr-26	N/A	N/A
	NB Neighborhood Gas Program	NB Neighborhood Gas Program	7,502,347	Jul-16	Dec-22	N/A	N/A
	Bare Steel Service Replacement Program	Bare Steel Service Replacement Program- utilizing graphical leak analysis	3,872,808	Jan-04	Dec-22	N/A	N/A
	Replacement Cast Iron Mains	Replacement Cast Iron Mains	3,473,387	Jan-04	Dec-35	N/A	N/A
	FEP - Tier 2 Gas	Facility Enhancement Program - Security Upgrade	1,903,652	Oct-17	Jun-22	N/A	N/A
	Bolt-On Tee Replacements	Bolt-On tees have failed in the industry. PECO used these tees from mid 1990s-2004. The PUC requirement is to remove any bolt-on tees when identified.	1,000,000	Oct-19	Dec-35	N/A	N/A
	Relocate Indoor Gas Meters	Relocate Indoor Gas Meters to Outdoor	820,636	Aug-16	Dec-35	N/A	N/A
Programmatic Total			**189,154,454**				
Specific Project	Natural Gas Reliability	Install 11.5 miles OHP gas main, upgrade LNG plant and construct a new gate station	82,481,428	Oct-19	Jun-23	33,888,385	28%
	FR - Rte 202 - Section 61N	PennDOT relocation project on route 202 in Montgomery County. This is for Section 61N.	3,547,125	Nov-18	Dec-22	4,304,905	22%
	EU Analytics - Advanced Metering Infrastructure (AMI)	AMI will deliver a multi-year use case roadmap to enhance and optimize today's meter analytics while building towards the Utility of the Future.	1,113,070	May-17	Oct-21	1,309,493	12%
	LNG Plant BOC	Install two new boil off compressors in LNG Plant.	807,114	Sep-19	Jun-22	2,052,628	18%
	2020 AGIMP – Abington Twp. Small Diameter	~5.64 miles of cast iron and bare steel pipe will be replaced with plastic or coated steel main which will result in ~5.17 miles of main being retired in 2020.	752,064	Jul-19	Dec-21	2,025,563	50%
	2020 AGIMP – Springfield Twp. Small Diameter	~2.09 miles of cast iron and bare steel pipe will be replaced with plastic or coated steel main which will result in ~1.99 miles of main being retired in 2020.	480,559	Jun-19	Jan-22	452,682	50%
	Oracle Implementation	Oracle Project Implementation	101,116	Jun-17	Jan-21	375,856	15%
Specific Project Total			**89,282,476**				
		FPTY Gross Plant Additions	**332,110,800**				
		Calculated Cost of Removal	**(9,964,378)**				
		FPTY Plant Additions	**322,146,422**				

NOTES

Baseline Costs spend to Date go back many years however the amount included under the heading "Additions to Capital per Schedule C-2 for the FPFTY" would not be spent until the period of July 1, 2021 - June 30, 2022.
Amounts reflected in the column "Additions to Capital per Schedule C-2 for the FPTY" represents Cap Additions for the FPFTY, while the start and completion date is the beginning and ending of the program

a.	**(Dollars in Thousands)**	**Jul 2020 - Jun 2021**
	Labor	
	Base Labor	$ 35,640
	Overtime Wages	$ 6,025
	AA00087 - Salaries and Wages	**$ 41,665**
	Severance	
	Annual Incentive Plan	$ 4,892
	Total	**$ 46,556**

b.	Jan 1 Increase (for Bargaining Unit employees)	2.5% budgeted %
	March 1 Increase (for Management employees)	2.5% budgeted %

c. See item (b)

d. Total annual payroll increases is as follows (does not include impact of AIP):

	($,000)
Projected Payroll	$ 41,665
Total Prior Year Payroll	40,672
Change in Base Payroll	993

e. Total payroll for 12 months

	($,000)
	$ 40,672
Change in average headcount	298
Wage increase	1,017
Overtime	(1,121)
Other	798
Total	$ 993

f. Employee Benefits

	($,000)
Medical	$ 4,021
Dental	250
Other Benefit Plan	147
401K Plan	1,306
ESPP	79
Disability Plan	112
Excess Benefits Saving Plan	7
Worker's Comp	145
Pension	922
OPEB	270
	$ 7,259

g. Support the annualized pension cost figures

(i) State whether these figures include any unfunded pension costs
Explain.

PECO's test year claim is based on expected contributions for 2020 and 2021, which are largely determined by the plans unfunded obligation

PECO and other Exelon subsidiaries account for the participation in Exelon's pension plans by applying multiemployer accounting, as prescribed by authoritative guidance. Employee-related assets and liabilities are allocated to PECO as applicable. The pension obligation is recorded at the Exelon (plan sponsor level) for financial reporting purposes. The costs and contributions attributed to PECO and Exelon's other subsidiaries are based on an annual actuarial valuation that represents the obligation that each subsidiary is required to fund over time.

Exelon's pension plan had an unfunded obligation of $4.3 billion at December 31, 2019, which results in a funded status of approximately 81%. ERISA guidelines (as amended by the Pension Protection Act of 2006) require companies to maintain certain minimum funding thresholds and generally represents the amount by which the plan's funding liability is expected to increase in the upcoming year, plus an amount to "make up" any existing underfunding over a 7-year period.

(ii) Provide latest actuarial study used for determining pension accrual rates.

The Company's most recent pension plan actuarial study is as of December 31, 2019 and is dated January 23, 2020. Refer to Confidential Attachment III-A-21(b) for the sections of the study showing PECO's 2020 and 2021 costs and contributions as of December 31, 2019

h. Prior Year Deferred Compensation Plans (in $000) **$ 72**

Pennsylvania Public Utility Commission
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PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Bureau of Investigation and Enforcement
IE Set II

Response Date: 11/04/2020

IE-RE-8-D

Reference PECO Volume IV, Section 53.53-III-A-21(a) concerning employee salaries, wages, and benefits of the Gas Division, provide the following:

A. Monthly payroll cost by each type and broken down by union and management employees for the 12-month periods ended June 30, 2018, June 30, 2019, HTY 2020, and projected for the FTY 2021, and FPFTY 2022;

B. Dollar amount of capitalized payroll cost included in response to Part A above and the capitalization percentage for the 12-month periods ended June 30, 2018, June 30, 2019, HTY 2020, and projected for the FTY 2021, and FPFTY 2022;

C. Average monthly employee count broken down by union and management for the 12-month periods ended June 30, 2018, June 30, 2019, HTY 2020, and projected for the FTY 2021, and FPFTY 2022;

D. Detailed basis and supporting documentation for allocation of affiliated Company's employee payroll cost in the HTY 2020, FTY 2021, and FPFTY 2022; and

E. Supporting documents (union contracts and/or other support) for annual pay increases for the HTY 2020, FTY 2021, and FPFTY 2022.

RESPONSE:

Refer to Public Attachment IE-RE-8-D(a) which contains the requested information pertaining to the 12-month periods ending respectively, June 30, 2018 June 30, 2019, as well as the HTY, the FTY 2021 and FPFTY 2022. Additionally, Confidential Attachment IE-RE-8-D(a) contains supporting documentation pertinent to annual pay increases of union employees for the HTY 2020, FTY 2021, and FPFTY 2022.

THE CONFIDENTIAL ATTACHMENT IS BEING PROVIDED ONLY SUBJECT TO THE EXECUTION OF A SUITABLE STIPULATED PROTECTIVE AGREEMENT WITH THE RECIPIENT PENDING THE ISSUANCE OF A PROTECTIVE ORDER IN THIS CASE. PECO WILL PROVIDE A STIPULATED PROTECTIVE AGREEMENT DEEMED SUITABLE TO THE COMPANY FOR EXECUTION, WHICH IS SIMILAR TO THE STIPULATED PROTECTIVE AGREEMENT EMPLOYED IN PECO'S PRIOR BASE RATE CASE.

Responsible Witness: Robert Stefani

A & B. PECO payroll costs are not journalized in a manner that delineate between union and management employees. This data limitation does not permit for the provision of payroll cost by union and management employees. Below please find monthly payroll expenses by cost type including the capitalization percentage for the requested 12-month periods.

	Regular							
Month/YR		**Capital**		**Expense**		**Gas Total**	**Capital**	**Expense**
Jul-17	$	1,403,583	$	2,629,836	$	4,033,419	35%	65%
Aug-17	$	1,600,333	$	3,073,033	$	4,673,366	34%	66%
Sep-17	$	1,692,720	$	2,346,104	$	4,038,824	42%	58%
Oct-17	$	1,820,859	$	2,701,032	$	4,521,892	40%	60%
Nov-17	$	1,594,116	$	2,541,741	$	4,135,858	39%	61%
Dec-17	$	1,209,146	$	2,139,140	$	3,348,287	36%	64%
Jan-18	$	1,305,513	$	3,304,969	$	4,610,483	28%	72%
Feb-18	$	1,480,072	$	2,705,149	$	4,185,221	35%	65%
Mar-18	$	1,430,060	$	2,523,030	$	3,953,090	36%	64%
Apr-18	$	1,771,403	$	2,769,245	$	4,540,649	39%	61%
May-18	$	2,000,032	$	2,680,042	$	4,680,074	43%	57%
Jun-18	$	1,903,165	$	2,336,859	$	4,240,024	45%	55%
Jul-18	$	1,838,035	$	2,531,055	$	4,369,089	42%	58%
Aug-18	$	2,004,968	$	2,669,750	$	4,674,718	43%	57%
Sep-18	$	1,800,620	$	2,301,064	$	4,101,684	44%	56%
Oct-18	$	2,110,589	$	2,993,401	$	5,103,989	41%	59%
Nov-18	$	1,817,390	$	2,529,802	$	4,347,192	42%	58%
Dec-18	$	1,648,780	$	2,576,496	$	4,225,276	39%	61%
Jan-19	$	1,621,361	$	3,070,359	$	4,691,720	35%	65%
Feb-19	$	1,586,399	$	2,916,771	$	4,503,170	35%	65%
Mar-19	$	1,759,103	$	3,087,220	$	4,846,323	36%	64%
Apr-19	$	1,912,170	$	2,923,517	$	4,835,688	40%	60%
May-19	$	1,885,444	$	2,759,307	$	4,644,751	41%	59%
Jun-19	$	1,788,658	$	2,578,655	$	4,367,313	41%	59%
Jul-19	$	1,789,118	$	2,350,187	$	4,139,306	43%	57%
Aug-19	$	2,009,256	$	2,350,140	$	4,359,396	46%	54%
Sep-19	$	2,079,727	$	2,429,587	$	4,509,314	46%	54%
Oct-19	$	2,491,570	$	2,879,481	$	5,371,051	46%	54%
Nov-19	$	2,081,532	$	2,224,166	$	4,305,698	48%	52%
Dec-19	$	1,777,725	$	2,564,224	$	4,341,949	41%	59%
Jan-20	$	1,814,398	$	2,993,684	$	4,808,082	38%	62%
Feb-20	$	1,893,876	$	2,962,051	$	4,855,927	39%	61%
Mar-20	$	1,968,230	$	3,457,039	$	5,425,269	36%	64%
Apr-20	$	1,940,778	$	3,408,217	$	5,348,995	36%	64%
May-20	$	1,728,641	$	3,111,937	$	4,840,578	36%	64%
Jun-20	$	2,088,206	$	2,795,589	$	4,883,795	43%	57%
Jul-20	$	1,944,451	$	2,983,073	$	4,927,524	39%	61%
Aug-20	$	1,825,908	$	3,116,813	$	4,942,721	37%	63%

Sep-20	$	1,875,018	$	3,275,594	$	5,150,612	36%	64%
Oct-20	$	2,032,954	$	3,506,377	$	5,539,331	37%	63%
Nov-20	$	1,743,096	$	3,033,677	$	4,776,773	36%	64%
Dec-20	$	1,555,305	$	3,014,112	$	4,569,417	34%	66%
Jan-21	$	1,711,151	$	3,063,452	$	4,774,603	36%	64%
Feb-21	$	1,394,119	$	2,788,055	$	4,182,175	33%	67%
Mar-21	$	1,655,878	$	2,949,690	$	4,605,568	36%	64%
Apr-21	$	1,994,265	$	2,647,550	$	4,641,815	43%	57%
May-21	$	1,865,742	$	2,516,320	$	4,382,063	43%	57%
Jun-21	$	2,054,723	$	2,745,273	$	4,799,995	43%	57%
Jul-21	$	1,920,782	$	2,702,540	$	4,623,321	42%	58%
Aug-21	$	1,857,881	$	2,856,677	$	4,714,558	39%	61%
Sep-21	$	1,864,180	$	2,998,991	$	4,863,172	38%	62%
Oct-21	$	1,612,404	$	2,999,863	$	4,612,267	35%	65%
Nov-21	$	1,260,247	$	3,010,822	$	4,271,069	30%	70%
Dec-21	$	1,461,911	$	3,668,487	$	5,130,398	28%	72%
Jan-22	$	1,712,756	$	3,145,564	$	4,858,320	35%	65%
Feb-22	$	1,395,427	$	2,862,785	$	4,258,212	33%	67%
Mar-22	$	1,657,432	$	3,028,752	$	4,686,184	35%	65%
Apr-22	$	1,996,136	$	2,718,514	$	4,714,649	42%	58%
May-22	$	1,867,492	$	2,583,767	$	4,451,259	42%	58%
Jun-22	$	2,056,650	$	2,818,856	$	4,875,506	42%	58%

C.

	Regular		
Month/YR	**Gas Union**	**Gas Non-Union**	**Gas Total**
Jul-17	312	258	570
Aug-17	311	259	570
Sep-17	312	261	573
Oct-17	314	262	576
Nov-17	313	261	573
Dec-17	313	261	573
Jan-18	302	254	556
Feb-18	315	254	569
Mar-18	312	252	564
Apr-18	309	252	561
May-18	306	252	558
Jun-18	305	253	558
Jul-18	301	256	557
Aug-18	300	263	563
Sep-18	301	263	564
Oct-18	318	263	581
Nov-18	322	263	585

Dec-18	321	262	584
Jan-19	324	276	600
Feb-19	314	273	587
Mar-19	312	273	585
Apr-19	309	275	584
May-19	320	275	595
Jun-19	314	278	592
Jul-19	312	274	585
Aug-19	309	272	582
Sep-19	330	274	604
Oct-19	329	277	606
Nov-19	328	277	605
Dec-19	325	276	601
Jan-20	324	275	599
Feb-20	326	279	605
Mar-20	320	283	603
Apr-20	320	283	603
May-20	314	285	599
Jun-20	314	288	602
Jul-20	314	289	603
Aug-20	315	288	602
Sep-20	315	290	604
Oct-20	333	304	637
Nov-20	332	303	635
Dec-20	332	303	635
Jan-21	333	304	637
Feb-21	332	304	636
Mar-21	332	304	636
Apr-21	331	304	634
May-21	330	303	633
Jun-21	331	305	635
Jul-21	330	305	635
Aug-21	329	304	633
Sep-21	329	304	633
Oct-21	334	307	641
Nov-21	332	306	638
Dec-21	332	306	638
Jan-22	333	306	639
Feb-22	333	306	639
Mar-22	333	306	639
Apr-22	333	306	639
May-22	333	306	639
Jun-22	333	306	639

D. Please refer to PECO Statement No. 2: Direct Testimony of Robert J. Stefani, Section VI – Affiliated Services.

E. Annual pay increases for Management employees are budgeted for at a 2.5% rate. Please refer to Confidential Attachment IE-RE-8-D(a) for information supporting wage increases of union employees.

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Response of PECO Energy Company
To Interrogatories of the
Bureau of Investigation and Enforcement
IE Set II

Response Date: 11/04/2020

IE-RE-15-D

Reference PECO Volume IV, Section 53.53-III-A-28(a) concerning regulatory commission (PUC assessment) and miscellaneous general expenses, provide the following:

A. Similar schedule adding a column for the 12-months ended June 30, 2018;

B. Detailed calculation and supporting documentation for projecting increases in regulatory commission expense from the HTY 2020 amount of $1,735,000 to $2,111,000 in the FTY 2021, and from $2,111,000 in the FTY 2021 to $2,197,000 in the FPFTY; and

C. Detailed basis and supporting documentation for projected increase in miscellaneous general expenses from the FTY 2021 claim of $511,000 to $536,000 in the FPFTY.

RESPONSE:

A) Refer to Attachment IE-RE-15-D(a).

B) The projected increases in regulatory commission expense are generally due to inflation adjustments.

C) The projected increase in miscellaneous general expenses is generally due to inflation adjustments.

Responsible Witness: Robert J. Stefani

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Response of PECO Energy Company
To Interrogatories of the
Bureau of Investigation and Enforcement
IE Set II

Response Date: 11/04/2020

IE-RE-16-D

Reference PECO Volume IV, Section 53.53-III-A-28(a) concerning outside services expense, provide the following:

A. Similar schedule adding a column for the 12-months ended June 30, 2018;

B. Breakdown by vendor for each category of outside services (various outside services, contracting professional, and contracting services);

C. Detailed basis and supporting documentation for the various outside services expense increase from the HTY 2020 actual amount of $11,555,000 to $14,622,000 in the FTY 2021 and from the FTY 2021 claim of $14,622,000 to $15,290,000 in the FPFTY;

D. Detailed basis and supporting documentation for contracting professional expense increase from the HTY 2020 actual amount of $715,000 to $905,000 in the FTY 2021 and from the FTY claim of $905,000 to $946,000 in the FPFTY; and

E. Detailed basis and supporting documentation for contracting services expense increase from the HTY 2020 actual amount of $548,000 to $694,000 in the FTY 2021 and from the FTY claim of $694,000 to $726,000 in the FPFTY.

RESPONSE:

A) Refer to Attachment IE-RE-16-D(a).

B) Refer to IE-RE-33-D.

C) The increases in various outside services expense are generally due to inflation adjustments. PECO does not budget by FERC account. For further detail pertaining to the FPFTY and FTY budgets by FERC account, refer to Exhibit MJT-1 and MJT-2, respectively.

D) The increases in contracting professional expense are generally due to inflation adjustments. PECO does not budget by FERC account. For further detail pertaining to the FPFTY and FTY budgets by FERC account, refer to Exhibit MJT-1 and MJT-2, respectively.

E) The increases in contracting services expense are generally due to inflation adjustments. PECO does not budget by FERC account. For further detail pertaining to the FPFTY and FTY budgets by FERC account, refer to Exhibit MJT-1 and MJT-2, respectively.

Responsible Witness: Robert J. Stefani

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Bureau of Investigation and Enforcement
IE Set II

Response Date: 11/04/2020

IE-RE-45-D

Reference PECO Volume II, Exhibits MJT-1, Schedule D-13 concerning the recovery of manufacturing gas plant (MGP) sites remediation cost of $804,000 in the FPFTY, provide the following:

A. Detailed calculation of the regulatory asset account of $7,237,000 since the last rate case of 2010;

B. Actual expenditure incurred by year through the 12-month period ended June 30, 2020 for remediation of MGP sites since the last rate case in 2010;

C. Projected expenditure in the FTY 2021 and FPFTY 2022;

D. Copy of Commission approval to establish a regulatory asset account for recovery of MGP remediation costs;

E. Number of MGP sites remediated/closed and pending;

F. Copy of PA DEP permit/consent agreement for MGP sites remediation; and

G. Basis for applying a nine-year amortization period to recover the unrecovered MGP remediation cost in future rates.

RESPONSE:

A. Refer to Attachment IE-RE-45-D(a) for a detailed calculation.

B. Actual expenditures by year through the 12-month period ended June 30, 2020 for remediation of MGP sites since the last rate case in 2010 are as follows:

12 Month Period Ended June 30	MGP Spend
2011	$5,888,299
2012	$5,659,477
2013	$5,908,050
2014	$5,968,236
2015	$6,301,466
2016	$5,200,085
2017	$5,090,973
2018	$4,379409
2019	$7,692278
2020*	$642,191
* Through June 2020	

C. Projected expenditure in the FTY and FPFTY are as follows:
- FTY - $4,866,599
- FPFTY - $3,191,091

D. The recovery mechanism for MGP remediation costs was approved by the PUC in PECO's 2008 base rate case and provides a valid basis for booking as a regulatory asset MGP costs in excess of the amount included in PECO's current base rates. Refer to Attachment IE-RE-45-D(b) for a copy of the Settlement of PECO's 2008 Gas Rate Case and Attachment IE-RE-45-D(c) for the Commission Order approving the Settlement.

E. To date, a total of 18 sites have been remediated/closed and 8 sites are pending.

F. Not Applicable, PECO does not have a consent agreement with the PADEP for any of our MGP sites. PECO has entered its MGP sites into the voluntary Pennsylvania Department of Environmental Protection Act 2 Program.

G. The nine-year amortization period is based on recovery of the unrecovered MGP remediation costs over three future rate cases as PECO expects to file a base rate case every three years.

Responsible Witness: Michael J. Trzaska

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Bureau of Investigation and Enforcement
IE Set II

Response Date: 11/04/2020

IE-RE-47-D

Reference PECO Volume II, Exhibits MJT-1, Schedule D-15 concerning the parent company allocated O&M cost of $370,000 in the FPFTY to achieve merger saving, provide the following:

A. Breakdown of merger costs allocated to the Gas Division by year 2016 ($601,000), 2017 ($430,000), and 2018 ($80,000) and a detailed basis of allocation;

B. Provide the docket number indicating Commission approval to defer recovery of allocated one-time merger cost aggregating to $1,111,000; and

C. Basis for applying a three-year amortization period to recover the allocated merger costs.

RESPONSE:

A. Refer to the table below for a breakdown of merger costs allocated to the Gas Division:

FERC	($ thousands) 2016	2017	2018
923000: Outside Services Employed	$ 594	$ 430	$ 80
926000: Employee Pensions and Benefits	3	0	0
408100: Taxes Other Than Income Taxes	1	0	0
426400: Expenditures for Certain Civic, Political and Related Activities	0	0	0
426500: Other Deductions	4	0	0
Total	$ 601	$ 430	$ 80

B. PECO Energy did not request permission to "defer" for accounting purposes its share of the costs to achieve the merger savings that it is realizing, nor is it PECO Energy's position that permission to record an accounting deferral is necessary to make or substantiate its claim. Because the costs to achieve merger savings were incurred before the merger-related savings could be fully realized and because a full annual level of merger savings was reflected in developing the Company's revenue requirement in this case, it is proper to reflect, by amortization over a reasonable prospective period, the costs-to-achieve associated with the merger savings so that only an appropriate level of net merger savings is flowed-through to customers. Otherwise, customers would receive merger savings, which substantially exceed the costs to achieve the merger, but not bear any of the costs that were incurred to obtain those savings.

C. While the Company intends to carefully monitor its performance to determine when it will need to file another gas base rate case, PECO anticipates that base rate filings for its gas operations will be required every three years.

Responsible Witness: Michael J. Trzaska

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

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Response of PECO Energy Company
To Interrogatories of the
Bureau of Investigation and Enforcement
IE Set II

Response Date: 11/04/2020

IE-RE-50-D

Reference PECO Volume II, Exhibits MJT-1, Schedule D-16 concerning taxes other than income tax summary, provide the following:

A. Dollar amount of real estate tax incurred with breakdown and documentation to support real estate tax for the 12-month periods ended June 30, 2018; June 30, 2019; and June 30, 2020;

B. Dollar amount and detailed basis, calculation, and breakdown to support the FTY 2021 real estate tax claim; and

C. Detailed basis, calculation and breakdown to support the FPFTY 2022 real estate tax claim $1,568,000.

RESPONSE:

A. Refer to the response to IE-RE-19-D for a schedule showing real estate tax for the 12-month periods ended June 30, 2018, June 30, 2019, and June 30, 2020.

B. FTY real estate tax is based on the most recent property tax bills received including an inflation rate of 2.5%.

C. FPFTY real estate tax is based on the FTY real estate tax including a 2.5% inflation rate.

Responsible Witness: Michael J. Trzaska

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Bureau of Investigation and Enforcement
IE Set VII

Response Date: 11/18/2020

IE-RE-65-D

Reference PECO Volume II, Exhibits MJT-2 and MJT-3, and Schedule D-4 concerning the total manufactured gas production expense. Explain in detail the basis for an increase in the FTY pre-adjustment claim of $278,000 compared to the HTY pre-adjustment expense of $234,000.

RESPONSE:

The pre-adjustment expenses by FERC account for the FTY and FPFTY were determined using PECO's budget for the twelve-month periods ending June 30, 2021 and June 30, 2022 as a starting point. Budgeted expenses, which were prepared based on business activities and related cost elements such as payroll, employee benefits, and outside contracting costs, were distributed to FERC accounts based upon the actual distribution of costs experienced by the Company during calendar year-ended December 31, 2019.

Please refer to Attachment IE-RE-65-D(a) for expense variances based on business activities between HTY and FTY, and between FTY and FPFTY.

Responsible Witness: Michael J. Trzaska

PECO Energy Company
Gas Business
Operating and Maintenance Expenses
(In Thousands)

	HTY - Actual * Jul 2019 - Jun 2020	FTY - Budget Jul 2020 - Jun 2021	FPFTY - Budget Jul 2021 - Jun 2022
Bad Debt	$ 2,766	$ 2,249	$ 2,718
Base Payroll	34,210	36,180	35,941
BSC Contracting	20,787	21,069	22,142
Contracting/Materials	29,552	44,651	42,955
Incentive	4,935	4,892	5,052
Overtime	7,157	6,025	5,548
Pensions & Benefits	6,987	7,343	$ 7,676
Transportation	4,490	4,651	4,822
Travel Meals & Entertainment	680	845	1,032
Other Net	9,374	8,778	9,107
Total	**$ 120,938**	**$ 136,682**	**$ 136,994**

* Note: Results are GAAP based to align budget values

Bad Debt

HTY to FTY: The decrease from HTY is due to higher than expected Bad Debt expense in the HTY driven by the extension of the customer termination moratorium period related to the COVID-19 pandemic.

FTY to FPFTY: The increase from FTY is primarily due to higher forecasted revenue billings.

Contracting/Materials

HTY to FTY: The increase from HTY is due to lower than expected spend in the HTY driven by the impact of COVID-19 pandemic related restrictions.

FTY to FPFTY: No significant variances.

Travel Meals & Entertainment

HTY to FTY: The increase from HTY is due to lower than expected spend in the HTY driven by the impact of COVID-19 pandemic related restrictions.

FTY to FPFTY: The increase from FTY is primarily due to the inflation rate.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018929
	:	
PECO Energy Company – Gas Division	:	

VERIFICATION

I, Lafayette K. Morgan, hereby state that the facts set forth in my Direct Testimony, OCA Statement 2, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: December 22, 2020
*300674

Signature: Lafayette Morgan Jr.
Lafayette K. Morgan

Consultant Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-3575

OCA Statement No. 3

R-2020-3018929
2/17/21 JK

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**DOCKET NO. R-2020-3018929**
	:	
PECO ENERGY COMPANY – GAS DIVISION	:	

DIRECT TESTIMONY OF

KEVIN W. O'DONNELL, CFA

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

December 22, 2020

Table of Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Kevin W. O'Donnell. I am President of Nova Energy Consultants, Inc. My business address is 1350 SE Maynard Rd., Suite 101, Cary, North Carolina 27511.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate (*i.e.*, "OCA"). The OCA represents consumers before the Pennsylvania Public Utility Commission (*i.e.*, "the Commission").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND RELEVANT EMPLOYMENT EXPERIENCE.

A. I have a Bachelor of Science in Civil Engineering from North Carolina State University and a Master of Business Administration from Florida State University. I earned the designation of Chartered Financial Analyst (*i.e.*, "CFA") in 1988. I have worked in utility regulation since September 1984, when I joined the Public Staff of the North Carolina Utilities Commission (*i.e.*, "NCUC"). I left the NCUC Public Staff in 1991 and have worked continuously in utility consulting since that time, first with Booth & Associates, Inc. (until 1994), then as Director of Retail

Rates for the North Carolina Electric Membership Corporation (1994-1995), and since then in my own consulting firm.

I have been accepted as an expert witness on rate of return, cost of capital, capital structure, cost of service, rate design, and other regulatory issues in general rate cases, fuel cost proceedings, and other proceedings before the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Wisconsin Public Service Commission, the Virginia State Commerce Commission, the Minnesota Public Service Commission, the New Jersey Board of Public Utilities, the Colorado Public Utilities Commission, the District of Columbia Public Service Commission, and the Florida Public Service Commission. In 1996, I testified before the U.S. House of Representatives' Committee on Commerce and Subcommittee on Energy and Power, concerning competition within the electric utility industry. Additional details regarding my education and work experience are set forth in **Appendix A** to my answering testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to present my findings and recommendations to the Commission as to the proper rate of return to allow PECO Energy Company – Gas Division (*i.e.*, "PECO", "PECO Gas" or "the Company") in the current proceeding.

Q. WHAT RATE OF RETURN IS PECO REQUESTING AS PART OF THIS PROCEEDING?

A. According to the testimony of PECO's Witness Paul R. Moul, PECO is seeking an overall rate of return of 7.70% based on the capital structure and cost rates as set forth in **Table 1** below.

Table 1: PECO's Requested Cost of Capital[1]

Component	Ratio (%)	Cost Rate (%)	Weighted Cost Rate (%)
Long-Term Debt	46.62%	3.97%	1.85%
Common Equity	53.38%	10.95%	5.85%
Total Capitalization	**100.00%**		**7.70%**

Q. DO YOU AGREE WITH PECO'S RATE OF RETURN REQUEST?

A. No. I disagree with PECO's requested capital structure, cost of debt, and return on equity.

Q. PLEASE SUMMARIZE YOUR PRIMARY RECOMMENDATIONS IN THIS CASE.

A. My recommendations in this case are as follows:

- I first want to note that I concur with the OCA's primary position as presented by OCA Witness Scott Rubin.[2] Due to the COVID-19 pandemic

[1] Witness Moul Direct Testimony, page 2: line 2.
[2] Witness Rubin Direct Testimony, page 3, lines 16 – 21.

that PECO's customer base is still dealing with, it is not just or reasonable for PECO to impose a rate increase on its customers at this time;

- However, should the Commission proceed to review the PECO base rate filing on a more standard ratemaking basis, I note that the proper return on equity on which to set rates for PECO in this proceeding in a business-as-usual environment should be 8.75%;
- The proper capital structure to use in this proceeding is 50.00% common equity and 50.00% long-term debt;
- The proper embedded cost of debt to use in this proceeding is PECO's future cost of debt of 3.84%[3] as of June 30, 2022;
- My recommended capital structure and ROE is shown below within **Table 2** as based upon the results and data shown within **Exhibit KWO-1**:

Table 2: OCA Recommended Overall Rate of Return

Component	Ratio (%)	Cost Rate (%)	Weighted Cost
Debt	50.00%	3.84%	1.92%
Common Equity	50.00%	8.75%	4.38%
Total Capitalization	**100.00%**		**6.30%**

- The return on equity recommended by Witness Moul for PECO of 10.95% is excessive, unreasonable, and not indicative of current market conditions; and

[3] Witness Moul Direct Testimony, page 22: line 14.

- The 25-basis point adder for “exemplary management performance” as posited by Witnesses Moul and Bradley is neither supported nor warranted, especially in light of the economic crisis tied to the COVID-19 pandemic.

II. CURRENT STATE OF THE FINANCIAL MARKETS

Q. PLEASE DESCRIBE THE CORPORATE STRUCTURE OF PECO GAS.

A. PECO Energy is comprised of a Gas Division and Electric Division. Accordingly, PECO Energy is owned by the overall parent holding company, Exelon Corporation (*i.e.*, "Exelon"). Exelon is therefore the entity that raises the capital that is the basis of the PECO Energy – Gas Division cost of capital request.

Q. HOW HAS THE DEBT MARKET FOR PECO ENERGY CHANGED SINCE THE COMPANY'S LATEST RATE CASE?

A. PECO Energy – Gas Division's last rate case was under R-2010-2161592. In the Company's 2010 rate case, a ROE of 11.75% was requested, along with a common equity to total capital structure of 53.18%. That rate case was ultimately settled and approved by the Commission on December 16, 2010.[4] PECO Energy – Electric Division's most recent rate case was under Docket No. R-2018-3000164. That rate filing by the Company's electric utility affiliate was made on March 29, 2018, included a 10.95% ROE request and was partially settled and approved by the Commission on December 20, 2018.[5]

In **Chart 1** below, I have provided the change in the 30-year US Treasury bonds since the latest PECO Energy rate case (*i.e.*, December 20, 2018 – December 11, 2020). However, over the past year, long-term interest rates have fallen. On

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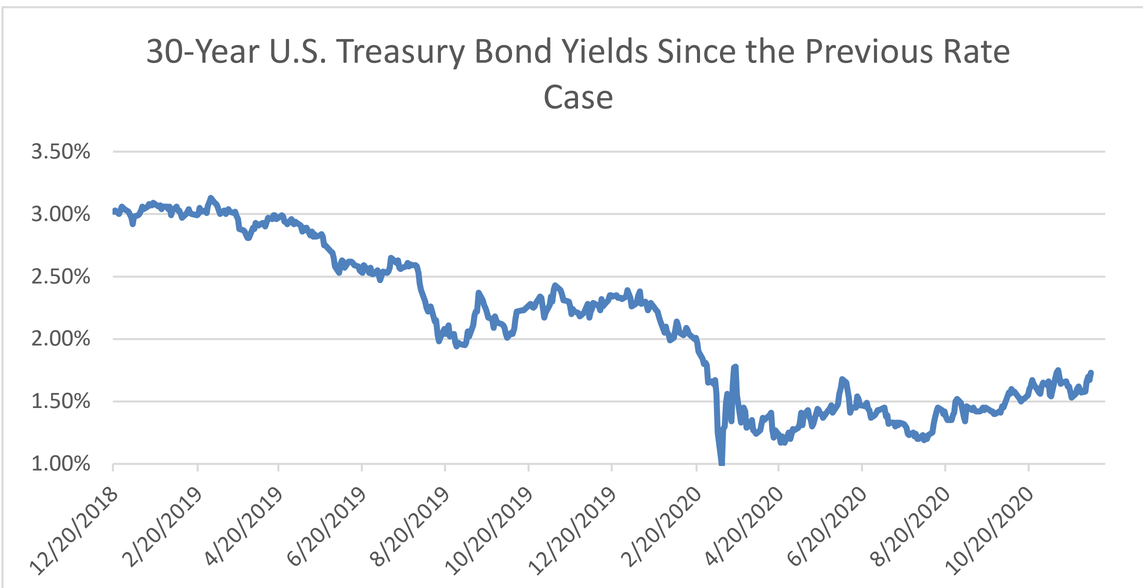
[4] S&P Global Rate Case History (Past Rate Cases); Years: All; Service Type: All; Company List: PECO Energy Co.; States: Pennsylvania; Date Accessed: October 19, 2020. The Settlement resolved all issues, but one issue regarding cost allocation, which is not materially relevant for the purposes of this testimony.

[5] *Id.*

December 11, 2019, the yield on 30-year US Treasury bonds was 2.23% and as of December 11, 2020, the yield on 30-year US Treasury bonds was 1.63%, which equates to a decrease of 60-basis points in the yield on 30-year US Treasury bonds. The maximum value over this one-year period was 2.39%, the average value was 1.59%, and the minimum value was 0.99%. Refer to **Chart 1** below for further details on the yield on 30-year US Treasury Bonds subsequent to the previous rate case.

Chart 1: Yield on 30-Year US Treasury Bonds



Source: *Treasury.gov: Date Accessed December 14, 2020.*[6]

Q. HOW HAS THE FEDERAL RESERVE CHANGED THE FEDERAL FUNDS RATE DURING THE LAST 18 MONTHS?

[6] https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

A. On September 19, 2019, the Federal Reserve decreased the Federal Funds target range to 1.75% from 2.0%.[7] On October 30, 2019, the Federal Reserve lowered the target federal funds rate to 1.5% from 1.75%.[8] Subsequently, in its mid-December meeting, the Federal Reserve chose not to change interest rates.[9] Then, on March 3, 2020, the Federal Reserve decreased the Federal Funds rates 50-basis points to a targeted range of between 1% and 1.25% in response to recent market conditions.[10] Finally, on March 15, 2020 in response to the COVID-19 outbreak and the disruptions to economic activity in this country across the globe, the Federal Reserve reduced the Federal Funds rate to .25%.[11]

The first few items noted in the above paragraph that occurred during 2019 were the result of the Federal Reserve perception that the economy was in an inflationary state and attempting to adjust the Federal Funds Rate accordingly. However, the sharp decline in the Federal Funds Rate that occurred during March 2020 was the result of the Federal Reserve's reaction to the COVID-19 pandemic. In this circumstance, due to the drastic shift in the country's economic outlook, many individuals were looking for relative safe harbors for which to invest their money with the turbulence felt in the stock markets. Accordingly, prices for bonds

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[7] *See* Board of Governors of the Federal Reserve System, *Federal Reserve Issues FOMC Statement* (Sept. 18, 2019), available at: https://www.federalreserve.gov/newsevents/pressreleases/monetary20190918a.htm.

[8] *See* Board of Governors of the Federal Reserve System, *Federal Reserve Issues FOMC Statement* (Oct. 30, 2019), available at: https://www.federalreserve.gov/newsevents/pressreleases/monetary20191030a.htm.

[9] *See* Board of Governors of the Federal Reserve System, *Federal Reserve Issues FOMC Statement* (Dec. 11, 2019), available at: https://www.federalreserve.gov/newsevents/pressreleases/monetary20191211a.htm.

[10] https://www.cnbc.com/2020/03/03/heres-what-this-surprise-fed-rate-cut-means-for-you.html

[11] *See* Board of Governors of the Federal Reserve System, *Federal Reserve Issues FOMC Statement* (Mar. 15, 2020), available at: https://www.federalreserve.gov/newsevents/pressreleases/monetary20200315a.htm

were bid up, and the long-term yields and interest rates have also decreased as exhibited above in **Chart 1**.

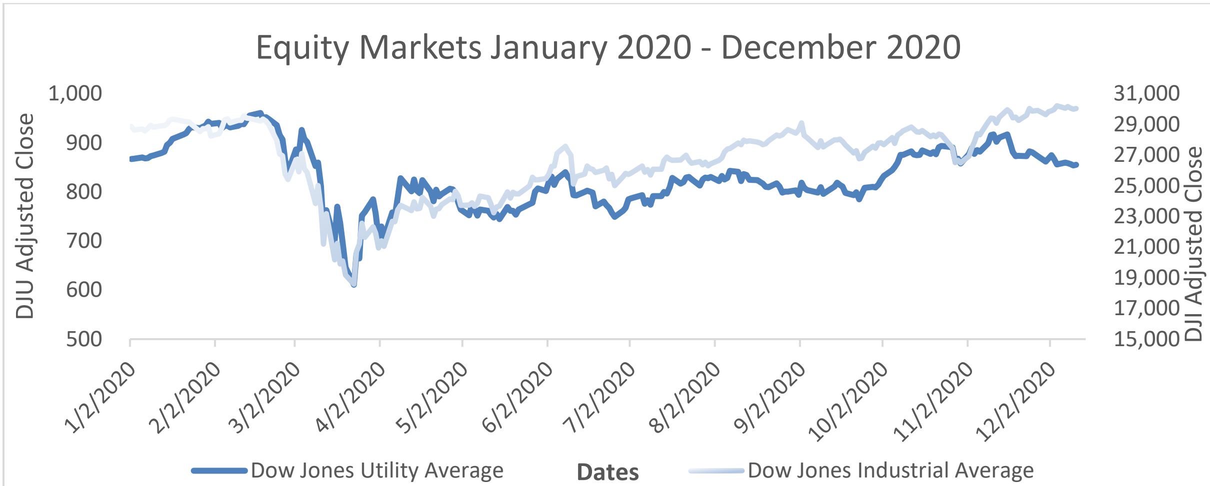
Q. DOES THIS MEAN THAT THE COST OF CAPITAL HAS DECREASED FOR COMPANIES LIKE PECO?

A. Yes. The Federal Funds Rate represents the interest rate at which banks borrow short-term money. The decrease in the Federal Funds Rate contributed to the sharp decline as seen within the yield on 30-year US Treasury rates as shown in **Chart 1** above.

Q. HOW HAS THE STOCK MARKET FOR UTILITIES CHANGED OVER THE PAST YEAR?

A. As shown below in **Chart 2**, which is a double y-axis graph, the Dow Jones Utility Average (*i.e.*, "DJUA") has fallen approximately 1.35% since the start of 2020 (*i.e.*, 1/2/2020 – 12/11/2020), as compared to the Dow Jones Industrial Average (*i.e.*, "DJIA") increase of 4.08% over the same period.

Chart 2: DJIA to DJUA Comparison



***Source**: Yahoo Finance Date Accessed: December 14, 2020*[12]

Although the DJIA has increased at a greater percentage than that of the DJUA over the course of the year through December 11, 2020, the fluctuation in the DJIA throughout 2020 since the beginning of the COVID-19 pandemic in March 2020 has been much more dramatic than that of the DJUA. Refer to **Table 3** below for reference.

[12] https://finance.yahoo.com/quote/%5EDJU/components/ and https://finance.yahoo.com/quote/%5EDJI/history

Table 3: DJUA – DJIA Annual Fluctuation Comparison[13]

Date Range	DJUA Fluctuation	DJIA Fluctuation
1/2/2020 – 3/31/2020	(12.77%)	(24.08%)
1/2/2020 – 4/30/2020	(10.21%)	(15.67%)
1/2/2020 – 5/29/2020	(6.91%)	(12.07%)
1/2/2020 – 6/30/2020	(11.46%)	(10.59%)
1/2/2020 – 7/31/2020	(4.16%)	(8.45%)
1/2/2020 – 8/31/2020	(7.34%)	(1.52%)
1/2/2020 – 9/30/2020	(6.01%)	(3.77%)
1/2/2020 – 10/30/2020	(1.04%)	(8.20%)
1/2/2020 – 11/30/2020	(0.59%)	2.67%
1/2/2020 – 12/11/2020	(1.35%)	4.08%
Max	(0.59%)	4.08%
Min	(12.77%)	(24.08%)
Range	**(12.18%)**	**(28.16%)**

As shown in the table above, over the course of the year, the DJUA has been more stable in comparison to the DJIA (*i.e.*, a max to min range variance of 12.18% for the DJUA versus a 28.16% variance for the DJIA). This is particularly noteworthy in a year such as 2020 when the COVID-19 pandemic has caused extreme fluctuation and variability within the financial markets. Although the DJUA has

[13] *Id.*

fluctuated as well, its fluctuation pales in comparison to the type of month over month change seen within the DJIA. This relative comparison between the equity price for utilities versus that of industrials can be attributed to the fact that utilities are needed to provide essential services, even during a year such as 2020 when a large swath of the economy has been shut down due to the COVID-19.

Additionally, on April 29, 2020, the S&P Global Market Intelligence published an article entitled "*Utility sector 'far and away' least impacted by EPS estimate cuts*."[14] Note that the date that this article was published was when markets were at their most volatile early on during the COVID-19 pandemic. The article provided the following observation:

> *The S&P 500 utility sector has "far and away" experienced the least impact from earnings revisions since Feb. 28, the corporate bond research firm found. Despite market turmoil and the ongoing economic downturn, analysts have only cut earnings per share expectations for stocks in the utility sector by an average 1% for 2020 and 2021, according to CreditSights.*
>
> *By comparison, consumer staples, the next least-impacted sector, saw an average 5% decrease to EPS estimates for both years. Technology followed with a 9% estimate cut for 2020 and 2021.*
>
> *CreditSights pulled the data to measure the consensus view that utilities provide a safe harbor to investors. "Water is wet, the sun will rise in the east and U.S. utilities are a defensive sector, but how defensive? Very defensive," CreditSights analysts Andrew DeVries and Nick Moglia wrote in an April 29 research note.*[15]

Q. WHY HAVE UTILITY STOCKS PERFORMED RELATIVELY BETTER THAN OTHER INVESTMENT SECTORS?

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[14] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/utility-sector-far-and-away-least-impacted-by-eps-estimate-cuts-58358458.
[15] *Id.*

A. Utilities have always been considered a safe harbor for investors during market turbulence or uncertainty. The COVID-19 pandemic is no different. The ability for utilities to recover uncollectible expenses typically ranging from small usage customers to demand ratchets for larger customers all combine to provide a safety net for utilities that simply do not exist in the larger, industrial business world.

Economic activity plummeted subsequent to the outbreak of COVID-19 and the accompanying stay-at-home orders. Prior to the COVID-19 pandemic, during the fourth quarter of 2019, the United States' gross domestic product (*i.e.*, "GDP") increased at an annual rate of 2.1%.[16] However, for comparison purposes, in response to the COVID-19 pandemic, the United States' GDP decreased at an annual rate of 4.8%[17] in the first quarter of 2020 annualized quarter-over-quarter and then decreased at a 32.9%[18] rate in the second quarter of 2020 annualized quarter-over-quarter. During the third quarter of 2020, the United States' GDP rebounded to a 33.1%[19] rise annualized quarter-over-quarter, with continued economic recovery expected to maintain at a more moderate pace through the conclusion of the fourth quarter of 2020.

While utilities might look at such a scenario that occurred during the first half of 2020 and request higher ROE's from the associated regulatory commissions

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[16] https://www.bea.gov/news/2020/gross-domestic-product-fourth-quarter-and-year-2019-advance-estimate.

[17] https://finance.yahoo.com/news/gdp-1q-2020-us-economic-activity-COVID-19-pandemic-155756514.html.

[18] https://finance.yahoo.com/news/q2-gdp-us-economy-coronavirus-pandemic-consumer-171558880.html

[19] https://finance.yahoo.com/video/u-q3-gdp-grew-33-200116075.html#:~:text=According%20to%20the%20Commerce%20Department,Final%20Round%20panel%20to%20discuss.

in an effort to provide a greater return to investors and to combat potential credit downgrades, this type of thinking does not recognize the position of ratepayers who must continue to make non-discretionary purchases, such as gas and electricity from the monopoly utility, regardless of the impact of the COVID-19. In order to achieve that higher ROE for the utility, rates for consumers would need to be increased to a sufficient level to earn the authorized ROE.

Many consumers at the residential, commercial, and industrial levels are already struggling to pay their bills, unemployment levels have spiked during 2020 and remain higher than average into the second half of the year, and various businesses have been shut down for extended periods of time. As such, a utility seeking to raise rates on customers would only exacerbate adverse financial circumstances. Additionally, increased ROE requests from the utilities on the basis that the utilities should be compensated for prolonged struggles due to the COVID-19 pandemic makes even less sense when one considers the rebound and growth seen in the overall market as exhibited by the growth rate seen in the third and fourth quarters of 2020.

Q. WHAT RETURN ON EQUITY (ROE) DID THE COMPANY SEEK IN ITS PREVIOUS BASE RATE CASE AND WHAT WAS GRANTED BY THE COMMISSION?

A. As previously referenced, PECO Energy – Gas Division's last completed natural gas rate case was in 2010 and PECO Energy – Electric Division's last completed rate case was in 2018. PECO Energy's utility divisions sought an 11.75% and a

10.95% ROE in these rate cases, respectively.[20] Each of these cases were settled, and no approved ROE's were presented in the settlements approved by the Commission's orders.[21]

Q. WHAT ROE IS THE COMPANY SEEKING IN THIS RATE CASE?

A. In the current filing, the Company is seeking a 10.95% ROE, which includes a 25-basis point adder for "*exemplary performance of the Company's management*."[22]

Q. DO YOU BELIEVE THE COMPANY'S REQUEST IN THIS CASE IS APPROPRIATE GIVEN THE CURRENT STATE OF THE FINANCIAL MARKETS IN LIGHT OF THE COVID-19 PANDEMIC?

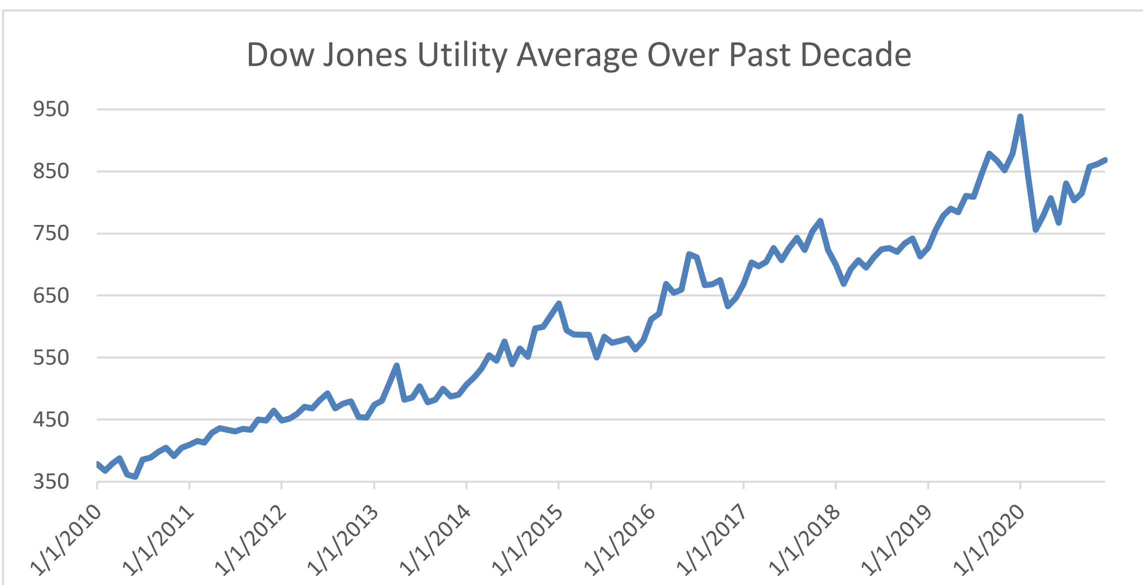
A. No. I do not. As I referenced above, I note that I fully agree with OCA Witness Scott Rubin[23] in that as a result of the COVID-19 pandemic, it is not just or reasonable for PECO to impose a rate increase on its customers at this time. As explained throughout this testimony, much of PECO's customer base is still dealing with ongoing financial struggles linked to a variety of factors, such as higher than average unemployment numbers throughout the calendar year. However, I note that throughout this direct testimony, I have presented my recommendation for what I believe would be appropriate should the Commission still proceed with reviewing the rate filing on a standard ratemaking basis.

[20] S&P Global Rate Case History (Past Rate Cases); Years: All; Service Type: All; Company List: PECO Energy Co.; States: Pennsylvania; Date Accessed: October 19, 2020.
[21] *Id.*
[22] Witness Moul Direct Testimony, page 5: line 4.
[23] Witness Rubin Direct Testimony, page 3, lines 16 – 21.

Q. DO YOU BELIEVE THE COMPANY'S REQUEST IN THIS CASE IS APPROPRIATE GIVEN THE CHANGE IN THE COST OF CAPITAL SINCE ITS LAST RATE CASE?

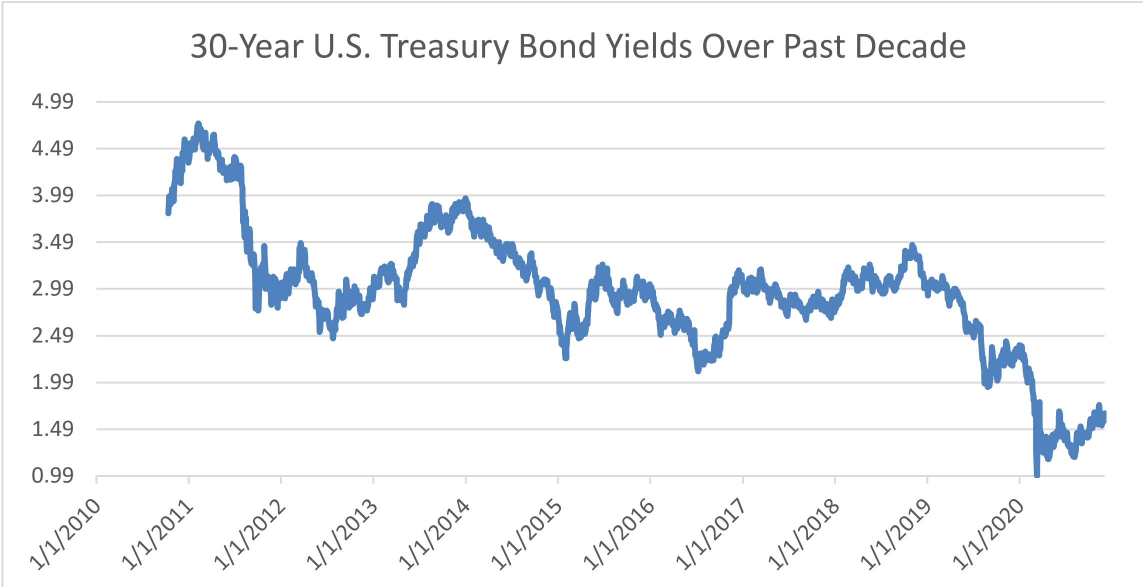
A. No. The Company's proposed ROE and, by default, the proposed weighted cost of capital fail to adequately reflect that the cost of debt financing and equity financing has decreased substantially since its previous natural gas rate case over a decade ago in 2010. In the current case, Mr. Moul's recommendation is only 80-basis points (*i.e.*, 11.75% requested in 2010 rate case as compared to the 10.95% requested in this rate case) lower than what was sought 10 years ago. In contrast, refer below to **Chart 3** and **Chart 4**, which show the rise in the DJUA and decline in the US Treasury 30-year Yield, respectively, from the beginning of 2010 through December 1, 2020:

Chart 3: DJUA 2010 - 2020[24]



[24] https://finance.yahoo.com/quote/%5EDJU/history?p=%5EDJU

Chart 4: 30-Year US Treasury Bond Yield 2010 – 2020[25]



When one evaluates Mr. Moul's recommendations in contrast to the Company's request in its previous gas rate case, it can be seen that Mr. Moul failed to recognize the tremendous increase within the DJUA and the corresponding drop in the lower expected returns on utility investments, as well as the lower risk-free rate in consideration of the 30-Year US Treasury.

Q. IS THE COMPANY'S RISK GREATER THAN THAT OF OTHER COMPARABLE COMPANIES TO NECESSITATE A HIGHER ROE?

A. No, it is not. Within his testimony, Mr. Moul noted that "*Changes in the business environment can negatively affect these companies, and, in that way, cause material reductions in throughput on PECO Energy's distribution system. This risk*

[25] https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

is especially apparent in this time of economic recession."[26] He then later indicated that the Company's risk profile was increased due to "*substantial investments to maintain and upgrade existing facilities in its service territory to ensure safe and reliable service to its customers*."[27]

However, what Mr. Moul failed to acknowledge is that every single company in the country right now is dealing with fallout from the COVID-19 pandemic and that changes within the business environment is not something solely applicable to PECO. Additionally, the same is true in regard to substantial investments that the Company must make to its facilities as each and every utility has to make similar investments at one point or another to upgrade its infrastructure. Therefore, this is similarly not something that would indicate PECO's risk to be higher than that of other comparable companies.

Q. DOES PECO ENERGY – GAS DIVISION'S RATE CASE REQUEST REFLECT THE MOST RECENT MARKET CONDITIONS?

A. No. The Company filed their base rate case in Pennsylvania on September 30, 2020, which was after Pennsylvania Governor Wolf's March 16, 2020 Disaster Proclamation. The COVID-19 pandemic began to significantly impact financial markets in March 2020, as exhibited within the CNN article, "The Global COVID-19 Pandemic is Beginning," published on March 16, 2020.[28]

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[26] Witness Moul Direct Testimony, page 9: lines 22 – 23, and page 10: lines 1 – 2.
[27] Witness Moul Direct Testimony, page 10: lines 14 – 16.
[28] https://www.cnn.com/2020/03/16/economy/global-recession-COVID-19/index.html

While Mr. Moul's testimony mentions the uncertainty associated with the COVID-19 pandemic,[29] it does not consider the impact of this pandemic on the customers dependent on PECO for natural gas distribution service. The entirety of Mr. Moul's consideration of the COVID-19 pandemic is centered around his opinion of the Company's level of risk and does not consider the continued and prolonged struggles encountered by the customers of PECO during 2020.

Additionally, while Mr. Moul's testimony speaks to his opinion of the Company's risk, his testimony is not based upon what can be considered recent data. As previously mentioned, the Company filed their rate case on September 30, 2020. However, Mr. Moul's testimony dated September 30, 2020 only incorporates data as recent as June 2020.[30] **Schedule 1** of **PECO Exhibit PRM-1** includes the results of the various financial cost of equity models used by Mr. Moul within his testimony (*i.e.,* Discounted Cash Flow "DCF", Risk Premium "RP", Capital Asset Pricing Model "CAPM", and Comparable Earnings "CE"). The top of this schedule explicitly notes that these cost of equity results were based on data "*as of June 30, 2020.*"[31] Within his direct testimony, Mr. Moul notes that he utilized a dividend yield based upon the "*twelve months ended June 2020*"[32] and claims that "*the use of this dividend yield will reflect <u>current capital costs,</u>*"[33], despite the fact the data he included from June 2020 was 3 months old by the time his testimony was filed.

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[29] Witness Moul Direct Testimony, page 8: lines 2 – 7.
[30] Witness Moul Direct Testimony, page 24: lines 21.
[31] Witness Moul Direct Testimony: PECO Exhibit PRM-1, Schedule 1.
[32] Witness Moul Direct Testimony, page 25: line 5.
[33] Witness Moul Direct Testimony, page 25: line 11. (underline emphasis added)

Additionally, the growth rates utilized within Mr. Moul's testimony for his comparable company proxy group, as explained in detail later on in this testimony, were sourced from outdated company-specific *Value Line Investment Surveys* from May 29, 2020.[34] As such, Mr. Moul has ignored at least an entire quarter's worth of data within his testimony given that updated company-specific *Value Line Investment Surveys* are published by industry on a quarterly basis, and that the most recent quarterly updates for the companies included in Mr. Moul's comparable company proxy group prior to the filing of his direct testimony were published on August 28, 2020. This is even more notable in the current financial climate given the market recovery experienced during the third quarter of 2020 that Mr. Moul has omitted entirely from his September 30, 2020 filed direct testimony relative to the first two quarters of the year.

Q. HOW DOES PECO ENERGY – GAS DIVISION'S RATE CASE REQUEST COMPARE TO THE ROE REQUEST FROM PECO ENERGY'S MOST RECENT RATE CASE?

A. The Company requested a return on equity (10.95%) at the same level that was requested in the PECO Energy – Electric Division rate case filed in early 2018, when there was no pandemic, no state-wide Disaster Proclamation, and no economic crisis. In reference to the comparison between electric and natural gas rate case annual average allowed ROE's, I analyzed the allowed ROE's from across the United States for the past 15 years and found that electric utilities, on average,

[34] Witness Moul Direct Testimony: PECO Exhibit PRM-1, Schedules 8 and 9.

have been allowed ROE’s that were 15-basis points higher than that of natural gas utilities. My results can be seen in **Table 4** below.

Table 4: Natural Gas v. Electric Utilities Annual Average Allowed ROE’s[35]

	Return on Equity (%)	Return on Equity (%)
Year	**Natural Gas Utilities**	**Electric Utilities**
2005	10.41	10.51
2006	10.40	10.32
2007	10.22	10.30
2008	10.39	10.41
2009	10.22	10.52
2010	10.15	10.37
2011	9.92	10.29
2012	9.94	10.17
2013	9.68	10.03
2014	9.78	9.91
2015	9.60	9.85
2016	9.54	9.77
2017	9.72	9.74
2018	9.59	9.60
2019	9.71	9.65
Average	**9.95**	**10.10**
Difference	**0.15**	

As can be seen in the above table, on average, gas utilities have been allowed ROE’s that are on average 15-basis points less than electric utilities from the period of 2005 through 2019.

Q. DOES PECO’S RATE CASE REQUEST INCLUDE ANY OTHER ITEMS THAT ARE NOT REFLECTIVE OF THE MOST RECENT MARKET CONDITIONS?

[35] S&P Global Market Intelligence Statistics and Graphs; Date Range: 15 Years; Service Type: Natural Gas / Electric; Chart Item: Return on Equity %; Date Accessed: October 19, 2020.

A. Yes. The Company's request also includes an upward ROE adjustment of 25-basis points as a reward for what the Company claims has been exemplary performance of its management.

Simply put, the Company made its rate filing during the midst of a global pandemic and still felt that it was appropriate to request a 25-basis point upward adjustment to reward shareholders for the Company's performance spanning many years prior to the current rate case. The Company's request is at odds with the hardships faced by PECO customers currently, many of whom have been unemployed or underemployed and may struggle to pay for PECO's gas service at current rates.

The Company's "business as usual" cost of capital request is not appropriate. As noted previously within this testimony in reference to the COVID-19 pandemic, investors generally would want to obtain a greater return for their willingness to invest in, and hold, common stocks. While granting the Company a higher ROE would ensure in theory that investors would see a higher return, the Company's consumers are going to bear the brunt of this by being required to pay increased rates during a year when the National GDP declined precipitously during the first two quarters of the year and unemployment has been well above previous annual averages as well. While the financial markets have rebounded during the third and fourth quarters of 2020 as previously mentioned in this testimony, the average civilian unemployment rate was 8.83% during Q3 2020, and has averaged

8.25% during the entirety of 2020 (*i.e.,* January 2020 – November 2020).[36] For comparison purposes, the average monthly civilian unemployment rate from 2019 was 3.67%[37]. When comparing the unemployment rates between 2019 and 2020, this simply further reinforces that the Company's "business as usual" request is not appropriate in the current climate.

Q. HOW HAVE THE CAPITAL MARKETS FOR UTILITIES CHANGED AS A RESULT OF THE COVID-19 PANDEMIC?

A. As can be seen in **Chart 1** and **Chart 2** above, the COVID-19 pandemic has contributed to declining interest rates. Equity markets were also negatively impacted during the first two quarters of 2020 before rebounding during Q3 and Q4 2020. During the majority of the year, businesses have been closed and workers have been staying home as the United States and world economies slowed dramatically prior to the beginning of phased reopening plans around the world. While I note that there is expectation that the economy will sustain its rebound throughout the remainder of Q4 2020, there is no current expectation that the economy will fully recover, or that the civilian unemployment rate will reach near-2019 levels, at any point in the near-term.

As referenced in an interview with CBS 60 Minutes on May 13, 2020, Federal Reserve Chairman Jerome Powell noted the following regarding economic recovery:

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[36] https://www.bls.gov/charts/employment-situation/civilian-unemployment-rate.htm: Date Accessed: December 9, 2020
[37] *Id.*

> *It may take a while. It may take a period of time. It could stretch through the end of next year…I will say that it's a reasonable assumption that the economy will begin to recover in the second half of the year, that unemployment will move down, that economic activity will pick up.… And I think it's a reasonable expectation that there'll be growth in the second half of the year. I would say though we're not going to get back to where we were quickly. We won't get back to where we were by the end of the year. That's unlikely to happen.*[38]

Subsequent to the quote provided above, Federal Reserve Chairman Powell later reinforced the assertion that although there was growth in the second half of 2020, the timeline for a full economic recovery is uncertain as referenced within the following quote from December 1, 2020:

> *Economic activity has continued to recover from its depressed second quarter level. The reopening of the economy led to a rapid rebound in activity, and real gross domestic product, or GDP, rose at an annual rate of 33 percent in the third quarter. In recent months, however, the pace of the improvement has moderated…The economic downturn has not fallen equally on all Americans, and those least able to shoulder the burden have been the hardest hit...The economic dislocation has upended many lives and created great uncertainty about the future…As we have emphasized throughout this pandemic, the outlook for the economy is extraordinarily uncertain…*[39]

Note that the above-stated drop in interest rates provides some benefit to utilities as interest rates are currently very low. On April 2, 2020, S&P Global Intelligence published an article entitled "*US utilities demonstrate access to capital with billions in debt offerings*". This article described how utilities are tapping the current credit markets to obtain low-cost debt as noted in the excerpt below:

> *Several utilities, including Xcel Energy and NextEra Energy Inc. subsidiary Florida Power & Light Co., which issued $1.1 billion in*

[38] https://www.cbsnews.com/news/full-transcript-fed-chair-jerome-powell-60-minutes-interview-economic-recovery-from-COVID-19-pandemic/

[39] https://www.federalreserve.gov/newsevents/testimony/powell20201201a.htm

> *first mortgage bonds, are "using the opportunity to take advantage of attractive borrowing costs, so there does not appear to be an inability to access capital," they said.*
>
> *"Utilities are reporting that recent deals have been significantly (7x) oversubscribed, highlighting that the capital markets are open for investment grade-rated utilities," the analysts wrote. "At the same time, we have also observed some utility companies that have fully drawn their bank lines as a precaution to provide them with liquidity in the event that markets seize up," such as Duke Energy Corp. and American Electric Power Co. Inc.*[40]

In regard to equities, the decline in utility prices has caused an increase in dividend yields, but also a decrease in expected growth rates. Furthermore, on April 2, 2020, S&P Global Intelligence published an article entitled "*Gas Utilities Tap Great Recession Playbook, New Tools to Confront COVID-19*."

> *Utilities are bracing for a drop in gas volumes and electric power load during the looming recession, just like they experienced in the 2007-2009 downturn. Once again, they are looking to take out costs, but new or expanded technologies and regulatory policies also give some utilities additional levers to pull.*[41]

The above referenced articles note the ability of utilities to continue to operate based upon the conditions of the debt and equity markets. This has allowed many utilities to continue to perform strongly even in the face of the COVID-19 pandemic as referenced in the December 9, 2020 article from S&P Global Intelligence, entitled "*Resilient Utilities Post Notable EPS Gains, Solid ROEs Despite COVID-19 Pandemic*". Within this article the following selection was included:

> *Despite the significant challenges caused by an economy that continued to be negatively impacted by COVID-19, utilities overall*

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[41] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/gas-utilities-tap-great-recession-playbook-new-tools-to-confront-COVID-19-57859955

> *posted solid earnings growth and earned returns on equity during the third quarter, illustrating the tenet that utility finances hold up comparatively well in challenging economic environments.*[42]

As stated within the above referenced article, although the utility sector has been impacted by the COVID-19 pandemic just like the rest of the economy, utilities have been much more resilient than companies across other industries. This resilient performance of utilities supports that the fact that utilities have still been able to access capital markets throughout the entirety of the year.

Q. ARE INTEREST RATES EXPECTED TO CHANGE OVER THE NEXT FEW YEARS?

A. No. The Federal Reserve is not expected to change interest rates any time in the foreseeable future. On June 10, 2020, Chairman Jerome Powell made the following statement in an article *The Wall Street Journal* titled "*Fed Officials Project No Rate Increases Through 2022*":

> "*We are strongly committed to using our tools to do whatever we can and for as long as it takes to provide some relief and stability," Fed Chairman Jerome Powell said Wednesday at a virtual news conference after a two-day policy meeting.*[43]

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[42] https://platform.marketintelligence.spglobal.com/web/client?auth=inherit#news/article?id=61646964&KeyProductLinkType=14&utm_campaign=top_news_2&utm_medium=top_news&utm_source=news_home

[43] https://www.wsj.com/articles/fed-debates-how-to-set-policy-for-the-post-pandemic-economy-11591781402#:~:text=Federal%20Reserve%20Chair%20Jerome%20Powell,coronavirus%20testing%2C%20treatments%20and%20vaccines

III. ECONOMIC AND REGULATORY POLICY GUIDELINES FOR A JUST AND REASONABLE RATE OF RETURN

Q. PLEASE BRIEFLY DESCRIBE THE ECONOMIC AND REGULATORY POLICY CONSIDERATIONS YOU HAVE TAKEN INTO ACCOUNT IN DEVELOPING YOUR RECOMMENDATION CONCERNING THE JUST AND REASONABLE RATE OF RETURN THAT UTILITY COMPANIES SHOULD HAVE AN OPPORTUNITY TO EARN.

A. The theory of utility regulation assumes that public utilities perform functions that are natural monopolies. Historically, it was believed or assumed that it was more efficient for a single firm to provide a particular utility service than multiple firms. Even though deregulation for the supply of natural gas and generation of electric power and energy has occurred in recent years, delivery distribution and transmission of these products to end-use customers is still a monopolistic business and will, for the foreseeable future, be regulated. On this basis, state legislatures and state utility commissions established exclusive franchised territories to public utilities in order for these utilities to provide services more efficiently and at the lowest reasonable cost. In exchange for the protection within its monopoly service area, the utility is obligated to provide service that is adequate and non-discriminatory at just and reasonable rates.

This trade-off logically leads to the question - what constitutes a just and reasonable rate? The generally accepted answer is that a prudently managed utility should be allowed to charge prices that allow the utility the opportunity to recover the reasonable and prudent costs of providing utility service and the opportunity to earn a just and reasonable rate of return on invested capital. The just and reasonable rate of return on capital should allow the utility, under prudent management, to provide adequate service and attract capital to meet future expansion needs in its service area. Since public utilities are capital-intensive businesses, the cost of capital is a crucial issue for utility companies, their customers, and regulators.

If the allowed rate of return is set too high, then consumers are burdened with excessive costs, current investors receive a windfall, and the utility has an incentive to overinvest. If the return is set too low, adequate service is jeopardized because the utility will not be able to raise capital on reasonable terms. As such, regulators are tasked with balancing the related interests of the interested parties (*i.e.*, the utility's equity investors, the utility itself, and the utility's customers at the varying residential, commercial, and industrial levels). This balancing act results in what regulators, analysts, and courts often refer to as setting rates within a "zone of reasonableness." Since every equity investor faces a risk-return tradeoff, the issue of risk is an important element in determining the just and reasonable rate of return for a utility.

As I previously referenced above, PECO filed this rate case on September 30, 2020, a time during which the country remains in midst of an economic recession spurred on by a pandemic the likes of which have not been seen in this country for over a century. Accordingly, what might have been deemed as constituting "just and reasonable" rates earlier on in 2020 or during 2019 may simply be construed as unreasonable today given the current economic climate.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF THE SUPREME COURT'S *HOPE* AND *BLUEFIELD* DECISIONS.

A. Regulatory law and policy recognize that utilities compete with other firms in the market for investor capital. The United States Supreme Court set the guidelines for a fair, just, and reasonable rate of return in two often-cited cases: *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*. 262 U.S. 679; and the *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

In the *Bluefield* case, the U.S. Supreme Court stated:

> *A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.* (262 U.S. at 692)

In the above finding, the Court found that utilities are entitled to earn a return on investments of comparable risks and that a corresponding return should be sufficient enough to support credit activities and to raise funds to carry out its mission.

In *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944), the U.S. Supreme Court recognized that utilities compete with other firms in the market for investor capital. Historically, this case has provided legal and policy guidance concerning the return which public utilities should be allowed to earn. In *Hope Natural Gas*, the U.S. Supreme Court stated that the return to equity owners (or shareholders) of a regulated public utility should be commensurate to returns on investments in other enterprises whose risks correspond to those of the utility being examined:

> *[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain credit and attract capital.* (320 U.S. at 603)

IV. DEVELOPMENT OF PROXY GROUP

Q. PLEASE DESCRIBE HOW YOU SELECTED A PROXY GROUP FOR ESTIMATING PECO'S RETURN ON EQUITY.

A. The number of available gas utilities needed to develop a reasonably reliable comparable group of companies is dwindling. Over the past several years, various gas utilities have announced that they were being acquired by larger electric utility holding companies. These acquisitions make sense for the electric utilities as they desire to grow their source of regulated earnings while, at the same time, gain control over natural gas infrastructure that allows them to control the distribution of natural gas, which is expected to be the predominant fuel choice for many years to come.

In regard to the composition of my comparable company proxy group, I have opted to use the full group of gas utilities compiled and followed by *Value Line*. As such, each of the companies included by Mr. Moul within his proxy group are also included within my own proxy group. However, in contrast to Mr. Moul, I did not remove UGI Corporation from my proxy group. My reasoning for this is detailed in the below Q&A.

Mr. Moul also opted to include a non-utility comparable company proxy group for comparison purposes to PECO within his Comparable Earnings Analysis as he noted that:

> *…I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return.*[44]

[44] Witness Moul Direct Testimony, page 51: lines 3 – 5.

In contrast, I have chosen not to include a non-utility group within any of the analyses included within my testimony as, in my view, such non-regulated companies are not truly comparable to PECO and should not be examined in regard to the proper ROE to grant a regulated utility such as PECO. While utilities are in a sense "competing" against non-utilities strictly for the capital of investors looking to build their portfolio, only regulated utilities have the ability to seek regulatory relief as does PECO.

PECO has a set of consumers at the residential, commercial, and industrial levels that are locked into purchasing gas distribution service from PECO. If PECO feels that it needs to increase its ROE in order to result in a greater overall ROR, PECO has the ability to request regulatory relief through a rate case in an effort to increase rates on captive customers, as is occurring in this current rate case. Unregulated entities do not have the ability to ask for rate relief like regulated utilities. Seeking rate relief is an integral part of the business model of a utility and is not a practice that is available to any such non-utilities.

Q. WHY DID YOU CHOOSE TO INCLUDE UGI CORP WITHIN YOUR COMPARABLE GROUP, WHILE MR. MOUL OMITTED THE COMPANY FROM HIS ANALYSIS?

A. On page 5 of his testimony, Mr. Moul states that in developing his comparable company proxy group, he first began with the companies included in *Value Line's* Natural Gas Utility Industry. However, he made an adjustment in that he excluded companies that he deemed not to be predominantly engaged in natural gas distribution (*i.e.*, UGI Corp). Specifically, he noted that he excluded "*UGI Corporation from the Value Line group because it is more diversified outside of the gas distribution business than the other companies in the Gas Group. Specifically, UGI Corporation reports its financial results for six separate segments consisting of propane sales, two international liquefied petroleum gas businesses, energy services and electric generation.*"[45]

For context, I do recognize that UGI Corp. has a diversified business portfolio. However, by comparison, Chesapeake Utilities[46], which Mr. Moul included in his proxy group, also operates a diverse set of businesses that includes "*natural gas distribution, transmission and marketing; electric distribution; propane gas distribution and wholesale marketing; advanced information services and other related services*."[47] As such, for consistency purposes, and in consideration of the fact that both companies are included by *Value Line* within their Natural Gas Utility Industry classification, I did not feel it appropriate to include one diverse company within my proxy group, while simultaneously excluding another.

[45] Witness Moul Direct Testimony, page 6: lines 1 – 6.
[46] Note that Chesapeake Utilities (CPK) as referenced throughout this testimony is not related to Chesapeake Energy (CHK), which declared bankruptcy in 2020.
[47] https://chpkgas.com/about-us/about-us/#:~:text=Chesapeake%20Utilities%20is%20the%20natural,advanced%20information%20services%20and%20other

V. CAPITAL STRUCTURE

Q. WHAT IS A CAPITAL STRUCTURE AND HOW DOES IT IMPACT THE REVENUES THAT PECO IS SEEKING?

A. The term "*capital structure*" refers to the relative percentage of debt, equity, and other financial components that are used to finance a company's investments. A company's capital structure typically includes some combination of three principal financing methods. The first method is to finance an investment with common equity, which essentially represents ownership in a company and its investments. Common equity is comprised of all investments from investors, including common stock, retained earnings, and additional paid in capital. Returns on common equity, which in part take the form of dividends to stockholders, are not tax deductible which, on a pre-tax basis alone, makes this form of financing about 21% more expensive than debt financing.

The second form of corporate financing is preferred stock, which is normally used to a much smaller degree in capital structures. Dividend payments associated with preferred stock are not tax deductible.

Corporate debt is the third major form of financing used in the corporate world. There are two basic types of corporate debt: long-term and short-term. Long-term debt is generally understood to be debt that matures in a period of more than one year. Short-term debt is debt that matures in a year or less. Long-term debt and short-term debt, both of which are "above the line" expenses for tax purposes, represent liabilities on the company's books that must be repaid prior to any common stockholders or preferred stockholders receiving a return on their investment.

Q. HOW IS A UTILITY'S TOTAL RETURN CALCULATED?

A. A utility's total return is developed by multiplying the component percentages of its capital structure, represented by the percentage ratios of the various forms of capital financing relative to the total financing on the company's books, by the cost rates associated with each form of capital and then totaling the results over all of the capital components. When these percentage ratios are applied to various cost rates, a total after-tax rate of return is developed. Because the utility must pay dividends associated with common equity and preferred stock with after-tax funds, the post-tax returns are then converted to pre-tax returns by grossing up the common equity and preferred stock dividends for taxes. The final pre-tax return is then multiplied by the Company's rate base in order to develop the amount of money that customers must pay to the utility for return on investment and tax payments associated with that investment.

Q. HOW DOES CAPITAL STRUCTURE IMPACT THIS CALCULATION?

A. Costs to consumers are greater when the utility finances a higher proportion of its rate base investment with common equity and preferred stock versus long-term debt. However, long-term debt, which is first in line for repayment, imposes a contractual obligation to make fixed payments on a pre-established schedule, as opposed to common equity where no similar obligations exist.

Q. WHY SHOULD THIS COMMISSION BE CONCERNED ABOUT HOW THE COMPANY FINANCES ITS RATE BASE INVESTMENT?

A. There are two reasons that the Commission should be concerned about how PECO finances its rate base investment. First, PECO's cost of common equity is higher than the cost of long-term debt, meaning that a relatively higher equity percentage will translate into higher costs to PECO's customers without any corresponding improvement in quality of service. Long-term debt is a financial promise made by the company and is carried as a liability on the company's books. Common stock is ownership in the company. Due to the contingent nature of an equity investment, common stockholders require higher rates of return to compensate them for the extra risk involved in owning part of the company versus having a more senior claim against the company's assets.

The second reason the Commission should be concerned about PECO's capital structure is due to the tax treatment of debt versus common equity. Public corporations, such as Exelon Corp. (*i.e.*, the parent company of PECO), can deduct payments associated with debt financing. Corporations are not, however, allowed to deduct common stock dividend payments for tax purposes. All dividend payments must be made with after-tax funds, which are more expensive than pre-tax funds. The regulatory process allows utilities to recover reasonable and prudent expenses, including taxes, within their rates. Accordingly, if a utility is allowed to use a capital structure for ratemaking purposes that is top-heavy in common stock, customers will be forced to cover the higher income tax burden, which can result in unjust, unreasonable, and unnecessarily high rates. Setting rates through the use of a capital structure that is weighted too heavily to common equity violates the fundamental principles of utility regulation that rates must be just and reasonable and only high enough to support the utility's provision of safe, adequate, and reliable service at a fair price.

Q. HOW DOES THE UTILITY'S SELECTION OF EQUITY VERSUS DEBT IMPACT RATEPAYERS?

A. Selecting the ratio of equity to debt is important. Entities in more competitive markets have a profit motive that provides an incentive for such entities to select the most efficient capitalization ratio. However, utilities operating in monopoly, rate-regulated service territories have an incentive to maximize the amount of common equity in their capital structure so as to increase rates and, correspondingly, the utility profit. Rate-regulated utilities should only be allowed to recover in rates a revenue requirement derived from a capitalization ratio that allows the utility to provide reliable service at the least cost. Therefore, finding the right balance between debt and equity is critical.

If a utility issues more common equity and less debt for a certain project, the rates could potentially be set at an unbalanced debt to equity level. This could result in the ratepayer paying higher rates to support a capital structure that is neither prudent nor reasonable to support the company's current credit rating or the company's adequate access to the capital markets. It is also important to recognize how rate levels affect economic development. The reality in today's economy is that economic development opportunities for large loads occur in places where costs are lower. A utility with unduly high rates will, all else being equal, cause its service territory to lose out on economic development opportunities.

If, on the other hand, the utility incurs too much debt, the utility's capitalization ratios present excess financial risk to the capital markets, thereby driving up the costs required by the equity markets to compensate for the added risk. In this case, the consumer would also suffer harm because the cost it must pay the utility for accessing the capital markets is higher than it would pay using a less debt-leveraged capital structure.

One role of regulation is to balance the needs of the capital markets, including utility stockholders, with the needs of ratepayers. Either too much equity or too much debt can harm both the stockholders of the corporation, as well as the consuming public. A careful study of the risks and costs of various capitalization ratios is important.

Q. HAVE YOU REVIEWED THE CAPITAL STRUCTURE REQUESTED BY THE COMPANY IN THIS PROCEEDING?

A. Yes, I have.

Q. WHAT CAPITAL STRUCTURE IS THE COMPANY PROPOSING IN THIS CASE?

A. PECO has proposed the following capital structure:

Table 5: PECO Requested Capital Structure[48]

Component	Capital Structure Ratio (%)
Total Debt	46.62%
Common Equity	53.38%
Total Capitalization	**100.00%**

Q. WHAT IS THE AVERAGE COMMON EQUITY RATIO OF THE COMPANIES IN YOUR PROXY GROUP?

A. **Table 6** below shows the average common equity ratio of each utility in my natural gas comparable company proxy group, as well as the common equity ratio of PECO's parent company, Exelon Corp. Given that Exelon Corp. is classified as an electric utility, I have presented data related to Exelon separately from that of my comparable company proxy group for the Natural Gas Industry.

[48] Witness Moul Direct Testimony, page 21: lines 13 – 14.

Table 6: Proxy Group Equity Ratio[49]

Company	2019 Ratio
Atmos	62.00%
Chesapeake	56.10%
New Jersey Res	50.20%
NiSource Inc.	36.90%
NWNG	51.80%
OneGas	62.30%
South Jersey	40.80%
Southwest Gas	52.10%
Spire	55.00%
UGI Corp.	39.80%
Average	**50.70%**
Exelon Corp	50.40%

As can be seen in the table above, the average common equity ratio in the proxy group is 50.70%, and the equity ratio for Exelon (*i.e.*, the ultimate parent of PECO as previously referenced) is 50.40%, which are both below the requested equity ratio in this case of 53.38%.

Q. WHAT IS THE AVERAGE COMMON EQUITY RATIO GRANTED BY UTILITY REGULATORS ACROSS THE UNITED STATES?

A. The average common equity ratio granted by regulators in 2019 was 51.75%.[50]

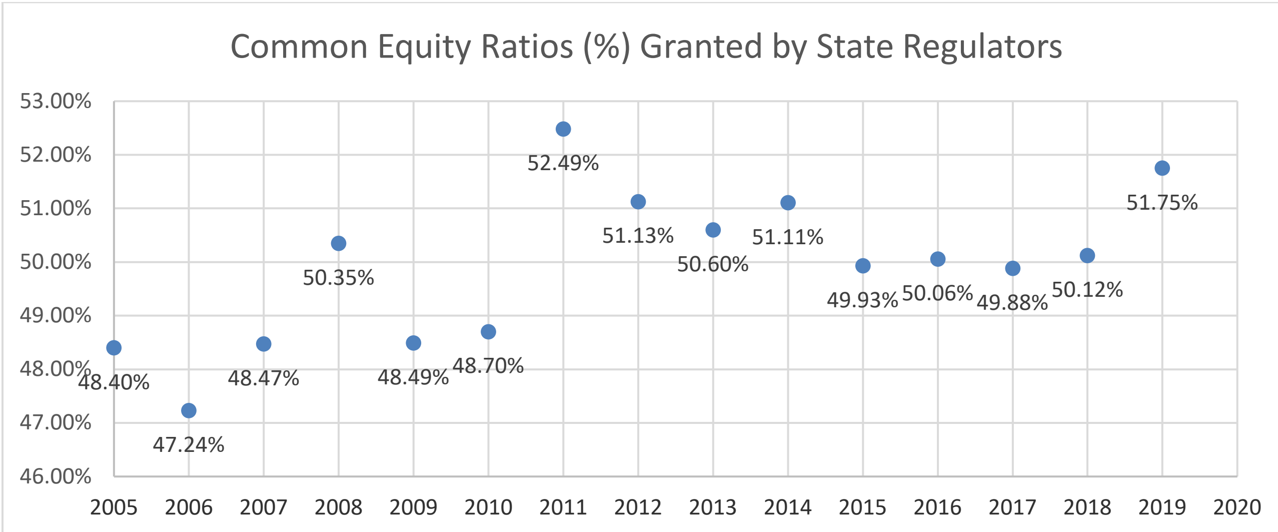
[49] *The Value Line Investment Survey*, November 13, 2020 (Electric Utilities East) and November 27, 2020 (Natural Gas).

[50] S&P Global Market Intelligence Rate Case Statistics; Date Range: 15 Years; Service Type: Natural Gas; Chart Items: Common Equity to Total Capital, Return on Equity; Date Accessed: October 19, 2020.

Q. WHAT COMMON EQUITY RATIOS HAVE STATE REGULATORS ACROSS THE UNITED STATES GRANTED TO NATURAL GAS UTILITIES OVER THE PAST 15 YEARS?

A. State regulators have been quite consistent with their rulings in natural gas cases over the past 15 years. From 2005 through 2019, common equity ratios have ranged from 47.24% to 52.49%, with an average of 49.91%. If one were to evaluate this data over the previous 12 years, the average common equity ratio over this period would be 50.28%, the average ratio over the previous 10 years would be 50.58%, and the average ratio over the previous 8 years would be 50.57%. However, regardless of the period examined, the average common equity ratio granted by state regulators much more closely approximates a ratio of 50.00% as opposed to PECO's request of 53.38%. In **Chart 5** below I have presented the average annual common equity ratios granted by state regulators for each year over the past 15 years.

Chart 5: Common Equity Ratios Granted by State Regulators (2005-2019)[51]



Q. PLEASE SUMMARIZE YOUR FINDINGS IN REGARD TO THE REQUESTED EQUITY RATIO IN THIS CASE RELATIVE TO THE EQUITY RATIO OF OTHER GAS UTILITIES.

A. **Table 7** below provides a summary of how PECO's request in this case compares to the average equity ratio of the proxy group companies, that of its parent company Exelon, the average equity ratio allowed by state regulators across the country in 2019, and the average equity ratio allowed by state regulators from 2005 – 2019.

[51] *Id.*

Table 7: Common Equity Ratio Comparison

PECO's Eq Ratio Request	53.38%
OCA Eq Ratio Recommendation	50.00%
2019 O'Donnell Proxy Group Eq Ratio Average	50.70%
2019 Exelon Eq Ratio	50.40%
2019 Average Regulator Granted Eq Ratio	51.75%
2005-2019 Average Regulator Granted Eq Ratio	49.91%

Q. GIVEN THE ABOVE, DO YOU BELIEVE THAT THE CAPITAL STRUCTURE PROPOSED BY PECO ENERGY - GAS DIVISION IN THIS CASE IS APPROPRIATE FOR RATEMAKING PURPOSES?

A. No. The requested capital structure for PECO Energy – Gas Division is not reasonable for ratemaking purposes. Nothing in the make-up of PECO Energy – Gas Division suggests that it requires a high equity ratio in the range that they are requesting, which would translate into lower financial risk, than any of the companies within the comparable company proxy group. Indeed, some of the companies in the proxy group are involved in a wide array of different businesses that involve more business risk than a utility's distribution of natural gas within its monopoly service territory. As such, if anything, the financial risk (as represented by the equity ratio) of the comparable company proxy group should be higher, not lower, than a traditional natural gas utility such as PECO Energy – Gas Division. Customers of PECO Energy – Gas Division should not pay higher rates associated with a capital structure that consists of so much common equity which, as previously discussed, is more expensive than debt.

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND THIS COMMISSION ADOPT FOR USE IN SETTING THE REVENUE REQUIREMENT IN THIS CASE?

A. I first note that I agree with OCA Witness Scott Rubin's[52] recommendation of no rate increase. However, should the Commission opt to proceed with this case on a more standard rate making basis, my recommendation is for the Commission to employ a capital structure that contains an equity ratio that is more equivalent to the common equity ratio granted by state regulators across the country for 2019, the common equity ratio granted by state regulators across the country over the previous 15-year period, the common equity ratio of the proxy group included above, and the common equity ratio of PECO's own parent company Exelon. Specifically, my recommended capital structure and embedded cost of debt is as follows:

Table 8: OCA Recommended Capital Structure

Component	Capital Structure Ratio (%)	Cost Rate %	Wgtd. Cost Rate (%)
Long-Term Debt	50.00%	3.84%	1.92%
Common Equity	50.00%	8.75%	4.38%
Total Capitalization	100.00%		6.30%

Q. HOW DID PECO DEVELOP ITS REQUESTED COMMON EQUITY RATIO OF 53.38%?

A. As outlined within Mr. Moul's testimony:

> *Because rate-setting is prospective, the rate of return should, a minimum, reflect known or reasonably foreseeable changes which will occur during the course of the test year. As a result, I will adopt*

[52] Witness Rubin Direct Testimony, page 3, lines 16 – 21.

> *the Company's FPFTY capital structure ratios of 46.62% long-term debt and 53.38% common equity.*[53]

However, upon examination of Mr. Moul's testimony, the only substantiating discussion included as a basis for the decision to utilize the 53.38% common equity ratio is the following:

> *The five-year common equity ratios, based on permanent capital were 54.1% for PECO Energy, 52.6% for the Gas Group, and 42.2% for the S&P Public Utilities. The Company's common equity ratio was fairly similar to the Gas Group, thereby indicating similar financial risk.*[54]

From a purely quantitative perspective, Mr. Moul's testimony includes **Schedule 3** on page 5 of **PECO Exhibit PRM-1**. This schedule showcases the historical common equity ratios for Mr. Moul's proxy group. Within **Schedule 3** of Mr. Moul's **PECO Exhibit PRM-1**, he presented the average common equity ratios for his proxy group over the five-year historical period from 2015 through 2019 on a permanent capital and total capital basis. It is important to note that Mr. Moul's analysis, as described above, does not tell the complete picture in the analysis. As one can see as presented on **Schedule 3** on page 5 of his **PECO Exhibit PRM-1**, the common equity ratio for his Gas Group from 2015-2019 on a total capital basis is 47.2%,[55] which is obviously well below my recommendation of a 50.00% common equity ratio. Additionally, an examination of the common equity ratio for his Gas Group from 2015-2019 on a permanent capital basis saw a decline from 54.0% in 2015 to 50.3% in 2019.[56] Also as shown within **Schedule 3** on page 5 of

[53] Witness Moul Direct Testimony, page 21: lines 11 – 14.
[54] Witness Moul Direct Testimony, page 13: lines 3 – 6.
[55] Witness Moul Direct Testimony: Schedule 3 of PECO Exhibit PRM-1.
[56] Witness Moul Direct Testimony: Schedule 3 of PECO Exhibit PRM-1.

his **PECO Exhibit PRM-1**, the common equity ratio for Mr. Moul's Gas Group from 2015-2019 on a total capital basis saw a decline from 48.7% in 2015 to 45.3% in 2019. In consideration of these points, I believe these values further support a debt to equity split for the Company's capital structure of 50% - 50%.

Q. WHAT IS THE DIFFERENCE BETWEEN A CAPITAL STRUCTURE BASED ON PERMANENT CAPITAL AND TOTAL CAPITAL?

A. Permanent capital excludes short-term debt whereas total capital includes short-term debt. Given that gas utilities are a definite seasonal business, and that short-term debt is often replaced with long-term debt, I believe the more accurate comparison is by total capital, which includes short-term debt.

Q. HOW DOES YOUR RECOMMENDED COMMON EQUITY RATIO DIFFER FROM MR. MOUL'S?

A. My recommended common equity ratio percentage of 50.00%, and Mr. Moul's of 53.38%, primarily differ in the data used to support our recommendations. I have utilized various percentages shown in **Table 7** above and have discussed in detail why I feel the above percentages would lead one to conclude that a 50.00% common equity ratio would be more appropriate for setting rates for PECO. Mr. Moul instead presented a five-year average of the common equity ratios for the companies within his proxy group on a permanent capital basis from 2015 – 2019 within **Schedule 3** on page 5 of **PECO Exhibit PRM-1** as quantitative support.

Additionally, Mr. Moul has excluded UGI Corp. from his comparable company proxy group, but has left Chesapeake in his comparable company proxy group, which I have discussed my disagreement with earlier in this testimony. Just in looking at the historical common equity ratios from 2019 provided for UGI Corp. as published by *Value Line* of 39.80%,[57] if Mr. Moul had opted to include UGI Corp. within his proxy group, it would have led to a lower average common equity ratio.

Q. WHAT IS YOUR REASONING BEHIND NOT UTILIZING PROJECTED COMMON EQUITY RATIOS TO SUPPORT YOUR RECOMMENDATION?

A. I have long maintained that the most accurate projection of future common equity ratios are the current common equity ratios. Most projections tend to set common equity at too high a value given the inherent subjectivity and erratic nature of where common equity ratios may actually fall out in future years. This is additionally relevant given the current economic climate in 2020 where the COVID-19 pandemic has increased the uncertainty associated with projected future common equity ratios.

[57] *The Value Line Investment Survey*, November 27, 2020.

VI. COST OF DEBT

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED 3.97% COST OF DEBT?

A. No. I have three areas of disagreement with the Company's proposed cost of debt of 3.97%. First, I disagree with the Company's forecasted cost of debt issuances expected to take place in March 2021, September 2021, and March 2021. Second, I disagree with the Company's estimated cost for its Trust Preferred Capital Securities issuance that matures on April 6, 2028. Third, I disagree with the rate of return assigned to the Company's Trust Preferred Capital Securities that also mature on April 6, 2028.

Q. PLEASE EXPLAIN YOUR DISAGREEMENT WITH THE FORECASTED COST OF DEBT ISSUANCES THE COMPANY HAS USED TO CALCULATE ITS REQUESTED COST OF DEBT.

A. In reviewing the details as presented by Mr. Moul in this case, I noticed that the data he used to develop his embedded cost of debt calculations was dated. Specific to Mr. Moul's cost of debt analysis, this data was dated December 31, 2019. In the Company's response to data request **OCA-XII-2**, I asked Mr. Moul to update the information upon which he based his cost of debt calculations as found in his direct testimony. In response, Mr. Moul provided the updated information as shown in his response to data request **OCA-XII-2** within **Attachment OCA-XII-2(a)**, page 1. Within that document, one can find that the cost rates for the March 2021, September 2021, and March 2022 anticipated "First and Refunding Mortgage Bonds" debt issuances all fell from the levels previously estimated by Mr. Moul.

As a result, I simply updated the forecasted cost of debt rates to comply with the new forecasts provided by Mr. Moul. Mr. Moul's original cost of debt calculation can be found within **Exhibit KWO-8**, page 1 (*i.e.*, as sourced from Mr. Moul's calculation from **OCA-XII-1**, **Attachment OCA-XII-1(a)**, page 3), this shows Mr. Moul's original cost of debt value of 3.97%. Additionally, my updated cost of debt calculation can be found within **Exhibit KWO-8**, page 2 for comparison purposes. The updates referenced within this Q&A, as well as the update within the Q&A below, have reduced the cost of debt from 3.97% to 3.84%. Note that the updated cost rates I utilized within **Exhibit KWO-8**, page 2 were sourced from Witness Moul's response to **OCA-XII-2** within **Attachment OCA-XII-2(a)**, page 1, and are signified within the "First and Refunding Mortgage Bonds" section of **Exhibit KWO-8**, page 2 within the bold outlined cells therein.

Q. PLEASE EXPLAIN YOUR ISSUE REGARDING MR. MOUL'S COST OF DEBT ISSUANCE OF APRIL 6, 1998 WITH AN ASSUMED COST RATE OF 6.75%.

A. PECO Gas has variable rate Trust Preferred Capital Securities that were issued on April 6, 1998. These securities are priced at the Prime Rate plus 200-basis points. For the estimated cost rate on June 30, 2022, Mr. Moul estimated the Prime Rate to be 4.75%.[58] I disagree with that forecast as the current Prime Rate is 3.25%,[59] and there is no sign that the Prime Rate is going to increase by 150-basis points by June 30, 2022, as Mr. Moul claims.

As evidence of my belief that interest rates will remain low for the foreseeable future, I note that on September 4, 2020, CNBC published an article entitled "*Powell says low interest rates could last for years*". In that article, the Chairman of the Federal Reserve, Jerome Powell stated the following:

> "*We think that the economy's going to need low interest rates, which support economic activity, for an extended period of time," Powell told NPR in an interview after the nonfarm payrolls report was released earlier in the day. "It will be measured in years.*"[60]

Since the current Prime Rate is 3.75% and the above-stated variable Trust Preferred Capital Security is priced at the Prime Rate plus 200 basis points, I have adjusted the cost of these particular securities from 6.75% as requested by Mr. Moul to my recommended 5.25% as shown within **Exhibit KWO-8**.

As referenced above, Mr. Moul's original cost of debt calculation can be found within **Exhibit KWO-8**, page 1, which shows Mr. Moul's original cost of debt value of 3.97%. Additionally, my updated cost of debt calculation can be found within **Exhibit KWO-8**, page 2 for comparison purposes. The update referenced within this Q&A, as well as the updates within the Q&A above, have reduced the cost of debt for this rate case proceeding from 3.97% to 3.84%. Note that the updated cost rates I utilized within **Exhibit KWO-8**, page 2 were sourced from

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[54] Company response OCA XII-1(a).xlsx
[59] https://www.bankrate.com/rates/interest-rates/prime-rate.aspx
[60] https://www.cnbc.com/2020/09/04/powell-says-duration-of-low-interest-rates-will-be-measured-in-years.html

Witness Moul's response to **OCA-XII-2** within **Attachment OCA-XII-2(a)**, page 1, and are signified within **Exhibit KWO-8**, page 2 within the bold outlined cells therein.

Q. PLEASE EXPLAIN YOUR CONCERN WITH THE FIXED 7.38% TRUST PREFERRED CAPITAL SECURITIES ALSO DATED ON APRIL 6, 1998.

A. The 7.38% Trust Preferred Capital Securities are part of a Trust that used the proceeds of those Capital Securities to purchase Series D Preferred Securities as the sole assets of the Trust.[61] PECO Energy Capital then lent the proceeds from the sale of these Series D securities, as well as its own capital, to PECO Energy Company in the form of a loan at the stated rate of 7.38% and labeled as a Subordinated Deferrable Interested Debentures, Series D, due 2028.

Capital Trust IV was created by PECO on May 9, 2003 with the following intent:

> *We were formed for the exclusive purposes of: ‰ issuing and selling our preferred securities and common securities; ‰ using the proceeds from the sale of the preferred securities and the common securities to acquire the subordinated debentures from PECO; and engaging in only those other activities necessary or incidental to these purposes.*[62]

In data request **OCA-VIII-12**, I asked for the Company to explain all efforts expended by PECO Energy to reduce the cost of its entire portfolio of securities. In its response to data request **OCA-VIII-12**, PECO noted that specific to its Trust IV securities, early redemption of these securities would be cost prohibitive, however

[61] Witness Stefani response to Question No. **OCA-VIII-12, Attachment OCA-VIII-12(a)**.
[62] *Id.*

PECO failed to offer any such evidence to that point. For context, a 7.38% interest rate on debt in today's market is incredibly high. In my view, issuing such debt in the complicated arrangement as stated above is yet another example of why the Company has not earned a 25-basis point "management adder" as PECO should have redeemed the 7.38% PECO Energy fixed income securities long ago. As a result of PECO's inaction, consumers are paying an excessive rate of interest on the $80.5 million of outstanding securities issued at 7.38%.

I am not, however, recommending an adjustment to substitute a lower interest rate for this 7.38% debt issuance. I am simply pointing out that PECO Energy could have, and should have, dealt with this debt issuance a long time ago.

Q. WHAT IS THE RESULT OF YOUR ADJUSTMENTS TO THE PECO GAS REQUESTED EMBEDDED COST OF DEBT?

A. As previously referenced, the two updates that I made to Mr. Moul's cost of debt calculations can be found in **Exhibit KWO-8**, page 2 and ultimately result in PECO Gas' embedded cost of debt being reduced from 3.97% as requested by the Company to 3.84%.

VII. <u>COST OF COMMON EQUITY</u>

Q. PLEASE EXPLAIN HOW THE ISSUE OF DETERMINING AN APPROPRIATE RETURN ON A UTILITY'S COMMON EQUITY INVESTMENT FITS INTO A REGULATORY AUTHORITY'S DETERMINATION OF JUST AND REASONABLE RATES FOR THE UTILITY.

A. In Pennsylvania, as in virtually all regulatory jurisdictions, a utility's rates must be "just and reasonable."[63] Thus, regulation recognizes that utilities are entitled to an opportunity to recover the reasonable and prudent costs of providing service, and the opportunity to earn a just and reasonable rate of return on the capital invested in the utility's facilities, such as gas distribution equipment, buildings, vehicles, and similar long-lived capital assets.

Q. HOW DO REGULATORY AUTHORITIES DETERMINE A JUST AND REASONABLE RATE OF RETURN ON EQUITY FOR A UTILITY COMPANY?

A. Regulatory commissions and boards, as well as financial industry analysts, institutional investors, and individual investors, use different analytical models and methodologies to estimate/calculate reasonable rates of return on equity. Among the measures used are the Discounted Cash Flow (*i.e.*, "DCF") Model, the Capital Asset Pricing Model (*i.e.*, "CAPM"), and the Comparable Earnings Analysis (*i.e.*,

[63] Chapter 13 of the Pennsylvania Public Utility Code sets forth rate-making standards, including the requirement that utility rates be just and reasonable.

"CEA"). I believe the most useful methodology is the DCF analysis, but I have also presented the CAPM and the CEA within this testimony as checks for my DCF results.

Q. CAN YOU EXPLAIN WHY REGULATORY AUTHORITIES AND FINANCIAL ANALYSTS NEED TO USE THESE METHODOLOGIES TO DERIVE A COMPANY'S ESTIMATED RATE OF RETURN ON EQUITY?

A. Yes. There is no direct, observable way to determine the rate of return required by equity investors in any company or group of companies. Investors must make do with indications from market data and analysts' predictions to estimate the appropriate price of a share. The principal and most reliable methodology for obtaining these indications is the DCF Model. Other procedures, such as the CAPM and the CEA, are less reliable than the DCF Model in my opinion.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE DCF MODEL IS SUPERIOR TO THE CAPM AND COMPARABLE EARNINGS APPROACHES.

A. The DCF Model is an investor-driven model that incorporates current investor expectations based on daily and ongoing market prices. When a situation develops in a company that affects its earnings and/or perceived risk level, the price of the stock adjusts to reflect those developments. Since the stock price is a major component in the DCF Model, the change in risk level and/or earnings expectations is captured in the investor return requirement with either an upward or downward movement.

The CEA is based on earned returns from book equity, not market equity, as well as a comparison of what other commissions across the country are awarding regulated utilities. There is no direct and immediate stockholder input into the CEA and, as a fault, that model lacks a clear and unmistaken link to stockholder expectations.

The CAPM suffers, in my opinion, from the same inherent issues as found within the CEA in that there is not a direct and immediate link from stock market prices to the CAPM result. The beta in the CAPM can reflect changes in the ROE, but the delay can oftentimes make the CAPM results of little or no value.

Q. WHY DID YOU NOT USE THE RISK PREMIUM MODEL?

A. The Risk Premium Model is very similar in nature to the CAPM. In both models, one examines risk premiums, but from varying comparison points. The CAPM considers the risk premium relative to the risk-free rate whereas the risk premium model often develops the risk premium relative to utility bond yields.

Q. COULD YOU PERFORM A COST OF EQUITY ANALYSIS DIRECTLY ON PECO?

A. No. PECO is ultimately a subsidiary of Exelon. Exelon is traded on the New York Stock Exchange (*i.e.*, "NYSE") and is followed by the *Value Line Investment Survey*, which is the data source I used extensively in my cost of equity analyses.

Note however that Exelon is classified as an electric utility by *Value Line* rather than a natural gas utility such as PECO Energy – Gas Division.

A. <u>Discounted Cash Flow (DCF) Model</u>

Q. PLEASE EXPLAIN THE DISCOUNTED CASH FLOW MODEL.

A. The DCF Model is a widely used method for estimating an investor's required return on a firm's common equity. In my thirty-four years of experience, first with the Public Staff of the North Carolina Utilities Commission, and later as a consultant, I have seen the DCF Model used much more often than any other method for estimating the appropriate return on common equity. Consumer advocate witnesses, utility witnesses and other intervenor witnesses have used the DCF Model, either by itself or in conjunction with other methods such as the CEA or the CAPM, in their analyses.

The DCF Model is based on the concept that the price which the investor is willing to pay for a stock is the discounted present value (*i.e.*, its present worth) of what the investor expects to receive in the future as a result of purchasing that stock. This return to the investor is in the form of future dividends and price appreciation. However, price appreciation is only realized when the investor sells the stock, and a subsequent purchaser presumably is also focused on dividend growth following his or her purchase of the stock. Mathematically, the relationship is:

Let D = dividends per share in the initial future period

g = expected growth rate in dividends

k = cost of equity capital

P = price of asset (or present value of a future stream of dividends)

$$\text{then } P = \frac{D}{(1+k)} + \frac{D\,(1+g)}{(1+k)^2} + \frac{D\,(1+g)}{(1+k)^3} + \ldots\ldots + \frac{D\,(1+g)}{(1+k)^t}$$

This equation represents the amount (P) an investor will be willing to pay *today* for a share of common equity with a given dividend stream over (t) periods.

Reducing the formula to an infinite geometric series, we have:

$$P = \frac{D}{k - g}$$

Solving for k yields:

$$k = \frac{D}{P} + g$$

Q. DO INVESTORS IN UTILITY COMMON STOCKS REALLY USE THE DCF MODEL IN MAKING INVESTMENT DECISIONS?

A. Yes, I believe that to be so. There are two primary reasons for my conclusion. First, there is much literature that supports the fact that, while emotional or so-called "irrational" behavior in the short term may affect (and has affected) share prices, over the long term a company's financial fundamentals drive the market.[64] Secondly, analysts give great weight to earnings, dividend, and book value growth in formulating their recommendations to clients.

Thus, in today's market environment, investors will likely calculate (or seek a calculation of) the amount of funds they will receive relative to the initial investment, which is defined as the current dividend yield, as well as the amount of funds that the investor can expect in the future from the growth in the dividend. The combination of the current dividend yield and the future growth in dividends is central to the basic tenet of the DCF Model.

Q. IS THE DCF FORMULA STRAIGHTFORWARD?

A. Yes. While the DCF formula as outlined above may appear complicated, it is a relatively straightforward model. To determine the total rate of return one expects from investing in a particular equity security, the investor adds the dividend yield, which they expect to receive in the future, to the expected growth in dividends over time.

Q. CAN YOU PROVIDE AN EXAMPLE?

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[64] See, for example, "*Valuation: Measuring and Managing the Value of Companies*", 4th Edition, McKinsey & Company Inc., Tim Koller, Marc Goedhart, David Wessels ("Provided that a company's share price eventually returns to its intrinsic value in the long run, managers would benefit from using a discounted-cash-flow approach for strategic decisions. What should matter is the long-term behavior of the share price of a company, not whether it is undervalued by 5 or 10 percent at any given time." http://www.mckinsey.com/business-functions/strategy-and-corporate-finance/our-insights/do-fundamentalsor-emotionsdrive-the-stock-market (Date Accessed March 2, 2016). See also, for example, http://www.businessinsider.com/what-drives-the-stock-market-2012-8 (Date Accessed March 2, 2016).

A. Yes. If investors expect a current dividend yield of 5%, and also expect that dividends will grow at 4%, then the DCF model indicates that investors would buy the utility's common stock if it provided an ROE of 9%.

Q. WHAT DIVIDEND YIELD DO YOU THINK IS APPROPRIATE FOR USE IN THE DCF MODEL?

A. I have calculated the appropriate dividend yield by averaging the dividend yield expected to be paid over the next 12 months for each comparable company, as reported by the *Value Line Investment Survey*. The period covered is from September 25, 2020 through December 18, 2020. To study the short-term, as well as long-term, movements in dividend yields, I examined the 13-week, 4-week, and 1-week dividend yields for my comparable group. These results appear in **Exhibit KWO-2** and show an average dividend yield for the 13-week period of 3.7%, the 4-week period of 3.5%, and the 1-week period of 3.6% for the comparable company proxy group. I have also presented the results for Exelon within **Exhibit KWO-2** as PECO's parent company. The values for Exelon over these same periods were 4.0%, 3.8%, and 3.9%, respectively.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE DIVIDEND YIELD RANGES DISCUSSED ABOVE.

A. I developed the dividend yield range for my comparable company proxy group by averaging each company's *Value Line* forecasted 12-month dividend yield over the above-stated periods, as well as examining the most recent forecasted 12-month dividend yield reported by *Value Line* for each company. I averaged the dividend yield over multiple time periods in order to minimize the possibility of an isolated event skewing the DCF results.

Q. HOW DID YOU DERIVE THE EXPECTED DIVIDEND GROWTH RATE?

A. I used several methods in determining the growth in dividends that investors expect. These methods are, (1) the plowback ratio, (2) historical EPS, DPS, and BPS growth rates, and (3) forecasted EPS, DPS, and BPS growth rates.

The first method I used was an analysis commonly referred to as the "plowback ratio" method. If a company is earning a rate of return (r) on its common equity, and it retains a percentage of these earnings (b), then each year the earnings per share (EPS) are expected to increase by the product (br) of its earnings per share in the previous year. Therefore, br is a good measure of growth in dividends per share. For example, if a company earns 10% on its equity and retains 50% of that 10% (*i.e.,* with the other 50% of the 10% earnings on equity being paid out in dividends), then the expected growth rate in earnings and dividends is 5% (*i.e.*, 50% of 10%). To calculate a plowback for the comparable group, I used the following formula:

$$g = \frac{br(2018) + br(2019) + br(2020E) + br(2023E\text{-}2025E\ Avg)}{4}$$

The plowback estimates for all companies in the comparable company proxy group can be obtained from *The Value Line Investment Survey* under the title "*percent retained to common equity*". **Exhibit KWO-2** and **Exhibit KWO-3** list the plowback ratios for each company in the comparable company proxy group. **Exhibit KWO-5, page 2** shows the related calculations and results for this method with the plowback values being added to the dividend yield averages for the time periods of 1-week, 4-weeks, and 13-weeks. **Exhibit KWO-6** then shows these related calculations and results for PECO's parent company, Exelon.

Q. PLEASE DESCRIBE THE SECOND METHOD YOU USED TO DEVELOP THE EXPECTED DIVIDEND GROWTH RATE.

A. A key component in the DCF Model is the expected growth in dividends. In analyzing the proper dividend growth rate to use in the DCF Model, the analyst must consider how dividends are created. Since over the long-term, dividends cannot be paid out without a corporation first earning the funds paid out, earnings growth is a key element in analyzing what if any growth can be expected in dividends. Similarly, what remains in a corporation after it pays its dividend is reinvested, or "plowed back", into a corporation in order to generate future growth. As a result, book value growth is another element that, in my opinion, must be considered in analyzing a corporation's expected dividend growth.

Therefore, to analyze the expected growth in dividends, I believe the analyst should also examine the historical record of past earnings, dividends, and book value. Hence, the second method I used to estimate the expected growth rate was to analyze the historical 10-year and 5-year historical compound annual rates of change for earnings per share (EPS), dividends per share (DPS), and book value per share (BPS) as reported by *Value Line* for each of the relevant corporations. My reasoning for also utilizing historical growth rates for EPS, DPS, and BPS, rather than solely relying upon forecasted growth rates is that historical growth rates capture the actual growth of the various rates over time based upon a Company's reported results. In contrast, forecasted growth rates are derived entirely from analyst projections, which can vary from analyst to analyst, and which also have a tendency to be overstated. As such, I have always found it important to use both historical and forecasted growth rates.

Q. DO ALL ANALYSTS UTILIZE HISTORICAL GROWTH RATES WITHIN THEIR DCF MODELS?

A. No, certain analysts do not present historical growth rates in their DCF analyses. This is true for Mr. Moul as evidenced through his DCF calculations in **Schedule 1** on page 2 of **PECO Exhibit PRM-1**, where Mr. Moul only factors forecasted growth rates from **Schedule 9** on page 17 of **PECO Exhibit PRM-1** into his DCF analysis. Mr. Moul explains this choice through the following passage of his testimony:

> *While historical data cannot be ignored, it is much less significant in applying the DCF model than projections of future growth. Investors cannot purchase the past earnings of a utility. To the contrary, they are only entitled to future earnings, which are the focus of growth projections. Furthermore, if significant weight is assigned to historical performance, the historical data are double*

counted because they are already factored into analysts' forecasts of earnings growth.[65]

While Mr. Moul presents the historical growth rates for his proxy group as of May 29, 2020 on **Schedule 8** on page 16 of **PECO Exhibit PRM-1**, nowhere within his DCF calculations does he factor in historical growth rates as explained in the selection from his testimony provided above. I believe that analysts who do not present the readily available historical data fail to provide the full extent of information on which investors base their expectations. While it is true that growth rates are inherently the rate that one would expect a company's stock to grow into future years, both historical growth rates and forecasted growth rates provide valuable data for what one can expect the ultimate growth rate for an individual stock will be. In order to present the full breadth of the available information, both historical and forecasted growth rates should be used. I believe this to be even more important given the current economic climate and market uncertainty caused by the COVID-19 pandemic. By focusing his entire analysis on forecasted growth rates, Mr. Moul is ignoring the value in historical growth rates that are readily available.

I note that *Value Line* is the most recognized investment publication in the industry and, as such, is used by professional money managers, financial analysts, and individual investors worldwide. A prudent investor tries to examine all aspects of an enterprise's performance when making a capital investment decision. As such, it is only practical to examine historical growth rates, in addition to the forecasted growth rates, for the corporation for which the analysis is being performed. **Exhibit**

[65] Witness Moul Direct Testimony, page 28: lines 13-19.

KWO-7 lists the historical and forecasted growth rates for the comparable company proxy group, and **Exhibit KWO-5, page 1** lists the related calculations and results for this method, with the historical and forecasted growth rate values being added to the dividend yield averages for the time periods of 1-week, 4-weeks, and 13-weeks. Also note that **Exhibit KWO-6**, **page 1** shows these results should this analysis be performed directly on PECO's parent company, Exelon.

Also note that Mr. Moul has sourced the historical and forecasted growth rates for his comparable company proxy group as presented in **Schedule 8** and **Schedule 9** of **pages 15** and **16** of **PECO Exhibit PRM-1**, respectively, from company-specific *Value Line Investment Surveys* from May 29, 2020. Additional company-specific *Value Line Investment Surveys* were made available by *Value Line* on August 28, 2020. Mr. Moul has not only neglected to use historical growth rates within his DCF Model, but he has opted to use forecasted growth rates that were outdated at the time that he filed his testimony on September 30, 2020.

Q. SHOULD ONLY EARNINGS (EPS) GROWTH RATES BE CONSIDERED IN THE DCF METHODOLOGY?

A. No, I do not believe it is appropriate to strictly rely upon EPS growth rates. Since the DCF formula is dependent on future *dividend* growth, I believe that it would be inaccurate to use only earnings growth rates in the DCF. Doing so produces unrealistically high return on equity numbers that cannot be sustained indefinitely. To mitigate this problem, I have presented EPS, DPS, and BPS figures and have explained my rationale for arriving at the corresponding growth rates. I believe it is incumbent upon every analyst to present such a robust analysis.

Q. PLEASE DESCRIBE THE THIRD METHOD YOU USED TO DEVELOP THE EXPECTED DIVIDEND GROWTH RATE.

A. The third method I used was forecasted EPS, BPS and DPS growth rates. I have obtained forecasted growth rates from the following data sources:

- Forecasted compound annual rates of change for earnings per share, dividends per share, and book value per share as provided by *Value Line*;
- Forecasted 3-year projected rate of change for earnings per share as recorded by the *Center for Financial Research and Analysis* (*i.e., CFRA*), a publication of S&P Global Market Intelligence; and
- Forecasted LT 3-5-year earnings growth rates, as provided by *Charles Schwab & Co (i.e., Schwab).* This forecasted rate of change is not a forecast developed solely by *Schwab*, but is – instead – a compilation of forecasts by industry analysts.

As such, the three methods referenced above all represent forecasted growth rates, but are sourced from three separate financial evaluation agencies, *Value Line, CFRA,* and *Schwab*.

Exhibit KWO-2 lists the forecasted growth rates for the comparable company proxy group and **Exhibit KWO-5, page 1** lists the related calculations & results for this method with the forecasted growth rate values being added to the dividend yield averages for the time periods of 1-week, 4-weeks, and 13-weeks. Also note that **Exhibit KWO-6**, **page 1** shows these results should this analysis be performed directly on PECO's parent company, Exelon. My ultimate DCF result range can be found on **Exhibit KWO-1**.

Q. HOW SHOULD THE RESULTS PRESENTED IN YOUR EXHIBITS BE VIEWED IN LIGHT OF FUNDAMENTAL DEVELOPMENTS IN THE NATURAL GAS UTILITY INDUSTRY THAT HAVE OCCURRED DURING THE PAST TEN PLUS YEARS?

A. As the Commission is aware, natural gas prices have plummeted since 2008. As a result of the drastically lower natural gas prices, many electric utilities and power generators across the country are planning to meet their future electric generation requirements through the use of natural gas. Distribution utilities that derive profits from the delivery of natural gas are now in high demand. For example, in 2016, AGL Resources and Piedmont Natural Gas were both sold to their neighboring electric utilities at sizable premiums. Remaining gas utilities are achieving solid growth as natural gas is in high demand across the country.

Q. WHAT IS THE INVESTOR RETURN REQUIREMENT FROM THE DCF ANALYSIS FROM A DIVIDEND YIELD PERSPECTIVE?

A. As shown in **Exhibit KWO-2** and **Exhibit KWO-5**, the average dividend yield for the comparable company proxy group for the 13-week period was 3.7%, the 4-week time period was 3.5%, and the 1-week period was 3.6%.

Additionally, note that within this section of my testimony, as well as within the accompanying exhibits, I have also included reference to the results specific to Exelon as PECO Energy – Gas Division's ultimate parent company. I have provided this additional information as a means to outline specific DCF analysis information for the company with the most direct link to PECO Energy – Gas Division. Note however, that with Exelon being an electric utility, the results specific to Exelon tend to differ slightly from the results for the natural gas company proxy group comparable to PECO Energy – Gas Division. This is expected given the data previously presented within **Table 4** with respect to differences in returns granted to electric and natural gas utilities. Therefore, as shown in **Exhibit KWO-2** and **Exhibit KWO-6**, the average dividend yield for Exelon for the 13-week period was 4.0%, the 4-week time period was 3.8%, and the 1-week time period was 3.9%.

Q. WHAT IS THE INVESTOR RETURN REQUIREMENT FROM THE DCF ANALYSIS FROM A HISTORICAL GROWTH RATE PERSPECTIVE?

A. In terms of the proper dividend growth rate to employ for the comparable company proxy group in the DCF analysis, it is appropriate to examine the recent history of earnings and dividend growth to assess and provide the best estimate of the dividend growth that investors expect in the future.

Within **Exhibit KWO-2**, I have presented the complete set of data for the entirety of the comparable company proxy group without any of the companies removed from the comparable company proxy group as published by *Value Line*.

The data and calculations shown therein at **Exhibit KWO-2** is the information that my recommendation was developed from.

An examination of the 10-year and 5-year historical growth rates for the comparable company proxy group within this exhibit show a difference between the average earnings and dividend growth rates. For the 10-year history, dividends per share (4.9%) grew faster than earnings per share (3.4%) in the comparable company proxy group.

However, if one were to remove the -11.0% growth rate for Northwest Natural Gas' EPS, the now shown 5.2% earnings per share return over the past 10 years is much more in line with the 10-year historical dividends per share of 4.9%. The same situation is also evident in the 5-year historical growth rates. If one were to remove the -17.0% for Northwest Natural Gas' EPS, the average 5-year EPS for the proxy group changes from 2.9% to 5.1%, which is much more in line with the 5-year average DPS growth rate of 6.0%. Additionally, the historical growth rates for Exelon ranged from -3.0% to 4.5% over the 5-year historical period and -4.5% to 6.5% over the 10-year historical period.

In consideration of the above-stated conditions and in light of the impact that Northwest Natural Gas has on the overall results, the proxy group's historical EPS, DPS, and BPS growth rates are all between approximately 3.0% to 5.0% (see **Exhibit KWO-2**), which indicates that the natural gas utility industry has historically experienced solid and steady growth in earnings, dividends, and book value. As such, I believe that the proper historical growth rate range to be factored into expectations within the DCF Model is approximately 3.0% to 5.0%. The DCF results based on the set of data previously mentioned for the entirety of the proxy group can be found in **Exhibit KWO-5, pages 1-2** and the related results for Exelon can be found in **Exhibit KWO-6, pages 1-2**.

Q. WHAT IS THE INVESTOR RETURN REQUIREMENT FROM THE DCF ANALYSIS FROM A FORECASTED GROWTH RATE PERSPECTIVE?

A. The forecasts of the comparable company proxy group's various growth rates are consistent with the understanding that natural gas is growing in prominence in the energy industry around the country. The forecasted growth rates from *Value Line* for the proxy group range from 5.6% (DPS) to 9.5% (EPS). However, again we note that the high end (9.5%) of the proxy group range is significantly influenced by the 24.5% forecasted EPS for Northwest Natural Gas from *Value Line*. If one were to remove that one growth rate, the average for *Value Line's* forecasted earnings per share is reduced from 9.5% to 7.8%. If one were to remove Northwest Natural Gas from the forecasted rates entirely as presented within **Exhibit KWO-2**, the forecasted growth rates from *Value Line* for the proxy group ranges from 6.2% to 7.8%. Additionally, the forecasted *Value Line* growth rates for Exelon ranged from 4.5% (*Value Line* EPS and BPS) to 5.5% (*Value Line* DPS).

In addition to the above forecasted *Value Line* growth rates, the average plowback (retained to common equity) growth rate for the proxy group is 4.3% (**Exhibit KWO-2** and **Exhibit KWO-3**), the *CFRA* 3-year forecasted EPS growth rate is 6.4% (**Exhibit KWO-2**), and the *Schwab* LT Growth Rate 3-5 year forecasted earnings growth rate is 5.5% (**Exhibit KWO-2**). These values for Exelon were 3.7%, 4.0%, and -2.4%, respectively.

In consideration of the above-stated conditions and in light of the impact that Northwest Natural Gas has on the overall results, the proxy group's forecasted EPS, DPS, and BPS growth rates are all between approximately 5.0% to 7.0% (see **Exhibit KWO-2**), which indicates that the natural gas utility industry is expecting solid and steady growth in earnings, dividends, and book value in the future. As such, I believe that the proper forecasted growth rate range to be factored into expectations within the DCF Model is approximately 5.0% to 7.0%. The DCF results based on the set of data previously mentioned for the entirety of the proxy group can be found in **Exhibit KWO-5, pages 1-2** and the related results for Exelon can be found in **Exhibit KWO-6, pages 1-2**.

Q. HOW DOES THE COVID-19 PANDEMIC IMPACT YOUR COST OF EQUITY FOR PECO IN THIS CASE?

A. The COVID-19 pandemic has had a dramatic impact on the equity markets, as well as long-term growth prospects for PECO. Prior to the COVID-19 pandemic, growth for gas utilities was perceived to have strong growth prospects for many years to come. However, following the pandemic, the markets have come to realize that the US economy will take quite a while to fully recover. During an interview with CBS 60 Minutes from May 13, 2020, Federal Reserve Chairman Jerome Powell stated that he expected that the US economy will take over a year to recover as evidenced from the following quote:

> *It may take a while. It may take a period of time. It could stretch through the end of next year…I will say that it's a reasonable assumption that the economy will begin to recover in the second half of the year, that unemployment will move down, that economic activity will pick up.… And I think it's a reasonable expectation that there'll be growth in the second half of the year. I would say though we're not going to get back to where we were quickly. We won't get back to where we were by the end of the year. That's unlikely to happen.*[66]

Fed Chairman Powell's comments are reflected in current yields in fixed income markets. On May 20, 2020, the *Wall Street Journal* stated the following in regard to bond yields and the future market recovery:

> *Yields on U.S. government bonds have stalled near all-time lows, a sign that investors are anticipating a difficult economic recovery and years of aggressive monetary stimulus.*
>
> *For much of the past month and a half, the yield on the benchmark 10-year U.S. Treasury note has hovered around two-thirds of a percentage point—a shade above its all-time low of around 0.5% set in March.*
>
> *Taken together, the low level of the 10-year yield and its stability suggest that bond investors not only hold a dreary economic outlook but also are unusually confident in that perspective, a contrast with the optimism that has carried stocks to their highest levels since early March.*[67]

Federal Reserve Chairman Powell later reinforced his assertions from May 2020 by noting that although there was economic growth seen during the second half of 2020, the timeline for a full economic recovery was still uncertain. Refer to the following quote from Chairman Powell from December 1, 2020:

> *Economic activity has continued to recover from its depressed second quarter level. The reopening of the economy led to a rapid*

[66] https://www.cbsnews.com/news/full-transcript-fed-chair-jerome-powell-60-minutes-interview-economic-recovery-from-COVID-19-pandemic/

[67] https://www.wsj.com/articles/behind-bond-markets-stall-investors-see-hard-times-ahead-11589967001?mod=hp_lead_pos4

rebound in activity, and real gross domestic product, or GDP, rose at an annual rate of 33 percent in the third quarter. In recent months, however, the pace of the improvement has moderated…The economic downturn has not fallen equally on all Americans, and those least able to shoulder the burden have been the hardest hit...The economic dislocation has upended many lives and created great uncertainty about the future…As we have emphasized throughout this pandemic, the outlook for the economy is extraordinarily uncertain…[68]

The comments from Fed Chairman Powell in conjunction with the selection included above from the *Wall Street Journal*, indicate that investors should tamp down expectations of a quick and lasting recovery. The information used in my analysis encompasses the data from the initial onset of the COVID-19 pandemic during Q1 and Q2 2020, as well as the market's recovery in both Q3 and Q4 2020. As a result, any decrease in the growth rates for the gas utility comparable group are already reflected in the sources, thereby recognizing that even though the recovery has begun, the US economy has significant headwinds ahead.

Q. PLEASE PROVIDE THE SPECIFIC RESULTS OF YOUR DCF ANALYSIS.

A. The average dividend yield for the comparable company proxy group for the 13-week period was 3.7%, the 4-week time period was 3.5%, and the 1-week period was 3.6%. Additionally, the average dividend yield for Exelon for the 13-week period was 4.0%, the 4-week time period was 3.8%, and the 1-week time period was 3.9%. With the second portion of the DCF analysis relating to growth rates, I

[68] https://www.federalreserve.gov/newsevents/testimony/powell20201201a.htm

note that the historical growth rate range approximates 3.0% to 5.0% and the forecasted growth rate range approximates 5.0% to 7.0%.

I have included both historical and forecasted growth rate figures within my analysis as previously noted. However, due to the negative growth impact of COVID-19, as well as the fundamental changes that have occurred in the natural gas utility industry over the past ten years that I mentioned previously, I believe that it is proper to place more weight on forecasted figures than historical figures in estimating the cost of equity for the comparable group. As a result, I believe that the proper growth rate range for the comparable group of companies to use in the DCF analysis is 4.25% to 6.25%. This 4.25% to 6.25% growth rate estimate embodies the approximate range of the historical and forecasted growth rates as presented in **Exhibit KWO-5**.

As such, I have presented **Table 9** below which showcases the Dividend Yield Range values from the 13-week, 4-week, and 1-week dividend yield periods, plus the Historical Growth Rates from *Value Line*, the Forecasted Growth Rates from *Value Line*, *CFRA*, and *Schwab*, and the Plowback Growth Rates from *Value Line* for both my comparable company proxy group, as well as for PECO's parent company Exelon.

Table 9: DCF Results

DCF Results: Proxy Group (**Exhibit KWO-5**)			
	Minimum	Average	Maximum
Value Line Historical Growth Rate Averages + Value Line Div Yield Range	6.7%	8.2%	9.2%
Value Line Forecasted Growth Rate Averages + Value Line Div Yield Range	9.1%	10.4%	13.2%
Value Line Plowback Growth Rate Averages + Value Line Div Yield Range	8.0%	7.8%	7.8%
DCF Results: Exelon Parent Company (**Exhibit KWO-6**)			
	Minimum	Average	Maximum
Value Line Historical Growth Rate Averages + Value Line Div Yield Range	0.6%	4.6%	9.2%
Value Line Forecasted Growth Rate Averages + Value Line Div Yield Range	1.4%	6.7%	9.5%
Value Line Plowback Growth Rate Averages + Value Line Div Yield Range	7.7%	7.6%	7.6%

My ultimate DCF result range of 7.75% to 10.00% as shown in **Exhibit KWO-1** was determined based upon a review of the values shown in the table above. This range was developed as the low end of 7.75% is just below the midpoint of the average of the minimum values for the proxy group (7.9%) from the values in the table above sourced from **Exhibit KWO-5** and the high end of 10.00% aligns with the midpoint of the average of the maximum values for the proxy group (10.1%) from the values in the table above sourced from **Exhibit KWO-5**.

B. <u>Comparable Earnings Analysis (CEA)</u>

Q. PLEASE EXPLAIN HOW YOU PERFORMED THE COMPARABLE EARNINGS ANALYSIS?

A. I have conducted two different Comparable Earnings Analyses. The first examines returns on book value equity for the comparable group. The second examines allowed natural gas utility returns over an extended period of time to evaluate the trend in returns for companies of similar risk. However, as I have stated previously, I believe the CEA to be inferior to the DCF Model and that it should be given less weight in the determination of the ROE recommended in this case.

Q. PLEASE DESCRIBE YOUR FIRST COMPARABLE EARNINGS ANALYSIS?

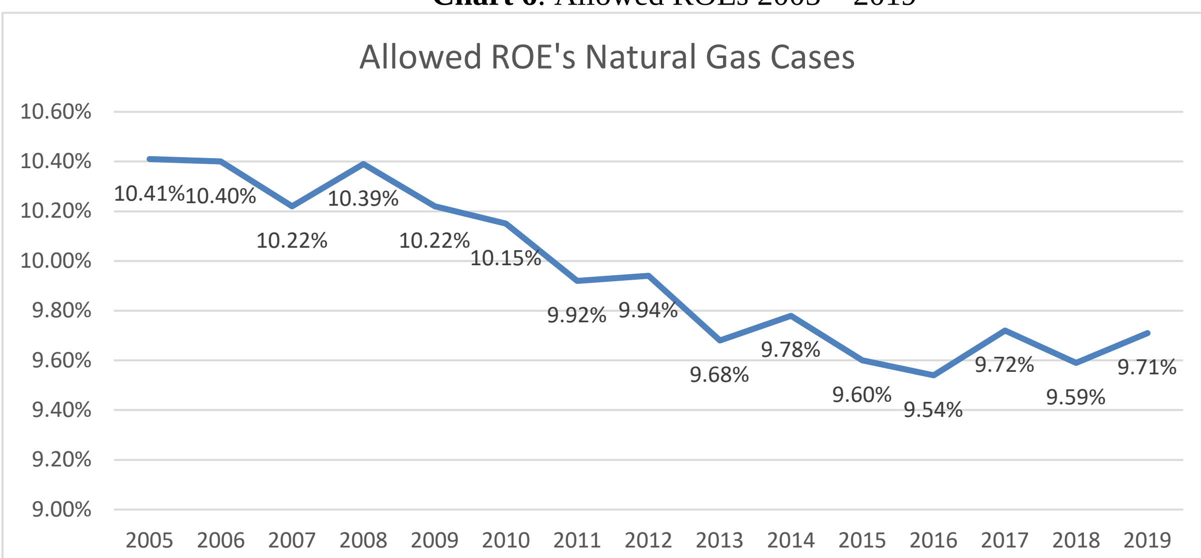
A. As noted above, an appropriate CEA should be applied to companies of similar risk. **Exhibit KWO-4** presents a list of historic and forecasted earned returns *on book value equity* of the proxy group over the period of 2018 through 2025E. I picked this range to provide the Commission with at least two periods of historical returns (*i.e.*, 2018 and 2019) and a forecasted return period of at least 5 years (*i.e.*, 2020E through 2025E). As can be seen in this exhibit, the average earned returns on equity for the comparable company proxy group range from 8.9% (2020E) to 10.4% (2018). Additionally, for PECO's parent company Exelon, this range was from 6.5% (2018) to 9.1% (2019).

Q. DO YOU HAVE ANOTHER COMPARABLE EARNINGS METHODOLOGY TO PRESENT IN THIS CASE?

A. Yes. It is important to understand what state regulatory commissions across the country are allowing for authorized ROEs. Allowed ROEs are widely known and discussed in the financial community and investors take these regulatory decisions into account when they bid prices in the open market for which they are willing to purchase the stock of a regulated utility.

As this Commission is likely aware, regulated ROEs have trended down over the past 15 years. Below, **Chart 6** shows the ROEs authorized for natural gas utilities by state regulators across the United States from 2005 through 2019. The average of the allowed ROEs over this period is 9.95% based on the data presented below.

Chart 6: Allowed ROEs 2005 – 2019



Source: *S&P Global Market Intelligence Rate Case Statistics; Date Range: 15 Years; Service Type: Natural Gas; Chart Items: Return on Equity (%); Date Accessed: October 19, 2020.*

As for the most recent year, 2019, the overall allowed ROE for natural gas utilities was 9.71%, which was up slightly from the 9.59% allowed by state regulators for natural gas utilities in 2018. However, for Q1, Q2 and Q3 2020, the average allowed ROE for natural gas utilities declined to 9.35%, 9.55%, and 9.52%, respectively.[69]

Q. WHAT CONCLUSIONS DO YOU DRAW FROM YOUR TWO COMPARABLE EARNINGS ANALYSES?

A. As noted previously, natural gas utilities are expected to have strong growth in the future due to the abundance of cheap natural gas now produced in the United States and the increasing demand for natural gas services. Electric generation companies, for example, are turning almost entirely now to constructing natural gas generation plants as opposed to nuclear and coal units. Hence, the strength in the natural gas industry should continue unabated for several years to come.

Regulators across the United States have continued to recognize the decrease in capital cost and as shown above in **Chart 5**, they have steadily reduced the allowed returns of utilities over the past 15 years.

Based on the above-stated findings, I believe the proper rate of return using a CEA is in the range of 9.25% to 10.25%. The 9.25% lower end of this range is slightly below the average comparable earnings range from 2018 – 2025E for the proxy group shown in **Exhibit KWO-4** of 9.5% and is close to the ROE granted by state regulators in 2019 of 9.71% (see **Chart 6**). The 10.25% high end of the

[69] S&P Global Market Intelligence Rate Case Statistics; Frequency: Quarterly; Date Range: 01/01/2020 – 10/29/2020; Service Type: Natural Gas; Chart Items: Return on Equity (%); Date Accessed: October 19, 2020.

range is slightly below the high end of the range for the comparable company proxy group from 2018 – 2025E shown in **Exhibit KWO-4** of 10.40%.

I have completed the Comparable Earnings Analyses as referenced above to provide the relevant data for the comparable group's book value equity, as well as the authorized and allowed returns across the industry over an extended period of time. However, as previously noted, it is my opinion that the DCF Model produces the most reliable results in determining an appropriate ROE. Additionally, I view the CAPM as a model that is appropriate to utilize as a check on the results of the DCF Model. Note that this is also true specific to cases in Pennsylvania, as the Pennsylvania Utility Commission has historically used the CAPM as a check on the reasonableness of the results derived from the DCF analysis as well.[70] Furthermore, given the current volatile economic climate brought on by the COVID-19 pandemic, the CEA does not appropriately capture the economic impacts of the pandemic within the output of the Model. As such, I believe that the CEA should be given much less weight in the determination of the ROE recommended in this case.

C. <u>Capital Asset Pricing Model (CAPM)</u>

Q. HAVE YOU PREVIOUSLY PRESENTED THE CAPM IN COST OF EQUITY TESTIMONIES?

[70] Pa. P.U.C. v. UGI Utilities – Electric Division, Opinion and Order at 119, Docket No. R-2017-2640058 (Oct. 25, 2018).

A. Yes, but I have not given it as much weight in comparison to the DCF Model. I have long maintained the application of the CAPM can lead one to erroneous results when it is applied in an inaccurate manner, such as when forecasted risk premiums or forecasted interest rates are employed. However, I am aware that some Commissions around the country are seeking review of models other than the DCF Model. For example, as previously mentioned within this testimony, it is notable that the Pennsylvania Utility Commission has historically used the CAPM as a check on the reasonableness of the results derived from the DCF Model.[71] As a result, I have included the CAPM in my analyses to supplement my DCF analysis as well as my CEA.

Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL.

A. The CAPM is a risk premium model that determines a firm's ROE relative to the overall market ROE. The formula for the CAPM is as follows:

$$ROE = Rf + Beta\,[E(RM) - Rf]$$

Where:

Rf is the risk-free rate;

Beta is the risk of the studied company relative to the overall market; and

E(RM) is the expected return on the market.

[71] Pa. P.U.C. v. UGI Utilities – Electric Division, Opinion and Order at 119, Docket No. R-2017-2640058 (Oct. 25, 2018).

To be specific, the CAPM is a measure of firm-specific risk, known as unsystematic risk and measured by beta, as well as overall market risk, otherwise known as systematic risk and measured by the expected return on the market.

The CAPM calculates ROE based on a company's risk and can be restated as follows:

$$ROE = Rf + (Beta * Risk\ Premium)$$

Where:

Risk Premium represents the adjusted company-specific risk of the company.

Q. HOW IS THE RISK-FREE RATE MEASURED?

A. The risk-free rate is designated as the yield on United States government bonds as the risk of default is seen as highly unlikely. Utility witnesses and consumer witnesses all use United States government bond yields as the risk-free rate in the CAPM. However, what is often debated in the risk-free portion of the CAPM is the term of those bonds. In my analysis for this case, I have developed risk premiums relative to the 30-year US Treasury bonds as this time period is the longest available in the marketplace, thereby affording consumers the longest protection at the risk-free rate. **Chart 1**, above, provides the yield on 30-year U.S. Treasury bonds over the period outlined in the chart.

Q. IS THE CURRENT LEVEL OF INTEREST RATES EXPECTED TO CHANGE MATERIALLY IN THE FORESEEABLE FUTURE?

A. Economic forecasters, as well as the FOMC, all believed in previous years that the current interest rate environment was expected to remain relatively stable for many years to come.

However, the FOMC cut rates during 2019 and then, in its December 2019 meeting, announced plans to keep interest rates at current levels throughout 2020.[72] Note however, that this was before the COVID-19 pandemic that played havoc on the markets throughout during Q1 and Q2 2020 before the market began to rebound during Q3 and Q4 2020. In response to the impact that the pandemic had on the market, on March 3, 2020 the FOMC decreased the Federal Funds Rates 50-basis points to a targeted range of between 1% and 1.25% in response to recent market conditions.[73] Additionally, on March 16, 2020 the FOMC dropped interest rates to near 0%.[74] As such, the interest rate market has been unexpectedly turbulent due to the COVID-19 pandemic throughout the 2020. The interest rates are thus expected to fluctuate again throughout the remainder of 2020 based on the results of the overall response to the pandemic.

Q. HOW IS BETA MEASURED IN THE CAPM?

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[72] Rugaber, C., *Federal Reserve leaves interest rates unchanged and foresees no moves in 2020*, PBS News Hour (Dec. 11, 2019), available at: https://www.pbs.org/newshour/economy/federal-reserve-leaves-interest-rates-unchanged-and-foresees-no-moves-in-2020.

[73] https://www.cnbc.com/2020/03/03/fed-cuts-rates-by-half-a-percentage-point-to-combat-COVID-19-slowdown.html

[74] https://www.federalreserve.gov/newsevents/pressreleases/monetary20200315a1.htm.

A. Beta is a statistical calculation of a company's stock price movement relative to the overall stock movement. A company whose stock price is less volatile than the overall market will have a beta less than 1.0. A company whose stock price is more volatile than the overall market will have a beta more than 1.0. Since utilities are generally conservative equity investments, utility betas are almost always less than 1.0.

Q. WHAT IS THE CURRENT MARKET RISK PREMIUM APPROPRIATE FOR USE IN THE CAPM?

A. The development of the current market risk premium is, undoubtedly, the most controversial aspect of the CAPM calculations. To gauge the historical risk premium, I turned to the Ibbotson database published by *Morningstar, Duff & Phelps*, and the *CFA Institute Research Foundation*. The long-term geometric and arithmetic returns for both equities and fixed income securities and the resulting risk premiums are presented below in **Table 10**.

Table 10: Equity Risk Premium Calculations

Asset Class	Geometric Mean	Arithmetic Mean
Large Company Stocks	10.7%	12.1%
Long-Term Govt. Bonds	8.0%	8.7%
Resulting Risk Premium	2.7%	3.4%

***Source**:* Ibbotson ® SBBI ®, 2020 Classic Yearbook: Stocks, Bonds, Bills and Inflation, 1972 – 2019 (Chicago: Morningstar, 2020).

Note that the above data from **Table 10** shows the statistics of annual total returns for large company stocks and long-term government bonds from 1972 to 2019. With this data being more recent than similar data provided over the period from 1926 to 2019, this data adds more credence to what a reasonable investor can expect for a return based upon more historically recent data.

Q. WHAT MARKET RETURNS ARE WELL-KNOWN PROFESSIONAL INVESTORS EXPECTING FOR THE FORESEEABLE FUTURE?

A. On April 23, 2020, *Morningstar.com* published an article entitled "*Experts Forecast Stock and Bond Returns: Crisis Edition.*"[75] This article was provided in response to the COVID-19 pandemic as an update to Morningstar's annual stock and bond return forecasts that was originally published during the year in January 2020.

[75] https://www.morningstar.com/articles/979744/experts-forecast-stock-and-bond-returns-crisis-edition

Note that by referring to future returns, the market experts referenced below are discussing total market returns, and not just the equity risk premium. Below are some of the market return forecasts from the previously referenced article:

<u>Grantham Mayor Van Otterloo (GMO)</u>

Negative 1.5% real returns for US large caps over the next seven years.[76]

<u>Morningstar Investment Management</u>

4.6% 10-year nominal returns for US stocks.[77]

<u>Research Affiliates</u>

1.5% real returns for US large caps during the next 10 years.[78]

<u>Vanguard</u>

Nominal equity market returns of 4.8% to 7.8% over the next decade.[79]

The above-stated equity returns display a very large range. On the low side is *GMO*, which forecasts that US large caps will, after inflation, lose 1.5% of asset value annually over the next seven years. On the more positive side is *Vanguard* that expects nominal equity market returns ranging between 4.8% and 7.8% over the next decade.

Additionally, Charles Schwab published an article on June 23, 2020 titled "*Why Market Returns May Be Lower and Global Diversification More Important*

[76] *Id.*
[77] *Id.*
[78] *Id.*
[79] *Id.*

in the Future".[80] This article noted that market returns on stocks and bonds over the next decade are expected to be beneath that of historical averages from 1970 to March 2020. Specifically, this article indicated that *Schwab's* estimates show that over the next decade for US large-capitalization stocks, the annual expected return is forecasted to be 7.1%.[81]

I also note that prior to the pandemic in 2018, Duke University finance professors published equity risk premium estimates that stated the expected average risk premium exhibited by a survey of U.S. Chief Financial Officers around the country is 4.42%.[82] The article states as follows:

> *During the past 18 years, we have collected almost 25,000 responses to the survey. Panel A of Table 1 presents the date that the survey window opened, the number of responses for each survey, the 10-year Treasury bond rate, as well as the average and median expected excess returns. There is relatively little time variation in the risk the historical risk premiums contained in Table 1.* ***<u>The current premium, 4.42%, is above the historical average of 3.64%</u>****. The December 2017 survey shows that the expected annual S&P 500 return is 6.79% (=4.42%+2.37%) which is slightly below the overall average of 7.11%. The total return forecasts are presented in Fig. 1b.2"*[83]

Q. WHAT IS YOUR CONCLUSION AS TO THE ESTIMATED EQUITY RISK PREMIUM FOR USE IN THE CAPM?

A. Using historical data as well as ex ante (forecasts) data, the evidence suggests the equity risk premium is clearly within the range of 4.25% to 6.25%.

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[80] https://www.schwab.com/resource-center/insights/content/why-market-returns-may-be-lower-in-the-future

[81] *Id.*

[82] "The Equity Risk Premium in 2018," John R. Graham and Campbell R Harvey, Duke University, March 28, 2018, pages 3-4.

[83] *Id*., pages 3-4. (underline and bold emphasis added)

Q. HOW DID YOU DETERMINE THE BETA YOU USED IN THE CAPM?

A. I used the *Value Line* derived Beta sourced from the most recent *Value Line* editions for each company in the comparable company proxy group.

Q. WHAT WERE YOUR CAPM RESULTS?

A. The actual calculations for the CAPM for my comparable company proxy group can be seen in **Exhibit KWO-6.**

As shown above in **Chart 1**, I have provided the change in the 30-year US Treasury bonds since PECO's most recent electric rate case (*i.e.*, December 6, 2018 – December 11, 2020). Note that over the past year (*i.e.,* December 11, 2019 through December 11, 2020), the yield on 30-year US Treasury bonds was 2.23% as of December 11, 2019 and was 1.63% as of December 11, 2020. This equates to a decrease of 60-basis points in the yield on 30-year US Treasury bonds. The Maximum value over this period was 2.39%, the Average value was 1.59%, and the Minimum value was 0.99%. Refer above to **Chart 1** for further details.

The average beta for the comparable company proxy group is 0.89 which, when multiplied by the risk premium range of 4.25% to 6.25%, produces a beta-adjusted risk premium of 3.78% to 5.56%. The 30-year US Treasury yield (Rf) range of 0.99% to 2.39% is next added to the beta-adjusted risk premium range of 3.78% to 5.56% to arrive at the comparable company proxy group CAPM result range of 4.80% (3.78% + 0.99% = 4.77%, rounded to 4.80%) to 8.00% (5.56% + 2.39% = 7.95%, rounded to 8.00%).

Additionally, the Beta for PECO's parent company Exelon is 0.95 which, when multiplied by the risk premium range of 4.25% to 6.25%, produces a beta-adjusted risk premium of 4.04% to 5.94%. The 30-year US Treasury yield (Rf) range of 0.99% to 2.39% is next added to the beta-adjusted risk premium range of 4.04% to 5.94% to arrive at the comparable company proxy group CAPM result range of 5.00% (4.04% + 0.99% = 5.03%, rounded to 5.00%) to 8.30% (5.94% + 2.39% = 8.33%, rounded to 8.30%).

Based on this range of results for the CAPM, as found in **Exhibit KWO-7**, I find the proper ROE derived from the CAPM is in the range of 5.00% to 7.75%. The low-end (5.50%) of this range is above the average of the comparable company proxy group CAPM results using the 4.0% equity risk premium (5.4%) and is aligned with the midpoint of Exelon's results using the 4.0% equity risk premium (5.7%) as well. The high end (7.75%) of the range is above the average of the comparable company proxy group CAPM results using the 6.0% equity risk premium (7.2%) and above the average of Exelon's results using the 6.0% equity risk premium (7.6%) as well.

D. <u>Return on Equity (ROE) Summary</u>

Q. MR. O'DONNELL, PLEASE SUMMARIZE THE RESULTS OF YOUR ROE ANALYSES IN THIS CASE.

A. **Table 11** below lists the results of my DCF, CEA, and CAPM analyses as outlined within **Exhibit KWO-1**.

Table 11: ROE Method Results

	ROE Results	
Method	Low	High
DCF	7.75%	10.00%
CEA	9.25%	10.25%
CAPM	5.50%	7.75%

Q. WHAT IS YOUR ROE RECOMMENDATION IN THIS PROCEEDING?

A. My recommendation in this case, should OCA Witness Scott Rubin's recommendation of no changes to the currently set rates as a result of the COVID-19 pandemic not be accepted, is shown in **Exhibit KWO-1**. This exhibit shows my recommendation that the Commission grant PECO a return on equity of 8.75%. This 8.75% ROE recommendation is close to the middle of my DCF result range. This recommendation is also above the CAPM range, which the Commission generally considers a check on the results of the DCF.

Q. THE RANGE OF RESULTS FOR THE COMPARABLE EARNINGS METHOD BASED ON BOOK RETURNS ARE HIGHER THAN THE RESULTS OF YOUR DCF ANALYSIS. IS THERE A REASON FOR THIS?

A. Yes. As previously explained, the CEA can be misinterpreted in that the return is often on book value and not a return on market value. As a result, the return on book values must be examined in light of the fact that market values, which are a primary determinant in the DCF Model, are well above book values, which are a primary determinant of the CEA. Investors cannot typically purchase stock of a company at lower book value, but must purchase at the relatively higher market price. It is for this reason that I maintain that the CEA should be used more as a check for the DCF results as the CEA is inferior to the DCF Model.

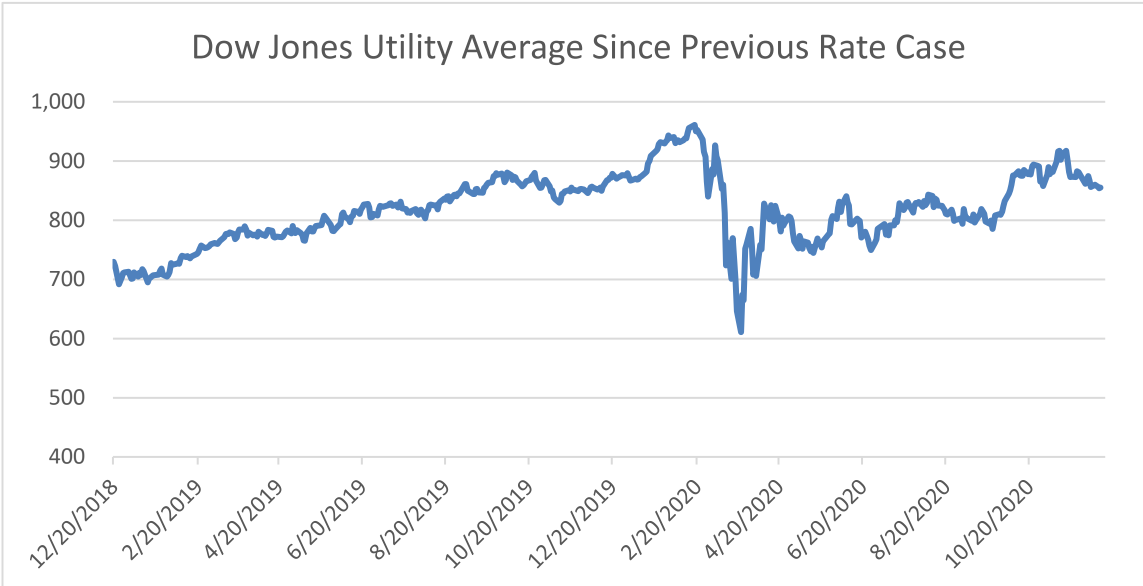
Q. SIMILARLY, THE RANGE OF RESULTS FOR THE COMPARABLE EARNINGS BASED ON ALLOWED ROES IS HIGHER THAN THE RESULTS OF YOUR DCF ANALYSIS. PLEASE EXPLAIN THE REASON FOR THIS DIFFERENCE.

A. As noted above, utility regulators have definitely noticed the declining trend in the cost of capital and the downward trend is continuing. However, market returns are much more dynamic and change every day. Regulators may not move at the pace of the general market in terms of the decline in the market cost of capital, but regulators are, without a doubt, moving in that direction as exhibited by the data included in my CEA section above.

Q. WOULD YOU PLEASE PROVIDE THE REASONS FOR YOUR RECOMMENDATION?

A. In making this recommendation, it is important to recognize the negative impact the COVID-19 pandemic has had on the United States and world economy before the market's recovery began in Q3 2020. Long-term growth prospects faced a sudden shock that have forced investors to re-examine their expectations for the future. One only need to look at **Chart 7**, below, to see how the utility market has reacted to the COVID-19 news.

Chart 7: Dow Jones Utility Average



***Source**: Yahoo Finance Date Accessed: December 14, 2020,* https://finance.yahoo.com/quote/%5EDJU/history?p=%5EDJU.

Utility prices were steadily moving upward until the COVID-19 news took over the entire news cycle and the world economy was, essentially, shut down. As noted previously, although there has been recovery within the DJUA and DJIA financial markets during Q3 and Q4 2020, Fed Chairman Powell has indicated that the overall sustainable economic recovery will take longer than many initially anticipated. In addition, the bond markets have languished into a period of lower yields thereby, again, indicating a long recovery timeframe. My point estimation of 8.75% is close to the middle of my DCF range, which I believe is the most accurate model in use by practitioners today.

Q. ARE UTILITY STOCKS CONSIDERED SAFE HAVENS AT TIMES OF ECONOMIC UNCERTAINTY?

A. Yes. Given that the United States faced a recession throughout the majority of 2020 due to the COVID-19 pandemic, and given that in general, utility stocks produce stable dividends, utilities are viewed as safe havens. The volatility of utility stocks is much less than the overall market (as exhibited by **Chart 2** above), which implies that utility stock valuations do not rise as quickly as the overall market in good times, but they also do not fall as much as the overall market in bad times.

Q. WHAT IS YOUR OVERALL RECOMMENDED RATE OF RETURN IN THIS PROCEEDING?

A. The overall rate of return I am recommending is 6.30%, based upon a 50% long-term debt – 50% common equity capital structure, an 8.75% ROE, and a 3.84% cost of debt, as summarized again in **Table 12**, below.

Table 12: Recommended Overall Rate of Return

Component	Ratio (%)	Cost Rate (%)	Wgtd. Cost Rate (%)
Debt	50.00%	3.84%	1.92%
Common Equity	50.00%	8.75%	4.38%
Total Capitalization	**100.00%**		**6.30%**

VIII. REVIEW OF COST OF COMMON EQUITY ANALYSIS OF WITNESS MOUL

Q. HOW DID MR. MOUL DEVELOP HIS LIST OF COMPARABLE COMPANIES?

A. Mr. Moul used S&P "Natural Gas" Utilities as a basis for developing his comparable group. The companies he chose to include within his S&P "Natural Gas" Utilities comparable company proxy group are followed by *The Value Line Investment Survey*. However, as previously referenced earlier within my testimony, of the 10 Natural Gas Utilities followed by *Value Line*, Mr. Moul opted to remove UGI Corporation (*i.e.*, "UGI") from his comparable company proxy group, leaving his comparable company proxy group comprised of nine companies. Mr. Moul explained on page 4 of his testimony that he:

> "*UGI Corporation from the Value Line group because it is more diversified outside of the gas distribution business than the other companies in the Gas Group. Specifically, UGI Corporation reports its financial results for six separate segments consisting of propane sales, two international liquefied petroleum gas businesses, energy services and electric generation.*"[84]

For context, UGI has a diversified business portfolio that, along with the natural gas utility, contains propane, international LPG, energy service, and electric generation. However, Chesapeake Utilities, which Mr. Moul chose to include in his proxy group, also operates a diverse set of businesses that includes "*natural gas distribution, transmission and marketing; electric distribution; propane gas*

[84] Witness Moul Direct Testimony, page 6: lines 1 – 6.

distribution and wholesale marketing; advanced information services and other related services."[85] As such, for consistency purposes, I did not feel it appropriate to include one diverse company within my proxy group while simultaneously excluding another.

Q. WHAT METHODS DID MR. MOUL USE IN HIS ANALYSIS OF THE COST OF EQUITY IN THIS PROCEEDING?

A. Mr. Moul used the Discounted Cash Flow ("DCF") Model, the Risk Premium Model ("RP"), the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings Method ("CE") in this case. Since the CAPM is a risk premium model similar in nature to the Risk Premium model, Mr. Moul is essentially employing a risk-premium model in two forms in his cost of equity analysis in this case.

Q. DO YOU AGREE WITH THE METHODS THAT MR. MOUL USED TO ESTIMATE PECO'S COST OF EQUITY?

A. No. I do not believe the Commission should rely upon Mr. Moul's models for the reasons discussed below. Instead, I recommend that the Commission rely on the results of my application of the DCF Model, with some consideration of the results of the CAPM and CEA as I have set forth above, to estimate the cost of equity for PECO.

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[85] https://chpkgas.com/about-us/about-us/#:~:text=Chesapeake%20Utilities%20is%20the%20natural,advanced%20information%20services%20and%20other

A. <u>Review of Moul's DCF Analysis</u>

Q. WHAT ARE THE PRIMARY DIFFERENCES BETWEEN YOUR APPLICATION OF THE DCF MODEL AND MR. MOUL'S APPLICATION OF THE DCF?

A. The primary differences between my application of the DCF Model and Mr. Moul's application of the DCF Model are the following:

- Mr. Moul applied a 12-basis point adjustment referenced in Mr. Moul's **Schedule 7** on page 15 of **PECO Exhibit PRM-1** to his average dividend yield for his comparable company proxy group;[86]
- Mr. Moul only utilized forecasted growth rates in his analysis as included within Mr. Moul's **Schedule 9** on page 17 of **PECO Exhibit PRM-1**, rather than using both historical and forecasted growth rates;[87] and
- Mr. Moul's applied a "unique" 196-basis point financial risk adjustment as shown in Mr. Moul's **Schedule 10** on page 18 of **PECO Exhibit PRM-1**.[88]

Q. DO YOU AGREE WITH MR. MOUL'S METHODS FOR DETERMINING HIS COMPARABLE GROUP'S AVERAGE DIVIDEND YIELD?

A. No. Mr. Moul began his DCF calculations by determining the dividend yield across his comparable group within his **Schedule 7** on page 15 of **PECO Exhibit PRM-1**. He sources this data from *Morningstar* and *SNL.com* for the twelve-months ending June 2020. Mr. Moul also noted that to determine the dividend yield within

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86 Witness Moul Direct Testimony, page 25: lines 15 – 20.
87 Witness Moul Direct Testimony, page 28: lines 11 – 19.
88 Witness Moul Direct Testimony, page 36: lines 13 – 24.

his DCF and Risk Premium Models, he utilized the three-month average for his comparable company proxy group as shown in **Schedule 7** on page 15 of **PECO Exhibit PRM-1** rather than the twelve-month or six-month average dividend yields.

As referenced in previous cases such as Docket No. 2020-3018835, Mr. Moul has historically utilized the six-month average dividend yield.[89] However, within his response to data request **OCA-IV-13**, Mr. Moul noted that he began using a three-month average dividend yield within his DCF analysis for rebuttal testimonies filed in Columbia Gas of Pennsylvania, Inc. rate case (Docket No. 2020-3018835) and in UGI Utilities, Inc. – Gas Division rate case (Docket No. R-2019-3015162).[90]

In examination of Mr. Moul's rebuttal testimony from the more recent Columbia Gas of Pennsylvania rate case (Docket No. 2020-3018835), he noted the following:

> *I have recalculated my cost of equity models using input data that includes conditions associated with the economic recession. I have accomplished this by using a three-month average period in compiling my later data. I have done this to avoid mixing expansion data with recession market data in my update. In the post expansion period, a 3-month period and current projections are far more representative of what the prospective cost of capital will be during the FPFTY than the data prior to the coronavirus outbreak.*[91]

Additionally, within his direct testimony within the current PECO rate case, Mr. Moul noted the following:

[89] Witness Moul Docket No. 2020-3018835 Direct Testimony, page 20: lines 7 – 8.
[90] Witness Moul's response to data request **OCA-IV-13**.
[91] Witness Moul's Docket No. 2020-3018835 Rebuttal Testimony, page 8: lines 5 – 11.

> *I have analyzed the cost of equity models using input data that follows the beginning of the economic recession…by using a 3-month average period in the DCF and Risk Premium models…I have taken this approach specifically for the case and I am not departing from my long-standing approach of using six-month data. By looking at the more recent three-month period, I have concluded that the current financial and economic data has materially increased the cost of common equity, as I will demonstrated in my testimony.*[92]

First of all, in the above selection from Mr. Moul's direct testimony in the current PECO rate case, Mr. Moul claims that he is not departing from his long-standing approach of using six-month data and that he has only used the three-month data approach specifically for this case. As noted previously, this is not the case as Mr. Moul noted within his response to **OCA-IV-13** that his entire set of cost of equity models were recalculated using the three-month data approach for dividend yields within his rebuttal testimony in two other recent rate cases, Columbia Gas of Pennsylvania, Inc. rate case (Docket No. 2020-3018835) and UGI Utilities, Inc. – Gas Division rate case (Docket No. R-2019-3015162).

Second, by departing from his long-standing practice of using the six-month data for the dividend yield portion of the DCF, and instead using the three-month data from the period of April 2020 through June 2020, Mr. Moul has increased the dividend yield used in his DCF from 3.06% to 3.16%, as shown in **Schedule 7** on Page 15 of **PECO Exhibit PRM-1**. In effect, the result of this change from using the six-month data to the three-month data in this case is the inflation of Mr. Moul's DCF results.

[92] Witness Moul's Direct Testimony, page 3: lines 10 – 19.

Q. DO YOU AGREE WITH MR. MOUL'S 12-BASIS POINT ADJUSTMENT FOR HIS COMPARABLE GROUP'S AVERAGE DIVIDEND YIELD?

A. No. In reference to the three-month average dividend yield that he utilized in this proceeding, Mr. Moul noted that he then:

> *…adjusted the six-month average*[93] *dividend yield in three different, but generally accepted, manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Schedule 7. This adjustment adds twelve basis points to the three-month average historical yield, thus producing the 3.68% adjusted dividend yield for the Gas Group.*[94]

However, other than simply providing the names of these adjustment methods within his **Schedule 7** on page 15 of **PECO Exhibit PRM-1**, Mr. Moul does not provide any explanation as to what these three "*different, but generally accepted, manners*" constitute. Simply put, this adjustment is not necessary to perform an appropriate DCF analysis and the use of such an adjustment is not generally accepted as claimed by Mr. Moul.

Q. DO YOU AGREE WITH MR. MOUL'S SOLE USE OF FORECASTED GROWTH RATES IN HIS DCF MODEL AND OMISSION OF HISTORICAL GROWTH RATES?

A. I previously noted in this testimony that I feel an analyst should present both the historical and forecasted growth rates within their DCF analysis for transparency purposes. Mr. Moul presents the historical growth rates for his proxy group within

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[93] Note that this reference to a "six-month average" within Witness Moul's testimony was a typographical error and should have read "three-month average" based on Witness Moul's response to data request **OCA-IV-12**.

[94] Witness Moul Docket No. R-2020-3018835 Direct Testimony, page 25: lines 16 – 20.

Schedule 8 on page 16 of **PECO Exhibit PRM-1**, but then entirely omits the use of any historical growth rates within his testimony, in favor of placing his full reliance on forecasted growth rates. If Mr. Moul finds no use for historical growth rates, then I am unsure of why he felt the need to present these historical growth rates within the schedules include in **PECO Exhibit PRM-1** at all. By not utilizing any of the historical growth rate data in conjunction with the use of forecasted growth rates, Mr. Moul is ignoring an entire group of data that is readily available.

As I noted previously in this testimony within the discussion of my own DCF results, I believe that it is important for an analyst to consider historical growth rates within their DCF analysis alongside any such forecasted growth rates. Historical growth rates capture the actual growth of the various rates over time based upon a Company's reported results and performance. In contrast, forecasted growth rates are derived entirely from analyst projections, which can vary from analyst to analyst, and which also tend to be overstated.

Q. ARE THERE OTHERS WITHIN THE FINANCIAL COMMUNITY THAT CALL INTO QUESTION PLACING FULL RELIANCE UPON FORECASTED GROWTH RATES?

A. Yes. There are various academic articles and journals that specifically call into question the accuracy of earnings predictions and forecasts. For example, in November 2003, Louis K. C. Chan, Jason Karceski and Josef Lakonishok published an article entitled "Analysts' Conflict of Interest and Biases in Earnings Forecasts" in the *Journal of Finance*. The conclusion of the paper stated:

> *. . . it is commonly suggested that one group of informed participants, security analysts, may have some ability to predict growth. The dispersion in analysts' forecasts indicates their willingness to distinguish boldly between high- and low-growth prospects. IBES long-term growth estimates are associated with realized growth in the immediate short-term future. Over long horizons, however, there is <u>little forecastability in earnings, and analysts' estimates tend to be overly optimistic</u>.*[95]

I recognize that there are other academic articles and journals that support the opposite viewpoint. However, given the fact that this remains a debated topic within the financial community, I have historically included EPS, DPS, BPS, and plowback growth rates and their associated DCF results within my analysis. In contrast, I believe that placing undue reliance upon forecasted EPS growth rates produces unrealistically high returns on equity numbers that cannot be sustained indefinitely.

Q. DO YOU AGREE WITH MR. MOUL'S USE OF FORECASTED GROWTH RATES?

A. Yes, I do agree with Mr. Moul's use of forecasted growth rates within his DCF Model. However, as shown in **Schedule 9** on page 17 of **PECO Exhibit PRM-1**, Mr. Moul sourced his forecasted growth rates from a date of May 29, 2020 from *Value Line*, and a date of June 30, 2020 for *Yahoo Finance* and *Zacks*. The values sourced by Mr. Moul for his forecasted growth rates were between three and four months old by the time that his testimony was filed and ignored the improvements experienced by the markets during Q3 and Q4 2020. The Company's base rate

[95] K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance* (2003), page 683. (underline emphasis added)

filing was made September 30, 2020. Solely from a *Value Line* perspective, *Value Line* publishes company-specific metrics and forecasts by industry on a quarterly basis. Mr. Moul's testimony utilized data from May 2020 and was never updated for the data published by *Value Line* during August 2020 prior to the filing of his testimony at the end of September 2020.

If an analyst places full reliance on forecasted growth rates, as opposed to basing any of their analysis on historical growth rates, I would contest that utilizing forecasts that are between three and four months old by the time that one's testimony is filed would not be the most prudent measure.

Q. DO YOU AGREE WITH MR. MOUL'S USAGE OF THE 196-BASIS POINT LEVERAGE ADJUSTMENT?

A. No. This adjustment stems from Mr. Moul's apparent belief that investors are unaware of debt on the Company's books and, therefore, they must be compensated for the additional risk. To this point, Mr. Moul explains:

> *My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.*[96]

Q. DO YOU AGREE WITH MR. MOUL'S STATEMENT THAT HIS 196-BASIS POINT LEVERAGE ADDER IS NOT A MARKET-TO-BOOK RATIO ADJUSTMENT?

[96] Witness Moul Direct Testimony, page 36: lines 21 – 24.

A. No. Mr. Moul's leverage adjustment is a market-to-book ratio adder that inflates his DCF results.

I have been providing ROE testimony to state regulatory bodies for over thirty-four years. I have seen Mr. Moul's market-to-book ratios in years past. In these other applications, the proposed ROE was adjusted upwards to account for a market value that was less than the book value. In the current case, Mr. Moul proposes a similar upward adjustment to his proposed ROE because utility market values are higher than book values. Hence, I have seen this market-to-book adjustment used to raise the recommended ROE in times when market values were above and below the book values. Such an adjustment serves only one purpose, and that is to raise the recommended ROE for the utility client.

In this case, Mr. Moul's leverage adjustment is, without a doubt, a market-to-book adjustment that should be summarily dismissed by the Commission as an attempt to justify an unreasonable return on equity for the Company.

Q. HAS THIS COMMISSION RULED ON MR. MOUL'S "LEVERAGE" ADJUSTMENT?

A. Yes. In a discovery reply, Mr. Moul noted that he has proposed a leverage adjustment within his DCF and CAPM models in thirty-seven different cases on behalf of a Pennsylvania public utility in the past ten years.[97] (**OCA-IV-5**) Notably however, Mr. Moul also stated that he was not aware of any Commission cases within the past ten years in which the Commission approved one of his leverage

[97] Witness Moul response to Question No. **OCA-IV-5**.

adjustments (**OCA-IV-6**).[98] In regard to historical precedence for this Commission, in the 2012 PPL rate case, the Commission determined the following:

> *The fact that we have granted leverage adjustments in a few select cases in the past as noted by PPL does not mean that such adjustments are warranted in all cases. The award of such an adjustment is not precedential but discretionary with the Commission. In fact, the Commission has rejected leverage/financial risk adjustments that are similar to the one proposed by PPL in this proceeding. See, e.g., Pa. PUC v. Aqua Pennsylvania, Inc., Docket No. R-00072711, at 38-39 (Order entered July 31, 2008). Moreover, in the context of our determination, supra, of a reasonable return on equity for PPL of 10.28%, we conclude that there is no need to have an artificial upwards adjustment to compensate for any perceived risk related to PPL's market-to-book ratio. Accordingly, we shall deny the Exceptions of PPL and adopt the ALJ's recommendation to reject PPL's requested leverage adjustment.*[99]

B. <u>Review of Moul's CAPM Analysis</u>

Q. WHAT ARE THE PRIMARY DIFFERENCES BETWEEN YOUR APPLICATION OF THE CAPM AND MR. MOUL'S APPLICATION OF THE CAPM?

A. The primary differences between my application of the CAPM and Mr. Moul's application of the CAPM are the following:

- Mr. Moul utilized a "leverage" adjustment on his betas within his CAPM that inflated the average beta value for his comparable company proxy group from 0.84[100] to 1.05[101];

[98] Witness Moul response to Question No. **OCA-IV-6**.
[99] Pa. PUC v. PPL Electric Utilities Corp., Dkt No. R-2012-2290597, Order p. 91 (2012). Available at http://www.puc.pa.gov/pcdocs/1206360.docx
[100] Witness Moul Direct Testimony: page 43: line 3.
[101] Witness Moul Direct Testimony: page 44: line 3.

- Mr. Moul utilized certain data points for his forecasted market return that inflated the overall market return used within his CAPM analysis; and
- Mr. Moul employed a size adjustment of 1.02% to his CAPM results based on his opinion that an adjustment was required to account for the size of PECO as a firm and the associated risk.

Q. PLEASE EXPLAIN HOW MR. MOUL APPLIES THE CAPM.

A. In his analysis (as shown on **Schedule 13** of **PECO Exhibit PRM-1**), Mr. Moul combines forecasted and historical market premiums, in conjunction with his estimated risk-free rate and re-leveraged Betas, to apply within his CAPM. Mr. Moul's decision to use certain forecasted values ultimately results in higher CAPM results for his utility client(s).

Q WHAT IS THE RISK-FREE RATE THAT MR. MOUL USES IN HIS CAPM ANALYSIS?

A. In his direct testimony, Mr. Moul cited various historical and forecasted interest rates and then concluded that 1.75% is a proper estimate for the risk-free rate in the CAPM.[102]

Q. DO YOU AGREE WITH MR. MOUL'S FORECASTED RISK-FREE RATE?

[102] Witness Moul Direct Testimony, page 46: lines 13 – 15.

A. I do not take issue with the risk-free rate used by Mr. Moul in this proceeding of 1.75%.[103] As shown within **Exhibit KWO-7**, I have used the 30-year US Treasury Bond Yield to approximate what I deem to be appropriate to use for the risk-free rate for application within the CAPM. This yield over the previous year from December 11, 2019 – December 11, 2020 ranged from 0.99% to 2.39%, with an average of 1.59%.

Q. DO YOU AGREE WITH MR. MOUL'S BETAS USED WITHIN HIS CAPM ANALYSIS?

A. No. As shown within Mr. Moul's **Schedule 3** on page 6 of **PECO Exhibit PRM-1**, the average beta used for Mr. Moul's 9 company proxy group is 0.84 based on the betas provided by the company specific *Value Line Investment Surveys* dated May 29, 2020. However, Mr. Moul contended that "…*Value Line betas cannot be used directly in the CAPM…*"[104] and then stated that he unleveraged and then releveraged the *Value Line* betas using the Hamada formula.[105] It is through this adjustment that Mr. Moul inflated the average Beta value for his comparable company proxy group for use within his CAPM from 0.84 to 1.05[106].

Q. WHY DO YOU DISAGREE WITH MR. MOUL'S RELEVERAGED BETAS?

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[103] *Id.*
[104] Witness Moul Direct Testimony, page 43: line 8.
[105] Witness Moul Direct Testimony, page 43: line 12.
[106] Witness Moul Direct Testimony, page 44: line 3.

A. Beta, in its simplest form, is used to indicate the volatility of a particular security in reference to a standard benchmark, such as the NYSE Composite Index or S&P 500 Index. In theory, the closer a particular security's Beta gets to 1.00, the more closely that the risk of that security approximates the risk of the chosen market benchmark. *Value Line* calculates the beta provided for each of the companies they follow by first performing a regression analysis "*of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Composite Index over a period of five years*."[107]

However, *Value Line* then adjusts these Betas to account "*for their long-term tendency to converge toward 1.00*"[108]. This adjustment employed by *Value Line* is termed the "Blume Adjustment." The Blume Adjustment first takes the unadjusted Betas that reflect the historic volatility of a security to the overall volatility of the chosen market benchmark and then adjusts them to represent forecasted Betas based on the nature of the security Betas to revert back to 1.00 (*i.e.*, the overall average volatility of the chosen market benchmark) over time.[109] As such, the unadjusted historical Beta values provided by *Value Line* for each of the utilities included within their Natural Gas Utility industry grouping have already been adjusted to represent what *Value Line* would deem to be proper forecasts for the Beta values going forward as time progresses.

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[107] https://www.valueline.com/Tools/Educational_Articles/Stocks/Using_Beta.aspx#.X6Fp8IhKiUk
[108] *Id.*
[109] M. Blume, "On the Assessment of Risk," Journal of Finance, March 1971.

Through the use of his Beta adjustment included within **Schedule 10** on page 18 of **PECO Exhibit PRM-1**, Mr. Moul has utilized an average Beta of 1.05[110] for his comparable company proxy group. This value is 0.45 higher than the 0.60 unadjusted historical beta for this same proxy group of Mr. Moul's.[111] In essence, what Mr. Moul is contending is that although the group of utilities included within his proxy group have historically had an average Beta of 0.60 in comparison to the overall market Beta of 1.00, he believes that the group of utilities included in his proxy group will have a forecasted Beta of 1.05 going forward and will therefore be riskier than the overall volatility seen within the entirety of the market.

Additionally, as noted above within **Table 3**, even during the course of a year such as 2020 when the COVID-19 pandemic has caused tremendous fluctuation within the financial markets, the Dow Jones Utility Average (*i.e.*, "DJUA") has been far less volatile than the Dow Jones Industrial Average (*i.e.*, "DJIA"). This is further evidence that there is nothing to suggest that a group of gas utilities are projected to be riskier on average than the overall market on a go-forward basis.

Value Line already performs an adjustment upon the historical unadjusted betas to ensure that the Betas presented through their service are forward looking and prospective. Mr. Moul provides no basis for why his unleveraging and releveraging of the Beta values provided by *Value Line* is warranted other than the fact he feels that the market value Betas provided by *Value Line* should be adjusted

[110] Witness Moul Direct Testimony, page 44, line 3.
[111] Witness Moul Direct Testimony, page 43: line 19.

to book value Betas. In essence, this is the same flawed logic that was provided as support for his leverage adjustment within his DCF.

Q. HAS THIS COMMISSION PREVIOUSLY RULED ON THE MERITS OF MR. MOUL'S CAPM LEVERAGE ADJUSTMENT?

A. Yes. As noted above within the Q&A in regard to Mr. Moul's DCF leverage adjustment, Mr. Moul acknowledged proposing a leverage adjustment within both the DCF and CAPM in thirty-seven different cases on behalf of a Pennsylvania public utility in the past ten years.[112] (**OCA-IV-5**) Notably however, Mr. Moul also acknowledged that he was not aware of any PA cases within the past ten years in which he had participated as a witness where the Commission approved such leverage adjustments.[113] (**OCA-IV-6**)

Additionally, for context in regard to Commission precedence, in the 2018 UGI Utilities - Electric general rate case the Commission rejected Mr. Moul's leverage adjustment and stated:

> *Finally, we <u>reject UGI's request for a leverage adjustment</u> and a size adjustment in the calculation of the CAPM cost of equity. <u>As previously noted, we find no basis in this proceeding to add a leverage adjustment</u>.*[114]

The Commission was not persuaded by the technical literature cited by Mr. Moul within this previous case and was not convinced that a leverage adjustment was appropriate for use within a utility setting.

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[112] Witness Moul response to Question No. **OCA-IV-5**.
[113] Witness Moul response to Question No. **OCA-IV-6**.
[114] Pa. P.U.C. v. UGI Utilities – Electric Division, Opinion and Order at 100, Docket No. R-2017-2640058 (Oct. 25, 2018). (underline emphasis added)

Q. WHAT EXPECTED MARKET RETURN DOES MR. MOUL USE IN THE CAPM ANALYSIS HE EMPLOYS IN THIS CASE?

A. Mr. Moul stated the following in regard to the market premium he utilizes:

> *For the historically based market premium, I have used the arithmetic mean obtained from the data presented on Schedule 12, page 1. On that schedule, the market return was 11.92% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.88% when interest rates were low. As such, I have carried over to Schedule 13, page 2, the average large common stock returns of 11.92% and the average yield on long-term government bonds of 2.88%. These financial returns rest between those experienced during periods of low interest rates and those experienced across all levels of interest rates. The resulting market premium is 9.04% (11.92% - 2.88%) based on historical data, as shown on Schedule 13, page 2.*[115]

As such, Mr. Moul first examined the Historical Market Premium by utilizing the arithmetic mean for the market return from 1926 – 2019 of 11.92% and the risk-free rate over the same period of 2.88% to arrive at a "Historical Market Premium" of 9.04%.

Mr. Moul then utilized forecasted market premiums as shown within his **Schedule 13** on page 25 of **PECO Exhibit PRM-1**. To begin this process, he utilized a "Median Appreciation Potential" of 13.34% and then adds to this a 2.4% "Dividend Yield", both values provided by *Value Line* on June 26, 2020, to arrive at a 15.74% "Median Total Return" to approximate one "DCF Result". He then performed a similar calculation by adding a 4.00% growth rate and a 2.07% dividend yield based on information provided from the *S&P 500* to arrive at 6.07%

[115] Witness Moul Direct Testimony, page 46: lines 18 – 23 and page 47: lines 1 – 5.

to approximate another "DCF Result". He then averaged the 15.74% "Median Total Return" from *Value Line* and the 6.07% return from *S&P 500* data to arrive at an average value of 10.91% to approximate his forecasted overall market return. Mr. Moul then deducted his 1.75% risk-free rate from the 10.91% to arrive at his "Forecast Market Premium" of 9.16%.[116]

Q. HOW DOES MR. MOUL CALCULATE HIS OVERALL MARKET RISK PREMIUM FOR USE IN THE CAPM?

A. Mr. Moul averaged his "Forecast Market Premium" of 9.16% and his "Historical Market Premium" of 9.04% to arrive at his overall market risk premium for use within his CAPM of 9.10%.[117]

Q. DO YOU AGREE WITH MR. MOUL'S MARKET PREMIUM ANALYSIS?

A. No. Mr. Moul's "Median Total Return" of 15.74% on **Schedule 13** on page 25 of **PECO Exhibit PRM-1** is based on a "Median Appreciation Potential" provided by *Value Line* on June 26, 2020 that approximates the overall market's 18-month appreciation price potential.[118] However, such price appreciation potentials vary widely, especially when an anomalous event such as the COVID-19 pandemic occurs. As an example of the variability of the appreciation price potential value used by Mr. Moul, within the same *Value Line* sourced from June 26, 2020 as provided by Mr. Moul in response to data request **OCA-IV-11**, it notes that the

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[116] Witness Moul Direct Testimony, Schedule 13: page 25 of PECO Exhibit PRM-1.
[117] Witness Moul Direct Testimony, Schedule 13: page 25 of PECO Exhibit PRM-1.
[118] Witness Moul response to Question No. **OCA-IV-11**, Attachment **OCA-IV-11(a) Page 1**

"Median Appreciation Potential" was just 7% "26 weeks" prior to June 26, 2020, was 72% during the "Market Low" period on March 23, 2020, and was 6% during the "Market High" period on February 19, 2020.[119] Each of these values clearly vary wildly from the 15.74% used by Mr. Moul within his CAPM in this proceeding. This exhibits a critical flaw with Mr. Moul's use of such data. An analyst should never use such short-term highly variable components as price potential for determining components in any cost of capital analysis.

As referenced above, **Schedule 13** on page 25 of **PECO Exhibit PRM-1** shows that Mr. Moul averaged forecasted market returns of 15.74% ("Value Line Return") and 6.07% ("DCF Result for the S&P 500 Composite") to arrive at a value of 10.91% to approximate his forecasted overall market return.[120] The 15.74% "Value Line Return" used by Mr. Moul does not come close to aligning with the 6.07% "DCF Result for the S&P 500 Composite" also used by Mr. Moul for application within his CAPM. These data points are in no way comparable, and by simply averaging them together to provide the 10.91% for his forecasted overall market return, Mr. Moul has inflated his "Forecast Market Premium" and his overall CAPM results.

Q. HOW DOES MR. MOUL'S FORECASTED MARKET RETURN COMPARE TO FORECASTS FROM OTHER ANALYSTS?

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[119] *Id.*
[120] Witness Moul Direct Testimony, Schedule 13: page 25 of PECO Exhibit PRM-1.

A. As I indicated previously, well-known entities such as Morningstar and Vanguard forecasted market returns from -1.5% to 7.8% during the early onset of the COVID-19 pandemic.[121] Mr. Moul's forecasted market return of 10.91% and "Forecast Market Premium" of 9.16%, as referenced above are, to say the least, unrealistic.

Q. HOW DOES MR. MOUL'S EXPECTED MARKET RETURN COMPARE TO HISTORICAL RETURNS IN THE MARKET?

A. As noted within Mr. Moul's **Schedule 13** on **page 25** of **PECO Exhibit PRM-1**, the historical market return based on the period of 1926-2019 was 11.92% on an arithmetic mean basis. The key data point used by Mr. Moul within **Schedule 13** on **page 25** of **PECO Exhibit PRM-1** (*i.e.*, the Median Appreciation Potential previously mentioned above) to inflate his forecasted market return to 10.91% indicates that a median total market return can be expected of 15.74%, which is clearly far higher than the historical market return indicated by Mr. Moul of 11.92%.

Whether the comparison is to the forecasts from current day analysts or to historical returns, Mr. Moul's market return forecasts simply have no underlying fundamental support or reasoning.

Q. HOW DOES MR. MOUL'S FORECASTED MARKET RETURN COMPARE TO WHAT EXELON ACTUALLY BELIEVES THE MARKET

[121] https://www.morningstar.com/articles/979744/experts-forecast-stock-and-bond-returns-crisis-edition

IS GOING TO EARN AS EVIDENCED IN THEIR PENSION CALCULATIONS?

A. According to the Company's response to discovery request **OCA-IV-20**, in calculating its pension plan needs, Exelon assumes a 7% expected return on pension assets.[122] Clearly, Mr. Moul's forecasted market return of 10.91%[123] is excessive in comparison to what his employer in this case actually believes will occur in the marketplace.

Q. DO YOU AGREE WITH MR. MOUL'S CAPM 102-BASIS POINT SIZE ADJUSTMENT?

A. No. As shown on his **Schedule 1** of **PECO Exhibit PRM-1**, Mr. Moul's CAPM analysis would have produced a result of 11.31% had he not employed any size adjustment. However, he opted to employ an additional 102-basis points to his end CAPM result, which moved his result from 11.31% to 12.33%.

As mentioned earlier, it is my belief that the CAPM is inferior to the DCF in determining the market required return on equity. Without a direct and immediate link to current stock market prices, the CAPM simply cannot reflect current investor sentiments of the market.

To support his 1.02% (102-basis points) adder, Mr. Moul notes that "*as the size of a firm decreases, its risk and required return increases.*"[124] As such, he is asserting that a 1.02% adder should be employed to adjust for the size of PECO

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[122] Witness Stefani response to Question No. **OCA-IV-20**.
[123] Witness Moul Direct Testimony, Schedule 13: page 25 of PECO Exhibit PRM-1.
[124] Witness Moul Direct Testimony, page 47: lines 15 – 16.

relative to other firms. He then proceeds to cite as support for this position, an article from *Public Utilities Fortnightly* dating back 25 years to 1995 and an article from *The Journal of Finance* dating back 28 years to 1992.[125]

There are two errors in this 102-basis point adjustment. First, it is unclear from Mr. Moul's testimony whether he is saying PECO is "mid-cap" or if he is saying Exelon, its parent company, is "mid-cap." If Mr. Moul is claiming Exelon is mid-cap, I direct him to the November 13, 2020 edition of Exelon's quarterly company-specific *Value Line* publication that has Exelon with a total capitalization of $40 billion and states that Exelon is "large cap." Hence, no adjustment would be warranted if Mr. Moul is applying his adjustment based on the size of Exelon.

If Mr. Moul is claiming that PECO is "mid-cap", the adjustment would make even less sense as the entire amount of the Company's equity is owned by Exelon, its parent holding company. In addition, many of the O&M expenses requested by PECO Gas in this case stem from its parent company's affiliation with Exelon Business Services. If PECO Gas wants to claim that it is a "mid-cap" utility, it must then admit that the expenses associated with Exelon Business Services are invalid and should not be included in this rate case. I highly doubt that PECO-Gas/Exelon will make such an admission.

Second, what Mr. Moul fails to reflect is that investors already know the size of Exelon and similar utility holding companies. To the extent investors feel these companies are a higher risk than larger entities, investors will price that

[125] Witness Moul Direct Testimony, page 47: lines 18 – 23.

premium into the current stock price. Hence, Mr. Moul's 1.02% adder simply double counts any size premium, assuming one exists at all.

Q. HAS THIS COMMISSION PREVIOUSLY RULED ON MR. MOUL'S SIZE RISK ADJUSTMENT ARGUMENT?

A. Yes. Mr. Moul acknowledged proposing a size risk adjustment within his CAPM in over thirty different cases on behalf of a Pennsylvania public utility in the past ten years.[126] (**OCA-IV-5**) Notably however, Mr. Moul also stated that he was not aware of any Commission cases within the past ten years in which the Commission approved this size adjustment.[127] (**OCA-IV-6**)

Additionally, for context in regard to Commission precedence, in the 2018 UGI Utilities - Electric general rate case the Commission rejected Mr. Moul's leverage and firm size adjustments and stated:

> *Finally, we reject UGI's request for a leverage adjustment and a size adjustment in the calculation of the CAPM cost of equity.*[128]

The Commission was not persuaded by the technical literature cited by Mr. Moul within this previous case and was not convinced that a size risk adjustment was appropriate for use within a utility setting.

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[126] Witness Moul response to Question No. **OCA-IV-5**.
[127] Witness Moul response to Question No. **OCA-IV-6**.
[128] Pa. P.U.C. v. UGI Utilities – Electric Division, Opinion and Order at 100, Docket No. R-2017-2640058 (Oct. 25, 2018). (underline emphasis added)

C. **Review of Moul's Risk Premium Method**

Q. MR. O'DONNELL, PLEASE EXPLAIN THE DIFFERENCE BETWEEN THE RISK PREMIUM MODEL AND THE CAPM?

A. The CAPM and the Risk Premium models are both essentially risk premium models. The primary difference is the CAPM is more company-specific due to its use of beta to measure systematic risk. However, both models compare market returns (either total market or utility markets) to bond yields.

Q. PLEASE EXPLAIN MR. MOUL'S APPLICATION OF HIS RISK-PREMIUM MODEL.

A. In his application of the Risk Premium model, Mr. Moul combines a forecasted utility bond yield and his determination of an appropriate risk premium. To be specific, Mr. Moul combines a forecasted A-rated bond yield of 3.50% (a risk-free rate of 1.75% combined with a yield spread of 1.75%) to a risk premium of 6.75% to derive a 10.25% risk premium result.

Q. DO YOU AGREE WITH MR. MOUL'S PRESENTATION OF THE RISK PREMIUM MODEL?

A. No. First, I disagree with the use of forecasted bond yields. The best predictor of future yields is the current yield curve. If the market feels interest rates are going to increase in the future, it will bid down current bond prices so that yields correspondingly increase. The reverse is also true in that, when the market feels interest rates will soon fall, it will bid up bond prices thereby reducing bond yields.

D. <u>Review of Moul's Comparable Earnings Model</u>

Q. PLEASE EXPLAIN THE MANNER IN WHICH MR. MOUL CONDUCTED HIS COMPARABLE EARNINGS ANALYSIS?

A. Mr. Moul developed a group of non-regulated companies that he believed were comparable in risk to PECO. Mr. Moul then compared the historical earned returns of these non-regulated companies to the results of his DCF and CAPM analyses which are based on market returns.

Q. DO YOU AGREE WITH MR. MOUL'S COMPARABLE EARNINGS ANALYSIS?

A. No, I have two areas of disagreement with Mr. Moul in his CEA. First, a non-regulated firm does not operate in a monopoly service territory and does not have the ability to seek higher rates from state regulators when they deem it necessary or desirable to do so. Hence, the operation of a regulated utility is inherently different from entities that operate in truly competitive markets. As an example, Mr. Moul has included "The Cheesecake Factory" and "Tootsie Roll" as part of the comparable group on which he bases his CEA for PECO, a regulated gas utility. I recognize that Dollar Tree Inc and Scholastic Corporation may have cleared certain financial benchmarks as set out by Mr. Moul for comparability to PECO to be included in his analysis in **Schedule 14** on page 27 of **PECO Exhibit PRM-1**, but they are clearly not operating in businesses that are anything close to the business of a regulated utility. Mr. Moul's comparable group is simply not comparable to the operation of a regulated gas utility with a monopoly market.

The second area of disagreement I have with Mr. Moul's CEA is my repeated concern of comparing book value with market value. Mr. Moul continues to conflate book value with market value. Clearly, the two are totally separate entities, and since market values are not well above book values, a return on book values as Mr. Moul espouses with result in returns that are excessive relative to what investors can actually receive in the marketplace. As a result, Mr. Moul's reliance on book value returns is misguided.

E. <u>Other Observations on Moul's Testimony</u>

Q. DO YOU AGREE WITH MR. MOUL'S ADJUSTMENT FOR EXEMPLARY MANAGEMENT PERFORMANCE?

A. No. I disagree with Mr. Moul's recommendation that PECO be rewarded a 10.95% ROE, inclusive of a 25-basis point ROE adder for exemplary management performance.[129]

I have reviewed the testimony of PECO Witness Ronald Bradley who cited several activities in which management has engaged that, in his opinion, constitutes exemplary management performance on behalf of PECO. Specifically, Mr. Bradley stated that the Company's management has been effective by launching various initiatives "*to ensure system safety and reliability, enhance customer service, community support and economic development, and protect and preserve the environment.*"[130]

[129] Witness Moul Direct Testimony, page 2: lines 6 – 7.
[130] Witness Bradley Direct Testimony, page 2: lines 9 – 14.

Q. WHAT IS THE BASIS OF YOUR DISAGREEMENT WITH MR. MOUL'S ADJUSTMENT FOR EXEMPLARY MANAGEMENT PERFORMANCE?

A. Mr. Moul's testimony indicated that this 25-basis point upward adjustment to reward the Company for perceived exemplary performance of management is based upon his "…*analysis of the Company* *and its superior performance is based upon the direct testimony of Mr. Ronald A Bradley, the Company's Vice President of Gas, and the direct testimony of other Company witnesses*."[131] However, Mr. Moul presents no details as to what "analysis" he performed that would exemplify why a 25-basis point upward adjustment is appropriate in this case. In response to data request **OCA-IV-19**, Mr. Moul explained the following in reference to what his analysis on this matter actually constituted:

> *The Company is entitled to 0.25% in recognition of its exemplary performance as part of its rate of return on common equity in this proceeding. The company's exemplary performance is explained in detail in the testimony of Mr. Ronald A. Bradley, in which he describes the various programs that promote high quality of service for PECO's customers and support for community and economic development in PECO's service territory. These programs go well beyond normal requirements mandated for a public utility. As Mr. Bradley notes, the high quality of PECO's customer service has been recognized by J.D. Power…The 0.25% increment provides recognition for PECO's exemplary overall management performance, yet maintains the equity return within the measures of the cost of equity revealed by the results of the Gas Group. The Company's proposed rate of return on common equity of 10.70% is established within the range comprised of 10.25% to 12.90% for all models and 10.25% to 12.74% for the market-based models (i.e., DCF, RP and CAPM). Mr. Moul's recommended 10.95% (i.e., 10.70% + 0.25%) rate of return on common equity provides*

[131] Witness Moul Direct Testimony, page 2: lines 7 – 10. (underlined emphasis added)

recognition for the Company's management effectiveness that includes this 0.25% increment.[132]

The data response provided by Mr. Moul in connection with data request **OCA-IV-19** provides no quantitative basis to support why a 25-basis point management adder to ROE would be appropriate in this case. There was no analysis performed on behalf of Mr. Moul to justify the appropriateness of this 25-basis point value other than to simply note that with or without this adjustment, the value would fall within the range he proposes is appropriate based on his analysis of his proxy company Gas Group.

Q. DO YOU AGREE THAT PECO MANAGEMENT HAS PERFORMED IN A MANNER THAT WOULD CONSTITUTE EXEMPLARY MANAGEMENT PERFORMANCE?

A. No. First, the Company has an obligation under state law to provide service to the public which is reasonable, safe, and adequate. PECO customers should not be charged extra for PECO to meet its service obligations under state law or regulations. Second, OCA witness Roger Colton has analyzed the Company's performance in certain areas related to customer service and found the Company's performance is not superior. Third, as shown above within the Company's response to data request **OCA-IV-19**, Mr. Moul stated that "*PECO's customer service has been recognized by J.D. Power*"[133] as support for the Company's perceived exemplary performance of management. However, if one were to examine the

[132] Witness Moul's response to **OCA-IV-19**.
[133] *Id.*

section of Mr. Bradley's testimony that references J.D. Power's review of PECO's customer service, it shows that:

> *…the PECO customer experience, as measured by J.D. Power has improved from a score of 628 to 748 in the last five years. This has resulted in PECO's customer service ranking among comparative utility companies increasing to 4th out of 12 in 2019.*[134]

To that point, simply because J.D. Power has recognized PECO's improved customer service does not inherently mean that PECO's management has been performing in an exemplary manner. Just in looking above at the selection from Mr. Bradley's testimony, one might surmise that PECO ranks at the top of the second quartile of the twelve comparative utility companies cited by Mr. Bradley. While that shows improvement on the behalf of PECO over the five-year period referenced by Mr. Bradley, being ranked 4th out of 12 companies by J.D. Power in the realm of customer service hardly seems to constitute that the performance of PECO's management has been exemplary in comparison to these other comparative utility companies. Indeed, the comparable info for 2020 shows that PECO scored 751 but ranked 7th out of 12 companies in J.D. Power's "East Large Segment." (**OCA-VIII-Att. 17(g), p. 4**)

Additionally, in response to data request **OCA-VIII-17**, Mr. Bradley provided a table that outlined the Company's J.D. Power rankings from 2014 through 2020 in the East Large Segment within the Residential Gas industry. This table showed PECO's score per the annual J.D. Power's rankings, the maximum score for the companies included in the East Large Segment (*i.e.*, "Segment

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[134] Witness Bradley Direct Testimony, page 21: lines 17 – 18 and page 22: lines 1 – 2.

Maximum"), the average score for the companies included in the East Large Segment (*i.e.*, "Segment Average), PECO's overall ranking within the segment, and the number of customers surveyed each year.

Based upon the table and J.D. Power summary of the East Large Segment, PECO scored below average within the East Large Segment from 2014 – 2016 and from 2017 – 2020 PECO's scores were generally closer to the Segment Average than they were to the Segment Maximum. For instance, the 2020 scores show a Segment Average score of 746, PECO's score of 751, and a Segment Maximum score of 784. The data shown within this table from the Company's response to data request **OCA-VIII-17** reinforces the fact that PECO's performance over this period does not constitute what would be perceived as exemplary in comparison to other utility companies as determined by J.D. Power, despite the Company's claims to the contrary.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS IN REGARD TO THE POINTS OUTLINED BY WITNESS BRADLEY USED TO SUPPORT THE COMPANY'S CLAIM OF EXEMPLARY MANAGEMENT PERFORMANCE?

A. Yes. Mr. Bradley stated that the Company's management has been effective by launching various initiatives "*to ensure system safety and reliability, enhance customer service, community support and economic development, and protect and preserve the environment.*"[135] However, as referenced throughout the testimony of

[135] Witness Bradley Direct Testimony, page 2: lines 9 – 14.

Mr. Bradley, certain of these improvements occurred many years ago. For instance, on Page 18 of his testimony, Mr. Bradley referenced that "*leaks have decreased 23%*"[136] since 2015. Any such improvements made years ago, such as the post-2015 improvements referenced from Mr. Bradley's testimony, would have already been factored in by the markets in these subsequent years. Therefore, the Company and its shareholders have already received the benefit from these improvements as the Company has made these improvements and disclosed such improvements and the related efforts/expenditures.

Additionally, throughout Mr. Bradley's testimony are efforts that the Company claims it has undertaken to enhance the safety and reliability of its gas distribution operations. These various items are presented by the Company as evidence that its management has performed in an exemplary manner in support of the 25-basis point ROE adder. However, certain of these efforts were items that the Company was required to perform as part of the "Penrose Lane Settlement." This settlement between I&E and PECO relates to a 2014 gas explosion that occurred at 118 Penrose Lane, Coatesville, PA.[137] The Commission approved the settlement, which included a civil penalty and conditions that PECO take steps to improve gas safety.[138] As indicated within the Company's response to data request **OCA-XI-3**, "*PECO did agree to develop a gas mapping program geared at enhancing PECO*

[136] Witness Bradley Direct Testimony, page 18: lines 16 – 17.
[137] https://www.inquirer.com/philly/business/energy/PUC-fines-Peco-900K-for-gas-blast-that-destroyed-a-home.html
[138] Bureau of Investigation and Enforcement v. PECO Energy – Gas Div., Docket No. C-2015-2479970, Order approving Settlement (entered Oct. 27, 2016). Also, Witness Bradley's response to data request **OCA-XI-4**.

infrastructure maps as part of the Penrose Lane Settlement."[139] This gas mapping program subsequently began in 2018 and is not expected to be completed until 2037.[140]

The Company also responded to data request **OCA-XI-4**, where it provided the total amount of capital investment made in 2017, 2018, 2019, and 2020 in connection with the Company's commitment to improve gas mapping pursuant to the Penrose Lane Settlement.[141] As such, I do not find it convincing, nor appropriate, that in support of the Company's claim of exemplary management performance, the Company has provided examples of items that relate to efforts that they were required to perform as part of the terms outlined within a settlement agreement. These items simply do not constitute support of what the Company perceives as exemplary management performance.

Q. DO YOU HAVE ANY COMMENTS RELATED TO PECO'S CLAIM OF EXEMPLARY MANAGEMENT PERFORMANCE IN REFERENCE TO THE COVID-19 PANDEMIC?

A. Yes. Ratepayers in Pennsylvania are already paying PECO's management to perform their jobs to the best of their abilities. As I noted above, the Company has requested this 25-basis point adjustment during the middle of global pandemic when much of the country, and PECO's related service territory, have been

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[139] Witness Bradley's response to data request **OCA-XI-3 (OCA-XI-3** attachments are Confidential).
[140] *Id.*
[141] Witness Bradley's response to data request **OCA-XI-4**.

unemployed or underemployed. The argument that a 25-basis point adder be implemented in relation to exemplary management performance, especially during a period when much of the rate paying public have been dealing with financial struggles linked to the COVID-19 pandemic, is questionable at best. The Company's request for an additional 25-basis points to the allowed ROE and resulting higher rates is unwarranted, especially in light of the COVID-19 pandemic and current economic conditions and does not reflect the current market conditions.

Furthermore, as I noted above, PECO Energy has failed to address the incredibly high rate of 7.38% for its Capital Trust Securities. The fact that the Company did not retire these securities long before now, when interest rates are at historic lows, is yet another example of reasons why PECO Gas should not be rewarded any ROE upward adjustment for any perceived exemplary performance of management on their part.

IX. SUMMARY

Q. MR. O'DONNELL, PLEASE SUMMARIZE YOUR TESTIMONY.

A. PECO's requested rate increase in this case is excessive, unnecessary, and burdensome on the ratepayers of Pennsylvania. My specific recommendations in this case are as follows:

- I agree with OCA Witness Scott Rubin[142] in that as a result of the COVID-19 pandemic that PECO's customer base is still dealing with, it is not just or reasonable for PECO to impose a rate increase on its customers at this time.
- However, should the Commission proceed to review the PECO base rate filing on a more standard ratemaking basis, I believe that the Company's proposed capital structure for ratemaking purposes is too costly;
- The proper capital structure to use in this proceeding is 50.00% common equity and 50.00% long-term debt;
- My recommended cost of debt is 3.84% to reflect the changes in the capital markets in contrast to what was included within Mr. Moul's pre-filed direct testimony;
- The Company's allowed return on equity should be set at 8.75%, based primarily upon the results of my DCF analysis and my recommended capital structure;

[142] Witness Rubin Direct Testimony, page 3, lines 16 – 21.

- The overall rate of return that PECO should be allowed to earn in this proceeding is 6.30%; and
- Mr. Moul's recommended ROE for PECO is unreasonable, excessive, and out-of-date, especially in light of the COVID-19 pandemic.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

301238

Appendix A

Kevin W. O'Donnell, CFA

Nova Energy Consultants, Inc. (Nova)

1350-101 SE Maynard Rd.
Cary, NC
919-461-0270
919-461-0570 (fax)
kodonnell@novaenergyconsultants.com

Kevin W. O'Donnell, is the founder of Nova Energy Consultants, Inc. in Cary, NC. Mr. O'Donnell's academic credentials include a B.S. in Civil Engineering - Construction Option from North Carolina State University as well as a MBA in Finance from Florida State University. Mr. O'Donnell is also a Chartered Financial Analyst (CFA).

Mr. O'Donnell has over thirty-four years of experience working in the electric, natural gas, and water/sewer industries. He is very active in municipal power projects and has assisted numerous southeastern U.S. municipalities cut their wholesale cost of power by as much as 67%. On Dec. 12, 1998, ***The Wilson Daily Times*** made the following statement about O'Donnell.

> **Although we were skeptical of O'Donnell's efforts at first, he has shown that he can deliver on promises to cut electrical rates.**

Through 2018, Mr. O'Donnell has completed 29 wholesale power projects for municipal and university-owned electric systems throughout North and South Carolina. In May of 1996 Mr. O'Donnell testified before the U.S. House of Representatives, Committee on Commerce, Subcommittee on Energy and Power regarding the restructuring of the electric utility industry.

Mr. O'Donnell has appeared as an expert witness in close to 120 regulatory proceedings before the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Virginia Corporation Commission, the Minnesota Public Service Commission, the New Jersey Board of Public Utilities, the Colorado Public Service Commission, Public Service Commission of the District of Columbia, the Maryland Public Service Commission, the Public Utility Commission of Texas, the Indiana Utility Regulatory Commission, the Wisconsin Public Service Commission, the Pennsylvania Public Service Commission, the Oklahoma State Corporation Commission, the California Public Utilities Commission, and the Florida Public Service Commission. His area of expertise has included rate design, cost of service, rate of return, capital structure, creditworthiness issues, fuel adjustments, merger transactions, holding company applications, as well as numerous other accounting, financial, and utility rate-related issues.

Mr. O'Donnell is the author of the following two articles: "Aggregating Municipal Loads: The Future is Today" which was published in the Oct. 1, 1995 edition of *Public Utilities Fortnightly;* and "Worth the Wait, But Still at Risk" which was published in the May 1, 2000 edition of *Public Utilities Fortnightly.* Mr. O'Donnell is also the co-author of "Small Towns, Big Rate Cuts" which was published in the January, 1997 edition of *Energy Buyers Guide.* All of these articles discuss how rural electric systems can use the wholesale power markets to procure wholesale power supplies.

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
2006	South Carolina Electric & Gas	SC	2006-192-E	South Carolina Energy Users Committee	Fuel application
2007	Duke Power	NC	E-7, Sub 790	Carolina Utility Customers Assoc.	Application to construct generation
2007	South Carolina Electric & Gas	SC	2007-229-E	South Carolina Energy Users Committee	Rate of return, accounting, rate design, cost of service
2008	South Carolina Electric & Gas	SC	2008-196-E	South Carolina Energy Users Committee	Base load review act proceeding
2009	Western Carolina University	NC	E-35, Sub 37	Western Carolina University	Rate of return, accounting, rate design, cost of service
2009	Duke Power	NC	E-7, Sub 909	Carolina Utility Customers Assoc.	Cost of service, rate design, return on equity, capital structure
2009	South Carolina Electric & Gas	SC	2009-261-E	South Carolina Energy Users Committee	DSM/EE rate filing
2009	Duke Power	SC	2009-226-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2009	Tampa Electric	FL	080317-EI	Florida Retail Federation	Return on equity, capital structure
2010	Duke Power	SC	2010-3-E	South Carolina Energy Users Committee	Fuel application - assisted in settlement
2010	South Carolina Electric & Gas	SC	2009-489-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2010	Virginia Power	VA	PUE-2010-00006	Mead Westvaco	Rate design
2011	Duke Energy	SC	2011-20-E	South Carolina Energy Users Committee	Nuclear construction financing
2011	Northern States Power	MN	E002/GR-10-971	Xcel Large Industrials	Return on equity, capital structure
2011	Virginia Power	VA	PUE-2011-0027	Mead Westvaco	Capital structure, revenue requirement
2011	Duke Energy	NC	E-7, Sub 989	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2011	Duke Energy	SC	2011-271-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2011	Dominion Virginia Power	VA	PUE-2011-00073	Mead Westvaco	Rate design
2012	Town of Smithfield/Partners Equity Group	NC	ES-160, Sub 0	Partners Equity Group	Rate design, asset valuation
2012	Florida Power & Light	FL	120015-EI	Florida Office of Public Counsel	Capital structure
2012	South Carolina Electric & Gas	SC	2012-218-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2013	Progress Energy Carolinas	NC	E-2, Sub 1023	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2013	Duke Energy Carolinas	NC	E-7, Sub 1026	Carolina Utility Customers Assoc.	Rate design
2013	Jersey Central Power & Light	NJ	BPU ER12111052	Gerdau Ameristeel	Return on equity, capital structure
2013	Duke Energy Carolinas	SC	2013-59-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2013	Tampa Electric	FL	130040-EI	Florida Office of Public Counsel	Capital structure and financial integrity
2013	Piedmont Natural Gas	NC	G-9, Sub 631	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2014	Dominion Virginia Power	VA	PUE-2014-00033	Mead Westvaco	Recoverable fuel costs, hedging strategies
2014	Public Service Company of Colorado	CO	14AL-0660E	Colorado Healthcare Electric Coordinating Council	Return on equity, capital structure
2015	WEC Acquisition of Integrys	WI	9400-YO-100	Staff of Wisconsin Public Service Commission	Merger analysis
2015	Dominion Virginia Power	VA	PUE-2015-00027	Federal Executive Agencies	Return on equity
2015	South Carolina Electric & Gas	SC	2015-103-E	South Carolina Energy Users Committee	Return on equity
2015	Western Carolina University	NC	E-35, Sub 45	Western Carolina University	Accounting, cost of service, rate design, ROE, capital structure
2016	Sandpiper Energy	MD	9410	Maryland Office of People's Counsel	Return on equity, capital structure
2016	Washington Gas Light	DC	FC 1137	Washington, DC Office of People's Counsel	Return on equity, capital structure
2016	Florida Power & Light	FL	160021-EI	Florida Office of Public Counsel	Capital Structure
2016	Jersey Central Power & Light	NJ	EM15060733	NJ Division of Rate Counsel	Asset valuation
2016	Rockland Electric Company	NJ	ER16050428	NJ Division of Rate Counsel	Rate design
2016	Dominon NC Power	NC	E-22, Sub 532	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2017	Potomac Electric Power	DC	FC 1139	Healthcare Council of the National Capitol Area (HCNCA)	ROE and capital structure
2017	Columbia Gas of Maryland	MD	FC 9447	Maryland Office of People's Counsel	ROE and capital structure
2017	Washington Gas Light	DC	FC 1142	Washington, DC Office of People's Counsel	Merger analysis
2017	Duke Energy Progress	NC	E-2, Sub 1142	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2018	Public Service Electric & Gas	NJ	GR17070776	NJ Division of Rate Counsel	ROE and capital structure
2018	Duke Energy Carolinas	NC	E-7, Sub 1146	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2018	Elkton Gas/SJI	MD	FC 9475	Maryland Office of People's Counsel	Merger analysis
2018	Entergy Texas	TX	PUC 48371	Entergy Texas Cities	ROE
2018	Duke Energy Carolinas	SC	2018-3-E	South Carolina Energy Users Committee	Fuel case

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
1985	Public Service Company of NC	NC	G-5, Sub 200	Public Staff of NCUC	Return on equity, capital structure
1985	Piedmont Natural Gas Company	NC	G-9, Sub 251	Public Staff of NCUC	Return on equity, capital structure
1986	General Telephone of the South	NC	P-19, Sub 207	Public Staff of NCUC	Return on equity, capital structure
1987	Public Service Company of NC	NC	G-5, Sub 207	Public Staff of NCUC	Return on equity, capital structure
1988	Piedmont Natural Gas Company	NC	G-9, Sub 278	Public Staff of NCUC	Return on equity, capital structure
1989	Public Service Company of NC	NC	G-5, Sub 246	Public Staff of NCUC	Return on equity, capital structure
1990	North Carolina Power	NC	E-22, Sub 314	Public Staff of NCUC	Return on equity, capital structure
1991	Duke Energy	NC	E-7, Sub 487	Public Staff of NCUC	Return on equity, capital structure
1991	North Carolina Natural Gas	NC	G-21, Sub 306	Public Staff of NCUC	Natural gas expansion fund
1991	North Carolina Natural Gas	NC	G-21, Sub 307	Public Staff of NCUC	Natural gas expansion fund
1991	Penn & Southern Gas Company	NC	G-3, Sub 186	Public Staff of NCUC	Return on equity, capital structure
1995	North Carolina Natural Gas	NC	G-21, Sub 334	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1995	Carolina Power & Light Company	NC	E-2, Sub 680	Carolina Utility Customers Assoc.	Fuel adjustment proceeding
1995	Duke Power	NC	E-7, Sub 559	Carolina Utility Customers Assoc.	Fuel adjustment proceeding
1996	Piedmont Natural Gas Company	NC	G-9, Sub 378	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Piedmont Natural Gas Company	NC	G-9, Sub 382	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Public Service Company of NC	NC	G-5, Sub 356	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Cardinal Extension Company	NC	G-39, Sub 0	Carolina Utility Customers Assoc.	Capital structure, cost of capital
1997	Public Service Company of NC	NC	G-5, Sub 327	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1998	Public Service Company of NC	NC	G-5, Sub 386	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1998	Public Service Company of NC	NC	G-5, Sub 386	Carolina Utility Customers Assoc.	Natural gas transporation rates
1999	Public Service Company of NC/SCANA Corp	NC	G-5, Sub 400	Carolina Utility Customers Assoc.	Merger case
1999	Public Service Company of NC/SCANA Corp	NC	G-43	Carolina Utility Customers Assoc.	Merger Case
1999	Carolina Power & Light Company	NC	E-2, Sub 753	Carolina Utility Customers Assoc.	Holding company application
1999	Carolina Power & Light Company	NC	G-21, Sub 387	Carolina Utility Customers Assoc.	Holding company application
1999	Carolina Power & Light Company	NC	P-708, Sub 5	Carolina Utility Customers Assoc.	Holding company application
2000	Piedmont Natural Gas Company	NC	G-9, Sub 428	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2000	NUI Corporation	NC	G-3, Sub 224	Carolina Utility Customers Assoc.	Holding company application
2000	NUI Corporation/Virginia Gas Company	NC	G-3, Sub 232	Carolina Utility Customers Assoc.	Merger application
2001	Duke Power	NC	E-7, Sub 685	Carolina Utility Customers Assoc.	Emission allowances and environmental compliance costs
2001	NUI Corporation	NC	G-3, Sub 235	Carolina Utility Customers Assoc.	Tariff change request.
2001	Carolina Power & Light Company/Progress E	NC	E-2, Sub 778	Carolina Utility Customers Assoc.	Asset transfer case
2001	Duke Power	NC	E-7, Sub 694	Carolina Utility Customers Assoc.	Restructuring application
2002	Piedmont Natural Gas Company	NC	G-9, Sub 461	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2002	Cardinal Pipeline Company	NC	G-39, Sub 4	Carolina Utility Customers Assoc.	Cost of capital, capital structure
2002	South Carolina Public Service Commission	SC	2002-63-G	South Carolina Energy Users Committee	Rate of return, accounting, rate design, cost of service
2003	Piedmont Natural Gas/North Carolina Natura	NC	G-9, Sub 470	Carolina Utility Customers Assoc.	Merger application
2003	Piedmont Natural Gas/North Carolina Natura	NC	G-9, Sub 430	Carolina Utility Customers Assoc.	Merger application
2003	Piedmont Natural Gas/North Carolina Natura	NC	E-2, Sub 825	Carolina Utility Customers Assoc.	Merger application
2003	Carolina Power & Light Company	NC	E-2, Sub 833	Carolina Utility Customers Assoc.	Fuel case
2004	South Carolina Electric & Gas	SC	2004-178-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2005	Carolina Power & Light Company	NC	E-2, Sub 868	Carolina Utility Customers Assoc.	Fuel case
2005	Piedmont Natural Gas Company	NC	G-9, Sub 499	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2005	South Carolina Electric & Gas	SC	2005-2-E	South Carolina Energy Users Committee	Fuel application
2005	Carolina Power & Light Company	SC	2006-1-E	South Carolina Energy Users Committee	Fuel application
2006	IRP in North Carolina	NC	E-100, Sub 103	Carolina Utility Customers Assoc.	Submitted rebuttal testimony in investigation of IRP in NC.
2006	Piedmont Natural Gas Company	NC	G-9, Sub 519	Carolina Utility Customers Assoc.	Creditworthiness issue
2006	Public Service Company of NC	NC	G-5, Sub 481	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2006	Duke Power	NC	E-7, 751	Carolina Utility Customers Assoc.	App to share net revenues from certain wholesale pwr trans

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
2018	Elkton Gas Company	MD	FC 9488	Maryland Office of People's Counsel	Accounting, ROE, capital structure
2018	Baltimore Gas & Electric	MD	FC9484	Maryland Office of People's Counsel	ROE, capital structure
2018	South Carolina Electric & Gas	SC	2017-370-E	South Carolina Energy Users Committee	Creditworthiness issue
2018	Jersey Central Power & Light	NJ	EO18070728	NJ Division of Rate Counsel	ROE and capital structure
2019	Duke Energy Carolinas	SC	2018-319-E	South Carolina Energy Users Committee	Accounting, rate design
2019	Duke Energy Progress	SC	2018-318-E	South Carolina Energy Users Committee	Accounting, rate design
2019	Public Service Electric and Gas	NJ	EO18060629	NJ Division of Rate Counsel	ROE and capital structure
2019	Potomac Electric Power	MD	FC 9602	Maryland Office of People's Counsel	ROE, capital structure
2019	Oklahoma Gas and Electric	OK	PUD 201800140	Sierra Club	Creditworthiness issue
2019	Peoples Natural Gas	PA	R-2018-3006818	Pennsylvania Office of Consumer Advocate	ROE, capital structure
2019	UGI Natural Gas	PA	R-2018-3006814	Pennsylvania Office of Consumer Advocate	ROE, capital structure
2019	Dominion Virginia Power	VA	PUR-2019-00050	Federal Executive Agencies	Return on Equity
2019	Piedmont Natural Gas	NC	G-9, Sub 743	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE
2019	Pacific Gas & Electric, Southern California Edison, San Diego Gas & Electric	CA	A-1904014, et al	Federal Executive Agencies	ROE, capital structure
2019	Duke Energy Indiana	IN	Cause 45253	Federal Executive Agencies	ROE, capital structure
2020	Duke Energy Carolinas	NC	E-7 Sub 1214	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE
2020	Duke Energy Progress	NC	E-2 Sub 1219	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE
2020	Dominion Virginia Power	VA	PUR-2019-00154	Southern Environmental Law Center	Financial analysis of plant investment
2020	Southwest Electric Power Company	LA	U-35324	Alliance for Affordable Energy	Financial analysis of plant investment
2020	Texas Gas Company	TX	PUC 10928	Texas Gas Cities	ROE, capital structure
2020	Potomac Electric Power	DC	FC 1156	District of Columbia Office of Peoples Counsel	ROE, capital structure
2020	UGI Gas	PA	R-2019-3015162	Pennsylvania Office of Consumer Advocate	ROE, capital structure, creditworthiness
2020	Columbia Gas of Maryland	MD	FC 9644	Maryland Office of People's Counsel	ROE, capital structure
2020	Columbia Gas of Pennsylvania	PA	R-2020-3018835	Pennsylvania Office of Consumer Advocate	ROE, capital structure
2020	New Mexico Gas Company	NM	19-00317-UT	Federal Executive Agencies	ROE, captial structure, accounting, rate design, cost of service
2020	Washington Gas Light	DC	FC 1162	District of Columbia Office of Peoples Counsel	ROE, capital structure
2020	Dominion Energy South Carolina	SC	2020-125-E	South Carolina Energy Users Committee	Accounting, rate design

OCA Recommended Overall Rate of Return

O'Donnell Financial Analyses ROE Results		
DCF	7.75%	10.00%
CEA	9.25%	10.25%
CAPM	5.50%	7.75%
Recommendation	**8.75%**	

O'Donnell Overall Recommendation			
Component	Capital Structure Ratio (%)	Cost Rate (%)	Wgtd. Cost Rate (%)
Long-Term Debt	50.00%	3.84%	1.92%
Common Equity	50.00%	8.75%	4.38%
Total Capitalization	100.00%		6.30%

O'Donnell Proxy Group
DCF Summary

Company	Forecasted Annualized Dividend Yield			Value Line 10-Year			Value Line 5-Year			Value Line Forecasted			Average Plowback Growth	CFRA 3-Year Projected	Schwab LT Growth Rate 3-5 Years
	13-Wks [1]	4-Wks [2]	Current [3]	EPS [4]	DPS [4]	BPS [4]	EPS [4]	DPS [4]	BPS [4]	EPS [4]	DPS [4]	BPS [4]	Rate [4]	EPS CAGR [5]	EPS (AEE) [6]
													Exhibit KWO-3		
Atmos Energy	2.6%	2.6%	2.6%	7.5%	4.0%	6.5%	9.5%	6.5%	8.5%	7.0%	7.5%	7.5%	4.6%	6.0%	7.1%
Chesapeake Utilities	2.0%	1.8%	1.8%	9.0%	5.5%	9.5%	8.0%	6.5%	10.5%	9.0%	8.5%	11.0%	6.2%	14.4%	-
New Jersey Resources	4.2%	3.8%	4.0%	7.0%	7.0%	7.0%	6.0%	6.5%	8.5%	2.0%	6.0%	8.5%	5.2%	8.0%	6.0%
NiSource Inc	3.6%	3.5%	3.5%	-1.0%	-2.0%	-3.0%	-8.0%	-5.0%	-7.0%	13.0%	7.5%	5.0%	3.2%	5.0%	1.7%
Northwest Natural	4.1%	4.0%	4.0%	-11.0%	2.0%	1.5%	-17.0%	0.5%	-0.5%	24.5%	0.5%	6.0%	1.9%	4.0%	3.1%
ONE Gas Inc	3.1%	3.0%	2.9%	-	-	-	9.5%	17.0%	2.5%	6.5%	7.5%	5.5%	3.6%	5.0%	5.0%
South Jersey Inds	5.9%	5.4%	5.4%	1.5%	8.0%	6.5%	-2.5%	6.0%	6.0%	12.5%	3.5%	5.0%	3.2%	6.0%	10.4%
Southwest Gas	3.5%	3.5%	3.6%	8.0%	8.5%	6.0%	4.5%	9.5%	6.5%	9.0%	4.0%	6.5%	4.1%	6.0%	4.0%
Spire Inc	4.5%	4.1%	4.0%	3.5%	4.0%	7.0%	9.5%	5.5%	7.0%	5.5%	5.0%	8.5%	3.5%	4.0%	5.4%
UGI Corp	3.8%	3.7%	3.7%	6.0%	7.5%	8.0%	9.5%	7.0%	6.0%	5.5%	6.0%	5.5%	7.0%	8.0%	7.2%
AVERAGE	**3.7%**	**3.5%**	**3.6%**	**3.4%**	**4.9%**	**5.4%**	**2.9%**	**6.0%**	**4.8%**	**9.5%**	**5.6%**	**6.9%**	**4.3%**	**6.6%**	**5.5%**
Exelon Corp	4.0%	3.8%	3.9%	-4.5%	-3.5%	6.5%	4.5%	-3.0%	4.0%	3.5%	5.5%	3.5%	3.7%	4.0%	-2.4%

Notes:
EPS = earnings per share
DPS = dividends per share
BPS = book value per share

Sources:

[1]	The Value Line Investment Survey, Summary and Index	9/25/2020	10/2/2020	10/9/2020	10/16/2020	10/23/2020	10/30/2020	11/6/2020	11/13/2020	11/20/2020
		11/27/2020	12/4/2020	12/11/2020	12/18/2020					
[2]	The Value Line Investment Survey, Summary and Index	11/27/2020	12/4/2020	12/11/2020	12/18/2020					
[3]	The Value Line Investment Survey, Summary and Index	12/18/2020								

[4] The Value Line Investment Survey 11/13/2020 (Electric Utilities East), 11/27/2020 (Nat Gas)
[5] CFRA Stock Report earnings estimates as of 12/7/2020 as provided by Schwab.com
[6] Schwab Equity Report earnings estimates as of 12/7/2020 as provided by Schwab.com

O'Donnell Proxy Group

Plowback Ratios

Company	2018	2019	2020E*	2023E* - 2025E*	AVERAGE
					Exhibit KWO-2, Exhibit KWO-5 pg. 2
Atmos Energy	4.8%	4.6%	4.5%	4.5%	4.6%
Chesapeake Utilities	6.7%	6.5%	6.0%	5.5%	6.2%
New Jersey Resources	10.2%	4.6%	3.0%	3.0%	5.2%
NiSource Inc	3.7%	2.7%	2.0%	4.5%	3.2%
Northwest Natural	2.1%	1.4%	1.0%	3.0%	1.9%
ONE Gas Inc	3.7%	3.8%	3.5%	3.5%	3.6%
South Jersey Inds	1.7%	NMF	2.5%	5.5%	3.2%
Southwest Gas	3.6%	3.9%	3.5%	5.5%	4.1%
Spire Inc	4.7%	2.7%	NMF	3.0%	3.5%
UGI Corp	8.4%	5.6%	6.5%	7.5%	7.0%
AVERAGE	**5.0%**	**4.0%**	**3.6%**	**4.6%**	**4.3%**

Exelon Corp	2.2%	4.7%	4.0%	4.0%	3.7%

*E = expected
Plowback = Percent retained to common equity
The Value Line Investment Survey: 11/13/2020 (Electric Utilities East), 11/27/2020 (Nat Gas)

O'Donnell Proxy Group
Returns on Book Value

Company	2018	2019	2020E*	2023E* - 2025E*
Atmos Energy	9.3%	8.9%	8.5%	9.0%
Chesapeake Utilities	10.9%	10.9%	10.5%	9.0%
New Jersey Resources	16.9%	11.3%	9.5%	9.5%
NiSource Inc	9.3%	8.6%	8.0%	11.0%
Northwest Natural	8.8%	7.5%	7.5%	8.5%
ONE Gas Inc	8.4%	8.8%	8.5%	8.5%
South Jersey Inds	9.2%	7.2%	10.0%	12.0%
Southwest Gas	8.1%	8.5%	8.5%	10.0%
Spire Inc	9.5%	7.9%	3.5%	7.0%
UGI Corp	13.2%	10.8%	14.5%	13.0%
AVERAGE	**10.4%**	**9.0%**	**8.9%**	**9.8%**

Exelon Corp	6.5%	9.1%	8.5%	8.5%

*E = expected
The Value Line Investment Survey: 11/13/2020 (Electric Utilities East), 11/27/2020 (Nat Gas)

O'Donnell: Proxy Group
DCF Results

O'Donnell DCF Calculation

	VL 13-Weeks **a**	VL 4-Weeks **b**	VL 1-Week **c**
	Exhibit KWO-2 →		
VL DIVIDEND YIELD AVERAGES	3.7%	3.5%	3.6%

Growth Rates	VL EPS **d**	VL DPS **e**	VL BPS **f**
	Exhibit KWO-2 →		
10-Year Growth Rate Averages	3.4%	4.9%	5.4%
5-Year Growth Rate Averages	2.9%	6.0%	4.8%
VL HISTORICAL GROWTH RATE AVERAGES	**3.1%**	**5.5%**	**5.1%**

	VL EPS **g**	VL DPS **h**	VL BPS **i**	CFRA EPS **j**	Schwab EPS **k**
	Exhibit KWO-2 →				
FORECASTED GROWTH RATE AVERAGES	**9.5%**	**5.6%**	**6.9%**	**6.6%**	**5.5%**

VL HISTORICAL GROWTH RATE AVERAGES + VL DIV YIELD AVERAGES	13-Weeks VL EPS **= a + d**	13-Weeks VL DPS **= a + e**	13-Weeks VL BPS **= a + f**
	Rx →		
	6.9%	9.2%	8.8%
	4-Weeks VL EPS **= b + d**	4-Weeks VL DPS **= b + e**	4-Weeks VL BPS **= b + f**
	Rx →		
	6.7%	9.0%	8.6%
	1-Week VL EPS **= c + d**	1-Week VL DPS **= c + e**	1-Week VL BPS **= c + f**
	Rx →		
	6.7%	9.0%	8.7%

	MIN	**AVG**	**MAX**
	ABOVE →		
VL HISTORICAL GROWTH RATE AVERAGES + VL DIV YIELD RANGE	**6.7%**	**8.2%**	**9.2%**

FORECASTED GROWTH RATE AVERAGES + VL DIV YIELD AVERAGES	13-Weeks VL EPS **= a + g**	13-Weeks VL DPS **= a + h**	13-Weeks VL BPS **= a + i**	13-Weeks CFRA EPS **= a + j**	13-Weeks Schwab EPS **= a + k**
	Rx →				
	13.2%	9.3%	10.6%	10.4%	9.3%
	4-Weeks VL EPS **= b + g**	4-Weeks VL DPS **= b + h**	4-Weeks VL BPS **= b + i**	4-Weeks CFRA EPS **= b + j**	4-Weeks Schwab EPS **= b + k**
	Rx →				
	13.0%	9.1%	10.4%	10.2%	9.1%
	1-Week VL EPS **= c + g**	1-Week VL DPS **= c + h**	1-Week VL BPS **= c + i**	1-Week CFRA EPS **= c + j**	1-Week Schwab EPS **= c + k**
	Rx →				
	13.0%	9.2%	10.5%	10.2%	9.1%

	MIN	**AVG**	**MAX**
	ABOVE →		
FORECASTED GROWTH RATE AVERAGES + VL DIV YIELD RANGE	**9.1%**	**10.4%**	**13.2%**

O'Donnell: Proxy Group
DCF Results

O'Donnell DCF Calculation (cont'd)

	VL DIV YIELD AVERAGES			VL PLOWBACK	VL PLOWBACK + VL DIV YIELD AVERAGES		
	13-Weeks	4-Weeks	1-Week				
	a	b	c	d	= a + d	= b + d	= c + d
	Exhibit KWO-2 →			Exhibit KWO-3 →	Rx →		
Atmos Energy	2.6%	2.6%	2.6%	4.6%	7.2%	7.2%	7.2%
Chesapeake Utilities	2.0%	1.8%	1.8%	6.2%	8.1%	8.0%	8.0%
New Jersey Resources	4.2%	3.8%	4.0%	5.2%	9.4%	9.0%	9.2%
NiSource Inc	3.6%	3.5%	3.5%	3.2%	6.8%	6.7%	6.7%
Northwest Natural	4.1%	4.0%	4.0%	1.9%	6.0%	5.8%	5.9%
ONE Gas Inc	3.1%	3.0%	2.9%	3.6%	6.7%	6.6%	6.5%
South Jersey Inds	5.9%	5.4%	5.4%	3.2%	9.1%	8.6%	8.6%
Southwest Gas	3.5%	3.5%	3.6%	4.1%	7.6%	7.7%	7.7%
Spire Inc	4.5%	4.1%	4.0%	3.5%	7.9%	7.5%	7.5%
UGI Corp	3.8%	3.7%	3.7%	7.0%	10.8%	10.7%	10.7%
AVERAGE	**3.7%**	**3.5%**	**3.6%**	**4.3%**	**8.0%**	**7.8%**	**7.8%**

O'Donnell: Exelon Parent Company

DCF Results

O'Donnell DCF Calculation

	VL 13-Weeks a	VL 4-Weeks b	VL 1-Week c
	Exhibit KWO-2 →		
VL DIVIDEND YIELD AVERAGES	4.0%	3.8%	3.9%

Growth Rates	VL EPS d	VL DPS e	VL BPS f
	Exhibit KWO-2 →		
10-Year Growth Rate Averages	-4.5%	-3.5%	6.5%
5-Year Growth Rate Averages	4.5%	-3.0%	4.0%
VL HISTORICAL GROWTH RATE AVERAGES	**0.0%**	**-3.3%**	**5.3%**

	VL EPS g	VL DPS h	VL BPS i	CFRA EPS j	Schwab EPS k
	Exhibit KWO-2 →				
FORECASTED GROWTH RATE AVERAGES	**3.5%**	**5.5%**	**3.5%**	**4.0%**	**-2.4%**

	13-Weeks VL EPS **= a + d**	13-Weeks VL DPS **= a + e**	13-Weeks VL BPS **= a + f**
	Rx →		
VL HISTORICAL GROWTH RATE AVERAGES + VL DIV YIELD AVERAGES	4.0%	0.7%	9.2%
	4-Weeks VL EPS **= b + d**	4-Weeks VL DPS **= b + e**	4-Weeks VL BPS **= b + f**
	Rx →		
	3.8%	0.6%	9.1%
	1-Week VL EPS **= c + d**	1-Week VL DPS **= c + e**	1-Week VL BPS **= c + f**
	Rx →		
	3.9%	0.7%	9.2%

	MIN	**AVG**	**MAX**
	ABOVE →		
VL HISTORICAL GROWTH RATE AVERAGES + VL DIV YIELD RANGE	**0.6%**	**4.6%**	**9.2%**

	13-Weeks VL EPS **= a + g**	13-Weeks VL DPS **= a + h**	13-Weeks VL BPS **= a + i**	13-Weeks CFRA EPS **= a + j**	13-Weeks Schwab EPS **= a + k**
	Rx →				
FORECASTED GROWTH RATE AVERAGES + VL DIV YIELD AVERAGES	7.5%	9.5%	7.5%	8.0%	1.6%
	4-Weeks VL EPS **= b + g**	4-Weeks VL DPS **= b + h**	4-Weeks VL BPS **= b + i**	4-Weeks CFRA EPS **= b + j**	4-Weeks Schwab EPS **= b + k**
	Rx →				
	7.3%	9.3%	7.3%	7.8%	1.4%
	1-Week VL EPS **= c + g**	1-Week VL DPS **= c + h**	1-Week VL BPS **= c + i**	1-Week CFRA EPS **= c + j**	1-Week Schwab EPS **= c + k**
	Rx →				
	7.4%	9.4%	7.4%	7.9%	1.5%

	MIN	**AVG**	**MAX**
	ABOVE →		
FORECASTED GROWTH RATE AVERAGES + VL DIV YIELD RANGE	**1.4%**	**6.7%**	**9.5%**

O'Donnell: Exelon Parent Company

DCF Results

O'Donnell DCF Calculation (cont'd)

	VL DIV YIELD AVERAGES		
	13-Weeks	4-Weeks	1-Week
	a	**b**	**c**
	Exhibit KWO-2		
Exelon Corp	4.0%	3.8%	3.9%

	VL PLOWBACK
	d
Exhibit KWO-3	
Exelon Corp	3.7%

VL PLOWBACK + VL DIV YIELD AVERAGES		
= a + d	**= b + d**	**= c + d**
Rx		
7.7%	7.6%	7.6%

O'Donnell Proxy Group
DCF Results

O'Donnell DCF Calculation (cont'd)

	VL DIV YIELD AVERAGES		
	13-Weeks	4-Weeks	1-Week
	a	**b**	**c**
	Exhibit KWO-2 →		
Exelon Corp	4.0%	3.8%	3.8%

	VL PLOWBACK
	d
Exhibit KWO-3 →	
Exelon Corp	3.7%

VL PLOWBACK + VL DIV YIELD AVERAGES		
= a + d	**= b + d**	**= c + d**
Rx →		
7.8%	7.5%	7.5%

O'Donnell Proxy Group
CAPM Results

Natural Gas Comparable Group

	30-Yr. Risk-Free Rate [1]	Average Proxy Group Beta [2]	Equity Risk Premium	Beta Adjusted Equity Risk Premium	Equity Cost Rate	Rounded Equity Cost Rate	
	a	b	c	d = b * c	= a + d	Rnd	
Treasury - Maximum	2.39%	0.89	4.25%	3.78%	6.17%	6.2%	
Treasury - Average	1.61%	0.89	4.25%	3.78%	5.40%	5.4%	
Treasury - Minimum	0.99%	0.89	4.25%	3.78%	4.77%	4.8%	LOW

	30-Yr. Risk-Free Rate [1]	Average Proxy Group Beta [2]	Equity Risk Premium	Beta Adjusted Equity Risk Premium	Equity Cost Rate	Rounded Equity Cost Rate	
	a	b	c	d = b * c	= a + d	Rnd	
Treasury - Maximum	2.39%	0.89	6.25%	5.56%	7.95%	8.0%	HIGH
Treasury - Average	1.61%	0.89	6.25%	5.56%	7.18%	7.2%	
Treasury - Minimum	0.99%	0.89	6.25%	5.56%	6.55%	6.6%	

Source:
[1] US Treasury Yields, November 27, 2019 through November 27, 2020:
https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?
[2] *The Value Line Investment Survey* : 11/27/2020 (Nat Gas)

Exelon

	30-Yr. Risk-Free Rate [1]	Average Proxy Group Beta [2]	Equity Risk Premium	Beta Adjusted Equity Risk Premium	Equity Cost Rate	Rounded Equity Cost Rate	
	a	b	c	d = b * c	= a + d	Rnd	
Treasury - Maximum	2.39%	0.95	4.25%	4.04%	6.43%	6.4%	
Treasury - Average	1.61%	0.95	4.25%	4.04%	5.65%	5.7%	
Treasury - Minimum	0.99%	0.95	4.25%	4.04%	5.03%	5.0%	LOW

	30-Yr. Risk-Free Rate [1]	Average Proxy Group Beta [2]	Equity Risk Premium	Beta Adjusted Equity Risk Premium	Equity Cost Rate	Rounded Equity Cost Rate	
	a	b	c	d = b * c	= a + d	Rnd	
Treasury - Maximum	2.39%	0.95	6.25%	5.94%	8.33%	8.3%	HIGH
Treasury - Average	1.61%	0.95	6.25%	5.94%	7.55%	7.6%	
Treasury - Minimum	0.99%	0.95	6.25%	5.94%	6.93%	6.9%	

Source:
[1] US Treasury Yields, November 27, 2019 through November 27, 2020:
https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?
[2] *The Value Line Investment Survey* : 11/13/2020 (Electric Utilities East)

Original Witness Moul Cost of Debt Calculation

Mr. Moul's Response to OCA-XII-1, Attachment OCA-XII-1(a).xlsx Page 3

PECO Energy Company
Calculation of the Embedded Cost of Long-Term Debt
Estimated at June 30, 2022

Series	Date of Maturity	Principal Amount Outstanding	Percent to Total	Effective Cost Rate [1]	Weighted Cost Rate
First and Refunding Mortgage Bonds					
2.375%	09/15/22	$ 350,000,000	7.43%	2.47%	0.18%
3.150%	10/15/25	350,000,000	7.43%	3.29%	0.24%
5.90%	05/01/34	75,000,000	1.59%	6.00%	0.10%
5.95%	10/01/36	300,000,000	6.37%	6.04%	0.38%
5.70%	03/15/37	175,000,000	3.72%	5.81%	0.22%
4.80%	10/15/43	250,000,000	5.31%	4.89%	0.26%
4.15%	10/01/44	300,000,000	6.37%	4.23%	0.27%
3.70%	09/15/47	325,000,000	6.90%	3.77%	0.26%
3.90%	03/01/48	650,000,000	13.80%	4.08%	0.56%
3.00%	09/15/49	325,000,000	6.90%	3.10%	0.21%
2.80%	06/15/50	350,000,000	7.43%	2.86%	0.21%
3.35%	03/01/51	300,000,000	6.37%	3.46%	0.22%
3.35%	09/01/51	375,000,000	7.96%	3.46%	0.28%
3.40%	03/01/52	350,000,000	7.43%	3.51%	0.26%
PIDC Loan					
2.00%	06/20/23	50,000,000	1.06%	2.27%	0.02%
Trust Preferred Capital Securities					
7.38%	04/06/28	80,520,619	1.71%	7.46%	0.13%
6.75%	04/06/28	805,206	0.02%	6.75%	0.00%
5.75%	06/15/33	103,092,784	2.19%	5.88%	0.13%
		4,709,418,609	100.00%		3.93%
Adjustment for Tenders and Calls		(2,214,000)			
Long-Term Debt		$ 4,707,204,609			
Annualized Cost		$ 185,080,151			
Adjustment for Tenders and Calls on Reacquired Debt		1,584,000			
Total Cost		$ 186,664,151			3.97%

Notes: [1] As calculated on page 4 of this schedule.

Source of Information: Company provided data

KWO Adjusted Cost of Debt Calculation*

PECO Energy Company
Calculation of the Embedded Cost of Long-Term Debt
Estimated at June 30, 2022

Source of Information: Mr. Moul's Response to OCA-XII-1, Attachment OCA-XII-1(a).xlsx Page 3

Series	Date of Maturity	Principal Amount Outstanding	Percent to Total	Effective Cost Rate (1)	Weighted Cost Rate	KWO Adjustments*
First and Refunding Mortgage Bonds						
2.375%	09/15/22	$ 350,000,000	7.43%	2.47%	0.18%	
3.150%	10/15/25	350,000,000	7.43%	3.29%	0.24%	
5.90%	05/01/34	75,000,000	1.59%	6.00%	0.10%	
5.95%	10/01/36	300,000,000	6.37%	6.04%	0.38%	
5.70%	03/15/37	175,000,000	3.72%	5.81%	0.22%	
4.80%	10/15/43	250,000,000	5.31%	4.89%	0.26%	
4.15%	10/01/44	300,000,000	6.37%	4.23%	0.27%	
3.70%	09/15/47	325,000,000	6.90%	3.77%	0.26%	
3.90%	03/01/48	650,000,000	13.80%	4.08%	0.56%	
3.00%	09/15/49	325,000,000	6.90%	3.10%	0.21%	
2.80%	06/15/50	350,000,000	7.43%	2.86%	0.21%	
2.80%	03/01/51	300,000,000	6.37%	2.90%	0.18%	Updated LTD rate per Attachment OCA-XII-2(a), p. 1
2.80%	09/01/51	375,000,000	7.96%	2.90%	0.23%	Updated LTD rate per Attachment OCA-XII-2(a), p. 1
2.90%	03/01/52	350,000,000	7.43%	3.00%	0.22%	Updated LTD rate per Attachment OCA-XII-2(a), p. 1
PIDC Loan						
2.00%	06/20/23	50,000,000	1.06%	2.27%	0.02%	
Trust Preferred Capital Securities						
7.38%	04/06/28	80,520,619	1.71%	7.46%	0.13%	
5.25%	04/06/28	805,206	0.02%	5.25%	0.00%	Reduced rate to reflect current prime rates as of 12/15/20
5.75%	06/15/33	103,092,784	2.19%	5.88%	0.13%	
		4,709,418,609	100.00%		3.80%	
Adjustment for Tenders and Calls		(2,214,000)				
Long-Term Debt		$ 4,707,204,609				
Annualized Cost		$ 178,957,907				
Adjustment for Tenders and Calls on Reacquired Debt		1,584,000				
Total Cost		$ 180,541,907			3.84%	

Notes: (1) As calculated on Mr. Moul's Response to OCA-XII-1, Attachment OCA-XII-1(a).xlsx Page 4.

Source of Information: Company provided data

*KWO Adjustments

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018929
	:	
PECO Energy Company – Gas Division	:	

VERIFICATION

I, Kevin W. O'Donnell, hereby state that the facts set forth in my Direct Testimony, OCA Statement 3, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: December 22, 2020
*300676

Signature: Kevin W. O'Donnell

Kevin W. O'Donnell

Consultant Address: Nova Energy Consultants, Inc.
1350 SE Maynard Road
Suite 101
Cary, NC 27511

OCA Statement No. 4

R-2020-3018929
2/17/21 JK

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
v.	)	Docket No. R-2020-3018929
	)	
	)	
PECO ENERGY COMPANY –	)	
GAS DIVISION	)	

PUBLIC VERSION

DIRECT TESTIMONY
OF
GLENN A. WATKINS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

DECEMBER 22, 2020

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 6377 Mattawan Trail, Mechanicsville, Virginia 23116.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am a President and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with offices in the Richmond, Virginia area. Except for a six-month period during 1987 in which I was employed by Old Dominion Electric Cooperative, as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my career at Technical Associates, I have conducted marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities, and have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. A more complete description of my education and experience as well as a list of my prior testimonies is provided in my Schedule GAW-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. Over the last 25-plus years, I have provided testimony before this Commission on issues concerning cost allocations, rate design, cost of capital, and revenue requirement on dozens of occasions.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Technical Associates, Inc. has been retained by the OCA to evaluate the reasonableness of PECO Energy Company's ("PECO" or "Company") natural gas class cost of service studies, proposed distribution of revenues by customer class and residential rate design. The purpose of my direct testimony is to discuss the recommendation of OCA witness Scott Rubin that an increase in rates in unreasonable at this time as well as provide the findings of my analyses concerning class cost of service, revenue allocations, and residential rate design.

II. OVERVIEW & SUMMARY

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR APPROACH TO THIS CASE AS WELL AS A SUMMARY OF YOUR RECOMMENDATIONS.

A. As set forth in the direct testimony of OCA witness Scott Rubin, OCA recommends no change in rates or rate elements as a result of this case. As a result, rate design, per se, becomes moot under OCA's recommendations. However, should the Commission determine that PECO should be authorized some increase in overall revenues, I have developed an alternative, "business as usual," class revenue allocation recognizing: (1) class cost of service study results should serve as only one of many tools in establishing class revenue responsibility; and, (2) a prior PECO General Rate Case settlement agreement that relates to class revenue allocations for this rate case.

In addition, should the Commission decide to authorize an overall increase in revenues and rates, I recommend that the current ratemaking treatment associated with Interruptible Sales service (Rate IS) be abandoned. Furthermore, if a revenue increase is authorized, the Company's proposed 36% increase in the Residential fixed monthly customer charge from $11.75 to $16.00 per month should be rejected and this rate be increased to no more than $13.00 per month.

With regard to negotiated rate customers, I recommend the Commission order PECO to reevaluate some of its negotiated rate contracts and report its findings to the Commission and OCA on, or before, its next general rate case.

III. CLASS COST OF SERVICE

A. Concepts and Methods

Q. PLEASE BRIEFLY EXPLAIN THE CONCEPT OF A CLASS COST OF SERVICE STUDY ("CCOSS") AND ITS PURPOSE IN A RATE PROCEEDING.

A. Generally there are two types of cost of service studies used in public utility ratemaking: marginal cost studies and embedded, or fully allocated, cost studies. Consistent with the practices of this Commission, PECO has utilized a traditional embedded cost of service study for purposes of establishing the overall revenue requirement in this case, as well as for class cost of service purposes.

Embedded class cost of service studies are also referred to as fully allocated cost studies because the majority of a public utility's plant investment and expense is incurred to serve all customers in a joint manner. Accordingly, most costs cannot be specifically attributed to a particular customer or group of customers. To the extent that certain costs can be specifically attributed to a particular customer or group of customers, these costs are directly assigned in the CCOSS. The costs jointly incurred to serve all or most customers; therefore, must be allocated across specific customers or customer rate classes.

It is generally accepted that to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although the cost analyst strives to abide by this concept to the greatest extent practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors, and must be subjectively assigned or allocated to customer rate classes. With regard to those costs in which cost causation can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor; e.g., peak demand, energy or throughput usage, number of customers, etc.

Q. IN YOUR OPINION, HOW SHOULD THE RESULTS OF A CCOSS BE UTILIZED IN THE RATEMAKING PROCESS?

A. Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive individual costs. These disagreements can and do arise as a result of the quality of data and level of detail available from financial records. There are also fundamental differences in opinions regarding the cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned previously, cost causation factors cannot be realistically ascribed to some costs such that subjective decisions are required.

In these regards, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS only as a guide, with the results being used as one of many tools to assign class revenue responsibility.

Q. HAVE THE HIGHER COURTS OPINED ON THE USEFULNESS OF COST ALLOCATIONS FOR PURPOSES OF ESTABLISHING REVENUE RESPONSIBILITY AND RATES?

A. Yes. In an important regulatory case involving Colorado Interstate Gas Company and the Federal Power Commission (predecessor to FERC), the United States Supreme Court stated:

> "But where, as here, several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[1]"

Q. DOES YOUR OPINION, AND THE FINDINGS OF THE U.S. SUPREME COURT, IMPLY THAT COST ALLOCATIONS SHOULD PLAY NO ROLE IN THE RATEMAKING PROCESS?

A. Not at all. It simply means that regulators should consider the fact that cost allocation results are not surgically precise and that alternative, yet equally defensible,

[1] 324 U.S. 581, 589 (1945), 65 S. Ct. 829, 833 (1945).

approaches may produce significantly different results. In this regard, when all cost allocation approaches consistently show that certain classes are over or under contributing to costs and/or profits, there is a strong rationale for assigning smaller or greater percentage rate increases to these classes. On the other hand, if one set of cost allocation approaches show dramatically different results than another approach, caution should be exercised in assigning disproportionately larger or smaller percentage increases to the classes in question.

Q. PLEASE EXPLAIN THE BASIC CONCEPTS OF COST ALLOCATION FOR PUBLIC UTILITIES AND NATURAL GAS DISTRIBUTION COMPANIES ("NGDCs").

A. As I mentioned earlier, the majority of a NGDC's plant investment serves customers in a joint manner. In this regard, the NGDC's infrastructure is a system benefiting all customers. If all customers were the same size and had identical usage characteristics, cost allocation would be simple (even unnecessary). However, in reality, a utility's customer base is not so simple. Customers (or customer groups) tend to vary greatly in the amount of service required throughout the year such that there are small usage and large usage customers. Therefore, differences in usage should be considered. Because different groups of customers also utilize the system at varying degrees during the year, consideration should also be given to the demands placed on the system during peak usage periods.

Q. WITH REGARD TO NGDCs, IS THERE ANY ASPECT OF CLASS COST ALLOCATION THAT TENDS TO OVERSHADOW OTHER ISSUES OR IS OFTEN CONTROVERSIAL?

A. Yes. For virtually every NGDC, the largest single rate base item (account) is distribution Mains. Furthermore, several other rate base and operating income accounts are typically allocated to classes based on the previous assignment of distribution Mains. As such, the methods and approaches used to allocate distribution Mains to classes are usually by far the most important (in terms of class rate of return ["ROR"] results) and tend to be the most controversial.

Q. WHAT METHODS ARE COMMONLY USED TO ALLOCATE NATURAL GAS DISTRIBUTION MAINS?

A. While a myriad of cost allocation methods and approaches have been developed, three methods predominate in the NGDC industry: "Peak Responsibility," "Peak and Average (P&A)" or "Demand/Commodity," and "Customer/Demand," which I will address shortly in more detail. These methods differ in the criteria used to allocate Mains, as cost allocation analysts do not universally agree on the cost causative factors or drivers influencing Mains investments. There are three criteria generally considered when selecting a Mains cost allocation method: peak demand (whether coincident, non-coincident, actual or design day); annual (average day) usage; and number of customers. Because a NGDC system must be capable of supplying gas to its firm customers during peak demand periods (i.e., on very cold days), relative class peak day demands are often considered a good proxy for measuring the cost causation of Mains investment.[2] Annual (or average day) throughput is also often used to allocate Mains as this factor reflects the utilization of a utility's Mains investment. Number of customers is also sometimes considered when allocating Mains. That is, customer counts by class serve as a basis for allocation Mains. Even though annual levels of usage and peak load requirements vary greatly between customer classes (Residential versus Large Industrial), some analysts are of the opinion that customer counts should be considered because at least some infrastructure investment in Mains is required simply to "connect" every customer to the system. With these three criteria identified, various methods weight and utilize these criteria differently within the cost allocation process. In other words, some methods rely on only one criterion while others consider two or more criteria with varying weights given to each factor utilized.

[2] Embedded cost allocations are directly concerned only with relative, not absolute, criteria. That is, because embedded cost allocations reflect nothing more than dividing total system costs between classes, it is the relative (percentage) contributors to total system amounts that are relevant.

The three most common natural gas cost allocation methods are: the "Peak Responsibility" method (whether coincident or class non-coincident) in which peak day demands are the only factor utilized to allocate Mains; the "Peak and Average" or "Demand/Commodity" approach in which both peak day and annual (average day) throughput is reflected within the allocation of Mains;[3] and the Customer/Demand method that utilizes a combination of peak day demands and customer counts to assign Mains cost responsibility.

Under the Customer/Demand method, the weights given to class customer counts and peak day demands are determined from a separate analysis using one of two approaches: minimum-size and zero-intercept. The "minimum-size" approach prices the entire system footage of Mains at the cost per foot of the smallest diameter pipe installed. This "minimum-size" cost is then divided by the actual total investment in Mains to determine the weight given to customer counts. One (1) minus the customer percentage is then given to the peak day demand within the allocation process. The second approach used to classify and allocate Mains based partially on customers and partially on peak demand is known as the "zero-intercept" method. Under this approach, statistical linear regression techniques are used to estimate the cost of a theoretical "zero size" Main. Similar to the minimum size approach, the cost of this estimated zero size pipe per foot is multiplied by the total system footage and is then divided by total Mains investment to arrive at a customer weighting.

Q. IS THERE ALSO ANOTHER COST ALLOCATION METHOD TO ALLOCATE DISTRIBUTION MAINS THAT SHOULD BE EXPLAINED AND DISCUSSED THAT IS RELEVANT TO THIS CASE?

A. Yes. There is another cost allocation method that is rarely applicable or used in the natural gas industry and is known as the Average & Excess ("A&E") method. The A&E

[3] Under the Peak and Average or Demand/Commodity approach, peak use and annual throughput are either weighted equally or based on system load factor, where load factor is ratio of average daily usage to peak day usage. When using a load factor approach to weight Peak and Average usage, the weighting of average day usage is that of the system load factor while the peak day weight is one minus the system load factor.

method should not be confused with the P&A method as these two approaches are materially different in concept and application.

Under the A&E method, distribution Mains costs are allocated to classes based upon a weighting of "average" use and "excess" demand. This weighting between "average" and "excess" is based on the company's coincident peak ("CP") system load factor wherein the "average" portion is weighted based on this load factor percentage while the "excess" portion is weighted based on one minus the system load factor.[4] Each class's "excess" demand is then defined as the difference between that class's peak demand and its average demand; i.e., the excess above average. The conceptual framework of this approach is that cost responsibility should consider both usage (average demand) as well as demand requirements over and above average usage. It is most important to understand that when calculating each class's excess demand, non-coincident peak ("NCP") demands must be utilized and not CP demands.[5]

To be clear, suppose Class A's NCP occurred on a Winter weekday, Class B's NCP occurred on a different Winter weekday, and Class C's NCP occurred on a Summer day. These individual class's average usages (throughout the year) are then subtracted from their respective NCP's to arrive at each class's "excess" demand.

Q. MATHEMATICALLY, HOW DOES THE A&E METHOD AFFECT CLASS COST ALLOCATIONS ON A RELATIVE BASIS?

A. Remembering that the "excess" portion is defined as each class's maximum NCP day demand minus its average day demand, classes with low load factors (e.g., Residential and Small Commercial) tend to have high levels of this so-called "excess" demand and are assigned the vast majority of the "excess" portion. Conversely, classes with high load factors (e.g., Industrial), tend to have low levels of this so-called "excess" demand and are assigned little, to no, excess demand. This can be seen in the hypothetical example below:

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[4] The CP system load factor is defined as system-wide average day demand divided by system coincident peak demand.

[5] If system coincident load factor is utilized as a weighting mechanism and if excess demands are based on class contributions to CP demands, the resulting A&E class allocation factors are exactly equal to CP demand. Therefore, class NCPs must be used in calculating "excess" demands.

TABLE 1						
Hypothetical Example of A&E Method						
			Resid.	Comm.	Ind.	Total
Absolute Amounts:						
	(1)	Annual Use	73,000	54,750	32,850	160,600
	(2)	Avg. Day Use: (1) ÷ 365	200	150	90	440
	(3)	CP Demand	600	500	95	1,195
	(4)	NCP Demand	600	500	100	1,200
	(5)	Excess Demand: (4) - (2)	400	350	10	760
Class Percentages:						
	(6)	Sys. CP Load Factor: (2) ÷ (3)				36.82%
	(7)	Average Percent	45.45%	34.09%	20.45%	100.00%
	(8)	CP Percent	50.21%	41.84%	7.95%	100.00%
	(9)	NCP Percent	50.00%	41.67%	8.33%	100.00%
	(10)	Excess Percent	52.63%	46.05%	1.32%	100.00%
	(11)	A&E Allocation Factor:				
		[(6) x (7)] + {[1 - (6)] x (10)}	49.99%	41.65%	8.36%	100.00%

Notice that the low load factor class' (Resid. and Comm.) excess demand percentages are somewhat larger than their respective class CP or NCP demands. At the same time, the high load factor class's (Ind.) excess demand percentage is very small compared to its CP or NCP demand percentage. In addition, because the Residential and Commercial NCP demands coincide with the system CP (and represent the majority of this company's business), the resulting class A&E factors are very similar to those that would be obtained under a 100% demand allocation scenario (either CP or NCP). As such, very little weight is given to the Industrial class's average day usage.

Q. IS THE A&E METHOD OFTEN USED IN THE NGDC INDUSTRY?

A. No. For the vast majority of NGDCs, individual class CP demands are the same as the corresponding class NCP demands. This is due to the fact that natural gas usage tends to be very weather sensitive such that most classes tend to peak on the same day. There are exceptions to this occurrence in that sometimes industrial and interruptible loads peak on different days than the system peak load.

Q. IS THERE ANY CONCEPTUAL MERIT TO THE A&E METHOD AS APPLIED TO NGDCs GENERALLY AND PECO SPECIFICALLY?

A. No. For public utility industries that are able to produce and store their product within their distribution system such as the water utility industry, the A&E approach has intuitive appeal particularly as it relates to water production and storage facilities. This is because even though a water utility may design its water treatment facilities to meet its maximum peak day demands, this capacity may not be large enough to meet maximum diurnal (hourly) demands. Because a water utility can produce and treat water during off-peak periods and then store water, it can then have enough resources to meet these peak hourly loads. The A&E method (known as the Base Extra Capacity method in the water industry) recognizes class load diversity in that all classes do not peak at the same time and also recognizes that water can be stored such that classes with higher load factors (more consistent usage throughout the year) are not assigned the same level of costs as classes with less consistent usage (low load factors) and demand profiles.

Such is not the case in the NGDC industry in that, for all intents and purposes, once gas is injected into the distribution system at the city gate, it cannot be stored and is consumed as gas flows through the distribution system. In other words, diversified class non-coincident demands have absolutely nothing to do with how natural gas distribution Mains are designed, operated, or how these costs are incurred.

NGDC's distribution Mains are not designed or operated based on the sum of maximum loads over different days. In short, and at least with respect to NGDCs, the A&E method results in a distinct bias against low load factor customers (because excess demands are greater for low load factor customers than for high load factor customers) in favor of high load factor customers and is in no way correlated or related to how distribution Mains are operated.

Q. WITH REGARD TO UTILITIES GENERALLY, AND NGDCs SPECIFICALLY, ARE THERE A COMMON SET OF EXTERNAL FACTORS, OR DRIVERS, USED IN VIRTUALLY EVERY CCOSS?

A. Virtually every utility cost allocation study rests on the analysts' selection of three primary external (exogenous) allocation factors: number of customers; peak demand; and, annual (average day) usage.[6] From these three exogenous factors, a host of internally generated allocation factors are developed based on previously allocated plant and expenses. In this regard, it is important to understand that the relative relationship across classes between these external allocators can be dramatically different.

Q. WITH RESPECT TO PECO, WHAT ARE THE RELATIVE CLASS RELATIONSHIPS OF THESE THREE PRIMARY ALLOCATION FACTORS?

A. The following table shows the relative amounts (percentages) of the three primary external allocation factors (customers, annual throughput, and design day demand) for PECO:

TABLE 2
Relative Percentages of Primary Allocation Factors

Rate Schedule		Number of Customers	Annual Throughput	Peak Demand
GR	Resid.	91.62%	49.85%	60.15%
GC	Gen. Svc.	8.24%	26.61%	32.13%
L	Lg. High LF	0.00% [a/]	0.02%	0.15%
MV-F	Mtr. Veh. Firm	0.00% [a/]	0.51%	0.13%
MV-I	Mtr. Veh. Interrupt	0.00% [a/]	0.00% [a/]	N/A
IS	Interruptible	0.00% [a/]	0.05%	N/A
TCS	Temp. Controlled	0.01%	0.21%	N/A
TS-F	Transportation Firm	0.09%	10.86%	7.44%
TS-I	Transportation Interrupt.	0.04%	11.90%	N/A

N/A means Not Available.
[a/] Actual amount is not zero but the percentage rounds to zero at four decimal places.

As can be seen above, there are significant differences in the relativities of these external allocation factors, such that the selection of a particular Mains allocation method will significantly affect the assignment of costs across the classes.

[6] It should be noted that "weighted" customer counts are often used for certain plant and expense accounts.

Q. IS THERE A PREFERRED METHOD TO ALLOCATE NATURAL GAS DISTRIBUTION MAINS COSTS?

A. Yes. The P&A approach is the most fair and equitable method to assign natural gas distribution Mains costs to the various customer classes. This method recognizes each class's utilization of the Company's facilities throughout the year yet also recognizes that some classes rely upon the Company's facilities (Mains) more than others during peak periods.

Q. HAS THIS COMMISSION PROVIDED GUIDANCE AS TO A PREFERRED APPROACH TO BE USED IN NGDC CLASS COST OF SERVICE STUDIES?

A. Yes. Although a Final Opinion and Order has not been issued by the Commission in the pending Columbia Gas of Pennsylvania General Rate Case (Docket No. R-2020-3018835), the Administrative Law Judge recommends the Commission accept the Peak & Average CCOSS wherein distribution Mains costs are allocated 50% on peak demand and 50% on annual, or average, demands.[7]

In addition, based on my experience in other natural gas distribution company rate cases before this Commission, as well as review of Commission Orders in similar cases in which I did not participate, this Commission has a long history of providing guidance as to the appropriate methods or approaches to allocate distribution Mains for NGDCs. First, the notion of allocating a portion of Mains investment based on the number of customers has been consistently rejected by this Commission.[8] Second, the Commission has consistently found that the allocation of Mains should consider both peak and annual (average) demands. For example, in its September 2007 Opinion & Order concerning a

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[7] Pa. PUC v. Columbia Gas of Pennsylvania, Inc., Docket No. R-2020-3018835, Recommended Decision, at page 395.

[8] See for examples: Pa. PUC v. Philadelphia Gas Works, Docket No. R-00061931, Opinion, 2007 Pa. PUC Lexis 46 (2007); Pa. PUC v. National Fuel Gas Distribution Corp., Docket No. R-00942991, Opinion and Order, 83 Pa. PUC 262 (1994); and, Pa. PUC v. National Fuel Gas Distribution Corp., Docket No. R-891468, Opinion and Order, 73 Pa. PUC 552 (1990).

Philadelphia Gas Works rate case (Docket No. R-00061931),[9] the Commission stated in its Order:

> "Reviewing the record, we find that the allocation of distribution Mains investment costs should be done using both annual and peak demands."[10]

Q. NOTWITHSTANDING THIS COMMISSION'S PRACTICE TO NOT CONSIDER NUMBER OF CUSTOMERS WITHIN THE ALLOCATION OF MAINS, WHAT IS THE RATIONALE TO ALLOCATE MAINS INVESTMENT, AT LEAST PARTIALLY, BASED ON CUSTOMER COUNTS?

A. I am aware of two rationales, or arguments, used to advocate the allocation of natural gas distribution Mains based partially on number of customers. While the conceptual argument has no economic or practical logic in my opinion, the second rationale may produce reasonable results in some instances, but is rarely applicable to NGDCs.

The first rationale used by some analysts is that, because every customer (regardless of size) must be physically connected to the utility's distribution network, there is some minimum level of investment required to simply connect customers to the distribution system. It is certainly true that, unless natural gas is delivered in a portable tank or cylinder, some form of a physical "plumbing" is required to deliver natural gas to each and every end-user.[11] Indeed, this is the very purpose of the distribution system. However, no customer connects to a NGDC system simply to be connected but never utilize natural gas, nor do NGDCs haphazardly install natural gas Mains where no usage is present or anticipated. Because there is no economic utility (benefit) derived from simply being connected to a system, there is no economic (or cost causative) basis for assigning some value of a NGDC's distribution Mains required to simply connect customers.

The second rationale used to consider number of customers within the allocation of Mains relates to customer densities and differences in the mix of customers (by class)

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[9] This appears to be the most recent litigated natural gas distribution case in Pennsylvania concerning the proper allocation of distribution Mains-related costs.

[10] Pa. PUC v. Philadelphia Gas Works, Docket No. R-00061931, Order, at Page 80.

[11] If natural gas was delivered to end-users in tanks (such as done with propane), there would be no distribution system, or Mains to allocate.

throughout a utility's service area. Possibly the best way to explain why customer densities may be relevant in the assignment of distribution costs to individual classes is by way of example. Consider two different utilities: a rural electric utility with urban, suburban, and rural service areas and another utility with only urban and suburban customers. With respect to the electric utility with a rural service area, many miles of conductors and associated plant must be installed in order to serve the demands of relatively few customers. Conversely, many more customers are served on a per mile basis for the urban/suburban utility. With respect to the utility with a rural service area, such an allocation based on usage or demand may be unfair if some classes are located mainly in urban or suburban areas, while other classes of customers are located in urban, suburban, and rural areas. As a result, some cost studies classify distribution plant as partially demand-related and partially customer-related.

Q. IN THE ABOVE EXAMPLE, YOU REFERRED TO ELECTRIC UTILITIES INSTEAD OF NATURAL GAS UTILITIES. IS THERE A REASON WHY YOU SELECTED THE ELECTRIC UTILITY INDUSTRY FOR YOUR EXAMPLE?

A. Yes. Although the concepts are the same between electric and natural gas distribution facilities (e.g., conductors are synonymous with Mains), electric utilities are required to serve rural (sparsely populated) areas. Such requirements, however, are <u>**not**</u> in place for NGDCs. Moreover, electric utilities are required to connect all consumers regardless of density or usage. Such is not the case for NGDCs, as their tariffs allow the utility to only connect those customers in areas with sufficient customer densities and usage.

As such, and as a general matter, a Customer/Demand classification of electric distribution facilities could be appropriate given the characteristics of a utility's service area, but are rarely appropriate for NGDCs with more densely populated service areas that are not required to serve all potential residences and businesses.

Q. SHOULD PEAK DAY DEMANDS BE THE ONLY CONSIDERATION WHEN ALLOCATING NATURAL GAS DISTRIBUTION MAINS?

A. No. Perhaps the most fundamental aspect of cost allocation is the desire to reasonably assign costs (plant and expenses) based on cost causation. As indicated earlier, while it is appropriate to consider and reflect class peak demands when allocating distribution Mains, it should not be the only criteria. A NGDC system is constructed and is in existence in order to serve the natural gas energy needs of its customers throughout the year. If PECO's (or any NGDC's) customers only required gas for one day of the year (the so-called peak day), the costs to deliver gas throughout the system would be prohibitively high such that a system would never exist. In other words, PECO's customers demand and utilize natural gas every day of the year, not just one day out of 365 days. If by chance, a customer did require gas for only one day a year, it would be prohibitively expensive to the Company (and ultimately the customer) to provide service as the investment in Mains would therefore be required to be recovered from a very small amount of natural gas energy (usage) and would be economically infeasible.

Q. IS PECO'S MAINS EXTENSION POLICY CONSISTENT WITH THE REALITY THAT CUSTOMERS UTILIZE NATURAL GAS THROUGHOUT THE YEAR AND NOT ON JUST A SINGLE DAY?

A. Yes. When PECO evaluates a main extension proposal or project, it considers the maximum load that will be placed on the extension in its determination of the required size of Main as well as the annual margin revenue that will be generated from the usage of natural gas along the extension.

Q. EVEN THOUGH MAINS ARE INSTALLED TO MEET THE NATURAL GAS ENERGY NEEDS OF CUSTOMERS THROUGHOUT THE YEAR AND IT WOULD BE PROHIBITIVELY EXPENSIVE TO SERVE A CUSTOMER FOR ONLY ONE DAY PER YEAR, DOES IT COST MORE TO INSTALL A MAIN WITH HIGHER PEAK DEMANDS PLACED UPON IT THAN ANOTHER SEGMENT WITH LOWER PEAK DAY DEMAND REQUIREMENTS?

A. While this is correct as a broadly general statement, there is not a direct and linear relationship between peak demands (capacity requirements) and costs. This is the most important concept. That is, if one were to consider allocating the cost of Mains based on the physical relationships of peak day demand (load), one must evaluate whether costs increase proportionally and in a linear manner with peak load. In reality, if the peak load on one line segment of Mains is double that of another line segment, the cost of Mains for a higher capacity pipe (to meet these additional costs) may be higher but is not double that of the lower capacity Main. This reality reflects the major shortcoming of the Peak Responsibility method (which allocates Mains entirely on peak day demand) because it is premised on the incorrect assumption that there is a direct and perfectly linear relationship between peak loads (demand), system capacity, and costs. With regard to system capacity, the amount of gas that can be delivered throughout a NGDC system is not only a function of the size of pipe(s) but also pressurization of gas within these pipes, and, as well, the presence or absence of looping various segments of the distribution system. In very simple terms, and all else constant, the capacity of pipes increases by a factor of exactly 4 to 1 as the diameter of pipe increases.[12] Therefore, if the size of pipe is doubled, the capacity of the pipe increases by a factor of four. At the same time, the cost of this additional capacity is far less than four times as much.[13]

Additionally, and as important as the geometric capacity of pipe at a given pressure, the amount of gas required to be pushed through a distribution system can be met with larger pipes at lower pressures or smaller pipes at higher pressures. With increases in materials, technology, and pipe coupling improvements, we are seeing that NGDCs are replacing their systems with smaller plastic pipes operated at higher pressures. Indeed, a 2-inch plastic pipe operating at 60 pounds per square inch gauge ("psig") has approximately 3.6 times the capacity of a 4-inch plastic line operating at low pressures (less than 1 psig). Because the allocation of Mains only concerns the assignment of the pipes costs, there is not a clear relationship between a main segment's capacity (peak load

[12] The volume of a cylinder (pipe) is equal to pi (3.14159) x Radius^2 x length. Therefore, it can be seen that as the diameter doubles, the area (volume) of the pipe increases by four times that of the smaller pipe.

[13] The cost of Mains investment reflects the cost of capitalized labor to install the Main plus the cost of materials (the piping). Although the labor cost of installing pipe increases somewhat with larger size pipe, these additional labor costs tend to be much smaller than the capacity added. Similarly, the materials cost of the pipe also increases but by a much smaller percentage than the capacity added.

ability) and the cost of that pipe. The relevance of this is that an allocation method that only considers peak load by definition assumes there is a direct and perfectly linear relationship between load (capacity) and the cost of Mains. This assumption is clearly not accurate.

Q. SINCE THERE IS NOT A DIRECT AND LINEAR RELATIONSHIP BETWEEN PEAK LOAD REQUIREMENTS AND THE COST OF MAINS, IS THERE A COST ALLOCATION METHOD THAT REASONABLY REFLECTS THE COST CAUSATION OF MAINS?

A. Yes. When properly applied, the P&A method reasonably and fairly models the economies of scale reflected in Mains investment. If all customers (and classes) demanded and utilized natural gas at a consistent rate throughout the year, the PECO system would be comprised of smaller size Mains. Obviously, such is not the case in that the Company's peak (design day) demands are about 4.18 times that of its average day firm service demands.[14] Even though the increased capacity required to serve design day peak loads is more than four times that required for average day loads, the actual cost of Mains is much smaller than this 4 to 1 relationship. In fact, it is apparent that the diameters of the Company's Mains are about twice as large as would be required under constant load conditions. However, the incremental cost of this additional capacity (to serve design day loads versus average day loads) is less than a factor of two. This indicates that a cost allocation method which allocates about half of the Company's Mains costs based on average demand and the remaining half on peak demand serves as a reasonable proxy for cost causation and fairly assigns class cost responsibility. To summarize, the allocation of Mains solely on peak demands does not reflect cost causation due to the economies of scale present in meeting the capacity (design day) needs of the company's distribution system; i.e., as peak demand increases, costs increase at a decreasing rate.

[14] Per witness Ding CCOSS (Exhibit JD-6). Total design day demand is 846,416 MCF, whereas average firm day demand is 202,627 MCF.

B. PECO's Class Cost of Service Study ("CCOSS")

Q. WHICH METHOD DID PECO USE TO ALLOCATE DISTRIBUTION MAINS IN THIS CASE?

A. Company witness Jiang Ding conducted her CCOSS utilizing an incorrect variant of the A&E method to allocate non-directly assignable distribution Mains across classes.

Q. PLEASE EXPLAIN HOW MS. DING INCORRECTLY APPLIED THE A&E METHOD IN HER ANALYSIS.

A. Although Ms. Ding claims that her A&E method comports with the method that has been recognized as an acceptable method by the American Gas Association's ("AGA") Gas Rate Fundamentals, 1987 Edition,[15] she is incorrect both conceptually and arithmetically. My Schedule GAW-2 provides a copy of the relevant pages from the referenced AGA Gas Rate Fundamentals, Fourth (1987) Edition. As shown on page 146 (Table 7-7) of this book, the Interruptible class is assigned 684 MCF of "excess" demand which is the difference between this class's NCP demand and its average day demand. As such, in the example set forth in the AGA book, the Interruptible class is assigned 41.03% of the "excess" portion within the A&E method (684 ÷ 1,667). As important, the Interruptible total A&E allocation factor in this example is 30.81% (1,284 ÷ 4,167) which compares to this class's average day percentage of 40.00% (1,000 ÷ 2,500) and its NCP percentage of 35.93% (3,000 ÷ 8,350).

The conceptual and arithmetic error made by Ms. Ding is that she has excluded all NCP demands associated with the various Interruptible classes. As a result, Ms. Ding has assigned no "excess" demands to the Interruptible classes as can be seen in her Exhibit JD-6, page 5, column H.

Conceptually, it is necessary to consider the NCP demands of Interruptible customers under the A&E approach since this methodology is based on the premise that class responsibility should be based upon the amount of each class's maximum demand regardless of when it occurs relative to its average use throughout the year. While it is true

[15] Ding direct testimony, page 14, lines 1 through 3.

that Interruptible customers may be interrupted during system peak days (CP), this is irrelevant under the A&E approach as excess demands are based on class NCP demands and not CP demands.

Q. HAS A SIGNIFICANT MATHEMATICAL ERROR BEEN DISCOVERED IN THE COMPANY'S AS-FILED CCOSS?

A. Yes. In developing each class' required (equalized) rate of return ("ROR") at the Company's proposed 7.70% cost of capital, Ms. Ding's Exhibit JD-1 contained a mathematical error that greatly impacted the required class RORs at the Company's proposed overall revenue requirement. Ms. Ding corrected this error in her response to OSBA-I-1 and OSBA-I-2. In this regard, it should be noted that class RORs at current rates were largely unaffected such that the correction relates only to class equalized RORs at the Company's proposed revenue requirement. The following table provides Ms. Ding's as-filed and corrected class RORs at current and equalized 7.70% RORs:

TABLE 3
Comparison of PECO's As-Filed and Corrected CCOSS Results

Rate Schedule		Distribution ROR @ Current Rates		Required Increase @ 7.70% ROR ($000)	
		As-Filed	Corrected	As-Filed	Corrected
GR	Resid.	4.72%	4.72%	$47,095	$71,153
GC	Gen. Svc.	8.11%	8.12%	$16,641	-$3,520
L	Lg. High LF	-2.04%	-2.08%	$59	$293
MV-F	Mtr. Veh. Firm	12.52%	12.56%	$57	-$140
MV-I	Mtr. Veh. Interrupt	32.06%	32.20%	$0	-$4
IS	Interruptible	-5.58%	-5.64%	$5	$34
TCS	Temp. Controlled	44.19%	44.40%	$30	-$562
TS-F	Transportation Firm	6.50%	6.50%	$3,345	$2,025
TS-I	Transportation Interrupt.	8.82%	8.84%	$1,476	-$848
Total Company		5.73%	5.73%	$68,709	$68,432

As can be seen in Table 3 above, whereas Ms. Ding's as-filed CCOSS indicates that the required (equalized ROR at 7.70%) revenue increase for Rate GR was $47.1 million, her correction results in a required increase of $71.2 million. Similarly, Ms. Ding's as-filed study indicated that the required increase for Rate GC was $16.6 million while her correction results in a required decrease of $3.5 million to this class. Similar significant differences are exhibited for other classes.

Q. SUBSEQUENT TO THE MAJOR CORRECTION DISCUSSED ABOVE, HAVE OTHER ERRORS BEEN DISCOVERED?

A. Yes. Four other errors were discovered. The first relates to the allocator used to assign Advertising Expenses (Account 909) and was corrected in response to OSBA-II-7. The second correction relates to the allocator named “DISTPLTXAR” which is Distribution Plant Excluding Asset Retirement Obligations. In the Company’s study, there is a double-counting of Meters and Meter Installations plant.

Ms. Ding’s third error relates to her treatment of the Interruptible Sales (Rate IS) class. Although Ms. Ding allocated rate base and expenses to the IS class, she reflects no revenue contributed from this class. As shown in Company witness Joseph Bisti’s Exhibit JAB-4, page 7, this rate schedule currently contributes $34,964 in base rate revenue. While I am aware of the current pricing and margin sharing mechanism associated with Rate IS, it makes no sense to assume revenues are zero and allocate costs to a particular rate class. In fact, there is no way to determine the reasonableness of the rates contributed by Rate IS nor is there any way to evaluate whether other ratepayers are subsidizing this rate under Ms. Ding’s approach. As a result, I have corrected Ms. Ding’s study to reflect the actual amount of revenue contributed by Rate IS. The ratemaking treatment of Rate IS will be discussed later in my testimony.

The fourth error relates to Ms. Ding’s calculated class required revenues at equalized rates of return. In developing her required class revenues, Ms. Ding did not appropriately reflect non-base rate revenues nor the additional forfeited discount revenues that will be generated as a result of the Company’s proposed overall increase. I have corrected these errors in my replication of Ms. Ding’s cost allocation approach using the A&E method.

Q. WHAT ARE THE IMPACTS OF THESE CORRECTIONS?

A. The following table provides PECO's fully corrected class RORs at current rates and the required class increases at equalized 7.70% RORs:

TABLE 4
Comparison of PECO's CCOSS Results Per OSBA-I-2 and Minor Corrected Results

Rate Schedule		Distribution ROR @ Current Rates		Required Increase @ 7.70% ROR ($000)	
		OSBA-I-2	Corrected	OSBA-I-2	Corrected
GR	Resid.	4.72%	4.70%	$71,153	$71,352
GC	Gen. Svc.	8.12%	8.16%	-$3,520	-$3,889
L	Lg. High LF	-2.08%	-2.08%	$293	$293
MV-F	Mtr. Veh. Firm	12.56%	12.56%	-$140	-$140
MV-I	Mtr. Veh. Interrupt	32.20%	32.33%	-$4	-$4
IS	Interruptible	-5.64%	9.84%	$34	-$5
TCS	Temp. Controlled	44.40%	44.42%	-$562	-$562
TS-F	Transportation Firm	6.50%	6.50%	$2,025	$2,021
TS-I	Transportation Interrupt.	8.84%	8.84%	-$848	-$850
Total Base Rate Revenues		5.73%	5.73%	$68,432	$68,215
Other Revenues				--	$88
Total Company				--	$68,304

C. OCA's Class Cost of Service Study

Q. HAVE YOU CONDUCTED A CCOSS UTILIZING THE PEAK & AVERAGE METHOD TO ALLOCATE DISTRIBUTION MAINS?

A. Yes. I have conducted a CCOSS in which Mains are allocated using the P&A methodology and have also allocated storage plant based on Ms. Ding's "storage" allocator.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED YOUR P&A ALLOCATION FACTOR.

A. Because Mains costs are incurred to meet peak load requirements as well as serve customers with natural gas throughout the year, my P&A allocation factors are weighted 50% on peak (design) day usage and 50% on average day usage. In developing my P&A allocation factors, I have assigned no "peak" responsibility to the Interruptible classes such that these classes allocation factors reflect only the weighted portion of average day usage.

In this way, I have recognized that Interruptible service is inferior to Firm natural gas service. The following table shows the development of P&A allocation factor:

TABLE 5
Development of P&A Allocation Factor

		Amount [16]		% of Total		P&A
Class		Peak	Avg.	Peak	Avg.	Factor
GR	Resid.	550,000	114,982	60.1477%	49.8452%	54.9964%
GC	Gen. Svc.	293,826	61,374	32.1327%	26.6057%	29.3692%
L	Lg. High LF	1,416	45	0.1549%	0.0197%	0.0873%
MV-F	Mtr. Veh. Firm	1,174	1,174	0.1283%	0.5087%	0.3185%
MV-I	Mtr. Veh. Interrupt	0	2	0.0000%	0.0008%	0.0004%
IS	Interruptible	0	110	0.0000%	0.0476%	0.0238%
TCS	Temp. Controlled	0	489	0.0000%	0.2121%	0.1061%
TS-F	Transportation Firm	68,000	25,052	7.4364%	10.8602%	9.1483%
TS-I	Transportation Interrupt.	0	27,451	0.0000%	11.9001%	5.9500%
Total Company		914,416	230,679	100.0000%	100.0000%	100.0000%

Q. PLEASE EXPLAIN THE DIFFERENCE IN THE WAY YOU HAVE ALLOCATED STORAGE PLANT TO MS. DING'S ALLOCATION OF STORAGE PLANT.

A. In her CCOSS, Ms. Ding developed a storage allocator in her Exhibit JD-6, page 6. Ms. Ding used this storage allocator only to assign natural gas storage expenses. However, with regard to storage plant, she allocated these rate base items on design day demands. I have allocated storage plant using Ms. Ding's storage allocator as this is more appropriate than design day demand for storage plant. It should be noted that there is a very minor difference between design day demand and Ms. Ding's storage allocator such that there is an immaterial impact on CCOSS results.

Q. WHAT ARE THE RESULTS OF YOUR CCOSS STUDY UTILIZING THE P&A METHOD TO ALLOCATE MAINS?

A. The following table provides class RORs at current rates as well as the required class increases at equalized 7.70% rates of return:

[16] Per Exhibit JD-6, page 5.

TABLE 6
OCA P&A Results At Current Rates and Equalized ROR

Rate Schedule		Distribution ROR @ Current Rates	Required Increase @ Equalized 7.70% ROR ($000)
GR	Resid.	4.93%	$64,230
GC	Gen. Svc.	8.75%	-$8,474
L	Lg. High LF	0.17%	$130
MV-F	Mtr. Veh. Firm	3.50%	$270
MV-I	Mtr. Veh. Interrupt	25.04%	-$3
IS	Interruptible	3.24%	$21
TCS	Temp. Controlled	25.21%	-$443
TS-F	Transportation Firm	4.56%	$6,469
TS-I	Transportation Interrupt.	3.13%	$6,017
Total Base Rate Revenues		5.73%	$68,217
Other Revenues			$88
Total Company			$68,305

The details of my CCOSS utilizing the P&A method to allocate distribution Mains is provided in my Schedule GAW-3.

IV. CLASS REVENUE ALLOCATION

Q. HOW DOES THE COMPANY PROPOSE TO ASSIGN ITS REQUESTED OVERALL REVENUE INCREASE TO INDIVIDUAL CLASSES?

A. This is unknown. Although Company witness Joseph Bisti sets forth his class revenue allocations in his Exhibit JAB-1, I have been informed that the Company will be proposing a significantly different class revenue allocation in its rebuttal testimony. It is my understanding that the significantly different revenue allocation will largely be the result of revisions made by Ms. Ding in her corrected CCOSS produced in response to OSBA-I-2.

Q. DO YOU HAVE RECOMMENDATIONS CONCERNING THE ASSIGNMENT OF REVENUE RESPONSIBILITY ACROSS CLASSES?

A. Yes. In accordance and consistent with the recommendations of OCA witness Scott Rubin, I recommend that no rates be changed as a result of this proceeding. This would entail no increases and no decreases in any rates or rate elements.

However, should the Commission decide that PECO's rate increase application should be treated as "business as usual" and thereby rejecting OCA's recommendation for no change in any rates, I have prepared an alternative class revenue allocation. Although the Company's proposed class revenue increases are not known at this time, my "business as usual" revenue allocation recommendation is based on the Company's overall requested net increase of $66.875 million.[17]

Q. BEFORE YOU DISCUSS YOUR ALTERNATIVE "BUSINESS AS USUAL" CLASS REVENUE ALLOCATION RECOMMENDATION, WAS THERE A PRIOR SETTLEMENT AGREEMENT THAT IS RELEVANT TO THIS CASE?

A. Yes. In the Company's 2008 General Rate Case (Docket No. R-2008-2028394), the parties reached a settlement that was approved by the Commission, which stated in part:

> PECO agrees that, over the course of its next two gas base rate filings, it will propose to move the Rate GC and L class rates of return to the system average rate of return by moving fifty percent (50%) towards that goal in the next such filing and removing all remaining difference through the following filing. All parties retain their rights, in such future rate proceedings, to challenge that proposal through the use of class rates of return obtained through alternative cost of service studies or other ratemaking principles.[18]

This is PECO's second rate case since the 2008 case. In developing my alternative "business as usual" class revenue allocations, I am aware that Rate GC is currently earning

[17] It is understood that this amount is not exactly equal to the $68.217 million requested by PECO in this case. Mr. Watkins' based his revenue allocation on the net rate revenue increase of $66,786,789 set forth in Exhibit JAB-1 plus forfeited discount increase of $88,491 per Exhibit JD-1.

[18] Pa. PUC v. PECO Energy Company, Joint Petition for Settlement of Rate Investigation, Docket No. R-2008-2028394, *et al*., II.d.3 (pages 5 and 6).

above the Company's requested ROR. However, in 2008, no one could have envisioned the current disastrous state of affairs associated with the COVID-19 pandemic. Therefore, I am basing my alternative class revenue allocations on the 2008 settlement provision that allows for "other ratemaking principles." While the pure arithmetic of allocated costs within my CCOSS would indicate that Rate GC's distribution rates should be reduced in accordance with the first part of the 2008 settlement agreement, adhering to a strictly mathematical approach would not result in just and reasonable rates for all customers at this point in time.

In order to understand why it is not possible to reduce Rate GC's rates, and at the same time, develop just and reasonable rates for all other classes (rate schedules), it must be recognized that PECO's natural gas operations are comprised predominately of Residential and Small Commercial customers as shown in the table below:

TABLE 7
Comparison of Current Distribution Revenues

Rate Schedule		Current Distribution Revenue Amount	% of Total
GR	Resid.	$233,528,109	64.58%
GC	Gen. Svc.	$100,578,711	27.81%
GR + GC	Resid. & Gen. Svc. Combined	$334,106,820	92.39%
All Other Rate Schedules		$27,508,230	7.61%
Total Company		$361,615,050	100.00%

Because revenue allocations and rate design tend to be a zero-sum game in that if one class's revenues are decreased, other rate classes must receive increases. PECO's General Service (Rate GC) customers represent almost 28% of PECO's total distribution revenues such that if this class's rates and revenues are reduced, the only rate class large enough to incur the corresponding increase would be the Residential class.

Given the state of our economy, levels of unemployment, and ability of customers to pay their natural gas bills, a decrease to General Service customers' rates with corresponding increases to Residential customers' rates would not result in fair and reasonable rates for all ratepayers. As a result, and to the extent the Commission authorizes some overall increase in revenues as a result of this case, I recommend that Rate GC's rates remain at their current levels.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED YOUR ALTERNATIVE "BUSINESS AS USUAL" CLASS REVENUE ALLOCATION PROPOSAL.

A. As indicated in my Table 6, the GC, MV-I and TCS rate schedules are currently earning rates of return higher than the 7.70% ROR requested by PECO. Under my alternative "business as usual" proposal, I have assigned no change in base rate revenues to these classes. With regard to Rate L, which is, for all intents and purposes, providing no return on the Company's investments at current rates (0.17% ROR), I recommend that this class receive twice the system average percentage increase (38.01%). With regard to Rates MV-F, IS and TS-I, I recommend that these classes receive one and a half times the system average increase as these classes' current RORs are significantly deficient; i.e., relative RORs significantly below 100%.[19] Finally, the relative RORs for Rates GR and TCS-F are reasonably close parity at current rates (86% and 79%, respectively) such that these two classes receive equal percentage increases based on the remaining overall increase.

The above-mentioned increases are before recognition of the Gas Procurement Charge ("GPC") and Merchant Function Charge ("MFC") reductions. The following table provides a summary of my alternative "business as usual" revenue allocation proposal while the details are provided in my Schedule GAW-4:

[19] The term relative ROR is the relative relationship of a class's absolute ROR on rate base to the total system ROR. For example, if an individual class has an absolute ROR of 6% and the system ROR is 7%, that class's relative ROR is 86% (6% ÷ 7%).

TABLE 8

OCA Alternative "Business As Usual" Class Revenue Allocation

Rate Schedule	Current Distribution Revenue	Total Increase Before GPC & MFC Reduction	GPC Reduction	MFC Reduction	Net Increase Amount	Net Increase Percent
GR	$233,528,109	$61,439,532	($693,000)	($800,000)	$59,946,532	25.67%
GC	$100,578,711	$0	($370,000)	($66,000)	($436,000)	-0.43%
OL	$423	$0			$0	0.00%
L	$75,475	$28,687			$28,687	38.01%
MV-F	$474,506	$135,266	($7,000)		$128,266	27.03%
MV-I	$5,022	$0			$0	0.00%
IS	$34,964	$9,967			$9,967	28.51%
TCS	$689,833	$0			$0	0.00%
TS-F	$16,719,224	$4,398,705			$4,398,705	26.31%
TS-I	$9,508,783	$2,710,632			$2,710,632	28.51%
Total Rate Revenue	$361,615,052	$68,722,789	($1,070,000)	($866,000)	$66,786,789	18.47%
Other Revenue	$1,528,291	$88,491			$88,491	5.79%
Total Company	$363,143,343	$ 68,811,280	($1,070,000)	($866,000)	$66,875,280	18.42%

Q. UNDER YOUR ALTERNATIVE CLASS REVENUE ALLOCATION PROPOSAL, DO ALL CLASSES MOVE TOWARDS PARITY (COST OF SERVICE)?

A. Yes. The following table provides a comparison of current and proposed RORs (absolute and relative) under my alternative revenue allocation approach:

TABLE 9
Comparison of Current & Proposed RORs
Under OCA's Alternative Class Revenue Allocations

	ROR		Relative ROR	
Rate Schedule	Current	Proposed	Current	Proposed
GR	4.93%	7.58%	86%	98%
GC	8.75%	8.75%	153%	113%
L	0.17%	1.83%	3%	24%
MV-F	3.50%	5.61%	61%	73%
MV-I	25.04%	23.05%	437%	325%
IS	3.24%	5.33%	56%	69%
TCS	25.21%	25.21%	440%	327%
TS-F	4.56%	6.70%	79%	87%
TS-I	3.13%	5.19%	55%	67%
Total Company	5.73%	7.71%	100%	100%

As can be seen in the table above, all classes' relative RORs move closer to parity under my alternative class revenue allocations.

Q. IN YOUR TABLE 8 ABOVE, YOU RECOMMEND A $9,967 INCREASE TO INTERRUPTIBLE SALES SERVICE (RATE IS). HISTORICALLY, PECO HAS NOT REFLECTED ANY INCREASES TO THIS RATE SCHEDULE AS ANY MARGINS GENERATED FROM THESE REVENUES ARE SHARED 75% TO RATEPAYERS AND 25% TO SHAREHOLDERS. THE RATEPAYERS' SHARE HAS THEN BEEN CREDITED AGAINST THE PURCHASE GAS CLAUSE ("PGC"). PLEASE EXPLAIN YOUR RATEMAKING TREATMENT FOR RATE IS.

A. PECO has utilized this sharing mechanism approach for 41 years and is the result of a Commission's Decision in Docket No. R-79030781. The current practice of this margin sharing and crediting to the PGC is outdated and should be abandoned.[20] The

[20] It is recognized that there is also a margin sharing mechanism in place for off-system sales within the PGC, however, the concepts and reasons for such margin sharing are different. With regard to off-system sales, an incentive is provided to PECO in order to sell unneeded gas that it has already purchased. With regard to the margin sharing associated with IS gross margins, this is a delivery service (base rate) in which this rate schedule is already being subsidized by other captive ratepayers and then shareholders are entitled to receive 25% of the gross margin associated with this base rate schedule's revenues.

natural gas industry is much different today than it was 41 years ago. In the late-1970s (when this margin sharing mechanism was implemented), natural gas was regulated at the well head and was a bundled product sold to NGDCs who then resold gas to retail customers. For all intents and purposes, there was no competition for natural gas at the well head nor was there open access to transportation from the well head to the NGDC. With FERC Order 636 in 1992, the entire natural gas industry changed. Indeed, we now see that the vast majority of PECO's Interruptible customers elect Interruptible Transportation service instead of Interruptible Sales service. Furthermore, and as discussed earlier, Rate IS is currently providing an inadequate rate of return on a fully allocated basis yet, PECO retains 25% of the gross margins (before allocation of overhead and other costs) for shareholders. Clearly, PECO's captive ratepayers are subsidizing this class such that the margin sharing mechanism should be abandoned and that a rate increase is warranted for this rate schedule should the Commission decide a "business as usual" approach to increase PECO's overall revenue requirement.

Q. TO THE EXTENT THE COMMISSION AUTHORIZES SOME INCREASE IN PECO'S OVERALL REVENUE REQUIREMENT BUT LESS THAN THAT REQUESTED BY THE COMPANY, HOW SHOULD THE OVERALL INCREASE BE ALLOCATED ACROSS CLASSES?

A. To the extent the Commission authorizes some overall increase but less than that requested by the Company, I recommend that any increase be distributed proportionally to my recommended class revenue allocations with no decreases to Rates GC, OL, MV-I and TCS (before recognition of GPC and MFC changes).

V. <u>RESIDENTIAL RATE DESIGN</u>

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT AND PROPOSED RESIDENTIAL RATE STRUCTURES.

A. PECO's Residential (Rate GR) rate structure is comprised of a fixed monthly customer charge and a flat volumetric distribution rate. PECO proposes to maintain this basic structure and increase its fixed monthly customer charge by 36.2% from $11.75 to $16.00. The remaining required increase will be collected from the volumetric distribution rate.

Q. IS PECO'S PROPOSED 36% INCREASE IN THE FIXED MONTHLY RESIDENTIAL CUSTOMER CHARGE FAIR AND REASONABLE?

A. No. As explained earlier in my testimony as well as the testimonies of OCA witness Rubin, there should be no change in any rates or rate elements as a result of this case. As it specifically relates to fixed monthly customer charges, even if the Commission decides that some increase in rates should be allowed, the Company's proposed 36% increase in the Residential fixed charge is unreasonable. Residential customers are currently experiencing exceptional hardship largely as a result of the COVID-19 pandemic. PECO's proposed 36% increase in the Residential customer charge is unavoidable and would have to be paid each and every month regardless of usage.

Furthermore, and notwithstanding the current state of affairs, the Company's proposed 36% increase in the fixed monthly charge clearly violates the principle of gradualism and is contrary to the goal of promoting energy conservation.

Q. PLEASE EXPLAIN WHY THE COMPANY'S PROPOSED RESIDENTIAL CHARGE VIOLATES THE PRINCIPLE OF GRADUALISM.

A. The concept of gradualism is a well-known and accepted principle in ratemaking generally and rate design specifically. That is, rates and rate elements should change in a gradual manner so as to avoid what is known as rate shock and also provide rate continuity across the various customers within a rate class. There is no doubt that a 36% increase in the unavoidable customer charge violates the principle of gradual changes.

Q. PLEASE EXPLAIN WHY THE COMPANY'S PROPOSED 36% INCREASE IN THE RESIDENTIAL CUSTOMER CHARGE IS CONTRARY TO THE GOAL OF ENERGY CONSERVATION.

A. As stated earlier, PECO's Residential rate structure is comprised of a fixed monthly customer charge and a volumetric distribution usage charge. If more revenue is collected from fixed monthly customer charges, then less revenue will be collected from volumetric charges. As a result, these lower than appropriate volumetric charges do not provide an appropriate incentive to conserve natural gas usage.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS CONCERNING PECO'S PROPOSED 36% INCREASE IN THE RESIDENTIAL FIXED MONTHLY CUSTOMER CHARGE?

A. Yes. By having a disproportionately larger increase in unavoidable fixed charges (relative to volumetric charges) means that customers have less ability to control their natural gas bills. This is simply because the fixed charge must be paid each and every month regardless of the amount of natural gas consumed.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING PECO'S RESIDENTIAL CUSTOMER CHARGE?

A. My primary recommendation is that no rates or rate elements should be increased as a result of this case. However, should the Commission decide some revenue increase should be allowed as a result of this case, I recommend that the Residential customer charge be increased to no more $13.00 per month. This represents a 10.6% increase in the current rate wherein I have attempted to limit the increase to approximately 10%, which would have resulted in a rate of $12.93 per month. In my opinion, a rounded $13.00 per month customer charge is more appropriate than a rate of $12.93. To the extent the Commission does authorize some revenue increase in this case but less than the amount requested by PECO, my $13.00 per month customer charge recommendation should be scaled-back proportionally to the overall authorized revenue increase.

VI. <u>NEGOTIATED (DISCOUNTED) RATES</u>

Q. DOES PECO HAVE ANY NEGOTIATED RATE CUSTOMERS?

A. Yes. In response to various OCA data requests, the Company identified six negotiated rate customers.

Q. WHAT IS PECO'S CLAIMED BASIS FOR OFFERING THESE CUSTOMERS DISCOUNTED RATES?

A. In response to OCA-I-6(a), the Company indicated that at the time PECO negotiated these agreements, each customer had demonstrated the existence of a viable and competitive alternative.

Q. HAS PECO PROVIDED ANY EVIDENCE AS TO THE REASONABLENESS OF EACH OF THESE NEGOTIATED RATES?

A. To some extent, yes. In response to OCA-I-6(b), the Company provided confidential financial analyses supporting three of the six individual negotiated rates.

Q. DO YOU HAVE ANY GENERAL COMMENTS CONCERNING PECO'S EVALUATION, ANALYSES AND DUE DILIGENCE IN OFFERING INDIVIDUAL NEGOTIATED RATE CONTRACTS?

A. Yes. Based on my cursory review of each contract along with other documentation provided by PECO in discovery responses, it appears that the Company has taken reasonable measures to minimize the discounts offered to individual customers at the time each contract was negotiated. However, I have observed that three of the contracts are very old in which there has been no increases to these contract rates for many years.

Q. PLEASE EXPLAIN.

A. With regard to what has been identified as Customer 3 in response to OCA-I-5 (and other discovery responses), this contract became effective **[BEGIN CONFIDENTIAL]** *[redacted]

[redacted] **[END CONFIDENTIAL]**

With regard to what has been identified as Customer 5, this contract became effective **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

With regard to what has been identified as Customer 6, this contract became effective **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. WHAT ARE YOUR RECOMMENDATIONS CONCERNING PECO'S NEGOTIATED RATES?

A. I recommend the Commission order PECO to completely reevaluate the terms and rates for each of the three negotiated rate contract customers discussed above. This reevaluation should include a detailed analysis of each customer's ability to use alternative fuels, whether such alternative fuels could viably be used to replace some or all of its current natural gas usage, a detailed analysis of the burner tip cost of the identified alternative fuel(s), and a financial analysis supporting each negotiated rate with adjustments to the current rates as appropriate. These findings should be provided to the Commission and OCA on, or before, the Company's next rate case filing.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

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BACKGROUND & EXPERIENCE PROFILE

GLENN A. WATKINS

PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Jan. 2017-Present	President/Senior Economist, Technical Associates, Inc.
Mar. 1993-Dec. 2016	Vice President/Senior Economist, Technical Associates, Inc. (Mar. 1993-June 1995 Traded as C. W. Amos of Virginia)
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. Public Utility Regulation

A. Costing Studies -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. Rate Design Studies -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

GLENN A. WATKINS

C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers' compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI's administrative assigned risk plan and pool expenses.

GLENN A. WATKINS

IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

YEAR	CASE NAME	PRE-FILED	TAI CASE NUMBER	JURISDICTION	CLIENT	DOCKET NO.	SUBJECT OF TESTIMONY
1985	SAVANNAH ELECT. & PWR CO.	YES	85.16	GA. PSC		3523U	SALES FORECAST, RATE DESIGN ISSUES
1990	CENTRAL MAINE PWR CO.	YES	89.13	ME. PUC		89-68	MARGINAL COST OF SERVICE
1990	WARNER FRUEHAUF	NO	90.13	U.S. BANKRUPTCY CT.		n/a	VALUE OF STOCK, COST OF CAPITAL
1990	COMMONWEALTH GAS SERVICES (Columbia Gas)	YES	90.21	VA. SCC		PUE900034	CLASS COST OF SERVICE
1991	W. VA. WATER	YES	91.18	WVA PSC		91-140-W-42T	RATE DESIGN
1992	ALLSTATE INSURANCE COMPANY (DIRECT)	YES	91.36	N.J. DEPT OF INSUR		INS 06174-92	COST ALLOCATIONS, PROFITABILITY
1992	ALLSTATE INSURANCE COMPANY (REBUTTAL)	YES	91.36	N.J. DEPT OF INSUR		INS 06174-92	COST ALLOCATIONS, PROFITABILITY
1992	GRASS v. ATLAS PLUMBING, et.al.	NO	92.05	RICHMOND CIRCUT CT		n/a	DAMAGES, BREACH OF COVENANT NOT TO COMPETE (PROFFERED TEST)
1992	S.C. WORKERS COMPENSATION	YES	92.14	SC DEPT OF INSUR		92-034	INTERNAL RATE OF RETURN
1992	VIRGINIA NATURAL GAS	YES	92.18	VA SCC		PUE920031	JURISDICTIONAL & CLASS COST OF SERVICE
1993	SOUTH WEST GAS CO.	YES	92.38	AZ. CORP COMM		U-1551-92-253	DIRECT: CLASS COST ALLOCATIONS
1993	SOUTH WEST GAS CO.	YES	92.38	AZ. CORP COMM		U-1551-92-253	SURREBUTTAL: CLASS COST ALLOCATIONS
1993	MOUNTAIN FORD v FORD MOTOR COMPANY	NO	92.32	FEDERAL DISTRICT CT		n/a	VEHICLE ALLOCATIONS, INVENTORY LEVELS, INCREMENTAL PROFIT, & DAMAGES
1993	POTOMAC EDISON CO.	YES	93.35	VA. SCC		PUE930033	COST ALLOCATIONS,RATE DESIGN
1995	NEW JERSEY AMERICAN WATER COMPANY	YES	95.18	N.J. B.P.U.		WR95040165	COST ALLOCATIONS,RATE DESIGN
1995	PIEDMONT NATURAL GAS COMPANY	YES	95.23	S.C. P.S.C.		95-715-G	COST ALLOCATIONS,RATE DESIGN,WEATHER NORMALIZATION
1995	CYCLE WORLD v. HONDA MOTOR CO.	NO	95.25	VA. DMV		None	MARKET PERFORMANCE, FINANCIAL IMPACT OF NEW DEALER
1995	VIRGINIA AMERICAN WATER CO.	YES	95.11	VA. SCC		PUE950003	JURISDICTIONAL ALLOCATIONS
1996	ELIZABETHTOWN WATER CO.	YES	96.03	N.J. B.P.U.		WR95110557	COST ALLOCATIONS,RATE DESIGN
1996	ELIZABETHTOWN WATER CO.	NO	96.03	N.J. B.P.U.		WR95110557	SURREBUTTAL COST ALLOCATIONS,RATE DESIGN
1996	SOUTH JERSEY GAS CO.	YES	96.09	N.J. B.P.U.		GR96010032	CLASS COST OF SERVICE
1996	SOUTH JERSEY GAS CO.	YES	96.09	N.J. B.P.U.		GR96010032	REBUTTAL - CLASS COST OF SERVICE
1996	HOUSE BILL # 1513	NO		VA. GEN'L ASSEMBLY		N/A	WATER / WASTEWATER CONNECTION FEES
1996	HOUSE BILL # 1513	NO		VA. GEN'L ASSEMBLY		N/A	WATER / WASTEWATER CONNECTION FEES
1996	VIRGINIA AMERICAN WATER CO.	YES	95.11	VA. SCC		PUE950003	JURISDICTIONAL ALLOCATIONS
1996	VIRGINIA LIABILITY INSURANCE COMPETITION	YES	96.14	VA. SCC		INS960164	COST ALLOCATIONS, INSURANCE PROFITABILITY
1997	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	YES	97.26	PA. PUC		R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	PHILADELPHIA SUBURBAN WATER CO. (REBUTTAL)	YES	97.26	PA. PUC		R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	PHILADELPHIA SUBURBAN WATER CO. (SURREBUTTAL)	YES	97.26	PA. PUC		R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	NISSAN v. CRUMPLER NISSAN	NO	97.36	VA. DMV		None	MARKET DETERMINATION & PERFORMANCE
1997	VIRGINIA AMERICAN WATER CO.	YES	97.43	VA. SCC		PUE970523	JURISDICTIONAL/CLASS ALLOCATIONS
1998	FREEMAN WRONGFUL DEATH	YES	98.31	FfEDERAL DISTRICT CT.			LOST INCOME, WORK EXPECTANCY
1998	EASTERN MAINE ELECTRIC COOPERATIVE	YES	98.25	MAINE PUC		98-596	REVENUE REQUIREMENT
1998	NEW JERSEY AMERICAN WATER COMPANY	YES	98.11	N.J. B.P.U.		WR98010015	CLASS COST OF SERVICE,RATE DESIGN, REVENUES
1998	VIRGINIA ELECTRIC POWER COMPANY	YES	97.25A	VA. SCC		PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
1998	AMERICAN ELECTRIC POWER COMPANY	YES	97.25B	VA. SCC		PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
1998	CREDIT LIFE/AH RATE FILING	YES	98.37	VA. SCC			PRIMA FACIA RATES, LEVEL OF COMPETITION
1999	MILLER VOLKSWAGEN v. VOLKSWAGEN oF AMERICA	YES	98.30	VA. DMV		None	VEHICLE ALLOCATIONS/CSI
1999	CREDIT LIFE & A&H LEGISLATION	NO		VA. GEN'L ASSEMBLY		N/A	COST ALLOCATIONS, INSURANCE PROFITABILITY
1999	COLUMBIA GAS of VIRGINIA	YES	99.15	VA. SCC		PUE980287	RATE STRUCTURE
1999	NCCI (WORKERS COMPENSATION INSURANCE)	YES		VA. SCC		INS990165	WORKERS COMPENSATION RATES
1999	ROANOKE GAS	YES	99.07	VA. SCC		PUE980626	Rate Design/ Weather Norm
2000	PERSON-SMITH v. DOMINION REALITY	NO	00.23	RICHMOND CIRCUIT		n/a	LOST INCOME
2000	CREDIT LIFE/AH RATE FILING	YES	0.17	VA. SCC			PRIMA FACIA RATES, LEVEL OF COMPETITION
2000	UNITED CITIES GAS	YESW	0.28	VA. SCC			Cost Allocations/ Rate Design
2001	SERRA CHEVROLET v. GENERAL MOTORS CORP.	NO	99.01	ALABAMA CIRCUIT CT.		98-2089	ECONOMIC DAMAGES
2001	VIRGINIA POWER ELECTRIC RESTRUCTURING	YES	01.08A	VA. SCC		PUE000584	RATE Design (UNBUNDLING)
2001	AMERICAN ELECTRIC POWER RESTRUCTURING	YES	01.08B	VA. SCC		PUE010011	RATE Design (UNBUNDLING)
2001	NCCI (WORKERS COMPENSATION INSURANCE)	YES	01.09	VA. SCC		INS010190	WORKERS COMPENSATION RATES
2001	VERMONT WORKERS COMPENSATION RATE CASE	YES	01.02	VT. INSURANCE COMM.		n/a	WORKERS COMPENSATION RATES
2002	HAROLD MORRIS PERSONAL INJURY	YES	01.30	FED. DIST CT (RICHMOND)		n/a	LOST WAGES
2002	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	YES	01.32	PA. PUC		R00016750	COST ALLOCATIONS AND RATE DESIGN
2002	PIEDMONT NATURAL GAS	YES	02.18	S.C. PSC		2002-63-G	REVENUE RQMT, COST OF CAPITAL
2002	SOUTH CAROLINA ELECTRIC & GAS (ELECTRIC)	YES	02.27	S.C. PSC		2002-223-E	REVENUE RQMT.
2002	VIRGINIA AMERICAN WATER COMPANY	YES	02.26	VA. SCC		PUE-2002-00375	JURISDICTIONAL/CLASS ALLOCATIONS
2002	ROANOKE GAS COMPANY	YES	02.30	VA. SCC		PUE-2002-00373	WEATHER NORMALIZATION RIDER
2003	NCCI (WORKERS COMPENSATION INSURANCE)	YES	03.05	VA. SCC		INS-2003-00157	WORKERS COMPENSATION RATES
2003	CREDIT LIFE/AH RATE FILING	YES	03.10	VA. SCC			PRIMA FACIA RATES, LEVEL OF COMPETITION
2003	ROANOKE GAS	YES	03.19	VA. SCC		PUE-2003-00425	WEATHER NORMALIZATION ADJUSTMENT RIDER
2003	SOUTHWESTERN VIRGINIA GAS CO.	YES	03.20	VA. SCC		PUE-2003-00426	WEATHER NORMALIZATION ADJUSTMENT RIDER
2004	NATIONAL FUEL GAS DISTRIBUTION	YES	04.38	PA. PUC		R00049656	COST ALLOCATIONS/ RATE DESIGN
2004	SOUTH CAROLINA PIPELINE COMPANY	YES	04.09	S.C. PSC		2004-6-G	COST OF GAS AND INTERUPT. SALES PROGRAM
2004	SCE&G FUEL CONTRACT	YES	04.18	S.C. PSC		2004-126-E	GAS CONTRACT FOR COMBINED CYCLE PLANT
2004	SCE&G RATE CASE (ELECTRIC)	YES	04.27	S.C. PSC		2004-178-E	COST OF CAPITAL/ REV RQMT.
2004	ATLAS HONDA v. HONDA MOTOR CO.	YES	04.21	VA. DMV		None	NEW DEALER PROTEST
2004	MEDICAL MALPRACTICE LEGISLATION	NO	04.39	VA. GENERAL ASSEMBLY		N/A	INDUSTRY RESTRUTURE/ PROFITABILITY
2004	VIRGINIA AMERICAN WATER COMPANY	YES	04.15	VA. SCC		PUE-2003-00539	JURISDICTIONAL/CLASS ALLOCATIONS
2004	WASHINGTON GAS LIGHT	YES	04.23	VA. SCC		PUE-2003-00603	RATE DESIGN/ WNA RIDER
2004	ATMOS ENERGY	YES	04.24	VA. SCC		PUE-2003-00507	RATE DESIGN/ WNA RIDER
2004	NCCI (WORKERS COMPENSATION INSURANCE)	YES	04.12	VA. SCC		INS-2004-00124	WORKERS COMPENSATION RATES
2005	NEWTOWN ARTESIAN WATER		05.22	PA. PUC			REV. RQMT./ RATE STRUCTURE
2005	CITY OF BETHLEHEM WATER RATE CASE		05.23	PA. PUC			REV. RQMT./ RATE STRUCTURE
2005	Serra Chevrolet	Yes	04.22	US Federal Ct.		CV-01-P-2682-S	Dealer incremental profits and costs
2005	WASHINGTON GAS LIGHT	YES	05.09	VA SCC		PUE-2005-00010	WEATHER NORMALIZATION ADJUSTMENT RIDER
2005	NCCI (WORKERS COMPENSATION INSURANCE)	YES	05.10	VA SCC		INS-2005-00159	WORKERS COMPENSATION RATES
2005	Virginia Natural Gas	YES	05.25	VA SCC		PUE-2005-00057	Revenue Requirement/ Alt. Regulation Plan
2006	Olathe Hyundai v. Hyundai Motors of America	YES	05.37	KS DMV		None	Dealer impact analysis

YEAR	CASE NAME	PRE-FILED	TAI CASE NUMBER	JURISDICTION	CLIENT	DOCKET NO.	SUBJECT OF TESTIMONY
2006	PPL Gas	YES	06.16	PA. PUC		R-00061398	COST ALLOCATIONS/ RATE DESIGN
2006	Virginia Credit Life & A&H Prima Facia Rates	YES	06.18	VA SCC		INS-2006-00013	Market Structure
2006	Columbia Gas of Virginia	YES	06.20	VA SCC		PUE-2005-00098	Revenue Requirements/ Alt. Regulation Plan
2006	NCCI (WORKERS COMPENSATION INSURANCE)	YES	06.11	VA SCC		INS-2006-00197	WORKERS COMPENSATION RATES
2007	Georgia Power	YES	06.31	Ga.PSC		25060-U	Cost Allocations/Rate Design
2007	Level of Private Pass. Auto Competition	YES	07.19	Ma. Dept of Insur		N/A	Private Pass Auto level of competition
2007	Valley Energy	YES	07.23	PA. PUC		R-00072349	Cost of Capital/Rate Design
2007	Wellsboro Electric	YES	07.23	PA. PUC		R-00072350	Cost of Capital/Rate Design
2007	Citizens' Electric Of Lewisburg, Pa	YES	07.23	PA. PUC		R-00072348	Cost of Capital/Rate Design
2007	WASHINGTON GAS LIGHT	YES	07.07	VA SCC		PUE-2006-00059	Cost Allocations/ Rate Design/ Alt Regulation Plan
2007	NCCI (WORKERS COMPENSATION INSURANCE)	YES	07.13	VA SCC		INS-2007-00224	WORKERS COMPENSATION RATES
2008	Blue Grass Electric Cooperative	YES	08.24	Ky PSC		2008-00011	Cost Allocations/Rate Design
2008	LG&E (Electric)	YES	08.38	Ky PSC		2008-000252	Cost Allocations/Rate Design/ Weather Normalization
2008	LG&E (Natural Gas)	YES	08.38	Ky PSC		2008-000252	Cost Allocations/Rate Design
2008	Kentucky Utilities	YES	08.38	Ky PSC		2008-00251	Cost Allocations/Rate Design/ Weather Normalization
2008	Columbia Gas of Ohio	YES	08.13	OH PUC		08-72-GA-AIR, et. al	Cost Allocations/Rate Design
2008	Columbia Gas of Pennsylvania	YES	08.10	PA. PUC		R-2008-2011621	COST ALLOCATIONS/ RATE DESIGN
2008	Equitable Natural Gas	YES	08.31	PA. PUC		R-2008-2029325	Cost Allocations/Rate Design/ Discounted Rates
2008	Pike County Natural Gas	YES	08.44	PA. PUC		R-2008-2046520	Cost Allocations/Rate Design
2008	Pike County Electric	YES	08.44	PA. PUC		R-2008-2046518	Cost Allocations/Rate Design
2008	Newtown Artesian Water	YES	08.43	PA. PUC		R-2008-2042293	Revenue Requirement
2008	Virginia Natural Gas	YES	08.36	Va SCC		PUE-2008-00060	Natl Gas Conservation/ Revenue Decoupling
2008	Greenway Toll Road Investigation	YES	08.03	VA. GENERAL ASSEMBLY		N/A	Affiliate Transactions
2008	Puget Sound Energy (Electric)	YES	08.04	WA UTC		UE-072300	Cost Allocations/Rate Design
2008	Puget Sound Energy (Gas)	YES	08.04	WA UTC		UE-072301	Cost Allocations/Rate Design
2009	Fairfax County v. City of Falls Church Virginia	YES	09.20	Fairfax Circuit Ct. (Va.)	City of Falls Church	CL-2008-16114	Water Revenue Requirement
2009	Columbia Gas of Kentuky	YES	09.30	Ky PSC	KY AG	2009-00141	Cost Allocations/Rate Design
2009	Duke Energy of Kentucky (Gas)	YES	09.42	Ky. PSC	KY AG	2009-00202	Rate Design
2009	Duke Energy Carolinas (Electric)	YES	09.38	NC UC	NC AG	E-7 Sub 909	Cost Allocations/Rate Design
2009	United Water of Pennsylvania		09.53	PA PUC	PA OCA	2009-212287	Cost Allocations/Rate Design
2009	Central Penn Gas, Inc.	YES	09.13	PA. PUC	PA OCA	R-02008-2079675	Cost Allocation/Rate Design
2009	Penn Natural Gas, Inc.	YES	09.14	PA. PUC	PA OCA	R-2008-2079660	Cost Allocation/Rate Design
2009	NCCI (Workers Compensation Rates)	YES	09.11	VA SCC	VA SCC Staff	INS-2009-00142	Workers Compensation Rates
2009	Leesburg Water & Sewer	YES		Va. Circuit Ct.	Various Homeowners	Civil Action 42736	Revenue Requirement/ Excess Rates
2009	Credit Life/ A&H ratemaking	YES	09.23	Va. SCC	VA SCC Staff	n/a	Market Structure and Availability
2009	Avista Utilities (Electric)	YES	09.17	WA UTC	WA Public Counsel	UE-090134	Electric rate Design
2009	Avista Utilities (Gas)	YES	09.17	WA UTC	WA Public Counsel	UG-090135	Gas Rate design
2009	PacifiCorp	YES	09.12	WA UTC	WA Public Counsel	UE-090205	Rate Design/Low Income
2009	Puget Sound Energy (Electric)	YES	09.33	WA UTC	WA Public Counsel	UE-090704	Cost Allocations/Rate Design
2009	Puget Sound Energy (Gas)	YES	09.33	WA UTC	WA Public Counsel	UG-090705	Cost Allocations/Rate Design
2010	Georgia Power Company		10.01	GA PSC	GA PSC Staff	Docket No. 31958	Cost Allocations/Rate Design
2010	Kentucky Utilities	YES	10.07	Ky PSC	KY AG	2009-00548	Cost Allocations/Rate Design/ Weather Normalization
2010	LG&E (Electric)	YES	10.07	Ky PSC	KY AG	2009-00549	Cost Allocations/Rate Design
2010	LG&E (Natural Gas)	YES	10.07	Ky PSC	KY AG	2009-00549	Cost Allocations/Rate Design/ Weather Normalization
2010	Philadelphia Gas Works	YES	10.03	PA PUC	PA OCA	2009-2139884	Cost Allocations/Rate Design
2010	Columbia Gas of Pennsylvania	YES	10.13	PA PUC	PA OCA	2009-2149262	Cost Allocations/Rate Design
2010	PPL Electric Company		10.17	PA PUC	PA OCA	2010-2161694	Cost Allocations/Rate Design
2010	York Water Company		10.25	PA PUC	PA OCA	2010-2157140	Cost Allocations/Rate Design
2010	Valley Energy, Inc.		10.20	PA PUC	PA OCA	2010-2174470	Cost of Capital/Revenue Requirement/Rate Design
2010	City of Lancaster, Bureau of Water		10.38	PA PUC	PA OCA	R-2010-2179103	Cost of Capital
2010	Aqua Virginia, Inc.	YES	09.54	VA SCC	VA OAG	PUE-2009-00059	Rate Design
2010	NCCI (WORKERS COMPENSATION INSURANCE)	YES	10.12	VA SCC	VA SCC Staff	INS-2010-00126	WORKERS COMPENSATION RATES
2010	Columbia Gas of Virginia			VA SCC	VA OAG	PUE-2010-00017	Cost of Capital/Revenue Requirement/Rate Design
2011	Arizona-American Water Company		11.37	AZ. CORP COMM	Various HOAs	W-01303A-10-0448	Excess Capacity/Need For Facilities
2011	Artesian Water Company		11.20	DE PSC	DE OAG	11-207	Cost Allocations/Rate Design
2011	Owen Electric Cooperative		11.12	KY PSC	KY AG	PUE-2011-00037	Rate Design
2011	Columbia Gas of Pennsylvania		11.08	PA PUC	PA OCA	R-2010-2215623	Cost Allocations/Rate Design
2011	United Water of Pennsylvania		11.25	PA PUC	PA OCA	2011-2232985	Cost Allocations/Rate Design
2011	PPL Electric Company (Remand)		11.24	PA PUC	PA OCA	2010-2161694	Negotiated Industrial Rate
2011	Virginia Natural Gas		11.17	VA SCC	VA OAG	PUE-2010-00142	Pipeline Prudency/Cost Allocations/Rate Design
2011	NCCI (WORKERS COMPENSATION INSURANCE)		11.10	VA SCC	VA SCC Staff	2011-00163	WORKERS COMPENSATION RATES
2012	Tidewater Utilities, Inc.		11.39	DE PSC	DE DPA	11-397	Cost of Capital/Revenue Requirement/Rate Design
2012	Kentucky Utilities	YES	12.16	Ky PSC	KY AG	2012-00221	Cost Allocations/Rate Design/ Weather Normalization
2012	LG&E (Electric)	YES	12.16	Ky PSC	KY AG	2012-00222	Cost Allocations/Rate Design
2012	LG&E (Natural Gas)	YES	12.16	Ky PSC	KY AG	2012-00222	Cost Allocations/Rate Design/ Weather Normalization
2012	PPL Electric		12.10	PA PUC	PA OCA	R-2012-2290597	Cost Allocations/Rate Design
2012	Columbia Gas of Pennsylvania		12.30	PA PUC	PA OCA	2012-2321748	Cost Allocations/Rate Design/Revenue Distribution
2012	NCCI (WORKERS COMPENSATION INSURANCE)		12.08	VA SCC	VA SCC Staff	INS-2012-00144	WORKERS COMPENSATION RATES
2012	Credit Life Accident & Health		12.09	VA SCC	VA SCC Staff	INS-2012-00014	Market Structure and Performance
2012	Avista Utilities (Electric)	YES	12.14	WA UTC	WA Public Counsel	UE-120436	Electric rate Design
2012	Avista Utilities (Gas)	YES	12.14	WA UTC	WA Public Counsel	UG-120437	Gas Rate design
2013	Delmarva Power & Light		13.7	DE PSC	DE DPA	12-546	Revenue Requirement/Rate Design
2013	Georgia Power Company		13.01	GA PSC	GA PSC Staff	36989	Cost Allocations/Rate Design
2013	Atmos Energy Kentucky		13.19	KY PSC	KY AG	2013-00148	Cost Allocations/Rate Design
2013	Columbia Gas of Kentucky		13.20	KY PSC	KY AG	2013-00167	Cost Allocations/Rate Design
2013	Columbia Gas of Maryland		13.12	MD PSC	MD OPC	9316	Cost Allocations/Rate Design
2013	Gas-On-Gas Competition - Generic Investigation		13.08	PA PUC	PA OCA	2012-232-0323	Treatment of Rate Discounts

YEAR	CASE NAME	PRE-FILED	TAI CASE NUMBER	JURISDICTION	CLIENT	DOCKET NO.	SUBJECT OF TESTIMONY
2013	Duquesne Light Company		13.26	PA PUC	PA OCA	R-2013-2372129	Cost Allocations/Rate Design
2013	Virginia Natural Gas - CARE Plan		13.04	VA SCC	VA OAG	2012-00118	Energy Conservation and Decoupling
2013	Northern Virginia Electric Cooperative Pole Attachment Fees		13.21	VA SCC	Comcast Cable	2013-00055	Financial Performance
2013	NCCI (Workers Compensation Insurance)		13.11	VA SCC	VA SCC Staff	INS-2013-00158	Workers Compensation Rates
2013	PacifiCorp		13.07	WA UTC	WA Public Counsel	13-0043	Residential Customer Charges
2014	Tidewater Utilities, Inc.		14.03	DE PSC	DE DPA	13-466	Cost of Capital/Rate Design
2014	Artesian Water Company		14.18	DE PSC	DE DPA	14-132	Revenue Requirement/Rate Design
2014	PEPCO Maryland		14.04	MD OPC	MD Public Counsel	9336	Rate Design
2014	CITY OF BETHLEHEM WATER RATE CASE		13.34	PA PUC	PA OCA	R-2013-2390244	Cost of Capital
2014	Columbia Gas of Pennsylvania		14.12	PA PUC	PA OCA	R-2014-2406274	Cost Allocations/Rate Design
2014	Columbia NAS Pilot		14.09	PA PUC	PA OCA	R-2014-2407345	Mains Extension Policy
2014	Emporium Water Company		14.19	PA PUC	PA OCA	R-2014-2402324	Cost of Capital
2014	City of Lancaster, Bureau of Water		14.19	PA PUC	PA OCA	R-2014-2418872	Cost of Capital
2014	Peoples Service Expansion Tariff		14.29	PA PUC	PA OCA	R-2014-2429613	Mains Extension Policy
2014	NCCI (Workers Compensation Insurance)		14.21	VA SCC	VA SCC Staff	INS-2014-00172	Workers Compensation Rates
2014	Avista Utilities, Inc. (Gas)		14.08	WA UTC	WA Public Counsel	UG-140189	Cost Allocations/Rate Design
2014	PacifiCorp		14.16	WA UTC	WA Public Counsel	UE-140762	Cost Allocations/Rate Design
2015	Exelon/PHI Acquisition		14.25	DE PSC	DE DPA	14-193	Merger/Acquisition
2015	Indianapolis Power & Light		14.37	Indiana IURC	Indiana OUCC	44576	Cost Allocations/Rate Design
2015	Choptank Electric Cooperative		14.34	MD OPC	MD OPC	9368	Cost Allocations/Rate Design
2015	PECO Energy Company-Service Expansion Tariff		14.35	PA PUC	PA OCA	R-2014-2451772	Mains Extension Policy
2015	PPL Electric Corporation		15.19	PA PUC	PA OCA	R-2015-2469275	Cost Allocations/Rate Design
2015	PECO Energy Company		15.20	PA PUC	PA OCA	R-2015-2468981	Cost Allocations/Rate Design
2015	Columbia Gas of Virginia		15.21	VA SCC	VA OAG	PUE-2014-00020	Rate Design-Customer Charges
2015	Credit Life/AH Rate Filing		15.25	VA SCC	VA SCC Staff	INS-2015-00022	Market Structure and Performance
2015	NCCI (Workers Compensation Insurance)		15.16	VA SCC	VA SCC Staff	INS-2015-00064	Workers Compensation Rates
2016	Chesapeake Utilities, Inc.		16.11	DE PSC	DE DPA	15-1734	Revenue Requirements/Cost Allocations/Rate Design
2016	Suez Water Company		16.15	DE PSC	DE DPA	16-0163	Revenue Requirements/Cost Allocations/Rate Design
2016	Delmarva Power & Light - Electric		16.34	DE PSC	DE DPA	16-0649	Revenue Requirements/Cost Allocations/Rate Design
2016	Delmarva Power & Light - Gas		16.34	DE PSC	DE DPA	16-0650	Revenue Requirements/Cost Allocations/Rate Design
2016	Northern Indiana Public Service Company		15.30	Indiana IURC	Indiana OUCC	Cause No. 44688	Cost Allocations/Rate Design
2016	Kansas Gas Service		16.25	KS CC	KS CURB	16-KGSG-491-RTS	Cost Allocations/Rate Design
2016	Kentucky Utilities		16.45	KY PSC	KY AG	2016-00370	Cost Allocations/Rate Design
2016	Louisville Gas & Electric		16.45	KY PSC	KY AG	2016-00371	Cost Allocations/Rate Design
2016	Washington Suburban Sanitary Complaint Comission		15.36	MD PSC	MD OPC	Case No. 9391	Rate Structure
2016	Columbia Gas of Maryland		16.21	MD PSC	MD OPC	Case No. 9417	Cost Allocations/Rate Design/Main Line Extensions Policy
2016	Atlantic City Sewerage		16.42	NJ BPU	NJ Ratepayer Advocate	WR16100957	Cost of Capital
2016	UGI Utilities, Inc. - Gas Division		16.12	PA PUC	PA OCA	R-2015-2518438	Cost Allocations/Rate Design
2016	Peoples Service Expansion Tariff		16.30	PA PUC	PA OCA	R-2016-2542918	Mains Extension Policy
2016	Anthem/Cigna Merger		15.39	VA SCC	VA SCC Staff	INS-2015-00154	Market Structure/Level of Competition
2016	NCCI (Workers Compensation Insurance)		16.03	Va SCC	VA SCC Staff	INS-2016-00158	Workers Compensation Rates: Cost of Capital, IRR
2016	Washington Gas Light		16.37	VA SCC	VA OAG	PUE-2016-00001	Cost Allocations/Rate Design
2016	Cascade Natural Gas		16.02	WA UTC	WA Public Counsel	UG-152286	Revenue Requirements
2016	Avista Utilities, Inc. (Gas & Electric)		16.19	WA UTC	WA Public Counsel	UE-160228/UG-160229	Attrition
2017	Indiana Michigan Power Company		17.179	Indiana IURC	Indiana OUCC	Cause No. 44967	Cost Allocations/Rate Design
2017	Duke Energy Kentucky		17.32	KY PSC	KY AG	2017-00321	Cost Allocations/Rate Design
2017	Choptank Electric Cooperative		17.31	MD PSC	MD OPC	Case No. 9459	Rate Design
2017	UGI Penn Natural Gas		17.04	PA PUC	PA OCA	R-2016-2580030	Cost Allocations/Rate Design
2017	Pennsylvania-American Water		17.12	PA PUC	PA OCA	R-2017-259583	Cost of Capital
2017	Aqua-Limerick Valuations		17.16	PA PUC	PA OCA	A-2017-2605434	Discounted Cash Flow Valuation
2017	PAWC-McKeesport Valuations		17.16	PA PUC	PA OCA	A-2017-2606103	Discounted Cash Flow Valuation
2017	Virginia Natural Gas		17.13	VA SCC	VA OAG	PUE-2016-00143	Cost Allocations/Rate Design
2017	NCCI (Workers Compensation Insurance)		17.02	VA SCC	VA SCC Staff	INS-2017-00059	Workers Compensation Rates: Cost of Capital, IRR
2017	Puget Sound Energy- Electric		17.06	WA UTC	WA Public Counsel	UG-170034	Cost Allocations/Rate Design
2017	Puget Sound Energy- Gas		17.06	WA UTC	WA Public Counsel	UG-170034	Cost Allocations/Rate Design
2018	Delmarva Power & Light - Electric		17.25	DE PSC	DE DPA	17-0977	Revenue Requirements and Rate Design
2018	Delmarva Power & Light - Gas		17.26	DE PSC	DE DPA	17-0978	Revenue Requirements and Rate Design
2018	Delmarva Power & Light Plug-In Vehicle Charging		18.01	DE PSC	DE DPA	17-1094	Ratepayer subsidies for Electric Vehicles
2018	Chesapeake Utilities, Inc. Natural Gas Expansion		18.02	DE PSC	DE DPA	17-1224	Mains Extension Policy
2018	Indianapolis Power & Light		18.04	Indiana IURC	Indiana OUCC	Cause No. 45029	Cost Allocations/Rate Design
2018	Kansas Gas Service		18.16	KS CC	KS CURB	18-KGSG-560-RTS	Cost Allocations/Rate Design
2018	Baltimore Gas & Electric Company		18.15	MD PSC	MD OPC	Case No. 9484	Cost Allocations/Rate Design
2018	Duquesne Light Company		18.07	PA PUC	PA OCA	R-2018-3000124	Cost Allocations/Rate Design/EV Subsidy/Microgrid
2018	PAWC-Sadsbury Valuations		18.12	PA PUC	PA OCA	A-2018-3002437	Discounted Cash Flow Valuation
2018	SUEZ Water Company-Mahoning Valuations		18.12	PA PUC	DE DPA	A-2018-3003519	Discounted Cash Flow Valuation
2018	Aqua Pennsylvania, Inc.		18.21	PA PUC	PA OCA	R-2018-3003558	Cost of Capital
2019	Chesapeake Utilities		19.25	DE PSC	DE DPA	19-0054	WNA Rider/Cost of Equity
2019	Northern Indiana Public Service Company		18.29	Indiana IURC	Indiana OUCC	Cause No. 45159	Cost Allocations/Rate Design
2019	Indiana Michigan Power Company		19.17	Indiana IURC	Indiana OUCC	Cause No. 45235	Cost Allocations/Rate Design
2019	Duke Energy Indiana		19.19	Indiana IURC	Indiana OUCC	Cause No. 45253	Cost Allocations/Rate Design
2019	Atmos Energy Kansas		19.22	KS CC	KS CURB	19-ATMG-525-RTS	Cost Allocations/Rate Design
2019	Kentucky Utilities/Louisville Gas & Electric		18.28	KY PSC	KY AG	2018-00294	Cost Allocations/Rate Design
2019	Montana-Dakota Utilities		18.22	Montana PSC	MT Consumer Counsel	D2018.9.60	Cost Allocations/Rate Design
2019	Sierra Pacific Power Company		19.18	NV PUC	NV BCP	19-06002	Cost Allocations/Rate Design
2019	Peoples Natural Gas Company		19.05	PA PUC	PA OCA	R-2018-3006818	Cost Allocations/Rate Design/Negotiated Rates
2019	PAWC-Exeter Valuations		18.12	PA PUC	PA OCA	A-2018-3004933	Discounted Cash Flow Valuation
2019	Aqua-Cheltenham Valuations		18.12	PA PUC	PA OCA	A-2019-3008491	Discounted Cash Flow Valuation
2019	PAWC-Steelton Valuations		18.12	PA PUC	PA OCA	A-2019-3006880	Discounted Cash Flow Valuation
2019	Washington Gas Light		18.13	VA SCC	VA OAG	PUR-2018-00080	Cost Allocations/Rate Design
2019	Virginia-American Water Company		19.12	VA SCC	VA OAG	PUR-2018-00175	Cost Allocations/Rate Design

EXPERT TESTIMONY
PROVIDED BY
GLENN A. WATKINS

YEAR	CASE NAME	PRE-FILED	TAI CASE NUMBER	JURISDICTION	CLIENT	DOCKET NO.	SUBJECT OF TESTIMONY
2019	Avista Remand (Customer Refunds)		19.14	WA UTC	WA Public Counsel	UE-150204 & UG-150205	Distribution of Refund to Classes
2019	Avista Utilities, Inc. - Gas		19.16	WA UTC	WA Public Counsel	UG-19-00335	Cost Allocations/Rate Design
2019	Puget Sound Energy-Electric		19.21	WA UTC	WA Public Counsel	UE-19-00529	Cost Allocations/Rate Design
2019	Puget Sound Energy-Gas		19.21	WA UTC	WA Public Counsel	UG-19-00530	Cost Allocations/Rate Design
2019	Duke Energy Kentucky		19.30	KY PSC	KY AG	2019-00271	Rate Design
2020	Aqua - East Norriton Valuation		18.12	PA PUC	PA OCA	2019-3009052	Discounted Cash Flow Valuation
2020	Delmarva Power & Light Maryland		19.34	MD PSC	MD OPC	9630	Cost Allocations/Rate Design
2020	Southern Pioneer Electric Company		20.01	KS PSC	KS CURB	20-SPEE-169-RTS	Rate Design/Grid Access Charges
2020	Cost Allocation Generic Rulemaking		18.06	WA UTC	WA Public Counsel	UE-170002 & UG-170003	Cost Allocation Methods
2020	SUEZ Water		19.31	DE PSC	DE DPA	19-0615	Cost Allocations/Rate Design/Revenue Requirement
2020	Appalachian Power Company		20.10	VA SCC	VA SCC Staff	2020-00015	Cost Allocations/Rate Design
2020	Delmarva Power & Light - Electric		20.07	DE PSC	DE DPA	20-0149	Revenue Requirements & Rate Design
2020	Delmarva Power & Light - Gas		20.06	DE PSC	DE DPA	20-0150	Revenue Requirements & Rate Design
2020	Washington Gas Light MD		20.16	MD PSC	MD OPC	9651	Cost Allocations/Rate Design
2020	Nevada Power Company		20.12	NV PUC	NV BCP	20-06003	Cost Allocations/Rate Design

GAS RATE FUNDAMENTALS

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American Gas Association Rate Committee
1515 Wilson Boulevard, Arlington, VA 22209

- It allocates costs to all groups of customers whether or not they create any demand at the time of the system peak. For this reason, the NCP method is inappropriate for incremental cost studies.
- It leads some analysts to contend that interruptible customers are charged for "too much" capacity because the capacity used by them is that "released" by others. Whether an interruptible customer should receive less than its proportional share of capacity costs or even no capacity costs depends on the *philosophy* of the cost analyst.

Average and Excess Demand Method (A&E)

Under the A&E method, also called "used and unused capacity," capacity costs are allocated by a two-part formula.[1] It recognizes both the average use of capacity and responsibility for the capacity required to meet the maximum system load. Used capacity costs are calculated by multiplying total capacity costs by the system load factor. These costs are allocated to the various classes in proportion to their respective use (Mcf sold). System load factor is the ratio, expressed as a percent, of used capacity (Mcf sold) to total capacity. The remainder of the capacity costs represent the costs associated with the unused portion of capacity (i.e., that portion above *average* requirements). These costs

TABLE 7-6
Cost Allocation by Non-Coincident Demand

Class of Service	Maximum Class Demand (Mcf/Day)	Ratio to Sum of Class Demands
Residential	4,500	0.375
Commercial	2,700	0.225
Industrial	4,000	0.333
Interruptible	800	0.067
Total (Non-Coincident)	12,000	1.000

[1] "Used capacity" is the minimum capacity needed to deliver the total gas used. Hence, it is numerically equal to the average deliveries. "Unused capacity" is the difference between average (used) capacity and peak capacity. Used, unused, or peak capacity may be expressed in terms of hours, days, year, or any other period. Peak capacity is usually expressed in terms of the peak hour or day.

are allocated to the various classes in the ratio that the individual group demands, in *excess* of used demands, bear to the summation of such excess demands. A simplified example is shown in Table 7–7.

Use of the A & E method has the following effects:

- Shifts in the time of the system peak do not greatly affect the cost allocations.
- The allocation of unused capacity is similar to the non coincident demand method except that it is applied only to the excess of class demands above the average.
- The load factor of the various classes is recognized.

Two additional cost-allocation approaches deserve discussion: the Seaboard and United methods. While generally referred to as allocation methods, they are really cost classification methods. These two approaches have been used in FERC proceedings involving pipeline cost allocation studies. Recent FERC decisions, however, have moved towards a modified fixed-variable approach, which will be discussed later. Some analysts argue that such cost allocation methods are actually pricing mechanisms.

The Seaboard method assigns 50 percent of the fixed (demand) costs to the commodity classification and the other 50 percent to the demand classification. These costs are allocated to the various classes by the appropriate demand and commodity-allocation factors. The Seaboard method shifts capacity-related costs from classes with lower load factors (e.g., seasonal heating requirements) to classes with a more uniform or stable year-round (i.e., higher) load factor.

The United method (sometimes called the "Modified Seaboard" method) assigns 75 percent of the fixed costs to the commodity classification and the rest to the demand classification. Again, capacity-related costs are shifted from low to high load factor customers. Cost causation is not the rationale.

In recent FERC proceedings, the modified fixed-variable approach has been used. This allocation method permits all fixed costs to be classified in the demand component, except for return on equity and associated taxes. These are placed in the commodity component. Then the demand costs are allocated 50 percent on the basis of historical Average Peak Day and 50 percent on the customer's Annual Volume.

ALLOCATION OF SPECIAL COSTS

Taxes

Taxes are levied by federal, state, and local authorities. Taxes can be classified on the basis of assessment (i.e., income, revenue, property,

TABLE 7-7
Cost Allocation by Average and Excess Demand

Class of Service	Annual Use (Mcf)	System Peak (Mcf/Day)	Class Max Demand (Mcf/Day)
	(1)	(2)	(3)
Residential	365,000	N/A	3,000
Commercial	182,500	N/A	1,250
Industrial	146,000	N/A	1,100
Interruptible	219,000	N/A	3,000
Total	912,500	4,167	8,350

Class of Service	Class Max Demand (Mcf/Day)	Average Demand (Mcf/Day)	Process Demand Alloc. Basis (Mcf/Day)
	(4)	(5)	(6)
Residential	3,000	1,000	2,000
Commercial	1,250	500	750
Industrial	1,100	400	700
Interruptible	3,000	600	2,400
Total	8,350	2,500	5,850

Class of Service	Average Demand (Mcf/Day)	Excess Demand (Mcf/Day)	A & E Demand (Mcf/Day)
	(7)	(8)	(9)
Residential	1,000	570	1,570
Commercial	500	214	714
Industrial	400	199	599
Interruptible	600	684	1,284
Total	2,500	1,667	4,167

Column

1: Total annual consumption by class. This is equivalent to the commodity allocation factor.
2: Actual (estimated) peak day(s) demands of the system. The individual class values are not shown because they are not used in the calculation.
3: The sum of the individual class maximum demands (class NCP). Each class maximum demand may occur at a different time.
4: The sum of the individual class maximum demands (class NCP). Each class maximum demand may occur at a different time.
5: Calculated by dividing each element in Column 1 by 365 days.
6: Column 4 less Column 5.
7: Calculated by dividing each element in Column 1 by 365 days.
8: Calculated by multiplying the ratio of each to the total in Column 6 times the system excess demand. The system excess demand is defined as the system peak less the total system average demand. For example:

System excess demand would be

4,167 less 2,500=1,667

Residential class excess demand would be

$$\frac{2,000}{5,850} \times 1,667 = 570$$

9: Sum of Column 7 and Column 8.

PECO Energy Company
Peak & Average Gas Class Cost of Service Study
(Summary)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
SUMMARY AT PRESENT RATES												
DEVELOPMENT OF RETURN EXCLUDING PURCHASED GAS												
OPERATING REVENUE												
Sales of Gas Revenue - Base	SCH , LN		$361,576	$233,489	$100,579	$75	$475	$5	$35	$690	$16,719	$9,509
Other Operating Revenue	SCH , LN		$1,528	$1,093	$325	$0	$2	$0	$0	$2	$65	$41
TOTAL OPERATING REVENUE			$363,104	$234,582	$100,903	$76	$477	$5	$35	$691	$16,785	$9,551
OPERATING EXPENSES												
Operation and Maintenance Expense Excl Pur Gas	SCH , LN		$144,391	$104,672	$28,708	$58	$206	$1	$16	$88	$6,417	$4,226
Depreciation and Amortization Expense	SCH , LN		$88,959	$59,790	$20,562	$39	$160	$1	$12	$69	$4,803	$3,524
Taxes Other Than Income Taxes-General	SCH , LN		$7,545	$5,177	$1,679	$4	$13	$0	$1	$5	$401	$266
Taxes Other Than Income Taxes-Distribution GRT	SCH , LN		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Income Taxes	SCH , LN		$18,763	$15,972	($77)	$27	$61	($1)	$5	($78)	$1,478	$1,375
TOTAL OPERATING EXPENSES			$222,133	$153,666	$51,025	$74	$318	$2	$24	$240	$10,143	$6,641
OPERATING INCOME (RETURN)			$140,971	$80,916	$49,878	$2	$159	$3	$11	$451	$6,642	$2,909
DEVELOPMENT OF RATE BASE EXCL PURCHASED GAS												
Gas Plant in Service	SCH , LN		$3,537,670	$2,354,227	$833,861	$1,732	$6,482	$20	$475	$2,651	$202,617	$135,606
Less: Accumulated Depreciation	SCH , LN		$893,447	$602,367	$211,688	$403	$1,503	$5	$106	$675	$43,214	$33,486
Plus: Rate Base Additions Excl Purchased Gas	SCH , LN		$167,673	$117,202	$38,257	$67	$219	$1	$17	$89	$7,020	$4,803
Less: Rate Base Deductions	SCH , LN		$353,635	$227,560	$90,349	$175	$660	$2	$48	$275	$20,717	$13,849
TOTAL RATE BASE EXCL PURCHASED GAS	SCH , LN		$2,458,260	$1,641,501	$570,081	$1,221	$4,537	$13	$337	$1,790	$145,707	$93,073
RATE OF RETURN EXCL PURCHASED GAS (PRESENT)			5.73%	4.93%	8.75%	0.17%	3.50%	25.04%	3.24%	25.21%	4.56%	3.13%
INDEX RATE OF RETURN EXCL PURCHASED GAS (PRESENT)			100%	86%	153%	3%	61%	437%	56%	440%	79%	55%
EQUALIZED RETURN AT PROPOSED ROR OF 7.70%												
DEVELOPMENT OF RETURN EXCL PURCHASED GAS (EQUALIZED RATE)												
Rate Base Excluding Purchased Gas	SCH S, LN 81		$2,458,260	$1,641,501	$570,081	$1,221	$4,537	$13	$337	$1,790	$145,707	$93,073
Change in Operating Income (Rate Base * (7.70% - ROR (Present)))	1.97%		$48,315	$45,480	($5,982)	$92	$191	($2)	$15	($313)	$4,577	$4,257
			7.70%	7.70%	7.70%	7.70%	7.70%	7.70%	7.70%	7.70%	7.70%	7.70%
OPERATING REVENUES												
Change in Revenue (Change in Return * 1.414)	1.41376		$68,305	$64,297	($8,457)	$130	$270	($3)	$21	($443)	$6,471	$6,019
Distribution Rate Revenue (Present Rates) Incl. Other Non-Gas Revenue	SCH S, LN 62		$363,104	$234,582	$100,903	$76	$477	$5	$35	$691	$16,785	$9,551
Total Dist Rate Revenue (Proposed Rate) Incl. Other Non-Gas Revenue	CALCULATED		$431,409	$298,879	$92,446	$206	$746	$2	$56	$248	$23,256	$15,569
Less: Forfeited Discounts Revenue Increase	REV_487	137	$88	$67	$17	$0	$0	$0	$0	$0	$3	$1
TOTAL REQUIRED BASE RATE REVENUES			$429,793	$297,719	$92,104	$205	$744	$2	$56	$247	$23,188	$15,527
OPERATING EXPENSES												
Operation and Maintenance Expense Excl Pur Gas	SCH S, LN 67		$144,391	$104,672	$28,708	$58	$206	$1	$16	$88	$6,417	$4,226
Depreciation and Amortization Expense	SCH S, LN 68		$88,959	$59,790	$20,562	$39	$160	$1	$12	$69	$4,803	$3,524
Additional Bad Debt Expense	0.00347		$237	$223	($29)	$0	$1	($0)	$0	($2)	$22	$21
Additional PUC / OTS & SBA Fee Expense	0.00308		$210	$198	($26)	$0	$1	($0)	$0	($1)	$20	$19
Taxes Other Than Income Taxes-General	SCH S, LN 69		$7,545	$5,177	$1,679	$4	$13	$0	$1	$5	$401	$266
Taxes Other Than Income Taxes-Distribution GRT	SCH S, LN 70		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL OPERATING EXPENSES BEFORE TAXES			$241,343	$170,060	$50,893	$102	$381	$1	$29	$159	$11,663	$8,056
State and Federal Income Taxes @ Effective Tax Rate	SCH S, LN 71		$18,763	$15,972	($77)	$27	$61	($1)	$5	($78)	$1,478	$1,375
State and Federal Income Taxes @ Statutory Rates	CALCULATED		($19,631)	($18,474)	$2,422	($37)	($77)	$1	($6)	$127	($1,858)	($1,728)
TOTAL OPERATING EXPENSES			$240,475	$167,557	$53,239	$91	$364	$2	$28	$208	$11,283	$7,703
NET OPERATING INCOME EXCL PURCHASED GAS			$190,934	$131,322	$39,207	$114	$382	$0	$29	$40	$11,973	$7,867
BASE RATE SALES EXCL PUR GAS @ EQUALIZED ROR 7.70%			$431,409	$298,879	$92,446	$206	$746	$2	$56	$248	$23,256	$15,569

PECO Energy Company
Peak & Average Gas Class Cost of Service Study
(Summary)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
TOTAL REVENUE INCREASE EXCL PUR GAS			$68,305	$64,297	($8,457)	$130	$270	($3)	$21	($443)	$6,471	$6,019
Less: Forfeited Discounts Revenue Increase			$88	$67	$17	$0	$0	$0	$0	$0	$3	$1
Required Base Rate Revenue Increase			$68,217	$64,230	($8,474)	$130	$270	($3)	$21	($443)	$6,469	$6,017
BASE RATE REVENUE INCREASE EXCL PUR GAS REVENUES (%)			18.87%	27.51%	-8.43%	172.18%	56.82%	-62.96%	60.87%	-64.24%	38.69%	63.28%
OCA "Business As Usual" Base Rate Increase			$68,723	$61,440	$0	$29	$135	$0	$10	$0	$4,399	$2,711
OCA Increase to Forfeited Discounts			$88	$67	$17	$0	$0	$0	$0	$0	$3	$1
Total OCA Revenue Increase			$68,811	$61,506	$17	$29	$135	$0	$10	$0	$4,401	$2,712
Revenue Conversion Factor			1.4138	1.4138	1.4138	1.4138	1.4138	1.4138	1.4138	1.4138	1.4138	1.4138
OCA Operating Income Increase			$48,673	$43,506	$12	$20	$96	$0	$7	$0	$3,113	$1,918
OCA Operating Income @ OCA Proposed Rates			$189,644	$124,422	$49,890	$22	$254	$3	$18	$451	$9,755	$4,828
Rate Base			$2,458,260	$1,641,501	$570,081	$1,221	$4,537	$13	$337	$1,790	$145,707	$93,073
ROR @ OCA "Business As Usual" Proposed Increase			7.71%	7.58%	8.75%	1.83%	5.61%	25.05%	5.33%	25.21%	6.70%	5.19%
Indexed ROR			100%	98%	113%	24%	73%	325%	69%	327%	87%	67%

PECO Energy Company
Peak & Average Gas Class Cost of Service Study
(Rate Base)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
GAS PLANT IN SERVICE												
INTANGIBLE PLANT												
301-Organization	TOTPLT	43	$18,229	$12,131	$4,297	$9	$33	$0	$2	$14	$1,044	$699
303-Miscellaneous Intangible Plant	TOTPLT	43	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL INTANGIBLE PLANT			$18,229	$12,131	$4,297	$9	$33	$0	$2	$14	$1,044	$699
PRODUCTION PLANT (LPG)												
305-Land and Land Rights	DPKDAYP	1	$1,206	$783	$418	$2	$2	$0	$0	$0	$0	$0
311- Liquefied Petroleum Gas Equipment	DPKDAYP	1	$14,334	$9,314	$4,976	$24	$20	$0	$0	$0	$0	$0
320-Other Equipment (SNG Plant)	DPKDAYP	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL PRODUCTION PLANT			$15,539	$10,097	$5,394	$26	$22	$0	$0	$0	$0	$0
STORAGE PLANT (LNG)												
360-Land and Land Rights	ESTORAGE	16	$16	$11	$5	$0	$0	$0	$0	$0	$0	$0
361-Structures and Improvements	ESTORAGE	16	$14,919	$9,974	$4,613	$3	$1	$0	$0	$0	$145	$184
362-Gas Holders.	ESTORAGE	16	$7,084	$4,736	$2,190	$1	$0	$0	$0	$0	$69	$87
363-Purification Equipment	ESTORAGE	16	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
363-1 Liquefaction Equipment	ESTORAGE	16	$50,409	$33,702	$15,586	$10	$3	$0	$0	$0	$489	$620
TOTAL STORAGE PLANT			$72,428	$48,423	$22,394	$14	$4	$0	$0	$0	$702	$891
TRANSMISSION PLANT												
371- Transmission Related Plant	DTRAN	3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL TRANSMISSION PLANT			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DISTRIBUTION PLANT												
374-Land & Land Rights	DDISTPLT	49	$3,637	$1,971	$1,052	$3	$11	$0	$1	$4	$357	$238
375-Structures & Improvements	DDISTPLT	49	$15,745	$8,532	$4,556	$14	$49	$0	$4	$16	$1,545	$1,028
376-Mains												
General	P&A	138	$1,756,701	$966,123	$515,928	$1,533	$5,596	$7	$418	$1,863	$160,709	$104,524
Direct Assignment	DAMAINS	5	$15,289	$0	$0	$0	$0	$0	$0	$0	$8,219	$7,070
Total Account 376			$1,771,990	$966,123	$515,928	$1,533	$5,596	$7	$418	$1,863	$168,928	$111,595
378-Measuring & Regulating Station Equip-General	PLT_376	55	$24,652	$13,441	$7,178	$21	$78	$0	$6	$26	$2,350	$1,553
379-Measuring & Regulating Station Equip-City Gate												
City Gate	PLT_376	55	$65,778	$35,863	$19,152	$57	$208	$0	$16	$69	$6,271	$4,142
Direct Assignment	DAMR	9	$11,382	$0	$0	$0	$0	$0	$0	$0	$6,292	$5,090
Total Account 379			$77,160	$35,863	$19,152	$57	$208	$0	$16	$69	$12,563	$9,233
380-Services	CSERVICE	19	$1,111,048	$959,749	$146,489	$26	$49	$7	$13	$102	$3,031	$1,581
381-Meters	CMETERS	20	$163,858	$114,453	$42,012	$4	$155	$2	$4	$226	$3,856	$3,145
Direct Assignment	CMETERSDA	21	$232	$0	$0	$0	$0	$0	$0	$0	$232	$0
Total Account 381			$164,090	$114,453	$42,012	$4	$155	$2	$4	$226	$4,088	$3,145
382-Meter Installations	CMETERS	20	$220,402	$153,948	$56,510	$6	$208	$3	$6	$304	$5,187	$4,230
Direct Assignment	CMETINSTDA	22	$681	$0	$0	$0	$0	$0	$0	$0	$681	$0
Total Account 382			$221,083	$153,948	$56,510	$6	$208	$3	$6	$304	$5,868	$4,230
387-Other Equipment	DISTPLT	41	$2,118	$1,409	$496	$1	$4	$0	$0	$2	$124	$83
388-Asset Retirement Costs for Distribution Plant	DISTPLTXAR	44	$1,454	$967	$340	$1	$3	$0	$0	$1	$85	$57
TOTAL DISTRIBUTION PLANT			$3,392,978	$2,256,455	$793,714	$1,666	$6,362	$19	$467	$2,613	$198,939	$132,741
GENERAL PLANT												
389-Land and Land Rights	SALWAGES	121	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
390-Structures and Improvements	SALWAGES	121	$10,387	$7,317	$2,175	$5	$16	$0	$1	$6	$521	$344
391-Office Furniture & Equipment	SALWAGES	121	$6,858	$4,832	$1,436	$3	$11	$0	$1	$4	$344	$227
393-Store Equipment	SALWAGES	121	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
394-Tools, Shop & Garage Equip.	SALWAGES	121	$16,155	$11,381	$3,383	$7	$26	$0	$2	$10	$810	$535
395-Laboratory Equipment	SALWAGES	121	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
397-Communication Equipment	SALWAGES	121	$4,872	$3,433	$1,020	$2	$8	$0	$1	$3	$244	$161
398-Miscellaneous Equipment	SALWAGES	121	$223	$157	$47	$0	$0	$0	$0	$0	$11	$7
TOTAL GENERAL PLANT			$38,495	$27,120	$8,061	$17	$61	$0	$5	$24	$1,931	$1,275
TOTAL GAS PLANT IN SERVICE			$3,537,670	$2,354,227	$833,861	$1,732	$6,482	$20	$475	$2,651	$202,617	$135,606

PECO Energy Company
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DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
LESS: ACCUMULATED DEPRECIATION												
INTANGIBLE PLANT ACCUMULATED DEPRECIATION	INTPLT	37	$16,737	$11,138	$3,945	$8	$31	$0	$2	$13	$959	$642
PRODUCTION PLANT ACCUMULATED DEPRECIATION	PRODPLT	38	$13,221	$8,591	$4,589	$22	$18	$0	$0	$0	$0	$0
STORAGE PLANT ACCUMULATED DEPRECIATION	STORPLT	39	$31,273	$20,908	$9,669	$6	$2	$0	$0	$0	$303	$385
TRANSMISSION PLANT ACCUMULATED DEPRECIATION	TRANPLT	40	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DISTRIBUTION PLANT ACCUMULATED DEPRECIATION												
374-Land Rights	PLT_374	50	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
375-Structures & Improvements	PLT_375	51	$5,864	$3,178	$1,697	$5	$18	$0	$1	$6	$575	$383
376-Mains												
General	PLT_376G	52	$363,344	$199,826	$106,711	$317	$1,157	$1	$86	$385	$33,240	$21,619
Direct Assignment	DAMAINSAD	6	$2,147	$0	$0	$0	$0	$0	$0	$0	$54	$2,094
Total Account 376			$365,491	$199,826	$106,711	$317	$1,157	$1	$86	$385	$33,294	$23,713
378-Measuring & Regulating Station Equip-General	PLT_378	56	$8,285	$4,517	$2,412	$7	$26	$0	$2	$9	$790	$522
379-Measuring & Regulating Station Equip-City Gate												
City Gate	PLT_379CG	57	$22,178	$12,092	$6,457	$19	$70	$0	$5	$23	$2,114	$1,397
Direct Assignment	DAMRAD	10	$2,689	$0	$0	$0	$0	$0	$0	$0	$58	$2,631
Total Account 379			$24,867	$12,092	$6,457	$19	$70	$0	$5	$23	$2,172	$4,028
380-Services	PLT_380	60	$262,159	$226,459	$34,565	$6	$12	$2	$3	$24	$715	$373
381-Meters	CMETERS	20	$71,643	$50,042	$18,369	$2	$68	$1	$2	$99	$1,686	$1,375
Direct Assignment	CMETERSDA	21	$3	$0	$0	$0	$0	$0	$0	$0	$3	$0
Total Account 381			$71,646	$50,042	$18,369	$2	$68	$1	$2	$99	$1,689	$1,375
382-Meter Installations	CMETERS	20	$75,785	$52,935	$19,431	$2	$72	$1	$2	$105	$1,784	$1,454
Direct Assignment	CMETERSDA	21	$8	$0	$0	$0	$0	$0	$0	$0	$8	$0
Total Account 382			$75,793	$52,935	$19,431	$2	$72	$1	$2	$105	$1,791	$1,454
387-Other Equipment	PLT_387	63	$1,428	$950	$334	$1	$3	$0	$0	$1	$84	$56
388-Asset Retirement Costs for Distribution Plant	PLT_388	64	$555	$369	$130	$0	$1	$0	$0	$0	$33	$22
TOTAL DISTRIBUTION PLANT ACCUMULATED DEPRECIATION			$816,087	$550,366	$190,106	$359	$1,427	$5	$102	$653	$41,142	$31,926
GENERAL PLANT ACCUMULATED DEPRECIATION	GENLPLT	42	$16,131	$11,364	$3,378	$7	$26	$0	$2	$10	$809	$534
TOTAL ACCUMULATED DEPRECIATION			$893,447	$602,367	$211,688	$403	$1,503	$5	$106	$675	$43,214	$33,486
NET GAS PLANT IN SERVICE			$2,644,222	$1,751,860	$622,173	$1,329	$4,979	$14	$368	$1,976	$159,403	$102,120
ADDITIONS AND DEDUCTIONS TO RATE BASE												
PLUS: ADDITIONS TO RATE BASE												
COMMON PLANT	SALWAGES	121	$136,770	$96,355	$28,641	$62	$217	$1	$17	$85	$6,861	$4,531
WORKING CAPITAL												
Cash Working Capital - Purchased Gas	SCH RBC, LN 37		$3,679	$2,753	$894	$1	$16	$0	$0	$14	$0	$0
Cash Working Capital	SCH RBC, LN 22		($456)	($118)	($44)	($1)	($1)	$0	($0)	$4	($168)	($127)
Gas Storage Inventory	ESTORAGE	16	$30,870	$20,639	$9,545	$6	$2	$0	$0	$0	$299	$380
Materials and Supplies	TOTPLT	43	$489	$326	$115	$0	$1	$0	$0	$0	$28	$19
TOTAL WORKING CAPITAL			$34,582	$23,599	$10,510	$6	$18	$0	($0)	$18	$159	$272
TOTAL ADDITIONS TO RATE BASE EXCL PURCHASED GAS			$167,673	$117,202	$38,257	$67	$219	$1	$17	$89	$7,020	$4,803
TOTAL ADDITIONS TO RATE BASE			$171,352	$119,954	$39,151	$68	$235	$1	$17	$103	$7,020	$4,803
LESS: DEDUCTIONS TO RATE BASE												
Customer Deposits	CUSTDEP	23	$13,418	$4,654	$8,461	$0	$3	$0	$0	$6	$194	$101
Customer Advances for Construction	CUSTADV	135	$1,334	$1,106	$228	$0	$0	$0	$0	$0	$0	$0

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Deferred Income Taxes and Credits												
Plant	TOTPLT	43	$383,270	$255,056	$90,340	$188	$702	$2	$51	$287	$21,951	$14,692
Common Plant	SALWAGES	121	$6,582	$4,637	$1,378	$3	$10	$0	$1	$4	$330	$218
Pension Assets / (Liability)	SALWAGES	121	($35,059)	($24,699)	($7,342)	($16)	($56)	($0)	($4)	($22)	($1,759)	($1,161)
ML Non-Conforming	TOTPLT	43	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Contributions in Aid of Construction (CIAC)	CUSTADV	135	($15,909)	($13,193)	($2,716)	$0	$0	$0	$0	$0	$0	$0
Total Deferred Income Taxes and Credits			$338,883	$221,800	$81,660	$175	$657	$2	$48	$269	$20,523	$13,748
TOTAL DEDUCTIONS TO RATE BASE			$353,635	$227,560	$90,349	$175	$660	$2	$48	$275	$20,717	$13,849
TOTAL PURCHASED GAS RATE BASE			$3,679	$2,753	$894	$1	$16	$0	$0	$14	$0	$0
TOTAL RATE BASE EXCLUDING PURCHASED GAS			$2,458,260	$1,641,501	$570,081	$1,221	$4,537	$13	$337	$1,790	$145,707	$93,073
TOTAL RATE BASE			$2,461,939	$1,644,254	$570,975	$1,222	$4,554	$13	$337	$1,804	$145,707	$93,073
CASH WORKING CAPITAL (LEAD LAG)												
TOTAL EXCLUDING PURCHASED GAS												
O&M EXPENSE RELATED CASH WORKING CAPITAL												
Payroll (Distribution Only)	SALWAGES	121	$42,209	$29,737	$8,839	$19	$67	$0	$5	$26	$2,117	$1,398
Pension	SALWAGES	121	$2,513	$1,771	$526	$1	$4	$0	$0	$2	$126	$83
Other Expenses												
Other Expenses	OMXPPPP	114	$97,082	$71,040	$18,915	$36	$130	$0	$10	$56	$4,150	$2,745
BSC	EBSC	18	$25,090	$16,201	$8,648	$6	$164	$2	$0	$69	$0	$0
Purchase of Recievables (POR)	REV_POR	136	$63,454	$45,995	$17,258	$0	$81	$1	$0	$118	$0	$0
TOTAL EXPENSES			$230,350	$164,744	$54,187	$63	$446	$3	$16	$271	$6,393	$4,226
TOTAL EXPENSES PER DAY			$631	$451	$148	$0	$1	$0	$0	$1	$18	$12
CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	5.2329		$3,302	$2,362	$777	$1	$6	$0	$0	$4	$92	$61
AVERAGE PREPAYMENTS			$2,047	$1,453	$458	$1	$3	$0	$0	$2	$81	$48
DISTRIBUTION ACCRUED TAXES			$189	$57	$134	($0)	($0)	$0	($0)	$2	$3	($6)
INTEREST PAYMENTS	TOTPLT	43	($5,995)	($3,990)	($1,413)	($3)	($11)	($0)	($1)	($4)	($343)	($230)
NET CASH WORKING CAPITAL EXCL PUR GAS REQUIREMENT			($456)	($118)	($44)	($1)	($1)	$0	($0)	$4	($168)	($127)
PURCHASED GAS												
O&M EXPENSE RELATED CASH WORKING CAPITAL												
Commodity Purchased - Contract Purchases	EGAS	17	$201,620	$150,877	$49,021	$70	$892	$9	$0	$750	$0	$0
Commodity Purchased - Spot Market Purchases	ETHRUPUTF	14	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL EXPENSES			$201,620	$150,877	$49,021	$70	$892	$9	$0	$750	$0	$0
TOTAL EXPENSES PER DAY			$552	$413	$134	$0	$2	$0	$0	$2	$0	$0
PP CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	6.65938		$3,679	$2,753	$894	$1	$16	$0	$0	$14	$0	$0
PURCHASED GAS ACCRUED TAXES	ETHRUPUTF	14	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NET PURCHASED GAS CASH WORKING CAPITAL REQUIREMENT			$3,679	$2,753	$894	$1	$16	$0	$0	$14	$0	$0
TOTAL NET CASH WORKING CAPITAL			$3,222	$2,635	$850	($0)	$15	$0	($0)	$17	($168)	($127)

PECO Energy Company
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DISTRIBUTION ACCRUED TAXES												
Federal Income Tax	EBT	115	$15,181	$6,837	$7,800	($9)	$3	$1	($0)	$98	$489	($37)
State Income Tax	EBT	115	$101,908	$45,896	$52,361	($63)	$18	$5	($0)	$659	$3,281	($249)
PURTA Taxes	TOTPLT	43	($159,522)	($106,157)	($37,601)	($78)	($292)	($1)	($21)	($120)	($9,136)	($6,115)
PA Capital Stock Tax	TOTPLT	43	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PA & Local Use Taxes	TOTPLT	43	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PA Property tax	TOTPLT	43	$111,596	$74,264	$26,304	$55	$204	$1	$15	$84	$6,392	$4,278
TOTAL ACCRUED TAXES			$69,163	$20,840	$48,865	($96)	($67)	$5	($6)	$722	$1,025	($2,123)
TOTAL ACCRUED TAXES PER DAY			$189	$57	$134	($0)	($0)	$0	($0)	$2	$3	($6)
DISTRIBUTION AVERAGE PREPAYMENTS												
AGA Membership Dues	SALESREV	122	$187	$121	$52	$0	$0	$0	$0	$0	$9	$5
EAPA & NGA Membership Dues	SALESREV	122	$49	$32	$14	$0	$0	$0	$0	$0	$2	$1
PUC Assess - Gas	CLAIMREV	132	$759	$545	$179	$1	$2	$0	$0	$1	$22	$10
Cellent Gas Meter Reading	PLT_381	61	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Gas Software Maintenance	DISTPLT	41	$13	$9	$3	$0	$0	$0	$0	$0	$1	$1
Customer and Research	CUSTBILLS	34	$38	$35	$3	$0	$0	$0	$0	$0	$0	$0
VEBA Adjustment	SALWAGES	121	$55	$39	$12	$0	$0	$0	$0	$0	$3	$2
Facility Contracts	DISTPLT	41	$18	$12	$4	$0	$0	$0	$0	$0	$1	$1
IT License & Maintenance	TOTPLT	43	$630	$419	$148	$0	$1	$0	$0	$0	$36	$24
Fleet Activities	GENLPLT	42	$76	$53	$16	$0	$0	$0	$0	$0	$4	$3
Prepared Rent	DISTPLT	41	$60	$40	$14	$0	$0	$0	$0	$0	$3	$2
Postage	CUSTBILLS	34	$162	$149	$13	$0	$0	$0	$0	$0	$0	$0
TOTAL AVERAGE PREPAYMENTS			$2,047	$1,453	$458	$1	$3	$0	$0	$2	$81	$48

PECO Energy Company
Peak & Average Gas Class Cost of Service Study
(Expenses)

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OPERATION & MAINTENANCE EXPENSE												
PRODUCTION EXPENSE												
Manufactured Gas Production Expense												
Operation												
710-Operations Labor	DPKDAYP	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
717-Liquefied Petroleum Gas Expenses	DPKDAYP	1	$80	$52	$28	$0	$0	$0	$0	$0	$0	$0
Total Operation			$80	$52	$28	$0	$0	$0	$0	$0	$0	$0
Maintenance												
741-Maintenance of Structures and Improvements.	DPKDAYP	1	$53	$35	$18	$0	$0	$0	$0	$0	$0	$0
742-Maintenance of Production Equipment	DPKDAYP	1	$133	$86	$46	$0	$0	$0	$0	$0	$0	$0
Total Maintenance			$186	$121	$65	$0	$0	$0	$0	$0	$0	$0
Total Manufactured Gas Production Expense			$266	$173	$92	$0	$0	$0	$0	$0	$0	$0
Other Gas Supply Expense												
Operation												
804-Natural Gas Purchases-PGC	EGAS	17	$201,620	$150,877	$49,021	$70	$892	$9	$0	$750	$0	$0
804-Natural Gas Purchases-BSC	EBSC	18	$25,090	$16,201	$8,648	$6	$164	$2	$0	$69	$0	$0
805-Other Natural Gas Purchases	ETHRUPUT	13	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
807-Purchased Gas Expenses	ESTORAGE	16	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
808.1 Gas withdrawn from storage—Debt.	ETHRUPUT	13	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
808.1 Gas withdrawn from storage—Direct	ETHRUPUTT	15	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Gas Supply Expense			$226,710	$167,079	$57,668	$77	$1,056	$11	$0	$819	$0	$0
TOTAL PRODUCTION EXPENSE			$226,976	$167,251	$57,761	$77	$1,056	$11	$0	$819	$0	$0
NATURAL GAS STORAGE EXPENSE												
Operation												
840-Operation Supervision and Engineering	ESTORAGE	16	$252	$169	$78	$0	$0	$0	$0	$0	$2	$3
841-Operation Labor & Expenses - Training	ESTORAGE	16	$812	$543	$251	$0	$0	$0	$0	$0	$8	$10
Total Operation			$1,065	$712	$329	$0	$0	$0	$0	$0	$10	$13
Maintenance												
843-Maintenance Expense	ESTORAGE	16	$4,414	$2,951	$1,365	$1	$0	$0	$0	$0	$43	$54
Total Maintenance			$4,414	$2,951	$1,365	$1	$0	$0	$0	$0	$43	$54
Total Natural Gas Storage Expense			$5,479	$3,663	$1,694	$1	$0	$0	$0	$0	$53	$67
TRANSMISSION EXPENSES												
Operation Expense	TRANPLT	40	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Maintenance Expense	TRANPLT	40	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL TRANSMISSION EXPENSE			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DISTRIBUTION EXPENSES												
Operation												
870-Operation Supervision and Engineering	SALWAGDO	116	$1,094	$797	$216	$0	$2	$0	$0	$1	$47	$31
874-Mains and Services Expenses	PLT_376380	66	$16,959	$11,328	$3,896	$9	$33	$0	$3	$12	$1,011	$666
875-Measuring & Reg. Station Exp.-General	PLT_378	56	$1,036	$565	$302	$1	$3	$0	$0	$1	$99	$65
877-Measuring & Reg. Station Exp.-City Gate Sta.	PLT_379	59	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0
878-Meter & House Regulator Expenses	PLT_3815	69	$5,979	$4,166	$1,529	$0	$6	$0	$0	$8	$155	$114
879-Customer Installations Expenses	CUSTINSTALL	25	$5,158	$4,726	$425	$0	$0	$0	$0	$0	$4	$2
880-Other Expenses	DISTPLT	41	$13,512	$8,986	$3,161	$7	$25	$0	$2	$10	$792	$529
Total Distribution Operation			$43,737	$30,568	$9,529	$17	$69	$0	$5	$32	$2,109	$1,408

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Maintenance												
887-Maintenance of Mains	PLT_376	55	$17,505	$9,544	$5,097	$15	$55	$0	$4	$18	$1,669	$1,102
889-Maint. of Measuring & Reg. Station Equip.-Gen	PLT_378	56	$1,014	$553	$295	$1	$3	$0	$0	$1	$97	$64
892-Maintenance of Services	PLT_380	60	$1,445	$1,248	$191	$0	$0	$0	$0	$0	$4	$2
893-Maint. of Meters & House Regulators	PLT_3815	69	$418	$291	$107	$0	$0	$0	$0	$1	$11	$8
894-Maintenance of Other Equipment	DISTPLT	41	$879	$585	$206	$0	$2	$0	$0	$1	$52	$34
Total Distribution Maintenance			$21,261	$12,221	$5,895	$16	$61	$0	$5	$21	$1,832	$1,211
TOTAL DISTRIBUTION PLANT O&M EXPENSES			$64,998	$42,789	$15,424	$34	$130	$0	$9	$53	$3,940	$2,618
TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)			$297,453	$213,703	$74,879	$112	$1,186	$12	$9	$872	$3,993	$2,686
CUSTOMER ACCOUNTS EXPENSES												
902-Meter Reading	CMETRDG	26	$199	$182	$16	$0	$0	$0	$0	$0	$0	$0
903-Customer Records and Collection Expense	CUSTREC	27	$14,723	$12,963	$1,294	$2	$5	$0	$1	$4	$297	$157
904-Uncollectible Accounts	EXP_904	133	$2,263	$2,046	$205	$0	$1	$0	$0	$1	$6	$4
904-Uncollectible Accounts - PPA	EXP_904PPA	134	$322	$322	$0	$0	$0	$0	$0	$0	$0	$0
905-Miscellaneous CA	CUSTCAM	28	$2,152	$1,971	$177	$0	$0	$0	$0	$0	$2	$1
TOTAL CUSTOMER ACCTS EXPENSE			$19,658	$17,484	$1,692	$2	$6	$0	$1	$6	$305	$161
CUSTOMER SERVICE & SALES EXPENSES												
908-Customer Assistance	CUSTASST	29	$7,742	$7,482	$217	$0	$0	$0	$0	$0	$28	$14
908-Customer Assistance	CUSTASSTDA	30	$500	$0	$499	$0	$0	$0	$0	$0	$0	$0
909-Advertisement	CUSTADVT	31	$309	$298	$9	$0	$0	$0	$0	$0	$1	$1
910-Miscellaneous CS	CUSTCSM	32	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
912-Demonstrating and Selling Expenses	CUSTSALES	33	$2,810	$2,716	$79	$0	$0	$0	$0	$0	$10	$5
916 Miscellaneous Sales Expenses	CUSTSALES	33	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CUSTOMER SERVICE & SALES EXP			$11,361	$10,496	$804	$0	$0	$0	$0	$1	$39	$21
TOTAL OPER & MAINT EXCL A&G			$328,472	$241,683	$77,376	$115	$1,193	$12	$11	$878	$4,337	$2,868
ADMINISTRATIVE & GENERAL EXPENSE												
920-Administrative Salaries	SALWAGES	121	$9,261	$6,524	$1,939	$4	$15	$0	$1	$6	$465	$307
921-Office Supplies & Expense	SALWAGES	121	$1,454	$1,025	$305	$1	$2	$0	$0	$1	$73	$48
923-Outside Service Employed	SALWAGES	121	$16,942	$11,935	$3,548	$8	$27	$0	$2	$11	$850	$561
924-Property Insurance	PSTDGPLT	46	$75	$50	$18	$0	$0	$0	$0	$0	$4	$3
925-Injuries and Damages	SALWAGES	121	$273	$192	$57	$0	$0	$0	$0	$0	$14	$9
926-Employee Pensions & Benefits	SALWAGES	121	$10,139	$7,143	$2,123	$5	$16	$0	$1	$6	$509	$336
928-Regulatory Commission	CLAIMREV	132	$2,717	$1,952	$640	$2	$6	$0	$0	$4	$78	$36
929-Duplicate Charges-Credit	CLAIMREV	132	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
930.1-General Advertising	CLAIMREV	132	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
930.2-Miscellaneous General	SALWAGES	121	$545	$384	$114	$0	$1	$0	$0	$0	$27	$18
932-Maintenance of General Plant	GENLPLT	42	$1,222	$861	$256	$1	$2	$0	$0	$1	$61	$40
TOTAL A&G EXPENSE			$42,629	$30,067	$9,000	$20	$69	$0	$5	$29	$2,080	$1,358
TOTAL OPERATION & MAINTENANCE EXPENSES			$371,101	$271,750	$86,376	$135	$1,262	$12	$16	$907	$6,417	$4,226
TOTAL PURCHASED GAS O&M EXPENSES			$226,710	$167,079	$57,668	$77	$1,056	$11	$0	$819	$0	$0
TOTAL O&M EXPENSES EXCLUDING PURCHASED GAS			$144,391	$104,672	$28,708	$58	$206	$1	$16	$88	$6,417	$4,226

PECO Energy Company
Peak & Average Gas Class Cost of Service Study
(Expenses)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
DEPRECIATION / AMORTIZATION EXPENSE												
INTANGIBLE PLANT EXPENSE	INTPLT	37	$10,333	$6,876	$2,436	$5	$19	$0	$1	$8	$592	$396
PRODUCTION PLANT EXPENSE	PRODPLT	38	$117	$76	$41	$0	$0	$0	$0	$0	$0	$0
LOCAL STORAGE PLANT EXPENSE	STORPLT	39	$1,729	$1,156	$535	$0	$0	$0	$0	$0	$17	$21
TRANSMISSION PLANT EXPENSE	TRANPLT	40	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DISTRIBUTION PLANT EXPENSE												
374-Land Rights	PLT_374	50	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
375-Structures & Improvements	PLT_375	51	$345	$187	$100	$0	$1	$0	$0	$0	$34	$23
376-Mains												
General	PLT_376G	52	$30,455	$16,749	$8,944	$27	$97	$0	$7	$32	$2,786	$1,812
Direct Assignment	DAMAINSDE	7	$155	$0	$0	$0	$0	$0	$0	$0	$54	$101
Total Account 376			$30,610	$16,749	$8,944	$27	$97	$0	$7	$32	$2,840	$1,913
378-Measuring & Regulating Station Equip-General	PLT_378	56	$508	$277	$148	$0	$2	$0	$0	$1	$48	$32
379-Measuring & Regulating Station Equip-City Gate												
City Gate	PLT_379CG	57	$1,361	$742	$396	$1	$4	$0	$0	$1	$130	$86
Direct Assignment	DAMRDE	11	$160	$0	$0	$0	$0	$0	$0	$0	$58	$102
Total Account 379			$1,521	$742	$396	$1	$4	$0	$0	$1	$188	$188
380-Services	PLT_380	60	$22,906	$19,787	$3,020	$1	$1	$0	$0	$2	$62	$33
381-Meters	CMETERS	20	$5,389	$3,764	$1,382	$0	$5	$0	$0	$7	$127	$103
Direct Assignment	CMETERSDA	21	$3	$0	$0	$0	$0	$0	$0	$0	$3	$0
Total Account 381			$5,392	$3,764	$1,382	$0	$5	$0	$0	$7	$129	$103
382-Meter Installations	CMETERS	20	$4,382	$3,061	$1,124	$0	$4	$0	$0	$6	$103	$84
Direct Assignment	CMETERSDA	21	$8	$0	$0	$0	$0	$0	$0	$0	$8	$0
Total Account 382			$4,390	$3,061	$1,124	$0	$4	$0	$0	$6	$111	$84
387-Other Equipment	PLT_378387	70	$133	$65	$34	$0	$0	$0	$0	$0	$19	$14
388-Asset Retirement Costs for Distribution Plant	PLT_388	64	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL DISTRIBUTION PLANT EXPENSE			$65,805	$44,632	$15,148	$29	$115	$0	$8	$50	$3,432	$2,390
GENERAL PLANT EXPENSE	GENLPLT	42	$1,723	$1,214	$361	$1	$3	$0	$0	$1	$86	$57
COMMON PLANT DEPRECIATION/AMORTIZATION	SALWAGES	121	$6,439	$4,536	$1,348	$3	$10	$0	$1	$4	$323	$213
NET MANUFACTURED GAS PLANT EXP	ETHRUPUT	13	$2,812	$1,299	$693	$1	$13	$0	$1	$6	$353	$447
TOTAL DEPRECIATION / AMORTIZATION EXPENSE			$88,959	$59,790	$20,562	$39	$160	$1	$12	$69	$4,803	$3,524

PECO Energy Company
Peak & Average Gas Class Cost of Service Study
(Expenses)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
OTHER OPERATING EXPENSES												
TAXES OTHER THAN INCOME TAXES												
General Taxes												
PURTA Taxes	TOTPLT	43	$2,050	$1,364	$483	$1	$4	$0	$0	$2	$117	$79
Capital Stock	TOTPLT	43	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Payroll Related	SALWAGES	121	$3,776	$2,660	$791	$2	$6	$0	$0	$2	$189	$125
Real Estate Tax	TOTPLT	43	$1,568	$1,043	$370	$1	$3	$0	$0	$1	$90	$60
PA and Local Use Tax	CLAIMREV	132	$152	$109	$36	$0	$0	$0	$0	$0	$4	$2
Total General Taxes			$7,545	$5,177	$1,679	$4	$13	$0	$1	$5	$401	$266
Franchise and Revenue Taxes												
Retail Revenue			$0									
Forfeited Discounts			$0									
Less: Bad Debt			$0									
Total Revenue	CALCULATED		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Distribution @ GRT Rate 0.00%	CALCULATED		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Franchise and Revenue Taxes			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL TAXES OTHER THAN INCOME			$7,545	$5,177	$1,679	$4	$13	$0	$1	$5	$401	$266

PECO Energy Company
Peak & Average Gas Class Cost of Service Study
(Revenues)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
OPERATING REVENUES												
SALES REVENUES												
Sales of Gas Revenues - Base		DIR	$361,576	$233,489	$100,579	$75	$475	$5	$35	$690	$16,719	$9,509
Sales Revenues - Purchased Gas-PGC	EGAS	17	$201,635	$150,889	$49,024	$70	$892	$9	$0	$750	$0	$0
Sales Revenues - Balancing Service Charge-BSC	EBSC	18	$25,075	$16,192	$8,643	$6	$164	$2	$0	$69	$0	$0
TOTAL SALES OF GAS			$588,286	$400,569	$158,245	$152	$1,531	$16	$35	$1,509	$16,719	$9,509
OTHER OPERATING REVENUES												
487-Forfeited Discounts	REV_487	137	$838	$634	$163	$0	$1	$0	$0	$1	$25	$14
488-Miscellaneous Service Revenues	OX_904	106	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
489-Transport of Gas of Others Revenue	PLT_376	55	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
494-Interdepartmental Rents	DISTPLT	41	$691	$459	$162	$0	$1	$0	$0	$1	$40	$27
TOTAL OTHER OPERATING REV			$1,528	$1,093	$325	$0	$2	$0	$0	$2	$65	$41
TOTAL OPERATING REVENUES			$589,814	$401,662	$158,570	$153	$1,533	$16	$35	$1,510	$16,785	$9,551

PECO Energy Company
Peak & Average Gas Class Cost of Service Study
(Labor)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
DEVELOPMENT OF SALARIES & WAGES ALLOCATION FACTOR												
PRODUCTION SALARIES & WAGES EXPENSE												
Manufactured Gas Production Expense												
Operation - Acct 717	OX_PRODM	83	$48	$31	$17	$0	$0	$0	$0	$0	$0	$0
Maintenance - Accts 741-742	MX_PRODM	84	$112	$73	$39	$0	$0	$0	$0	$0	$0	$0
Total Manufactured Gas Production Expense			$160	$104	$55	$0	$0	$0	$0	$0	$0	$0
Other Gas Supply Expense												
Operation - Accounts 804-808	OX_PRODO	85	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Gas Supply			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL PRODUCTION S&W EXP			$160	$104	$55	$0	$0	$0	$0	$0	$0	$0
STORAGE SALARIES & WAGES EXPENSE												
Operation - Accts 840-841	OX_STOR	86	$541	$362	$167	$0	$0	$0	$0	$0	$5	$7
Maintenance - Acct 843	MX_STOR	87	$1,672	$1,118	$517	$0	$0	$0	$0	$0	$16	$21
TOTALSTORAGE S&W EXP			$2,213	$1,479	$684	$0	$0	$0	$0	$0	$21	$27
TRANSMISSION SALARIES & WAGES EXPENSE												
Operation	OX_TRAN	88	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Maintenance	MX_TRAN	89	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL TRANSMISSION S&W EXP			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DISTRIBUTION SALARIES & WAGES EXPENSE												
Operation												
874-Mains and Services Expenses	OX_874	92	$5,809	$3,880	$1,335	$3	$11	$0	$1	$4	$346	$228
875-Measuring & Reg. Station Exp.-General	OX_875	93	$714	$389	$208	$1	$2	$0	$0	$1	$68	$45
878-Meter & House Regulator Expenses	OX_878	94	$1,217	$848	$311	$0	$1	$0	$0	$2	$31	$23
879-Customer Installations Expenses	OX_879	95	$3,662	$3,355	$302	$0	$0	$0	$0	$0	$3	$2
880-Other Expenses	OX_880	96	$2,695	$1,792	$630	$1	$5	$0	$0	$2	$158	$105
Total Operation			$14,096	$10,265	$2,786	$5	$20	$0	$1	$9	$607	$403
Maintenance												
887-Maintenance of Mains	MX_887	97	$9,628	$5,249	$2,803	$8	$30	$0	$2	$10	$918	$606
889-Maint. of Measuring & Reg. Station Equip.-Gen	MX_889	98	$494	$269	$144	$0	$2	$0	$0	$1	$47	$31
892-Maintenance of Services	MX_892	99	$710	$614	$94	$0	$0	$0	$0	$0	$2	$1
893-Maint. of Meters & House Regulators	MX_893	100	$285	$199	$73	$0	$0	$0	$0	$0	$7	$5
894-Maintenance of Other Equipment	MX_894	101	$116	$77	$27	$0	$0	$0	$0	$0	$7	$5
Total Distribution Maintenance			$11,234	$6,408	$3,141	$9	$32	$0	$2	$11	$981	$648
TOTAL DISTRIBUTION S&W EXP			$25,330	$16,673	$5,927	$14	$52	$0	$4	$20	$1,588	$1,052
TOTAL OPER & MAINT S&W EXP (PROD, STOR, TRAN,& DIST)			$27,702	$18,256	$6,666	$15	$53	$0	$4	$20	$1,610	$1,079
CUSTOMER ACCOUNTS EXPENSES												
902-Meter Reading	CMETRDG	26	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
903-Customer Records and Collection Expense	CUSTREC	27	$5,897	$5,192	$518	$1	$2	$0	$0	$2	$119	$63
904-Uncollectible Accounts	EXP_904	133	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
904-Uncollectible Accounts - PPA	EXP_904	133	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
905-Miscellaneous CA	CUSTCAM	28	$291	$266	$24	$0	$0	$0	$0	$0	$0	$0
TOTAL CUSTOMER ACCTS S&W EXPENSE			$6,188	$5,459	$542	$1	$2	$0	$0	$2	$119	$63

PECO Energy Company
Peak & Average Gas Class Cost of Service Study
(Labor)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
CUSTOMER SERVICE & SALES EXPENSES												
908-Customer Assistance	CUSTASST	29	$226	$219	$6	$0	$0	$0	$0	$0	$1	$0
909-Advertisement	CUSTADVT	31	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
910-Miscellaneous CS	CUSTCSM	32	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
912-Demonstrating and Selling Expenses	CUSTSALES	33	$388	$375	$11	$0	$0	$0	$0	$0	$1	$1
916 Miscellaneous Sales Expenses	CUSTSALES	33	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CUST SERVICE & SALES S&W EXP			$615	$594	$17	$0	$0	$0	$0	$0	$2	$1
TOTAL OPER & MAINT S&W EXP EXCL A&G			$34,505	$24,309	$7,226	$16	$55	$0	$4	$22	$1,731	$1,143
ADMINISTRATIVE & GENERAL EXPENSE												
920-Administrative Salaries	SALWAGXAG	120	$7,398	$5,212	$1,549	$3	$12	$0	$1	$5	$371	$245
921-Office Supplies & Expense	SALWAGXAG	120	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
923-Outside Service Employed	SALWAGXAG	120	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
924-Property Insurance	PSTDGPLT	46	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
925-Injuries and Damages	SALWAGXAG	120	$129	$91	$27	$0	$0	$0	$0	$0	$6	$4
926-Employee Pensions & Benefits	SALWAGXAG	120	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
928-Regulatory Commission	CLAIMREV	132	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
929-Duplicate Charges-Credit	CLAIMREV	132	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
930.1-General Advertising	SALWAGXAG	120	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
930.2-Miscellaneous General	SALWAGXAG	120	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
932-Maintenance of General Plant	GENLPLT	42	$177	$125	$37	$0	$0	$0	$0	$0	$9	$6
TOTAL A&G S&W EXPENSE			$7,704	$5,428	$1,613	$3	$12	$0	$1	$5	$386	$255
TOTAL OPER & MAINTENANCE SALARIES & WAGES EXP			$42,209	$29,737	$8,839	$19	$67	$0	$5	$26	$2,117	$1,398

PECO Energy Company
Peak & Average Gas Class Cost of Service Study
(Income Taxes)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
DEVELOPMENT OF INCOME TAXES												
TOTAL OPERATING REVENUES EXCL PURCHASED GAS			$363,104	$234,582	$100,903	$76	$477	$5	$35	$691	$16,785	$9,551
LESS:												
OPER. & MAINT. EXP. EXCL PURCHASED GAS	SCH , LN		$144,391	$104,672	$28,708	$58	$206	$1	$16	$88	$6,417	$4,226
DEPRECIATION AND AMORTIZATION EXPENSE	SCH , LN		$88,959	$59,790	$20,562	$39	$160	$1	$12	$69	$4,803	$3,524
TAXES OTHER THAN INCOME TAXES	SCH , LN		$7,545	$5,177	$1,679	$4	$13	$0	$1	$5	$401	$266
NET OPERATING INCOME BEFORE TAXES			$122,209	$64,944	$49,955	($25)	$98	$4	$6	$529	$5,164	$1,534
LESS:												
INTEREST EXPENSE (Rate Base * 1.85% Weighted Cost of Debt)			$45,478	$30,368	$10,546	$23	$84	$0	$6	$33	$2,696	$1,722
BASE TAXABLE DISTRIBUTION INCOME EXCL PURCHASED GAS			$76,731	$34,576	$39,408	($48)	$14	$4	($0)	$496	$2,468	($187)
FEDERAL & STATE TAX ADJUSTMENTS												
Regulatory Asset Prog M-1 (Pension & Post Ret)	SALWAGES	121	$3,054	$2,152	$640	$1	$5	$0	$0	$2	$153	$101
Other Property Basis Adjustment (CIAC/ICM)	DISTPLT	41	$12,276	$8,164	$2,872	$6	$23	$0	$2	$9	$720	$480
Removal Costs/Software	TOTPLT	43	$9,120	$6,069	$2,150	$4	$17	$0	$1	$7	$522	$350
AFUDC Equity	TOTPLT	43	$5,482	$3,648	$1,292	$3	$10	$0	$1	$4	$314	$210
Permanent Adjustments	TOTPLT	43	($775)	($516)	($183)	($0)	($1)	($0)	($0)	($1)	($44)	($30)
Repair Allowance Deduction	TOTPLT	43	$132,540	$88,202	$31,241	$65	$243	$1	$18	$99	$7,591	$5,081
TOTAL FEDERAL & STATE TAX ADJUSTMENTS			$161,697	$107,719	$38,011	$79	$296	$1	$22	$121	$9,256	$6,192
CALCULATION OF PA STATE INCOME TAXES												
BASE TAXABLE INCOME	SCH , LN		$76,731	$34,576	$39,408	($48)	$14	$4	($0)	$496	$2,468	($187)
LESS:												
State Tax Depreciation (Over) Under Book	TOTPLT	43	($25,538)	($16,995)	($6,019)	($13)	($47)	($0)	($3)	($19)	($1,463)	($979)
Total Tax Adjustments	SCH , LN		$161,697	$107,719	$38,011	$79	$296	$1	$22	$121	$9,256	$6,192
PA STATE TAXALBE DISTRIBUTION INCOME			($59,428)	($56,148)	$7,417	($114)	($236)	$3	($18)	$394	($5,325)	($5,401)
PA STATE INCOME TAXES @ Tax Rate 9.99%			($5,937)	($5,609)	$741	($11)	($24)	$0	($2)	$39	($532)	($540)
PLUS: DEFERRED STATE INCOME TAXES												
Net Operating Loss Utilization	CALCULATED		$5,937	$5,609	($741)	$11	$24	($0)	$2	($39)	$532	$540
TOTAL STATE INCOME TAX			$0									
Deferred Taxes on Timing Differences - State	TOTPLT	43	($1,531)	($1,019)	($361)	($1)	($3)	($0)	($0)	($1)	($88)	($59)
Deferred Taxes on State NOL	TOTPLT	43	$5,947	$3,958	$1,402	$3	$11	$0	$1	$4	$341	$228
TOTAL STATE INCOME TAX EXPENSE			$4,416	$2,938	$1,041	$2	$8	$0	$1	$3	$253	$169
CALCULATION OF FEDERAL INCOME TAXES												
BASE TAXABLE INCOME	SCH , LN		$76,731	$34,576	$39,408	($48)	$14	$4	($0)	$496	$2,468	($187)
LESS:												
PA State Income Taxes	SCH , LN		$0									
Federal Tax Depreciation (Over) Under Book	TOTPLT	43	($33,615)	($22,370)	($7,923)	($16)	($62)	($0)	($5)	($25)	($1,925)	($1,289)
Total Tax Adjustments	SCH , LN		$161,697	$107,719	$38,011	$79	$296	$1	$22	$121	$9,256	$6,192
FEDERAL TAXALBE DISTRIBUTION INCOME			($51,351)	($50,773)	$9,321	($110)	($221)	$3	($17)	$400	($4,862)	($5,091)
FEDERAL INCOME TAXES @ Tax Rate 21.00%			$10,784	$10,662	($1,957)	$23	$46	($1)	$4	($84)	$1,021	$1,069

PECO Energy Company
Peak & Average Gas Class Cost of Service Study
(Income Taxes)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
DEVELOPMENT OF INCOME TAXES CONTINUED												
FEDERAL INCOME TAXES @ Tax Rate 21.00%	SCH , LN		$10,784	$10,662	($1,957)	$23	$46	($1)	$4	($84)	$1,021	$1,069
PLUS: DEFERRED FEDERAL INCOME TAXES												
Deferred Taxes on Timing Differences - Federal	TOTPLT	43	$998	$664	$235	$0	$2	$0	$0	$1	$57	$38
Excess Deferred Amortization	TOTPLT	43	$3,455	$2,299	$814	$2	$6	$0	$0	$3	$198	$132
FIT Expense on Flow Through Adjustments	TOTPLT	43	($953)	($634)	($225)	($0)	($2)	($0)	($0)	($1)	($55)	($37)
LESS: OTHER FEDERAL TAX ADJUSTMENTS												
Amortization of ITC - Gas Plant	TOTPLT	43	($64)	($43)	($15)	($0)	($0)	($0)	($0)	($0)	($4)	($2)
TOTAL FEDERAL INCOME TAX EXPENSE			$14,347	$13,034	($1,117)	$25	$53	($1)	$4	($81)	$1,225	$1,206
TOTAL INCOME TAX EXPENSE EXCLUDING PURCHASED GAS			$18,763	$15,972	($77)	$27	$61	($1)	$5	($78)	$1,478	$1,375
DEVELOPMENT OF PURCHASED GAS TAXES												
PURCHASED GAS OPERATING REVENUES			$226,710	$167,080	$57,667	$77	$1,056	$11	$0	$819	$0	$0
LESS:												
OPERATION & MAINTAINENCE EXPENSE			$226,710	$167,079	$57,668	$77	$1,056	$11	$0	$819	$0	$0
NET OPERATING INCOME BEFORE TAXES			$0	$2	($2)	$0	($0)	($0)	$0	$0	$0	$0
LESS:												
INTEREST EXPENSE (Rate Base * 1.85% Weighted Cost of Debt)			$68	$51	$17	$0	$0	$0	$0	$0	$0	$0
BASE TAXABLE PURCHASED GAS INCOME			($68)	($49)	($18)	($0)	($0)	($0)	$0	($0)	$0	$0
LESS:												
PA STATE PURCHASED GAS INCOME TAXES @ Tax Rate 9.99%			($7)	($5)	($2)	($0)	($0)	($0)	$0	($0)	$0	$0
Net Operating Loss Utilization	CALCULATED		$7	$5	$2	$0	$0	$0	$0	$0	$0	$0
TOTAL STATE INCOME TAX			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
EQUALS:												
FEDERAL PURCHASED GAS INCOME TAXES @ Tax Rate 21.00%			$14	$10	$4	$0	$0	$0	$0	$0	$0	$0
TOTAL PA INCOME TAX EXPENSE			$4,416	$2,938	$1,041	$2	$8	$0	$1	$3	$253	$169
TOTAL FEDERAL INCOME TAX EXPENSE			$14,362	$13,044	($1,114)	$25	$53	($1)	$4	($81)	$1,225	$1,206
TOTAL INCOME TAX EXPENSE			$18,777	$15,983	($73)	$27	$61	($1)	$5	($78)	$1,478	$1,375
TOTAL OTHER TAX EXPENSE			$7,545	$5,177	$1,679	$4	$13	$0	$1	$5	$401	$266
TOTAL TAX EXPENSE			$26,323	$21,159	$1,606	$31	$74	($1)	$6	($73)	$1,879	$1,641

PECO Energy Company
Peak & Average Gas Class Cost of Service Study
(Allocation Amount)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
Capacity Production - Design Peak Day Sendout	DPKDAYP	1	846,416	550,000	293,826	1,416	1,174	0	0	0	0	0
Capacity Storage - Design Peak Day Sendout	DPKDAYS	2	846,416	550,000	293,826	1,416	1,174	0	0	0	0	0
Capacity Transmission - Design Peak Day Sendout	DTRAN	3	846,416	550,000	293,826	1,416	1,174	0	0	0	0	0
Capacity Distribution Mains (A&E) Excess Demand	DEXCESS	4	683,737	417,874	223,292	1,317	0	0	0	0	41,255	0
Capacity Distribution Mains (Direct Assign Plant)	DAMAINS	5	15,289	0	0	0	0	0	0	0	8,219	7,070
Capacity Distribution Mains (Direct Assign Acc Dep)	DAMAINSAD	6	2,147	0	0	0	0	0	0	0	54	2,094
Capacity Distribution Mains (Direct Assign Dep Exp)	DAMAINSDE	7	155	0	0	0	0	0	0	0	54	101
Capacity Distribution (Des Peak Day Sendout)	DESDAY	8	846,416	550,000	293,826	1,416	1,174	0	0	0	0	0
Capacity Distribution M&R (Direct Assign Plant)	DAMR	9	11,382	0	0	0	0	0	0	0	6,292	5,090
Capacity Distribution M&R (Direct Assign Acc Dep)	DAMRAD	10	2,689	0	0	0	0	0	0	0	58	2,631
Capacity Distribution M&R (Direct Assign Dep Exp)	DAMRDE	11	159	0	0	0	0	0	0	0	58	102
Capacity Avg Daily Del excl Direct	DAVGDD	12	230,679	114,982	61,374	45	1,174	2	110	489	25,052	27,451
Annual Gas Deliveries - Thruput (Mcf)	ETHRUPUT	13	90,879,246	41,968,538	22,401,370	16,559	428,356	649	40,050	178,588	11,394,081	14,451,056
Annual Gas Deliveries - Firm	ETHRUPUTF	14	76,208,903	41,968,538	22,401,370	16,559	428,356	0	0	0	11,394,081	0
Annual Gas Deliveries - Transportation Only	ETHRUPUTT	15	25,845,137	0	0	0	0	0	0	0	11,394,081	14,451,056
Commodity Gas Storage	ESTORAGE	16	100.00%	66.86%	30.92%	0.02%	0.01%	0.00%	0.00%	0.00%	0.97%	1.23%
Annual Gas Cost (PGC)	EGAS	17	$201,635	$150,889	$49,024	$70	$892	$9	$0	$750	$0	$0
Commodity - Balancing Service Charge (BSC)	EBSC	18	$25,075	$16,191	$8,642	$6	$164	$2	$0	$69	$0	$0
380-Services	CSERVICE	19	$3,347,375	$2,891,540	$441,344	$80	$149	$20	$40	$308	$9,131	$4,765
381-Meters (Avg Cost per meter)	CMETERS	20	$215,514	$150,533	$55,257	$6	$204	$3	$6	$297	$5,072	$4,136
381-Meters Direct Assignment	CMETERSDA	21	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
382-Meters Installations Direct Assignment	CMETINSTDA	22	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
Customer Deposits	CUSTDEP	23	$12,465	$4,323	$7,860	$0	$3	$0	$0	$5	$180	$94
Customer Deposits Interest	CUSTDEPINT	24	$351	$216	$130	$0	$0	$0	$0	$0	$3	$2
879-Customer Installation Expense	CUSTINSTALL	25	$539,593	$494,391	$44,450	$4	$15	$2	$2	$31	$459	$239
902-Meter Reading Expense	CMETRDG	26	$539,593	$494,391	$44,450	$4	$15	$2	$2	$31	$459	$239
903-Customer Records and Collections	CUSTREC	27	100.00%	88.05%	8.79%	0.02%	0.03%	0.00%	0.01%	0.03%	2.02%	1.06%
905-Miscellaneous Customer Accounts	CUSTCAM	28	$539,593	$494,391	$44,450	$4	$15	$2	$2	$31	$459	$239
908-Customer Assistance	CUSTASST	29	100.00%	96.64%	2.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.36%	0.19%
908-Customer Assistance - Direct Assignment	CUSTASSTDA	30	$44,498	$0	$44,450	$0	$15	$2	$0	$31	$0	$0
909-Informational and Instructional Advertising	CUSTADVT	31	$310	$299	$9	$0	$0	$0	$0	$0	$1	$1
910-Miscellaneous Customer Service	CUSTCSM	32	100.00%	96.64%	2.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.36%	0.19%
916-Miscellaneous Sales Expense	CUSTSALES	33	100.00%	96.64%	2.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.36%	0.19%
Number of Bills	CUSTBILLS	34	6,475,119	5,932,690	533,403	48	180	24	24	372	5,505	2,873
Number of Customers (Average Annual)	CUST	35	539,593	494,391	44,450	4	15	2	2	31	459	239
INTERNALLY DEVELOPED ALLOCATION FACTORS		36										
Intangible Plant	INTPLT	37	$18,229	$12,131	$4,297	$9	$33	$0	$2	$14	$1,044	$699
Production Plant	PRODPLT	38	$15,539	$10,097	$5,394	$26	$22	$0	$0	$0	$0	$0
Storage Plant	STORPLT	39	$72,428	$48,423	$22,394	$14	$4	$0	$0	$0	$702	$891
Transmission Plant in Service	TRANPLT	40	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution Plant in Service	DISTPLT	41	$3,392,978	$2,256,455	$793,714	$1,666	$6,362	$19	$467	$2,613	$198,939	$132,741
General Plant in Service	GENLPLT	42	$38,495	$27,120	$8,061	$17	$61	$0	$5	$24	$1,931	$1,275
Total Gas Plant In Service	TOTPLT	43	$3,537,670	$2,354,227	$833,861	$1,732	$6,482	$20	$475	$2,651	$202,617	$135,606
Distribution Plant Excl Asset Retirement	DISTPLTXAR	44	$3,391,524	$2,255,488	$793,374	$1,665	$6,359	$19	$467	$2,612	$198,854	$132,685
Total Transmission and Distribution Plant	TDPLT	45	$3,392,978	$2,256,455	$793,714	$1,666	$6,362	$19	$467	$2,613	$198,939	$132,741
Total Prod, Stor, Trans, Dist & Gen Plant	PSTDGPLT	46	$3,519,441	$2,342,096	$829,564	$1,723	$6,448	$20	$472	$2,638	$201,573	$134,908
Total Distribution and General Plant	DGPLT	47	$3,431,473	$2,283,575	$801,776	$1,683	$6,423	$20	$472	$2,638	$200,870	$134,017
Rate Base	RATEBASE	48	$2,461,939	$1,644,254	$570,975	$1,222	$4,554	$13	$337	$1,804	$145,707	$93,073
Distribution Plant in Service - Capacity Related	DDISTPLT	49	$1,873,803	$1,015,427	$542,258	$1,611	$5,881	$7	$439	$1,958	$183,841	$122,380
Account 374	PLT_374	50	$3,637	$1,971	$1,052	$3	$11	$0	$1	$4	$357	$238
Account 375	PLT_375	51	$15,745	$8,532	$4,556	$14	$49	$0	$4	$16	$1,545	$1,028
Account 376-General	PLT_376G	52	$1,756,701	$966,123	$515,928	$1,533	$5,596	$7	$418	$1,863	$160,709	$104,524
Account 376-General Average	PLT_376GA	53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Account 376-DA	PLT_376DA	54	$15,289	$0	$0	$0	$0	$0	$0	$0	$8,219	$7,070
Account 376	PLT_376	55	$1,771,990	$966,123	$515,928	$1,533	$5,596	$7	$418	$1,863	$168,928	$111,595
Account 378	PLT_378	56	$24,652	$13,441	$7,178	$21	$78	$0	$6	$26	$2,350	$1,553
Account 379-City Gate	PLT_379CG	57	$65,778	$35,863	$19,152	$57	$208	$0	$16	$69	$6,271	$4,142
Account 379-Joint	PLT_379DA	58	$11,382	$0	$0	$0	$0	$0	$0	$0	$6,292	$5,090
Account 379	PLT_379	59	$77,160	$35,863	$19,152	$57	$208	$0	$16	$69	$12,563	$9,233

PECO Energy Company
Peak & Average Gas Class Cost of Service Study
(Allocation Amount)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
Account 380	PLT_380	60	$1,111,048	$959,749	$146,489	$26	$49	$7	$13	$102	$3,031	$1,581
Account 381	PLT_381	61	$164,090	$114,453	$42,012	$4	$155	$2	$4	$226	$4,088	$3,145
Account 382	PLT_382	62	$221,083	$153,948	$56,510	$6	$208	$3	$6	$304	$5,868	$4,230
Account 387	PLT_387	63	$2,118	$1,409	$496	$1	$4	$0	$0	$2	$124	$83
Account 388-Asset Retirement Costs for Distribution	PLT_388	64	$1,454	$967	$340	$1	$3	$0	$0	$1	$85	$57
Accounts 376, 378 & 379 - Mains & M&R	PLT_376379	65	$1,873,803	$1,015,427	$542,258	$1,611	$5,881	$7	$439	$1,958	$183,841	$122,380
Accounts 376 & 380 - Mains & Services	PLT_376380	66	$2,883,038	$1,925,872	$662,418	$1,559	$5,645	$13	$431	$1,965	$171,958	$113,176
Accounts 380 & 381 - Services & Meters	PLT_380381	67	$1,275,138	$1,074,202	$188,502	$31	$204	$9	$18	$328	$7,119	$4,726
Accounts 374 & 375 - Land & Structures	PLT_374375	68	$19,382	$10,503	$5,609	$17	$61	$0	$5	$20	$1,902	$1,266
Accounts 381 through 385	PLT_3815	69	$385,173	$268,400	$98,523	$10	$363	$6	$10	$530	$9,957	$7,375
Accounts 378, 379, & 387	PLT_378387	70	$103,931	$50,713	$26,825	$79	$290	$0	$22	$97	$15,037	$10,868
Residential	DPLTRES	71	$1,159,369	$1,159,369	$0	$0	$0	$0	$0	$0	$0	$0
Small Commercial and Industrilal	DPLTCI	72	$233,983	$0	$233,983	$0	$0	$0	$0	$0	$0	$0
Large High Load Factor	DPLTLHLF	73	$166	$0	$0	$166	$0	$0	$0	$0	$0	$0
Motor Vehicle - Firm	DPLTMVF	74	$698	$0	$0	$0	$698	$0	$0	$0	$0	$0
Motor Vehicle - Interruptible	DPLTMVI	75	$10	$0	$0	$0	$0	$10	$0	$0	$0	$0
Interruptible Service	DPLTIS	76	$54	$0	$0	$0	$0	$0	$54	$0	$0	$0
Temperature Control	DPLTTC	77	$492	$0	$0	$0	$0	$0	$0	$492	$0	$0
Transportation Service - Firm	DPLTTSF	78	$34,595	$0	$0	$0	$0	$0	$0	$0	$34,595	$0
Transportation Service - Interruptible	DPLTTSI	79	$24,744	$0	$0	$0	$0	$0	$0	$0	$0	$24,744
Account 717	OX_717	80	$80	$52	$28	$0	$0	$0	$0	$0	$0	$0
Account 741	MX_741	81	$53	$35	$18	$0	$0	$0	$0	$0	$0	$0
Account 743	MX_743	82	$133	$86	$46	$0	$0	$0	$0	$0	$0	$0
Manufactured Gas Production Operation Expense	OX_PRODM	83	$80	$52	$28	$0	$0	$0	$0	$0	$0	$0
Manufactured Gas Production Maintenance Expense	MX_PRODM	84	$186	$121	$65	$0	$0	$0	$0	$0	$0	$0
Other Production Operation Expense	OX_PRODO	85	$226,710	$167,079	$57,668	$77	$1,056	$11	$0	$819	$0	$0
Storage Operation Expense	OX_STOR	86	$1,065	$712	$329	$0	$0	$0	$0	$0	$10	$13
Storage Maintenance Expense	MX_STOR	87	$4,414	$2,951	$1,365	$1	$0	$0	$0	$0	$43	$54
Transmission Operation Expense	OX_TRAN	88	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission Maintenance Expense	MX_TRAN	89	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission Salaries & Wages Accounts 511-567	SALWAGTO	90	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission Salaries & Wages Accounts 569-574	SALWAGTM	91	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Account 874	OX_874	92	$16,959	$11,328	$3,896	$9	$33	$0	$3	$12	$1,011	$666
Account 875	OX_875	93	$1,036	$565	$302	$1	$3	$0	$0	$1	$99	$65
Account 878	OX_878	94	$5,979	$4,166	$1,529	$0	$6	$0	$0	$8	$155	$114
Account 879	OX_879	95	$5,158	$4,726	$425	$0	$0	$0	$0	$0	$4	$2
Account 880	OX_880	96	$13,512	$8,986	$3,161	$7	$25	$0	$2	$10	$792	$529
Account 887	MX_887	97	$17,505	$9,544	$5,097	$15	$55	$0	$4	$18	$1,669	$1,102
Account 889	MX_889	98	$1,014	$553	$295	$1	$3	$0	$0	$1	$97	$64
Account 892	MX_892	99	$1,445	$1,248	$191	$0	$0	$0	$0	$0	$4	$2
Account 893	MX_893	100	$418	$291	$107	$0	$0	$0	$0	$1	$11	$8
Account 894	MX_894	101	$879	$585	$206	$0	$2	$0	$0	$1	$52	$34
O&M Accounts 874-880	OX_DIST	102	$42,643	$29,771	$9,313	$17	$68	$0	$5	$32	$2,061	$1,376
O&M Accounts 887-894	MX_DIST	103	$3,756	$2,677	$798	$1	$5	$0	$0	$2	$163	$108
Account 902	OX_902	104	$199	$182	$16	$0	$0	$0	$0	$0	$0	$0
Account 903	OX_903	105	$14,723	$12,963	$1,294	$2	$5	$0	$1	$4	$297	$157
Account 904	OX_904	106	$2,263	$2,046	$205	$0	$1	$0	$0	$1	$6	$4
O&M Accounts 902-905	OX_CA	107	$19,658	$17,484	$1,692	$2	$6	$0	$1	$6	$305	$161
Account908	OX_908	108	$7,742	$7,482	$217	$0	$0	$0	$0	$0	$28	$14
Account909	OX_909	109	$309	$298	$9	$0	$0	$0	$0	$0	$1	$1
Account910	OX_910	110	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M Accounts 908-910	OX_CS	111	$8,550	$7,780	$726	$0	$0	$0	$0	$0	$29	$15
Accounts 901-910	X_CACS	112	$31,019	$27,980	$2,497	$3	$6	$0	$1	$6	$344	$182
Total O&M less Purchased Gas	OMXPP	113	$144,391	$104,672	$28,708	$58	$206	$1	$16	$88	$6,417	$4,226
Total O&M less Purchased Gas, Payroll, & Pension	OMXPPPP	114	$86,740	$63,472	$16,900	$32	$116	$0	$9	$50	$3,708	$2,453
Base Taxable Income	EBT	115	$76,663	$34,526	$39,390	($48)	$13	$4	($0)	$496	$2,468	($187)
Salaries & Wages Accounts 870-880	SALWAGDO	116	$14,096	$10,265	$2,786	$5	$20	$0	$1	$9	$607	$403
Salaries & Wages Accounts 887-894	SALWAGDM	117	$11,234	$6,408	$3,141	$9	$32	$0	$2	$11	$981	$648
Salaries & Wages Accounts 902-905	SALWAGCA	118	$6,188	$5,459	$542	$1	$2	$0	$0	$2	$119	$63

PECO Energy Company
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Salaries & Wages Accounts 908-910	SALWAGCS	119	$226	$219	$6	$0	$0	$0	$0	$0	$1	$0
Salaries & Wages Excluding Admin & Gen	SALWAGXAG	120	$34,505	$24,309	$7,226	$16	$55	$0	$4	$22	$1,731	$1,143
Total Salaries and Wages Expense	SALWAGES	121	$42,209	$29,737	$8,839	$19	$67	$0	$5	$26	$2,117	$1,398
Base Rate Sales Revenue	SALESREV	122	$361,576	$233,489	$100,579	$75	$475	$5	$35	$690	$16,719	$9,509
Residential	SREVRES	123	$233,489	$233,489	$0	$0	$0	$0	$0	$0	$0	$0
Small Commercial and Industrilal	SREVCI	124	$100,579		$100,579							
Large High Load Factor	SREVLHLF	125	$75			$75						
Motor Vehicle - Firm	SREVMVF	126	$475				$475					
Motor Vehicle - Interruptible	SREVMVI	127	$5					$5				
Interruptible Service	SREVIS	128	$35						$35			
Temperature Control	SREVTC	129	$690							$690		
Transportation Service - Firm	SREVTSF	130	$16,719								$16,719	
Transportation Service - Interruptible	SREVTSI	131	$9,509									$9,509
Claimed Rate Sales Revenue	CLAIMREV	132	$656,974	$471,938	$154,803	$445	$1,392	$13	$34	$948	$18,742	$8,659
Total Write-Offs	EXP_904	133	100.00%	90.40%	9.07%	0.00%	0.04%	0.00%	0.00%	0.06%	0.27%	0.16%
Total Write-Offs	EXP_904PPA	134	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Customer Advances for Construction	CUSTADV	135	$1,004	$832	$171	$0	$0	$0	$0	$0	$0	$0
Purchase of Receivables	REV_POR	136	$63,454	$45,995	$17,258	$0	$81	$1	$0	$118	$0	$0
487-Forfeited Discounts	REV_487	137	$838	$634	$163	$0	$1	$0	$0	$1	$25	$14
P&A Allocator	P&A	138	100.00%	55.00%	29.37%	0.09%	0.32%	0.00%	0.02%	0.11%	9.15%	5.95%
Average Day Throughput Excl. Direct Assignment			230,679	114,982	61,374	45	1,174	2	110	489	25,052	27,451
Design Day Demand.			914,416	550,000	293,826	1,416	1,174	0	0	0	68,000	0
Memo: Development of P&A Allocator												
Average Day Demand Pct.			100.00%	49.85%	26.61%	0.02%	0.51%	0.00%	0.05%	0.21%	10.86%	11.90%
Design Day Demand Pct.			100.00%	60.15%	32.13%	0.15%	0.13%	0.00%	0.00%	0.00%	7.44%	0.00%
P&A Allocator			100.00%	55.00%	29.37%	0.09%	0.32%	0.00%	0.02%	0.11%	9.15%	5.95%

PECO Energy Company
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(Allocation Percent)

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Capacity Production - Design Peak Day Sendout	DPKDAYP	1	100.00%	64.98%	34.71%	0.17%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Capacity Storage - Design Peak Day Sendout	DPKDAYS	2	100.00%	64.98%	34.71%	0.17%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Capacity Transmission - Design Peak Day Sendout	DTRAN	3	100.00%	64.98%	34.71%	0.17%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Capacity Distribution Mains (A&E) Excess Demand	DEXCESS	4	100.00%	61.12%	32.66%	0.19%	0.00%	0.00%	0.00%	0.00%	6.03%	0.00%
Capacity Distribution Mains (Direct Assign Plant)	DAMAINS	5	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	53.76%	46.24%
Capacity Distribution Mains (Direct Assign Acc Dep)	DAMAINSAD	6	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.51%	97.49%
Capacity Distribution Mains (Direct Assign Dep Exp)	DAMAINSDE	7	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	34.76%	65.24%
Capacity Distribution (Des Peak Day Sendout)	DESDAY	8	100.00%	64.98%	34.71%	0.17%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Capacity Distribution M&R (Direct Assign Plant)	DAMR	9	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	55.28%	44.72%
Capacity Distribution M&R (Direct Assign Acc Dep)	DAMRAD	10	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.15%	97.85%
Capacity Distribution M&R (Direct Assign Dep Exp)	DAMRDE	11	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	36.17%	63.83%
Capacity Avg Daily Del excl Direct	DAVGDD	12	100.00%	49.85%	26.61%	0.02%	0.51%	0.00%	0.05%	0.21%	10.86%	11.90%
Annual Gas Deliveries - Thruput (Mcf)	ETHRUPUT	13	100.00%	46.18%	24.65%	0.02%	0.47%	0.00%	0.04%	0.20%	12.54%	15.90%
Annual Gas Deliveries - Firm	ETHRUPUTF	14	100.00%	55.07%	29.39%	0.02%	0.56%	0.00%	0.00%	0.00%	14.95%	0.00%
Annual Gas Deliveries - Transportation Only	ETHRUPUTT	15	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	44.09%	55.91%
Commodity Gas Storage	ESTORAGE	16	100.00%	66.86%	30.92%	0.02%	0.01%	0.00%	0.00%	0.00%	0.97%	1.23%
Annual Gas Cost (PGC)	EGAS	17	100.00%	74.83%	24.31%	0.03%	0.44%	0.00%	0.00%	0.37%	0.00%	0.00%
Commodity - Balancing Service Charge (BSC)	EBSC	18	100.00%	64.57%	34.47%	0.03%	0.65%	0.01%	0.00%	0.27%	0.00%	0.00%
380-Services	CSERVICE	19	100.00%	86.38%	13.18%	0.00%	0.00%	0.00%	0.00%	0.01%	0.27%	0.14%
381-Meters (Avg Cost per meter)	CMETERS	20	100.00%	69.85%	25.64%	0.00%	0.09%	0.00%	0.00%	0.14%	2.35%	1.92%
381-Meters Direct Assignment	CMETERSDA	21	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
382-Meters Installations Direct Assignment	CMETINSTDA	22	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
Customer Deposits	CUSTDEP	23	100.00%	34.68%	63.06%	0.00%	0.02%	0.00%	0.00%	0.04%	1.44%	0.75%
Customer Deposits Interest	CUSTDEPINT	24	100.00%	61.53%	37.14%	0.00%	0.01%	0.00%	0.00%	0.03%	0.85%	0.44%
879-Customer Installation Expense	CUSTINSTALL	25	100.00%	91.62%	8.24%	0.00%	0.00%	0.00%	0.00%	0.01%	0.09%	0.04%
902-Meter Reading Expense	CMETRDG	26	100.00%	91.62%	8.24%	0.00%	0.00%	0.00%	0.00%	0.01%	0.09%	0.04%
903-Customer Records and Collections	CUSTREC	27	100.00%	88.05%	8.79%	0.02%	0.03%	0.00%	0.01%	0.03%	2.02%	1.06%
905-Miscellaneous Customer Accounts	CUSTCAM	28	100.00%	91.62%	8.24%	0.00%	0.00%	0.00%	0.00%	0.01%	0.09%	0.04%
908-Customer Assistance	CUSTASST	29	100.00%	96.64%	2.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.36%	0.19%
908-Customer Assistance - Direct Assignment	CUSTASSTDA	30	100.00%	0.00%	99.89%	0.00%	0.03%	0.00%	0.00%	0.07%	0.00%	0.00%
909-Informational and Instructional Advertising	CUSTADVT	31	100.00%	96.45%	2.90%	0.00%	0.00%	0.00%	0.00%	0.00%	0.32%	0.32%
910-Miscellaneous Customer Service	CUSTCSM	32	100.00%	96.64%	2.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.36%	0.19%
916-Miscellaneous Sales Expense	CUSTSALES	33	100.00%	96.64%	2.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.36%	0.19%
Number of Bills	CUSTBILLS	34	100.00%	91.62%	8.24%	0.00%	0.00%	0.00%	0.00%	0.01%	0.09%	0.04%
Number of Customers (Average Annual)	CUST	35	100.00%	91.62%	8.24%	0.00%	0.00%	0.00%	0.00%	0.01%	0.09%	0.04%
INTERNALLY DEVELOPED ALLOCATION FACTORS		36										
Intangible Plant	INTPLT	37	100.00%	66.55%	23.57%	0.05%	0.18%	0.00%	0.01%	0.07%	5.73%	3.83%
Production Plant	PRODPLT	38	100.00%	64.98%	34.71%	0.17%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Storage Plant	STORPLT	39	100.00%	66.86%	30.92%	0.02%	0.01%	0.00%	0.00%	0.00%	0.97%	1.23%
Transmission Plant in Service	TRANPLT	40	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Distribution Plant in Service	DISTPLT	41	100.00%	66.50%	23.39%	0.05%	0.19%	0.00%	0.01%	0.08%	5.86%	3.91%
General Plant in Service	GENLPLT	42	100.00%	70.45%	20.94%	0.05%	0.16%	0.00%	0.01%	0.06%	5.02%	3.31%
Total Gas Plant In Service	TOTPLT	43	100.00%	66.55%	23.57%	0.05%	0.18%	0.00%	0.01%	0.07%	5.73%	3.83%
Distribution Plant Excl Asset Retirement	DISTPLTXAR	44	100.00%	66.50%	23.39%	0.05%	0.19%	0.00%	0.01%	0.08%	5.86%	3.91%
Total Transmission and Distribution Plant	TDPLT	45	100.00%	66.50%	23.39%	0.05%	0.19%	0.00%	0.01%	0.08%	5.86%	3.91%

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Total Prod, Stor, Trans, Dist & Gen Plant	PSTDGPLT	46	100.00%	66.55%	23.57%	0.05%	0.18%	0.00%	0.01%	0.07%	5.73%	3.83%
Total Distribution and General Plant	DGPLT	47	100.00%	66.55%	23.37%	0.05%	0.19%	0.00%	0.01%	0.08%	5.85%	3.91%
Rate Base	RATEBASE	48	100.00%	66.79%	23.19%	0.05%	0.18%	0.00%	0.01%	0.07%	5.92%	3.78%
Distribution Plant in Service - Capacity Related	DDISTPLT	49	100.00%	54.19%	28.94%	0.09%	0.31%	0.00%	0.02%	0.10%	9.81%	6.53%
Account 374	PLT_374	50	100.00%	54.19%	28.94%	0.09%	0.31%	0.00%	0.02%	0.10%	9.81%	6.53%
Account 375	PLT_375	51	100.00%	54.19%	28.94%	0.09%	0.31%	0.00%	0.02%	0.10%	9.81%	6.53%
Account 376-General	PLT_376G	52	100.00%	55.00%	29.37%	0.09%	0.32%	0.00%	0.02%	0.11%	9.15%	5.95%
Account 376-General Average	PLT_376GA	53	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Account 376-DA	PLT_376DA	54	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	53.76%	46.24%
Account 376	PLT_376	55	100.00%	54.52%	29.12%	0.09%	0.32%	0.00%	0.02%	0.11%	9.53%	6.30%
Account 378	PLT_378	56	100.00%	54.52%	29.12%	0.09%	0.32%	0.00%	0.02%	0.11%	9.53%	6.30%
Account 379-City Gate	PLT_379CG	57	100.00%	54.52%	29.12%	0.09%	0.32%	0.00%	0.02%	0.11%	9.53%	6.30%
Account 379-Joint	PLT_379DA	58	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	55.28%	44.72%
Account 379	PLT_379	59	100.00%	46.48%	24.82%	0.07%	0.27%	0.00%	0.02%	0.09%	16.28%	11.97%
Account 380	PLT_380	60	100.00%	86.38%	13.18%	0.00%	0.00%	0.00%	0.00%	0.01%	0.27%	0.14%
Account 381	PLT_381	61	100.00%	69.75%	25.60%	0.00%	0.09%	0.00%	0.00%	0.14%	2.49%	1.92%
Account 382	PLT_382	62	100.00%	69.63%	25.56%	0.00%	0.09%	0.00%	0.00%	0.14%	2.65%	1.91%
Account 387	PLT_387	63	100.00%	66.50%	23.39%	0.05%	0.19%	0.00%	0.01%	0.08%	5.86%	3.91%
Account 388-Asset Retirement Costs for Distribution	PLT_388	64	100.00%	66.50%	23.39%	0.05%	0.19%	0.00%	0.01%	0.08%	5.86%	3.91%
Accounts 376, 378 & 379 - Mains & M&R	PLT_376379	65	100.00%	54.19%	28.94%	0.09%	0.31%	0.00%	0.02%	0.10%	9.81%	6.53%
Accounts 376 & 380 - Mains & Services	PLT_376380	66	100.00%	66.80%	22.98%	0.05%	0.20%	0.00%	0.01%	0.07%	5.96%	3.93%
Accounts 380 & 381 - Services & Meters	PLT_380381	67	100.00%	84.24%	14.78%	0.00%	0.02%	0.00%	0.00%	0.03%	0.56%	0.37%
Accounts 374 & 375 - Land & Structures	PLT_374375	68	100.00%	54.19%	28.94%	0.09%	0.31%	0.00%	0.02%	0.10%	9.81%	6.53%
Accounts 381 through 385	PLT_3815	69	100.00%	69.68%	25.58%	0.00%	0.09%	0.00%	0.00%	0.14%	2.58%	1.91%
Accounts 378, 379, & 387	PLT_378387	70	100.00%	48.80%	25.81%	0.08%	0.28%	0.00%	0.02%	0.09%	14.47%	10.46%
Residential	DPLTRES	71	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Small Commercial and Industrilal	DPLTCI	72	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Large High Load Factor	DPLTLHLF	73	100.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Motor Vehicle - Firm	DPLTMVF	74	100.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Motor Vehicle - Interruptible	DPLTMVI	75	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
Interruptible Service	DPLTIS	76	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%
Temperature Control	DPLTTC	77	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%
Transportation Service - Firm	DPLTTSF	78	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
Transportation Service - Interruptible	DPLTTSI	79	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Account 717	OX_717	80	100.00%	64.98%	34.71%	0.17%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Account 741	MX_741	81	100.00%	64.98%	34.71%	0.17%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Account 743	MX_743	82	100.00%	64.98%	34.71%	0.17%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Manufactured Gas Production Operation Expense	OX_PRODM	83	100.00%	64.98%	34.71%	0.17%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Manufactured Gas Production Maintenance Expense	MX_PRODM	84	100.00%	64.98%	34.71%	0.17%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Other Production Operation Expense	OX_PRODO	85	100.00%	73.70%	25.44%	0.03%	0.47%	0.00%	0.00%	0.36%	0.00%	0.00%
Storage Operation Expense	OX_STOR	86	100.00%	66.86%	30.92%	0.02%	0.01%	0.00%	0.00%	0.00%	0.97%	1.23%
Storage Maintenance Expense	MX_STOR	87	100.00%	66.86%	30.92%	0.02%	0.01%	0.00%	0.00%	0.00%	0.97%	1.23%
Transmission Operation Expense	OX_TRAN	88	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transmission Maintenance Expense	MX_TRAN	89	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transmission Salaries & Wages Accounts 511-567	SALWAGTO	90	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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Transmission Salaries & Wages Accounts 569-574	SALWAGTM	91	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Account 874	OX_874	92	100.00%	66.80%	22.98%	0.05%	0.20%	0.00%	0.01%	0.07%	5.96%	3.93%
Account 875	OX_875	93	100.00%	54.52%	29.12%	0.09%	0.32%	0.00%	0.02%	0.11%	9.53%	6.30%
Account 878	OX_878	94	100.00%	69.68%	25.58%	0.00%	0.09%	0.00%	0.00%	0.14%	2.58%	1.91%
Account 879	OX_879	95	100.00%	91.62%	8.24%	0.00%	0.00%	0.00%	0.00%	0.01%	0.09%	0.04%
Account 880	OX_880	96	100.00%	66.50%	23.39%	0.05%	0.19%	0.00%	0.01%	0.08%	5.86%	3.91%
Account 887	MX_887	97	100.00%	54.52%	29.12%	0.09%	0.32%	0.00%	0.02%	0.11%	9.53%	6.30%
Account 889	MX_889	98	100.00%	54.52%	29.12%	0.09%	0.32%	0.00%	0.02%	0.11%	9.53%	6.30%
Account 892	MX_892	99	100.00%	86.38%	13.18%	0.00%	0.00%	0.00%	0.00%	0.01%	0.27%	0.14%
Account 893	MX_893	100	100.00%	69.68%	25.58%	0.00%	0.09%	0.00%	0.00%	0.14%	2.58%	1.91%
Account 894	MX_894	101	100.00%	66.50%	23.39%	0.05%	0.19%	0.00%	0.01%	0.08%	5.86%	3.91%
O&M Accounts 874-880	OX_DIST	102	100.00%	69.81%	21.84%	0.04%	0.16%	0.00%	0.01%	0.07%	4.83%	3.23%
O&M Accounts 887-894	MX_DIST	103	100.00%	71.27%	21.25%	0.04%	0.14%	0.00%	0.01%	0.07%	4.34%	2.88%
Account 902	OX_902	104	100.00%	91.62%	8.24%	0.00%	0.00%	0.00%	0.00%	0.01%	0.09%	0.04%
Account 903	OX_903	105	100.00%	88.05%	8.79%	0.02%	0.03%	0.00%	0.01%	0.03%	2.02%	1.06%
Account 904	OX_904	106	100.00%	90.40%	9.07%	0.00%	0.04%	0.00%	0.00%	0.06%	0.27%	0.16%
O&M Accounts 902-905	OX_CA	107	100.00%	88.94%	8.61%	0.01%	0.03%	0.00%	0.01%	0.03%	1.55%	0.82%
Account908	OX_908	108	100.00%	96.64%	2.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.36%	0.19%
Account909	OX_909	109	100.00%	96.45%	2.90%	0.00%	0.00%	0.00%	0.00%	0.00%	0.32%	0.32%
Account910	OX_910	110	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
O&M Accounts 908-910	OX_CS	111	100.00%	90.99%	8.49%	0.00%	0.00%	0.00%	0.00%	0.01%	0.33%	0.18%
Accounts 901-910	X_CACS	112	100.00%	90.20%	8.05%	0.01%	0.02%	0.00%	0.00%	0.02%	1.11%	0.59%
Total O&M less Purchased Gas	OMXPP	113	100.00%	72.49%	19.88%	0.04%	0.14%	0.00%	0.01%	0.06%	4.44%	2.93%
Total O&M less Purchased Gas, Payroll, & Pension	OMXPPPP	114	100.00%	73.17%	19.48%	0.04%	0.13%	0.00%	0.01%	0.06%	4.27%	2.83%
Base Taxable Income	EBT	115	100.00%	45.04%	51.38%	-0.06%	0.02%	0.00%	0.00%	0.65%	3.22%	-0.24%
Salaries & Wages Accounts 870-880	SALWAGDO	116	100.00%	72.82%	19.76%	0.04%	0.14%	0.00%	0.01%	0.06%	4.31%	2.86%
Salaries & Wages Accounts 887-894	SALWAGDM	117	100.00%	57.05%	27.96%	0.08%	0.29%	0.00%	0.02%	0.10%	8.73%	5.77%
Salaries & Wages Accounts 902-905	SALWAGCA	118	100.00%	88.21%	8.76%	0.02%	0.03%	0.00%	0.01%	0.03%	1.92%	1.02%
Salaries & Wages Accounts 908-910	SALWAGCS	119	100.00%	96.64%	2.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.36%	0.19%
Salaries & Wages Excluding Admin & Gen	SALWAGXAG	120	100.00%	70.45%	20.94%	0.05%	0.16%	0.00%	0.01%	0.06%	5.02%	3.31%
Total Salaries and Wages Expense	SALWAGES	121	100.00%	70.45%	20.94%	0.05%	0.16%	0.00%	0.01%	0.06%	5.02%	3.31%
Base Rate Sales Revenue	SALESREV	122	100.00%	64.58%	27.82%	0.02%	0.13%	0.00%	0.01%	0.19%	4.62%	2.63%
Residential	SREVRES	123	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Small Commercial and Industrilal	SREVCI	124	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Large High Load Factor	SREVLHLF	125	100.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Motor Vehicle - Firm	SREVMVF	126	100.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Motor Vehicle - Interruptible	SREVMVI	127	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
Interruptible Service	SREVIS	128	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Temperature Control	SREVTC	129	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%
Transportation Service - Firm	SREVTSF	130	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
Transportation Service - Interruptible	SREVTSI	131	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Claimed Rate Sales Revenue	CLAIMREV	132	100.00%	71.84%	23.56%	0.07%	0.21%	0.00%	0.01%	0.14%	2.85%	1.32%
Total Write-Offs	EXP_904	133	100.00%	90.40%	9.07%	0.00%	0.04%	0.00%	0.00%	0.06%	0.27%	0.16%
Total Write-Offs	EXP_904PPA	134	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Customer Advances for Construction	CUSTADV	135	100.00%	82.93%	17.07%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

PECO Energy Company
Peak & Average Gas Class Cost of Service Study
(Allocation Percent)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
Purchase of Receivables	REV_POR	136	100.00%	72.49%	27.20%	0.00%	0.13%	0.00%	0.00%	0.19%	0.00%	0.00%
487-Forfeited Discounts	REV_487	137	100.00%	75.65%	19.46%	0.00%	0.09%	0.00%	0.00%	0.13%	2.97%	1.69%
P&A Allocator	P&A	138	100.00%	55.00%	29.37%	0.09%	0.32%	0.00%	0.02%	0.11%	9.15%	5.95%
Average Day Throughput Excl. Direct Assignment			100.00%	49.85%	26.61%	0.02%	0.51%	0.00%	0.05%	0.21%	10.86%	11.90%
Design Day Demand.			100.00%	60.15%	32.13%	0.15%	0.13%	0.00%	0.00%	0.00%	7.44%	0.00%
Memo: Development of P&A Allocator												
Average Day Demand Pct.			100.00%	49.85%	26.61%	0.02%	0.51%	0.00%	0.05%	0.21%	10.86%	11.90%
Design Day Demand Pct.			100.00%	60.15%	32.13%	0.15%	0.13%	0.00%	0.00%	0.00%	7.44%	0.00%
P&A Allocator			100.00%	55.00%	29.37%	0.09%	0.32%	0.00%	0.02%	0.11%	9.15%	5.95%

PECO ENERGY COMPANY
OCA Alternative "Business As Usual" Class Revenue Allocation

Rate Schedule		P&A @ Current Rates ROR	P&A @ Current Rates Indexed ROR	Current Distribution Revenue 2/	Required Increase @ 7.70% ROR	Total Requested Increase	Step 1 Percent of System Average Increase	Step 1 Increase Amount	Step 2 Increase	Total Increase Before GPC & MFC Reduction	GPC Reduction 6/	MFC Reduction 6/	Net Increase Amount	Net Increase Percent
GR	Resid.	4.93%	86%	$233,528,109	$64,230,291		--	--	$61,439,532 5/	$61,439,532	($693,000)	($800,000)	$59,946,532	25.67%
GC	Gen. Svc.	8.75%	153%	$100,578,711	($8,474,341)		0%	$0		$0	($370,000)	($66,000)	($436,000)	-0.43%
OL	Outdoor Light	8.75% 1/	153% 1/	$423	$0 1/		0%	$0		$0			$0	0.00%
L	Lg. High LF	0.17%	3%	$75,475	$129,979		200%	$28,687		$28,687			$28,687	38.01%
MV-F	MV Firm	3.50%	61%	$474,506	$269,597		150%	$135,266		$135,266	($7,000)		$128,266	27.03%
MV-I	MV Inter.	25.04%	437%	$5,022	($3,162)		0%	$0		$0			$0	0.00%
IS	Interruptible	3.24%	56%	$34,964	$21,281		150%	$9,967		$9,967			$9,967	28.51%
TCS	Temp. Control	25.21%	440%	$689,833	($443,177)		0%	$0		$0			$0	0.00%
TS-F	Transp. Firm	4.56%	79%	$16,719,224	$6,468,796		--	--	$4,398,705 5/	$4,398,705			$4,398,705	26.31%
TS-I	Transp. Inter.	3.13%	55%	$9,508,783	$6,017,339		150%	$2,710,632		$2,710,632			$2,710,632	28.51%
Total Rate Revenue		5.73%	100%	$361,615,052	$68,216,603 4/	$68,722,789 4/		$2,884,552	$65,838,238	$68,722,789	($1,070,000)	($866,000)	$66,786,789	18.47%
Other Revenue				$1,528,291 3/	$88,491 3/	$88,491				$ 88,491			$88,491	5.79%
Total Company				$363,143,343	$68,305,094	$68,811,280				$ 68,811,280	($1,070,000)	($866,000)	$66,875,280	18.42%

1/ Outdoor Lighting is included within the GC class per response to OCA-I-4.
2/ Per Exhibits JAB-1 and JAB-4.
3/ Per Witness Ding's corrected CCOSS provided in response to OSBA-I-2.
4/ The total required increase in PECO's CCOSS does not match the total requested increase in Exhibit JAB-1.
5/ Equal percentage of remaining required increase.
6/ Per Exhibit JAB-1.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018929
	:	
PECO Energy Company – Gas Division	:	

VERIFICATION

I, Glenn A. Watkins, hereby state that the facts set forth in my Direct Testimony, OCA Statement 4, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: December 22, 2020
*300680

Signature: ______________________
Glenn A. Watkins

Consultant Address: Technical Associates, Inc.
6377 Mattawan Trail
P.O. Box 1690
Mechanicsville, VA 23116

OCA Statement No. 5

R-2020-3018929
2/17/21 JK

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

	:	
Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018929
	:	
PECO Energy Company –Gas Division	:	
	:	

Direct Testimony of
Roger D. Colton

On Behalf of:
Office of Consumer Advocate
Statement No. 5

December 22, 2020

Table of Contents

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, MA.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a principal in the firm of Fisher Sheehan & Colton, Public Finance and General Economics of Belmont, Massachusetts. In that capacity, I provide technical assistance to a variety of federal and state agencies, consumer organizations and public utilities on rate and customer service issues involving water/sewer, natural gas and electric utilities.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Office of Consumer Advocate.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I work primarily on low-income utility issues. This involves regulatory work on rate and customer service issues, as well as research into low-income usage, payment patterns, and affordability programs. At present, I am working on various projects in the states of New Hampshire, Maryland, Pennsylvania, Ohio, Michigan, Tennessee, Missouri, Colorado and Washington. My clients include state agencies (e.g., Pennsylvania Office of Consumer Advocate, Maryland Office of People's Counsel, Illinois Office of Attorney General), federal agencies (e.g., the U.S. Department of Health and Human Services), community-based organizations (e.g., National Housing Trust, Natural Resources Defense Council, Advocacy Centre Tenants Ontario), and private utilities (e.g., Unitil Corporation d/b/a Fitchburg Gas and Electric Company, Entergy Services, Xcel Energy d/b/a Public Service of Colorado). In addition to state-specific and utility-specific work, I engage in national work throughout the United States. For example, in 2011, I worked with the U.S. Department of Health and Human Services (the federal LIHEAP office) to advance the review and utilization of the Home Energy Insecurity Scale as an outcomes measurement tool for the federal Low-Income Home Energy Assistance Program ("LIHEAP"). In 2007, I was part of a team that performed a multi-sponsor public/private national study of low-income energy assistance programs. This year, I completed a study of water affordability in twelve U.S. cities for the London-based newspaper, The Guardian. This Fall, I prepared comments for a set of national consumer stakeholders (e.g., National Consumer Law Center, National Housing Trust, National Community Action Foundation) to submit to the U.S. Environmental Protection Agency regarding water affordability. A brief description of my professional background is provided in Appendix A.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. After receiving my undergraduate degree in 1975 (Iowa State University), I obtained further training in both law and economics. I received my law degree in 1981 (University of Florida). I received my Master's Degree (regulatory economics) from the MacGregor School in 1993.

Q. HAVE YOU EVER PUBLISHED ON PUBLIC UTILITY REGULATORY ISSUES?

A. Yes. I have published three books and more than 80 articles in scholarly and trade journals, primarily on low-income utility and housing issues. I have published an equal number of technical reports for various clients on energy, water, telecommunications and other associated low-income utility issues.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS OR OTHER UTILITY COMMISSIONS?

A. Yes. I have testified before the Pennsylvania Public Utility Commission ("PUC" or "Commission") on roughly 130 occasions regarding utility issues affecting low-income customers and customer service, and provided testimony before municipal utility regulatory agencies in Pennsylvania in an additional 20 instances. I have also testified in judicial and regulatory proceedings in more than 40 states and various Canadian provinces on a wide range of utility regulatory issues. A list of the states in which I have testified is listed in Appendix A.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR DIRECT TESTIMONY.

A. The purpose of my Direct Testimony is as follows.

- First, I examine the impacts of COVID-19 on utility customers, including both low-income and non-low-income customers, and on their ability-to-pay home utility bills and the reasonableness of a PECO Gas response thereto;
- Second, I examine the disproportionate harms that the proposed PECO Gas residential customer charge will impose on low-income customers of PECO Gas, as well as the relationship between income and natural gas consumption;

- Third, I examine multiple of PECO Gas performance metrics with respect to customer service and collections to assess whether there is a basis to conclude that PECO Gas engages in superior or exemplary management; and
- Fourth. I will examine the reasonableness of PECO Gas' proposed Fraud/Theft Investigation Charge.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Based on the data and discussion presented below, I recommend as follows:

1. That the recommendations of OCA witness Scott Rubin be adopted as to the appropriate regulatory response of the PUC to the requested PECO Gas rate increase in light of COVID-19.
2. That the proposed residential COVID-19 emergency relief program, as set forth in Schedule RDC-1 be adopted;
3. That the recommendations of OCA witness Glenn Watkins be adopted with respect to the PECO Gas proposed residential customer charge; and
4. That the recommendation of OCA witness Kevin O'Donnell be adopted, when he recommends that the PECO Gas requested 25 basis point adder for claims of "superior management" be denied.

Part 1. The Impact of COVID-19 on the Ability-to-Pay of Utility Customers.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I consider the impact of the COVID-19 pandemic on utility customers. In responding to the COVID-19 pandemic, PECO Gas should take into account the extent to which the health pandemic results in an economic crisis that adversely affects its customers. The immediate health emergency today facing the United States and PECO Gas also results in serious economic consequences.

A. The Disproportionate COVID-19 Impact to Low- and Moderate-Wage Workers.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. While the COVID-19 pandemic is obviously a critical public health crisis to the general population, it presents a ***particular*** health and economic crisis to the working poor. In this section of my testimony, I document those disproportionate impacts.

Q. HAVE YOU CONSIDERED THE DISPROPORTIONATE IMPACTS OF JOB LOSS AND INCOME REDUCTION TO THE WORKING POOR?

A. Yes. My discussion below focuses on the disproportionate COVID-19 impacts on lower-income employment. There is substantial research that explains the disproportionate adverse impact on low-wage workers. As of mid-March, more than 90 percent of the jobs lost were in low-wage industries, particularly in the accommodations and food services industries.[1] The loss of income, however, is not limited exclusively to the loss of

[1] Boushey and Park (April 2020). The coronavirus recession and economic inequality, at 13, Washington Center for Equitable Growth (available at https://equitablegrowth.org/the-coronavirus-recession-and-economic-inequality-a-roadmap-to-recovery-and-long-term-structural-change/, November 11, 2020), citing U.S. Bureau of Labor Statistics, "Current Employment Statistics Highlights (2020), available at www.bls.gov/web/empsit/ceshighlights.pdf (last accessed December 3, 2020).

employment. As the Urban Institute reports, based on its Health Reform Monitoring Survey (HRMS), conducted between March 25 and April 10, 2020, the health pandemic also results in a reduction in work hours even if jobs remain:

> Though the rise in unemployment insurance claims suggests the unemployment rate has soared over the past month, the official rate will likely understate the negative effects of the pandemic on families, because it will not account for reductions in work hours or work-related income (e.g., reduced business income) that are not connected to job losses. . .[W]e find that 41.5 percent of nonelderly adults reported that the coronavirus outbreak has had one or more of the following effects on their work or the work of someone in their family: losing or being laid off from a job (17.1 percent), being furloughed or having work hours reduced (28.8 percent), or losing earnings or income from a job or business (27.8 percent).[2]

According to the Urban Institute, "[t]he finding that about 4 in 10 adults were in families that lost work or work-related income is consistent with results from recent surveys and polls conducted by the Henry J. Kaiser Family Foundation (March 25–30), Pew Research Center (April 7–12), and Monmouth University Polling Institute (April 3–7)."[3] The Urban Institute's research, supported by the Robert Woods Johnson Foundation, reported further that:

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[2] Karpman et a. (April 2020). The COVID-19 Pandemic is Straining Families' Abilities to Afford Basic Needs, at 5, Urban Institute Health Policy Center: Washington D.C., available at https://www.urban.org/research/publication/covid-19-pandemic-straining-families-abilities-afford-basic-needs (last accessed December 3, 2020).

[3] Ashley Kirzinger, Audrey Kearney, Liz Hamel, and Mollyann Brodie, "KFF Health Tracking Poll – Early April 2020: The Impact of Coronavirus on Life in America," Henry J. Kaiser Family Foundation, April 2, 2020, https://www.kff.org/health-reform/report/kff-health-tracking-poll-early-april-2020/; Kim Parker, Juliana Menasce Horowitz, and Anna Brown, "About Half of Lower-Income Americans Report Household Job or Wage Loss Due to COVID-19," Pew Research Center, April 21, 2020, https://www.pewsocialtrends.org/2020/04/21/about-half-of-lower-income-americans-report-household-job-or-wage-loss-due-to-COVID-19/; "COVID-19 Impact on Daily Life Heightens," Monmouth University Polling Institute, April 13, 2020, https://www.monmouth.edu/polling-institute/reports/monmouthpoll_us_041320/. (last accessed December 3, 2020).

> About half of adults in families with incomes at or below poverty (51.1 percent) or between 100 and 250 percent of FPL (49.0 percent) reported that their families lost jobs, work hours, or work-related incomes because of the coronavirus outbreak […]. In contrast, just under one-third (32.2 percent) of adults in families with incomes at or above 400 percent of FPL reported job or income losses because of the outbreak.[4]

These numbers are consistent throughout research performed nationwide. The Pew Research Center, one of the nation's most respected research centers, *also* reported that:

> lower-income adults are more likely than middle- and upper-income adults to say they've experienced significant job disruption due to the coronavirus outbreak. About half of lower-income adults (52%) say they or someone in their household has lost a job or taken a cut in pay due to the outbreak. This compares with 42% of middle-income and 32% of upper-income adults.[5]

The Pew data is set forth in the Table below.

Table 1. More than four-in-ten adults say they or someone in their household has lost a job or taken a pay cut due to COVID-19 (Pew Research Center)

	Been laid off / lost job	Had to take cut in pay	Net either / both
Upper income	18%	26%	32%
Middle income	26%	32%	42%
Lower income	39%	41%	52%

Q. WHY IS THE ECONOMIC DISRUPTION GREATER FOR LOW-WAGE WORKERS?

A. One reason why low wage workers are so adversely affected is because they are far less likely to report being able to work from home than the highest-income group of workers

[4] Id., at 6.

[5] Parker, Horowitz and Brown (April 21, 2020). About Half of Lower-Income Americans Report Household Job or Wage Loss Due to COVID-19," at 7, Pew Research Center: Washington D.C. , available at https://www.pewsocialtrends.org/2020/04/21/about-half-of-lower-income-americans-report-household-job-or-wage-loss-due-to-covid-19/ (last accessed December 3, 2020).

(17.1% versus 54.6%).[6] Just under one-third of American workers stated that they could work from home - including those workers who were simply bringing their work home with them - according to the American Time Use Survey.[7] Even fewer workers—just 12%—actually did work from home at least once per month.[8] These numbers are far lower for those in the bottom quartile of workers: only 9% could work from home, and just 1% worked from home at least once per month.[9] Most workers do not have access to a flexible workplace that would permit them to work an agreed-upon portion of their schedule at home, but those in the bottom 10% of income are the least likely while the highest-paid workers are the most likely.

Loss of income arises, too, when the families of low-wage workers fall ill. Low-wage workers tend not to have paid leave, including paid sick leave, personal leave, or paid "vacation" time. Accordingly, when household members become ill, requiring caretakers to take time off, these households permanently lose income. Fewer than one-third of low-wage workers have access to paid leave at their place of work, as compared to 94% of those in the top 10% of income.

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[6] Urban Institute, at 7.

[7] Table 1. Workers Who Could Work at Home, Did Work at Home, and Were Paid for Work at Home, by Selected Characteristics, Averages for the Period 2017-2018. U.S. Bureau of Labor Statistics, U.S. Bureau of Labor Statistics, 24 Sept. 2019, available at: www.bls.gov/news.release/flex2.t01.htm. (last accessed December 3, 2020).

[8] Guyot, Katherine, and Isabel V. Sawhill. "Telecommuting Will Likely Continue Long after the Pandemic." Brookings Institution, 6 Apr. 2020,available at: www.brookings.edu/blog/up-front/2020/04/06/telecommuting-will-likely-continue-long-after-the-pandemic/ (last accessed December 3, 2020).

[9] Id.

This disproportionate exposure to becoming ill is not theoretical. It is well-established that those low-wage workers who do remain employed will likely be employed in high-risk jobs. Common occupations for low-wage workers include cashiers and retail salespersons, people who re-stock retail establishments and/or prepare orders for fulfillment, and others who have constant, close contact with the public (e.g., delivery people, drivers/truck drivers). Following the Bureau of Labor Statistics' National Compensation Survey, service occupations include health care support, protective service, food preparation, building and grounds, cleaning and maintenance, and personal care. These workers are at risk of exposure to the coronavirus due to the inherent person-to-person nature of their work, which also makes it nearly impossible for these service occupation employees to work from home. In 2019, just 1% of all workers in service occupations had access to a flexible workplace, which would allow them to complete their work at home or at an approved alternative location. As the vice-chair of the Congressional Joint Economic Committee noted, "without options for paid sick leave and working from home, workers in the service occupations are at risk of contracting and spreading the virus from sick co-workers and customers, and of bringing it home to their families."[10]

Q. ARE THERE ECONOMIC IMPACTS IN ADDITION TO THE LOSS OF JOBS OR REDUCTION IN INCOME?

[10] Congressman Don Beyer, Vice Chair, Congressional Joint Economic Committee, The Impact of Corona Virus on the Working Poor and People of Color, at 4, available at: https://www.jec.senate.gov/public/_cache/files/bbaf9c9f-1a8c-45b3-816c-1415a2c1ffee/coronavirus-race-and-class-jec-final.pdf (last accessed December 3, 2020).

A. Yes. In addition to those actually becoming ill, the people who are wage workers. Most low-wage workers lack paid benefits such as health insurance. According to the U.S. Bureau of Labor Statistics, only 24% of workers in the private sector in the lowest 10% wage category had access to employer-sponsored health care plans in 2019.[11] Moreover, COVID-19 is making this situation worse. In March-April 2020, 9.2 million workers may have lost their employer-provided health insurance as a result of COVID-19, with those losses highly concentrated in the accommodation and food services industry.[12]

B. Impact of Economic Disruption on Ability to Pay Utility Bills.

Q. HOW DO THESE ECONOMIC IMPACTS AFFECT PECO GAS CUSTOMERS IN THEIR CAPACITY AS UTILITY CUSTOMERS?

A. It is possible to quantify the extent to which the income loss discussed above, whether due to lost jobs or reduced incomes, affects a household's ability-to-pay utility bills. The Urban Institute, previously cited, examined the growth in "material hardships" attributable to COVID-19. The Urban Institute:

> define[s] [a material hardship as] being unable to pay their rent or mortgage, being unable to pay utility bills, reporting house-hold food insecurity, or having someone in the family go without medical care because of the cost. As noted, 31.0 percent of all adults and 42.0 percent of adults in families experiencing a loss of work or work-related income because of the pandemic reported that their families faced at least one type of hardship in the month

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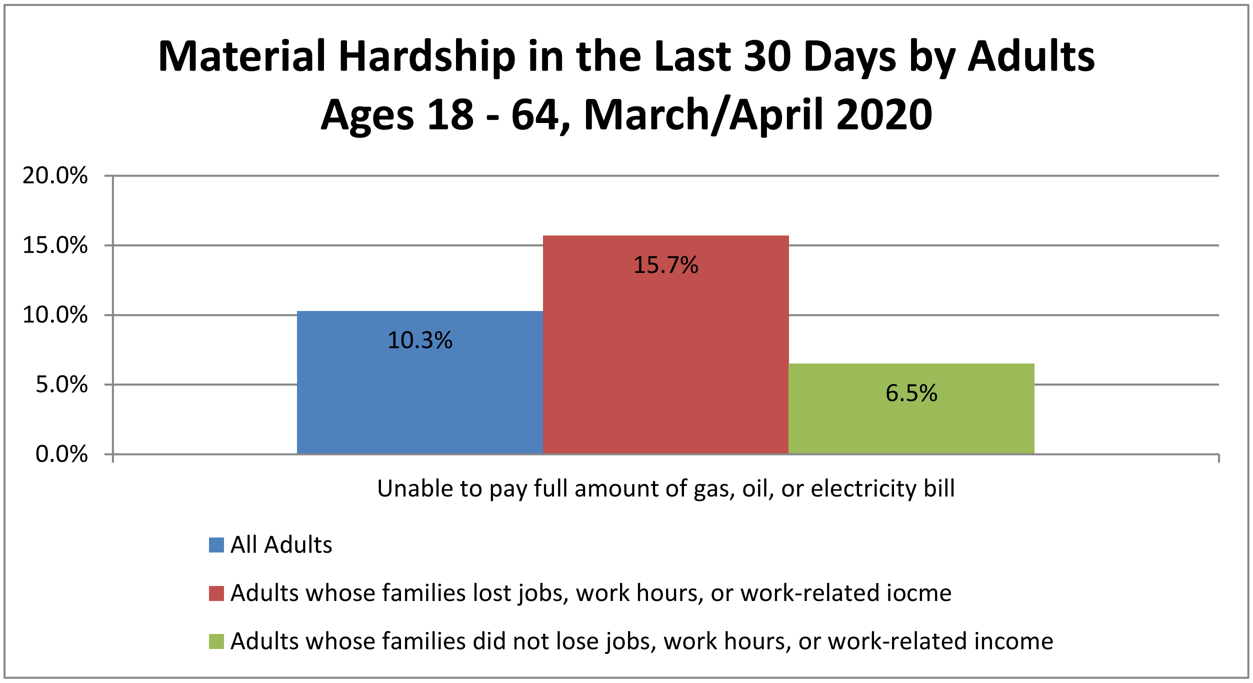
[11] Employee Benefits in the United States, March 2019.U.S. Bureau of Labor Statistics, National Compensation Survey (NCS) 2019. available at: https://www.bls.gov/ncs/ebs/benefits/2019/employee-benefits-in-the-united-states-march-2019.pdf (last accessed December 3, 2020).

[12] Economic Policy Institute (April 16, 2020) (updated May 14, 2020). 9.2 million workers likely lost their employer-provided health insurance in the past four weeks, available at: https://www.epi.org/blog/9-2-million-workers-likely-lost-their-employer-provided-health-insurance-in-the-past-four-weeks/ (last accessed December 3, 2020).

> before they completed the survey. This included 8.1 percent of adults whose households did not pay the full amount of the rent or mortgage or were late with such a payment; 10.3 percent who did not pay gas, oil, or electricity bills; 21.9 percent reporting household food insecurity; and 15.6 percent with unmet needs for medical care. These estimates likely understate housing hardship, because about three-quarters of respondents completed the survey before rent was due on April 1.
>
> Among adults in families that lost work or work-related income, the shares reporting each type of hardship were significantly higher than such shares among adults in families that have not lost work or income. Nearly one in three (29.6 percent) adults in families that lost work or income reported food insecurity for their household in the last 30 days, nearly twice the share of adults in families not losing work or income who reported food insecurity (16.3 percent). Food insecurity was the most commonly reported hardship among all adults and those in families that lost work or income, and that food insecurity occurred during a period when people were being encouraged to stock up on food and limit trips to grocery stores.
>
> * * *
>
> The share of adults reporting hardship falls sharply as family income increases: whereas more than two-thirds (68.6 percent) of adults with family incomes at or below poverty reported one or more hardships, 10.7 percent of adults with incomes at or above 400 percent of FPL reported hardship.[13]

Not surprisingly, the burden of material hardships attributable to COVID-19 fell hardest on adults whose families lost jobs, work hours, or work-related income.

[13] Urban Institute, supra, at 10, 11.



As I noted above, there is a substantial overlap between those adults and households who lost jobs or income and those households with lower income with which to begin. The Urban Institute further found the burden of increased material hardship fell overwhelmingly on the poor. With unpaid utility bills in particular, while 27.5% of consumers with income less than 100% of Poverty were unable to pay home energy bills, only 8.2% of families with income between 250% and 400% of Poverty, and only 2.6% of families with income greater than 400% of Poverty, were unable to do so.[14]

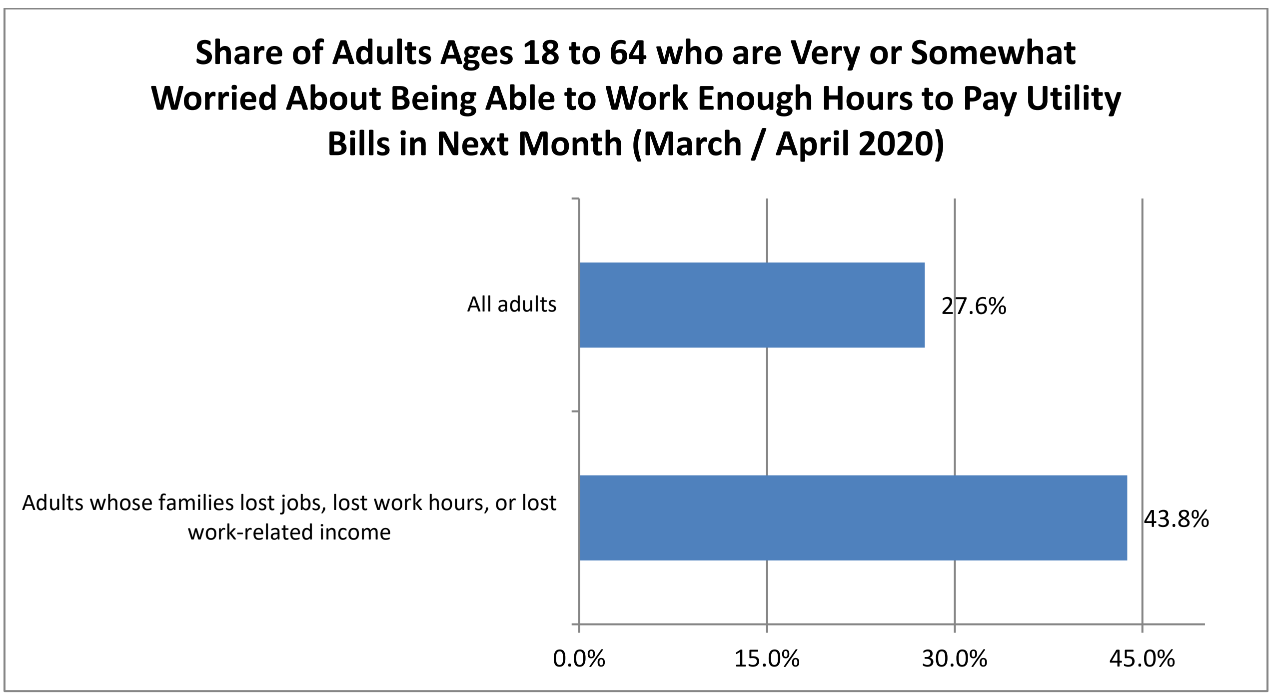
Table 2. Material Hardship in the Last 30 Day Reported by Adults Age 18 to 64, By Family Income (Federal Poverty Level), March/April 2020

	Family Income			
	At or below 100% FPL	100 – 250% FPL	250 – 400% FPL	400% FPL or more
Unable to pay full amount of gas, oil or electricity bills	27.5%	13.9%	8.2%	2.6%

[14] The Poverty Level ranges reported here are those used in the report, not those which I have developed.

Q. ARE THERE COVID-19 IMPACTS BEYOND ACTUALLY MISSING A UTILITY BILL PAYMENT?

A. Yes. My discussion above presented data on the percentage of households who have failed to make utility bill payments. In addition, that same study documented the percentage of households who *worry* about their ability to work sufficient hours to be able to pay their utility bills each month. "Among adults in families that lost work or income," the Urban Institute found, over half (50.6 percent) were "*worried about* being able to pay debts, and many also worried about being able to pay. . . utility bills (43.8 percent). . .*in the next month*. These data suggest that in addition to those who have already had problems paying their bills, a large share of adults in families losing work or income were *newly* at risk of falling behind on the rent, mortgage, or utility bills. . ."[15] (emphasis added).



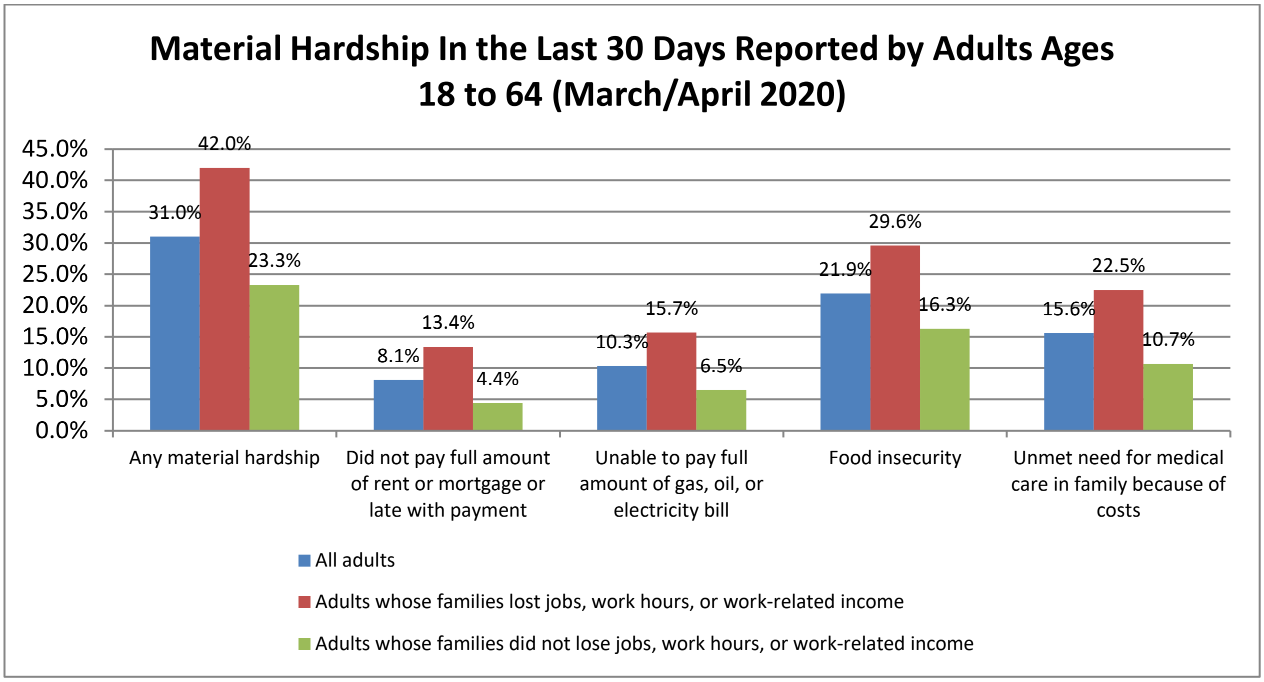
[15] Urban Institute, supra, at 14.

Q. WHY IS THE PRESENCE OF BEING "WORRIED ABOUT" BEING ABLE TO MAKE PAYMENTS OF SIGNIFICANCE?

A. As can be seen, customers are aware of their payment obligations, and have sufficient intent to pay those obligations that they are "very or somewhat worried about" whether their household will have sufficient resources to make those payments. If people had the ability to pay, but simply did not intend to do so, they would not report being "worried about" having sufficient resources.

Q. HAVE CUSTOMERS CONTINUED TO MAKE GOOD FAITH EFFORTS TO PAY THEIR UTILITY BILLS DURING THE COVID-19 PANDEMIC?

A. Yes. The problems identified above arise despite the fact that customers choose to pay their utility bills during the pandemic, where possible, even if that payment is at the cost of ***not*** paying for food and/or shelter. The Urban Institute study, previously cited, illuminates the choices that households are being forced to make in today's COVID-19 pandemic world. The Chart immediately below shows those choices that people are making. As documented above, one-in-six (15.7%) of adults are unable to pay their home energy bills when they lost jobs, or suffered lost work hours or reductions in work-related income. That number, however, does not tell the full story. Nearly one-in-three (29.6%) of adults who lost jobs/income experienced food insecurity, while nearly one-in-four (22.5%) were unable to received medical care for someone in their family because of cost. There are, in other words, people who are choosing to pay their utility bills ***before*** they are buying food or obtaining health care in the midst of the worst public health crisis in more than 100 years.



Q. PLEASE EXPLAIN WHY THIS DATA FROM MARCH/APRIL 2020 IS STILL RELEVANT AT THIS TIME?

A. Simply because the data above was generated in the "early" months of the pandemic does not mean that the information (and lessons to be learned from the information) is now out-dated. Table 3 below shows, for Pennsylvania specifically, that neither the loss of employment income nor the expected loss of employment income, has reversed from the first week of the Census Pulse Survey to the most recent (Week 20) of the Pulse Survey. Moreover, the disparity in employment outcomes (and expected outcomes) has remained the same (and perhaps even become somewhat more exacerbated) between Week 1 and Week 20. The information I present above helps to explain what is going on, and why. The data and conclusions have certainly not become out-of-date.

Table 3. Employment. Experienced and Expected Loss of Employment Income, by Select Characteristics: Pennsylvania								
	Week 1 (April 23 – May 5)				Week 20 (November 25 – December 7)			
	Experienced loss of employment income since March 13, 2020 (for self or household member)		Expected loss of employment income in next 4-weeks (for self or household member)		Experienced loss of employment income since March 13, 2020 (for self or household member)		Expected loss of employment income in next 4-weeks (for self or household member)	
	Yes	No	Yes	No	Yes	No	Yes	No
Less than $25,000	52.5%	46.6%	50.7%	49.3%	63.3%	36.7%	42.9%	57.1%
$25,000 - $34,999	39.7%	60.3%	32.9%	67.1%	65.8%	34.2%	41.7%	57.5%
$35,000 - $49,999	46.7%	53.3%	42.6%	57.4%	59.5%	40.5%	36.8%	63.2%
$50,000 - $74,999	49.2%	50.8%	35.3%	64.5%	50.4%	49.6%	34.3%	65.7%
$75,000 - $99,999	49.2%	50.8%	36.2%	63.8%	50.1%	49.9%	23.4%	76.6%
$100,000 - $149,999	42.4%	57.6%	33.1%	66.9%	42.7%	57.3%	16.3%	83.7%
$150,000 - $199,999	42.1%	57.9%	28.6%	71.4%	36.9%	63.1%	17.7%	82.3%
$200,000 and above	35.4%	63.5%	28.0%	70.9%	31.6%	68.4%	13.2%	86.8%

C. The Long-term Economic Impacts of COVID-19.

Q. WHAT ARE YOUR LONG-TERM EXPECTATIONS ABOUT THE ECONOMIC CONSEQUENCES OF COVID-19 FOR THE LOW-INCOME POPULATION?

A. The COVID-19 pandemic imposes two distinctly different crises to the customers of PECO Gas. On the one hand, there is the public health crisis. On the other hand, however, there is the associated economic crisis. The economic impacts of the COVID-19 pandemic may persist for years to come and any PECO Gas response to this economic crisis should take this long-term nature into account.

It should be recognized that the economic crisis which is associated with the COVID-19 pandemic will not be resolved when there is a publicly available vaccine. The economic impacts will result in a long-term economic disruption for customers of PECO Gas.

Q. WHAT IS THE FIRST LONG-TERM ECONOMIC IMPACT OF COVID-19?

A. The resolution of the COVID-19 health crisis will not end the economic crisis facing low-income customers. One analysis by the Center on Poverty and Social Policy at Columbia University projects the longer-term effects of the COVID-19 economic crisis.[16] The Columbia University research center forecasted poverty rates under three alternative unemployment scenarios: 10 percent; 20 percent, and 30 percent. The Center assumed that such high levels of unemployment lasted for two different scenarios: (1) one quarter, and (2) one year. The Center uses the "Supplemental Poverty Measure" (SPM), which differs somewhat from the Federal Poverty Level.[17]

[16] Parolin and Wimer (April 16, 2020). Forecasting Estimates of Poverty During the COVID-19 Crisis: Poverty Rates in the United States Could Reach Highest Levels in Over 50 Year, available at https://www.povertycenter.columbia.edu/news-internal/coronavirus-forecasting-poverty-estimates, (last accessed December 3, 2020.)

[17] In simplified terms, the Census Bureau explains that the Supplemental Poverty Measure, "takes into account family resources and expenses not included in the official measure as well as geographic variation. First, it adds the value of in-kind benefits that are available to buy basic goods to cash income. In-kind benefits include nutritional assistance, subsidized housing and home energy assistance. Then it subtracts necessary expenses for critical goods and services not included in the thresholds from resources. Necessary expenses that are subtracted include income taxes, Social Security payroll taxes, child care and other work-related expenses, child support payments to another household, and contributions toward the cost of medical care and health insurance premiums." What is the Supplemental Poverty Measure and How Does it Differ from the Official Measure, available at, https://www.census.gov/newsroom/blogs/random-samplings/2018/09/what_is_the_suppleme.html (last accessed December 16, 2020).

The Center began with a projected SPM of 12.4% in February 2020, the lowest recorded poverty rate since 2001. Its projected poverty rates after the onset of the COVID-19 pandemic, however:

> point to higher poverty rates today. If unemployment rates rise to 10 percent, comparable to the unemployment rate during the peak of the Great Recession, we project that poverty rates would rise to 15 percent. This is approximately the same rate of poverty observed in 2010. (note omitted). If unemployment rates rise to 20 percent, we project a poverty rate of 16.9 percent—the highest rate of poverty since 1967, the first year for which reliable estimates of poverty are available. Finally, if annual unemployment rates rise to 30 percent, we project a poverty rate of 18.9 percent. This would mark the highest rate of poverty over the past 50 years.[18]

Two observations are appropriate. On the one hand, unemployment in Pennsylvania did not reach the 20% or 30% levels represented by the two upper ranges in this analysis. Accordingly, the 20% and 30% unemployment scenarios are set aside for this discussion. Even with this lowest scenario, the Center stated: "under an optimistic scenario, in which employment rates return to pre-crisis levels during the summer of 2020, annual SPM poverty rates are still projected to reach levels comparable to the Great Recession."[19] On the other hand, employment rates, as we now know, did ***not*** return to the pre-crisis levels in the summer of 2020.

This increase in Poverty is important for purposes of this proceeding because it is not likely to be resolved in the short-term. The long-term danger arises because when people lose their jobs, the long-lasting effects are not just on their income. Unemployment has a

[18] Id., at 4 - 5.

[19] Forecasting Estimates of Poverty, supra note 16, at 9.

negative effect on workers' skills and education, even on their health—people who are unemployed become sicker. Human capital, the skills of the overall workforce, decays over time because of the loss of jobs. Moreover, with the COVID-19 pandemic, it is generally recognized that many of the jobs that have been lost will never come back. One recent research paper from the Becker Freidman Institute for Economics at the University of Chicago estimates that between 32% and 42% of COVID-19 induced layoffs will be permanent.[20]

Q. IS THERE A SECOND ECONOMIC IMPACT THAT SHOULD BE CONSIDERED IN THIS PROCEEDING?

A. Yes. Nearly 40% of U.S. households, including nearly all low-wage workers, fall into a category referred to as "liquid asset poor." "Liquid asset poverty," which is interchangeable with "liquid asset poor," is a term-of-art that refers to households who lack sufficient liquid assets to replace income in order to subsist at the Poverty Level for three months in the absence of income. According to a Pew Research Center report, "only about one-in-four (23%) [lower income adults] say they have rainy day funds set aside that would cover their expenses for three months in case of an emergency such as job loss, sickness or an economic downturn, compared with 48% of middle-income and 75% of upper-income adults." [21]

[20] Davis et al. (June 2020). COVID-19 is also a Reallocation Shock, available at: https://bfi.uchicago.edu/wp-content/uploads/BFI_WP_202059.pdf (last accessed December 3, 2020).

[21] Parker, Horowitz and Brown (April 21, 2020). About Half of Lower-Income Americans Report Household Job or Wage Loss Due to COVID-19, Pew Research Center: Washington D.C. Available at https://www.pewsocialtrends.org/2020/04/21/about-half-of-lower-income-americans-report-household-job-or-wage-loss-due-to-covid-19/ (last accessed November 17, 2020).

As the COVID-19 economic crisis moves into a more prolonged period, the impact of the lack of savings will become increasingly pronounced, with low-income customers, in particular, unable to draw on resources to pay day-to-day bills. A Pew Research Center study published in late September reported that half of all adults who said they had lost a job due to the coronavirus were still unemployed "roughly six months since the coronavirus outbreak sent shockwaves through the U.S. economy."[22] Moreover, according to Pew, even those who did not lose their job, but who nonetheless lost income, were still in bad economic shape. Pew reported:

> Of those who say they personally lost a job, half say they are still unemployed, a third have returned to their old job and 15% are in a different job than before. Lower-income adults who were laid off due to the coronavirus are less likely to be working now than middle- and upper-income adults who lost their jobs (43% vs. 58%). Adults ages 18 to 29 are less likely than those 30 to 64 to have returned to their previous job.
>
> Even if they didn't lose a job, many workers have had to reduce their hours or take a pay cut due to the economic fallout from the pandemic. About a third of all adults (32%) say this has happened to them or someone in their household, with 21% saying this happened to them personally. Most workers who've experienced this (60%) are earning less now than they were before the coronavirus outbreak, while 34% say they are earning the same now as they were before the outbreak and only 6% say they are earning more.[23]

Pew continues, however, to note that "lower-income adults who lost their jobs because of the coronavirus outbreak are more likely than those with middle or upper incomes to

[22] Kim Parker, Rachel Minkin and Jesse Bennett (September 24, 2020). Economic Fallout from COVID-19 Continues to Hit Lower-Income Americans the Hardest, at 1, Pew Research Center (Washington D.C.). (hereafter COVID-19 Economic Fallout), https://www.pewsocialtrends.org/2020/09/24/economic-fallout-from-covid-19-continues-to-hit-lower-income-americans-the-hardest/ (last accessed November 17, 2020).

[23] Id., at 5, 7, 8.

remain unemployed. Some 56% of workers with lower incomes who lost their job because of the coronavirus outbreak say they are currently unemployed, compared with 42% of middle- and upper-income adults."[24]

This long-term job loss is significant because one of the long-term economic implications of the job loss and other loss of income is just now becoming more evident. Economic difficulties, particularly for lower-income households, will prevail for an extended period of time not only because these households have been forced to use their emergency savings, but also because they have been forced to incur substantial debt during the COVID-19 pandemic to date. According to Pew:

> Those affected by coronavirus related job loss or pay cuts are much more likely than those who have not experienced these setbacks to have drawn on additional resources. Fully 46% of adults who say they or someone in their household have either been laid off or taken a pay cut as a result of the coronavirus outbreak say they have used money from a savings or retirement account to pay their bills, compared with 17% of those who have not experienced these setbacks.[25]

As the COVID-19 economic crisis continues, these households are now running out of savings to draw down. A Bankrate survey found that "of households with income below $50,000, about 44% say their savings has dropped, compared with 27% of those earning above that amount. . ." Bankrate reported that 27% of Americans say that they now have emergency savings that would last less than three months; 20% say their emergency

[24] Id., at 7 – 8.

[25] Covid-19 Economic Fallout, supra note 22, at 12.

savings would last from three to five months; and 25% say their emergency savings would last six months.[26]

Q. HAVE YOU EXAMINED DATA SPECIFIC TO THE COMMONWEALTH OF PENNSYLVANIA?

A. Yes. The discussion below is based on the U.S. Census Bureau's "Household Pulse Survey." The Pulse Survey was designed to quickly and efficiently deploy data collected on how peoples' lives have been affected by the COVID-19 pandemic. According to the Census Bureau, data collection for the Household Pulse Survey began on April 23, 2020. The Census Bureau expected to collect data for 90 days, and to release data on a weekly basis. The Census Bureau began a "Phase II" of the Pulse Survey on September 9, 2020. The data discussed below is from Week 19 of the Pulse Survey, for the week of November 11 through November 23.[27]

Q. WHAT DO YOU KNOW ABOUT PENNSYLVANIA IN PARTICULAR?

A. The problems posed by consumers being forced to use credit and/or savings to pay household bills during the pandemic can be seen from data specific to Pennsylvania. According to the Census Bureau's Pulse Survey (Week 19: November 11 –November 23), these households have substantially greater difficulties in meeting their household needs. While 16.9% of Pennsylvania residents using credit, and 22.6% drawing down

[26] Survey: Nearly 3 times as many Americans say they have less emergency savings versus more since pandemic, available at https://www.bankrate.com/banking/savings/emergency-savings-survey-2020/ (last accessed November 17, 2020).

[27] Available at https://www.census.gov/data/tables/2020/demo/hhp/hhp19.html (last accessed December 10, 2020).

savings, find it “very difficult” to pay “usual household expenses,” only 6.2% using their pre-pandemic income sources do so. While 27.3% (money from savings or selling assets) to 29.8% (credit cards or loans) of Pennsylvania households find it “somewhat difficult” to pay their “usual household expenses,” only roughly one-third that number (12.4%) using their normal pre-pandemic incomes sources do so. In total, nearly half of Pennsylvania residents who have been forced to use credit (29.8% + 16.9% = 46.7%), and exactly half forced to draw down savings or sell assets (27.35% + 22.63% = 50.0%), find it “somewhat” or “very” difficult to pay their usual household expenses during the pandemic.

In contrast, only 15.7% to 24% using credit or savings find it “not at all difficult” to pay their usual household expenses, compared to 58.8% of those who can use their normal pre-pandemic income sources.

Table 4. Difficulty paying for usual household expenses during the coronavirus pandemic (Pennsylvania) (November 11 – November 23, 2020)				
HH Income	Not at all difficult	A little difficult	Somewhat difficult	Very difficult
Less than $25,000	18.1%	28.3%	28.3%	24.9%
$25,000 - $34,999	26.8%	23.7%	25.4%	24.1%
$35,000 - $49,999	27.0%	31.8%	14.4%	26.8%
$50,000 - $74,999	36.7%	22.9%	23.2%	17.2%
$75,000 - $99,999	51.1%	29.4%	11.1%	8.4%
$100,000 - $149,999	65.7%	19.0%	10.1%	5.1%
$150,000 - $199,999	77.0%	15.3%	3.1%	4.5%
$200,000 and above	81.3%	17.5%	1.2%	0.0%
Used in the last 7 days to meet spending needs[28]				
Regular income sources like those used before the pandemic	58.8%	22.6%	12.4%	6.2%
Credit cards or loans	24.0%	29.1%	29.8%	16.9%
Money from savings or selling assets	15.7%	34.3%	27.3%	22.6%

Q. WHAT DO YOU CONCLUDE?

A. The conclusion to be drawn from this data is that low-wage households are a long ways away from achieving any post-pandemic economic stability. Even should the public health crisis associated with COVID-19 end in the coming months, the associated economic crisis will continue. It is that economic crisis far more than the public health crisis that PECO Gas should address. It is the ongoing economic crisis that will adversely affect the ability-to-pay of PECO Gas customers.

Q. WHAT DO YOU RECOMMEND FIRST?

A. Based on the data and discussion above, I recommend that the proposed regulatory response offered through OCA witness Scott Rubin be adopted in this proceeding.

[28] Totals may not sum to 100% as the question allowed multiple responses to be marked.

Q. DO YOU HAVE AN ADDITIONAL RECOMMENDATION?

A. I recommend that PECO Gas adopt an Emergency COVID-19 Relief Program for residential customers. The structure of the Emergency Relief Program which I recommend is set forth in Schedule RDC-1 below. In summary, with the details set forth in Schedule RDC-1, the recommended Emergency Relief Program provides financial and collection relief to residential customers. The Company has already proposed a program for small business customers and I am recommending this program for residential customers as an additional measure. My program establishes a timeline at which point the proposed relief will come to an end. It provides for a forward-looking process upon the termination of the relief which is set forth. It provides for cost recovery through a deferral mechanism so as to not increase current rates until the full extent of this pandemic and its economic consequences is known.

Q. WHY DOES YOUR RECOMMENDED COVID-19 EMERGENCY RELIEF PROGRAM EXTEND BEYOND LOW-INCOME CUSTOMERS?

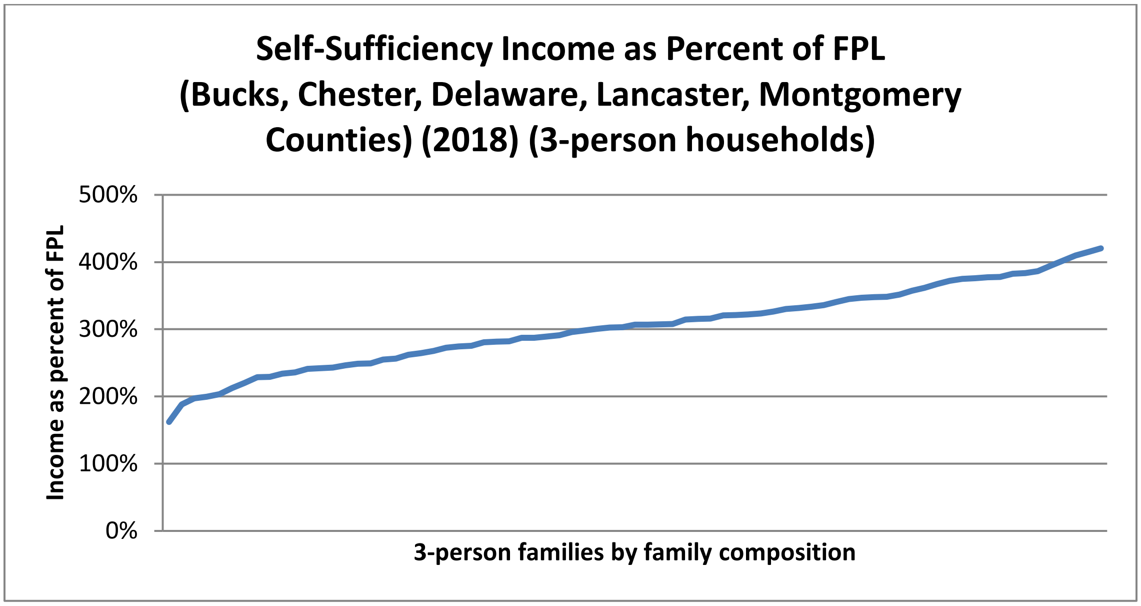
A. "Low-income" is a defined term in Pennsylvania, primarily defining that population of customers to whom certain customer service protections and universal service programs extend. As I discuss in detail above, however, the economic crisis facing PECO Gas customers is not limited to low-income customers. The research I cite above instead considers the impacts of COVID-19 on low-wage households.

It is not uncommon to consider the difference between households who are considered "poor" as per the PUC definition, and households who are insufficiently poor to be income-qualified for PECO Gas universal service programs, but who have insufficient resources to meet their day-to-day obligations (e.g., utility bill payments) during the pandemic. One way to identify these customers is by reference to Pennsylvania's self-sufficiency standard. I discuss the self-sufficiency standard in PECO Gas counties in more detail below.[29]

The data on Pennsylvania's self-sufficiency standard in the PECO Gas counties demonstrates that customers may not be "low-income" as per the PUC's definition, but may have insufficient household resources to respond to the economic crisis created by the COVID-19 pandemic. I consider the five counties which PECO Gas lists in its Tariff as comprising (in whole or part) its service territory (Bucks, Chester, Delaware, Lancaster, Montgomery counties). In the Figure below, I graph the self-sufficiency incomes, limited to three-person households, for these five PECO Gas counties. In this Figure, I order the self-sufficiency incomes from lowest to highest (left-to-right). As can be seen, the lowest self-sufficiency income for a 3-person household in the PECO Gas counties is $33,686 (Lancaster County: 1 adult, 2 teenagers) (162% of Poverty), while the higher self-sufficiency income for a 3-person household in the PECO Gas counties is $87,363 (Chester County: 1 adult; 2 infants) (420% of Poverty).

[29] See, Table 21, infra, and accompanying text.

The biggest portion of 3-person self-sufficiency incomes in the PECO Gas counties, however, fall between 200% of Poverty and 330% of Poverty (n=47 of 75). A significant number of 3-person self-sufficiency incomes in the PECO Gas counties fall between 200% and 300% of Poverty (n=31 of 75).



Since my point is not to associate specific 3-person self-sufficiency incomes with specific counties, but rather to present the range of such incomes in the PECO Gas service territory, the Chart above simply ranks self-sufficiency incomes from high-to-low, left-to-right.

Part 2. PECO Gas' Proposed Increase to its Residential Customer Charge.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGE INCREASE.

A. PECO Gas proposes to increase its residential customer charge from its current level of \$11.75 to \$16.00 per month. (PECO Gas St. 7, at 14). This represents a 36% increase in the residential customer charge standing alone (\$16.00 / \$11.75 = 1.362). When combined with other increases in rates proposed by PECO Gas, lower use customers receive a higher percentage increase in their bills. Overall, a customer bill at 3 MCF will increase by 12.7% under PECO's proposed rates, while a customer bill at 10 MCF will increase by 8.2%. A customer bill at 30 MCF will increase by 6.4%. (PECO Attachment III-E-11(a), page 1). As I will demonstrate below, low-income customers disproportionately fall into the lower usage ranges.

A. PECO's CAP Does Not Protect Low-Income Customers from Increased Fixed Charges.

Q. TO WHAT EXTENT WOULD PECO'S CAP PROTECT THE COMPANY'S LOW-INCOME POPULATION FROM THE DISPROPORTIONATE ADVERSE IMPACTS OF INCREASING THE CUSTOMER CHARGE?

A. The PECO Gas Customer Assistance Program (CAP) would protect low-income customers from any increase in rates, including the increased customer charge, if and to the extent that the program limits the PECO Gas bill to an affordable percentage of income. This protection, however, is limited. The PECO Gas CAP program protects a very small percentage of its low-income customer base from the harms of an increased customer charge. While the PECO Gas CAP serves roughly 5% of its total residential customer base, the percentage of population in the PECO Gas service territory with annual income less than 150% of Poverty Level is nearly 12%. Three-of-five low-income customers in the PECO Gas service territory, in other words, are not served by the Company's CAP and thus gain no protection against the increase in this unavoidable fixed charge.

Q. CAN YOU PUT THE DOLLAR IMPACT OF THE INCREASED CUSTOMER CHARGE, STANDING ALONE, ON PECO GAS LOW-INCOME CUSTOMERS INTO SOME CONTEXT?

A. Yes. In 2019, [30] PECO reported having 74,914 estimated low-income customers.[31] Using that number, PECO's proposed customer charge increase, standing alone (i.e., without taking into account any other aspect of the PECO Gas rate increase), will draw $3,812,614 a year out of the Company's low-income population ($4.25/month x 12 months x 74,914 = $3,812,614). As shown in the Table below, that is more than the total amount of LIHEAP received by PECO Gas customers in the past two years (program year 2019, program year 2020), and nearly as much LIHEAP as received by PECO Gas customers in program year 2018. (OCA-III-7)

Table 5. LIHEAP Cash Grants Received by PECO Gas Customers by Year (OCA-III-7)

Season	Date Range	Count	Dollars
2018	10/1/17 - 9/30/18	21,821	$3,932,016
2019	10/1/18 - 9/30/19	13,000	$3,352,426
2020	10/1/19 - 9/30/20	14,564	$3,709,858

One should keep in mind that the amount of LIHEAP benefits will not increase simply because PECO's rates (and thus bills) increase. Pennsylvania's allocation of federal LIHEAP dollars is set by a statutory formula. That allocation will remain constant even

[30] 2019 is the last year published by BCS. 2020 data was not used (as provided in response to OCA-III-4) because of a concern that COVID-19 might skew the numbers.

[31] PA PUC, Bureau of Consumer Services, Report on Universal Service Programs and Collection Performance, at 7 (annual) (available at: http://www.puc.state.pa.us/filing_resources/universal_service_reports.aspx) (last accessed December 3, 2020).

if the number of Pennsylvania (PECO) customers needing assistance increases, or even if the dollar amount of need for assistance increases.

Q. WHAT DO YOU CONCLUDE?

A. The PECO Gas proposed increase in its residential customer charge will have an adverse impact on low-income customers. Most of the PECO Gas low-income customers are not protected from rate increases, including this proposed 36% increase in the unavoidable part of the utility's rate structure, by the Company's CAP. While CAP is a critically important low-income program, it serves fewer than 2-of-5 of PECO's low-income customers. Moreover, the proposed increase in the customer charge –just the amount of the proposed increase, not the customer charge as a whole—will take more money out of the PECO Gas low-income population than those customers have been receiving in federal fuel assistance (LIHEAP). Merely because PECO Gas' rates are increasing, including the unavoidable fixed charge element of the PECO Gas rates does not mean that the amount of federal fuel assistance will increase. Increasing the customer charge will impose unavoidable fixed charges on PECO Gas' low-income customers with no offsetting increase in federal fuel assistance to help ensure that those bills can be paid. In short, the proposed increase in the PECO Gas customer charge, standing alone, will dilute the efficacy of federal fuel assistance (i.e., LIHEAP) benefits, along with generating increased utility costs on low-income households, in addition to the social consequences appurtenant thereto.

B. Harms to Low-Income from Increased Customer Charge.

Q. PLEASE SUMMARIZE HOW THE INCREASED CUSTOMER CHARGE WILL HARM LOW-INCOME CUSTOMERS.

A. Without limitation, I find that the PECO Gas proposal to increase its customer charge will harm low-income customers in each of the following ways (with each bullet below incorporating every other bullet):

- It will increase both the breadth and depth of arrears, each of which imposes additional utility costs on low-income households along with the social consequences appurtenant thereto.

- It will increase the incidence of service disconnections for nonpayment, along with the increased utility costs on low-income households in addition to the social consequences appurtenant thereto.

- It will increase the incidence of the threat of service disconnections for nonpayment, along with the increased utility costs and social consequences appurtenant thereto.

- It will decrease the ability of low-income customers to maintain deferred payment arrangements through which they can retire past-due balances outside of the participation in CAP.

- It will increase Home Energy Insecurity, along with the resulting utility costs on low-income households, in addition to the social consequences appurtenant thereto.[32]

Q. WHY IS IT SIGNIFICANT THAT PECO GAS UNDER-ENROLLS ITS CONFIRMED LOW-INCOME CUSTOMER POPULATION INTO ITS CAP PROGRAM?

[32] See, Colton, Measuring the Outcomes of Home Energy Assistance Programs through a Home Energy Insecurity Scale, which, by this reference thereto, is incorporated herein as if fully set forth, available at http://fsconline.com/05_FSCLibrary/lib2.html (last accessed December 14, 2020).

A. The under-enrollment of the PECO confirmed low-income population into CAP, as discussed above, is significant because the Company's confirmed low-income population has substantially greater payment difficulties than does the residential population as a whole. Table 6 sets forth the data from the BCS annual report on universal service programs and collections performance.

Table 6. Average Arrears[33] (PECO Gas)
(2015 – 2019)

	Residential	Confirmed Low-Income
2015	$463.98	$976.70
2016	$402.06	$828.50
2017	$389.10	$778.23
2018	$383.03	$792.98
2019	$456.57	$996.13

Table 6 shows that the confirmed low-income customers of PECO Gas are substantially more seriously in arrears than are residential customers generally. Indeed, the difference is even greater than shown. The "Residential" class has, as one sub-component, the "Confirmed Low-Income" customers. The higher numbers for the Confirmed Low-Income customers, in other words, will pull the Residential customer numbers upwards. If the comparison was between customers who are Confirmed Low-Income and those who are *not* Confirmed Low-Income, the differences would be even greater.

[33] BCS (annual). Universal Service Programs and Collections Performance. available at: http://www.puc.state.pa.us/filing_resources/universal_service_reports.aspx (last accessed December 4, 2020).

Table 7 below shows the ratio of the payment difficulties of Confirmed Low-Income customers to Residential customers generally as presented in the annual BCS report. The average arrearage for Confirmed Low-Income customers was from 100% to 118% higher than the average arrears for Residential customers.[34] As can be seen, when Confirmed Low-Income customers are in arrears they are also deeper in arrears than residential customers overall.

Table 7. Ratio Confirmed Low-Income (numerator) to Residential (denominator) Average Arrears of Accounts in Arrears (PECO Gas) (2015 – 2019)

	Average Arrears of Accounts in Arrears (Confirmed Low-Income / Residential)
2015	211%
2016	206%
2017	200%
2018	207%
2019	218%

In addition to being deeper in arrears, the breadth of arrearages for the low-income customers of PECO Gas is greater as well. The Table immediately below shows that up to 75% (0.098 / 0.056 = 1.75) more Confirmed Low-Income customers have been in arrears in the five most recent years for which BCS has reported data. In fact, the extent to which the percentage of Confirmed Low-Income customers is higher than the Residential percentage has increased each year 2015 through 2019 (the most recent year for which BCS has reported data).

[34] If the numbers were identical, the ratio would be 100%. A ratio of 200% thus means that the Confirmed Low-Income number was twice as high as the Residential number, or a 100% increase.

Table 8. Percent Accounts in Arrears[35] (PECO Gas) (2015 – 2019)		
	Residential	Confirmed Low-Income
2015	5.4%	8.3%
2016	5.3%	9.1%
2017	5.2%	9.0%
2018	5.6%	9.8%
2019	5.4%	9.2%

One impact of this greater depth of arrears (i.e., dollar amount of arrears) and breadth of arrears (i.e., percent of accounts in arrears) is that proportionately more low-income customers have their service terminated for nonpayment each year. As the Table below shows, in 2019, the percentage of PECO Gas Confirmed Low-Income customers experiencing a nonpayment disconnection was nearly four times higher than the percentage of residential customers experiencing a nonpayment disconnection. Of the PECO Gas Confirmed Low-Income customers, nearly one-in-five had their service terminated for nonpayment.

This is particularly disturbing given that those PECO Gas customers who are identified as "Confirmed Low-Income" tend to be the PECO Gas low-income customers who have been in contact with the utility to address their arrearage balances, or who have otherwise received some type of public assistance (such as LIHEAP) to help pay their PECO Gas bills.

[35] BCS (annual). Universal Service Programs and Collections Performance. available at: http://www.puc.state.pa.us/filing_resources/universal_service_reports.aspx (last accessed December 20, 2020).

Table 9. Termination Rate[36] (PECO Gas) (2015 – 2019)		
	Residential	Confirmed Low-Income
2015	4.8%	21.3%
2016	4.4%	16.8%
2017	4.1%	17.7%
2018	4.1%	19.4 %
2019	5.4%	19.0%

Q. WHAT IS THE SIGNIFICANCE OF THE PAYMENT DIFFICULTIES THAT YOU IDENTIFY ABOVE?

A. The data on payment difficulties that I discuss above is directly relevant to assessing the reasonableness of the PECO Gas proposal to increase its residential customer charge. What PECO Gas is doing is increasing the unavoidable fixed monthly customer charge, resulting in a disproportionately higher percentage bill increase, to those customers who can least afford to make their bill payments in the first instance. Not only does this place the continuation of service to these low-income customers in jeopardy, but this also causes PECO Gas to incur credit and collection costs that will, in turn, be passed on to all ratepayers in future rates.

[36] BCS (annual). Universal Service Programs and Collections Performance. available at: http://www.puc.state.pa.us/filing_resources/universal_service_reports.aspx (last accessed December 20, 2020).

C. Income and Usage.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I document that low-income customers, both disproportionately, and on average, are also low-use customers. In making this observation, I note the obvious: that my statement is *not* that *all* low-income customers are also low-use. My statement is that low-income customers are disproportionately, and on average, low-use. The proposed increase in the fixed monthly residential customer charge imposes a disproportionate increase in bills to these low-income, low-use customers.

Q. PLEASE EXPLAIN THE EXTENT TO WHICH PECO GAS HAS STUDIED THE RELATIONSHIP BETWEEN USAGE AND INCOME.

A. PECO Gas has not studied the relationship between natural gas consumption and income. When asked, PECO Gas responded that it "does not have any studies, evaluations or other written documents, prepared by or on behalf of PECO Gas, discussing the relationship between: (a) heating gas consumption and income; (b) non-heating gas consumption and income." (OCA-III-39).

Q. PLEASE EXPLAIN THE EXTENT TO WHICH PECO GAS HAS STUDIED THE RELATIONSHIP BETWEEN USAGE AND HOUSING CHARACTERISTICS.

A. PECO Gas has not studied the relationship between natural gas usage and housing. When asked for all studies performed within the past five years of the relationship between residential usage and housing type, as well as between residential usage and housing size (whether measured in terms of square feet, number of rooms, number of bedrooms or some other metric), PECO Gas replied that "PECO does not have any studies undertaken by, or on behalf of the Company, within the past five years, of residential usage by housing type or residential usage by housing size. . ." (OCA-III-35; see also, OCA-III-38 [no such studies within past ten years]). In fact, PECO has not developed any information on housing in its service territory, particularly as compared to other geographic areas. When asked for studies, PECO Gas responded that it "does not have any studies undertaken by or on behalf of the Company within the past five years which discusses (sic) the difference in housing structures (e.g., age, type, size) within the PECO Gas service territory and: (a) the City of Philadelphia; (b) the State of Pennsylvania." (OCA-III-36).

Q. HAVE YOU EXAMINED THE USAGE OF RESIDENTIAL PECO GAS CUSTOMERS AND LOW-INCOME PECO GAS CUSTOMERS?

A. Yes. PECO Gas provided average monthly consumption for residential customers and for confirmed low-income customers. According to PECO Gas, "The number of confirmed low-income customers were defined as those customers with verified financial statements within the last two years. These numbers include CAP customers who were verified within the last two years." (OCA-III-34). According to that Company data, somewhat fewer residential customers have lower usage during the heating season months (defined as November through March) than do confirmed low-income customers (5.1% residential have usage less than 10 CCF vs. 6.7% confirmed low-income have usage less than 10 CCF). Somewhat more residential customers have higher usage during the heating season than do confirmed low-income customers (85.9% residential customers have usage higher than 30 CCF vs. 82.6% confirmed low-income have usage higher than 30 CCF).

This finding is significant for reasons beyond the fact that PECO Gas reports a higher percentage of low-income customers with lower usage and a lower percentage of low-income customers with higher usage. While PECO reports nearly 430,000 gas heating customers for its residential customer base, it also reports an additional 65,000 gas non-heating customers. (OCA-III-3). More than 13% of its total residential customers, in other words, do not use natural gas for their primary heating service. In contrast, while PECO Gas does not explicitly limit its CAP to gas heating customers (OCA-III-1(k)), the percentage of income burdens imposed by PECO Gas effectively limit CAP participation to heating customers. The PECO Gas numbers cited above, in other words, show proportionately fewer low use residential customers, and proportionately more high use residential customers (as compared to confirmed low-income) even though the bulk of the confirmed low-income customers are CAP customers, who are exclusively higher use heating customers.

Q. PLEASE EXPLAIN YOUR CONCLUSION THAT PECO GAS CUSTOMERS ARE DISPROPORTIONATELY LOW-USE CUSTOMERS.

A. In the PECO Gas service territory, there is a relationship between the presence of low-income households and the housing attributes which the Department of Energy (DOE) has identified, through its Residential Energy Consumption Survey (RECS), as being associated with lower natural gas consumption.

Q. WHAT IS THE RELATIONSHIP BETWEEN RENTER STATUS AND NATURAL GAS CONSUMPTION?

A. The RECS reports that renters tend to use less natural gas than do homeowners, holding constant the type of housing unit occupied. The DOE data is set forth in Table 10 below. On a per-household basis, usage is higher for owner-occupied units. For single-family units, homeowner units use 94 MCF compared to 86 MCF for rented single-family units. For multi-family units, owner-occupied units consume 61 MCF compared to 53 MCF for renter-occupied multi-family units. The same difference exists when natural gas usage is measured on a million Btu basis.

Table 10. Household Site Fuel Consumption in the Northeast Region, Totals and Averages, British Thermal Units (Btu), Final (2009 RECS Table CE2.2)

Housing Unit Characteristics and Natural Gas Usage Indicators	Per Household (million Btu)	Per Household (thousand CF)
Ownership of Housing Unit[5]		
Owned	95.4	89
Single-Family	99.5	94
Multi-Family	75.8	61
Rented	55.9	58
Single-Family	76.3	86
Multi-Family	41.9	53

Q. IS THERE A RELATIONSHIP BETWEEN LOW-INCOME STATUS AND RENTER STATUS IN THE PECO GAS SERVICE TERRITORY?

A. Yes. Table 11 shows the data for the zip codes comprising the PECO Gas service territory.[37] Zip codes with low percentages of households with income less than 150% of Poverty Level also have low percentages of renter-occupied housing units. The Table shows that while 28 of the zip codes in the three lowest deciles of low-income status are also in the three lowest income deciles of percentage of housing units occupied by renters, only three of the zip codes in the three highest deciles of low-income status are also in the lower three deciles of renter-occupied units (yellow-shaded cells). At the same time, the Table shows that while 24 of the zip codes in the three ***highest*** deciles of low-income status are also in the three highest deciles of renter-occupied units, only six zip codes with a low penetration of low-income households also have a high penetration of renters (blue-shaded cells).

[37] One should remember that when I match Census Data to PECO Gas data, I am matching Zip Code Tabulation Areas (ZCTAs) to Zip Codes. ZCTAs are virtually, but not quite, identical to Zip Codes. ZCTAs are used by the U.S. Census Bureau, while Zip Codes are creatures of the U.S. Postal Service. According to the Census Bureau: "ZIP Code Tabulation Areas (ZCTAs) are generalized areal representations of United States Postal Service (USPS) ZIP Code service areas. The USPS ZIP Codes identify the individual post office or metropolitan area delivery station associated with mailing addresses. USPS ZIP Codes are not areal features but a collection of mail delivery routes." U.S. Census Bureau, Zip Code Tabulation Areas (ZVTAs), https://www.census.gov/programs-surveys/geography/guidance/geo-areas/zctas.html (last accessed November 16, 2020). In my testimony, the terms "ZCTA" and "zip code" are used interchangeably.

Table 11. Low-Income Zip Codes[38] by Deciles of Percentage of Renters in Zip Code											
No. of Zip Codes by decile (pct population below 150% FPL)	**Number of Zip Codes by Decile (percentage of renters)**										
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**Grand Total**
1	7	2	1	2						2	14
2	3	3	5	1	2		1				15
3	1	5	1		3	1		1	2	1	15
4	2	1		3	3	2	1	1	2		15
5	1		2	3	1	4	2	2			15
6		2	1	2	4	1	3	1	1		15
7		1	3			3	1	3	3	1	15
8			1	3	2	3	4		2		15
9		1				1	2	5	5	1	15
10			1	1			1	2		9	14
Grand Total	**14**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**14**	**148**

One would conclude from this data that natural gas usage in the low-income housing units in the PECO Gas service territory is lower than natural gas consumption in the non-low-income housing units.

Q. WHAT IS THE RELATIONSHIP BETWEEN THE SIZE OF A HOUSING UNIT AND NATURAL GAS CONSUMPTION?

A. The RECS reports that smaller housing units tend to use less natural gas than do larger housing units. The DOE data is set forth in Table 12 below. As can be seen, as housing units get bigger (in terms of square footage of space), natural gas usage becomes greater as well.

[38] Low-income status of a zip code is measured by the percentage of population with annual income at or below 150% of Federal Poverty Level. (ACS, 5YR, 2018, Table C17002).

Table 12. Household Site Fuel Consumption in the Northeast Region, Totals and Averages, British Thermal Units (Btu), Final (2009 RECS Table CE2.2)		
Housing Unit Characteristics and Natural Gas Usage Indicators	Per Household (million Btu)	Per Household (thousand CF)
Total Square Footage		
Fewer than 500	41.1	40
500 to 999	48.9	48
1,000 to 1,499	68.9	67
1,500 to 1,999	85.0	83
2,000 to 2,499	87.5	85
2,500 to 2,999	94.3	92
3,000 to 3,499	105.3	103
3,500 to 3,999	97.9	96
4,000 or More	125.5	122

Housing units with fewer than 500 square feet to 999 square feet have gas usage (in physical units of energy) of between 40 and 48 thousand cubic feet. In contrast, housing units with 3,000 or more square feet (with a slight down-tick at 3,500 to 3,999 square feet) have natural gas usage of 100 thousand cubic feet. Housing units with 2,000 to 3,000 square feet fall in the middle.

Q. IS THERE A RELATIONSHIP BETWEEN LOW-INCOME STATUS AND HOUSING UNIT SIZE IN THE PECO GAS SERVICE TERRITORY?

A. Yes. The Census Bureau does not directly report data on the size of housing units (in square feet). However, conclusions can be drawn about the size of a housing unit by looking at the number of rooms in the unit, as well as by looking at the number of bedrooms in a housing unit. A housing unit with more rooms is more likely to be "larger" while a housing unit with fewer rooms will be "smaller." Similarly, a housing unit with more bedrooms will be larger while a housing unit with fewer bedrooms will be smaller. The data is set forth in the Tables below.

As the Table immediately below shows, while 19 zip codes within the three highest deciles of low-income penetration also fall within the three highest deciles of penetrations of smaller housing units (i.e., fewer than three rooms), only 9 zip codes within the three deciles with the smallest percentages of low-income households (Deciles 1 – 3) fall within the three deciles with the highest penetration of smaller housing units (Deciles 8 – 10) (blue-shaded cells).

Table 13. Low-Income Zip Codes[39] by Percentage of Homeowner Units with <3 Rooms

No. of Zip Codes by decile (pct population below 150% FPL)	**Number of Zip Codes by Decile (percentage owner units with fewer than 3 rooms))**										**Grand Total**
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	
1	7	3	2	1					1		14
2	2		4	2	1	1	1		2	2	15
3	1	1	3	1	2	2	1		3	1	15
4		1	1	3	3	1	1	2	1	2	15
5	1		2	4	1	3	3	1			15
6	1	2	1	2	1	3	2	1	1	1	15
7					3	2	3		3	4	15
8		2		2	2	1	1	4	2	1	15
9	1	4				1	2	4	2	1	15
10	1	2	2		2	1	1	3		2	14
Grand Total	**14**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**14**	**148**

Even more compelling is the observation that while 23 zip codes with low penetrations of low-income population fall within the three lowest deciles of income with the lowest

[39] Low-income status of a zip code is measured by the percentage of population with annual income at or below 150% of Federal Poverty Level. (ACS, 5YR, 2018, Table C17002).

penetrations of smaller housing units, only twelve (12) zip codes with high percentages of low-income population fall within the three deciles with the lowest percentage of small housing units (yellow-shaded cells). Clearly, as the percentage of lower-income households increases in the PECO Gas service territory, so, too, does the percentage of smaller housing units increase.

The same observation can be made from the opposite perspective. As the percentage of low-income population increases in PECO Gas zip codes, the percentage of larger housing units (i.e., greater than 7 rooms) declines. The data is set forth in Table 14 below. This Table shows that while only three (3) zip codes with a high penetration of low-income population also have a high penetration of larger housing units (>7 rooms), 31 zip codes with low penetrations of low income population have a high penetration of larger housing units (blue-shaded cells). In contrast, while four (4) zip codes with a low percentage of low-income population have a low penetration of larger housing units, 30 zip codes with a high percentage of low-income population have a high percentage of larger housing units (yellow-shaded cells).

Table 14. Low-Income Zip Codes[40] by Percentage of Homeowner Units with >7 Rooms											
No. of Zip Codes by decile (pct population below 150% FPL)	**Number of Zip Codes by Decile (percentage owner units with more than 7 rooms))**										**Grand Total**
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	
1	3							1	2	8	14
2						3	2	2	5	3	15
3		1			1	1	2	5	5		15
4			1	2	3	3	4	2			15
5			1	2	3	4	2	2		1	15
6		1	1	2	4	2	1	1	2	1	15
7	1		5	3	3		2			1	15
8		3	3	3		2	2	1	1		15
9	3	4	4	2	1			1			15
10	7	6		1							14
Grand Total	**14**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**14**	**148**

Clearly, as the percentage of low-income population increases throughout the PECO Gas service territory, the percentage of larger housing units, with higher natural gas consumption, increases as well.

Q. WHAT IS THE RELATIONSHIP BETWEEN THE TYPE OF A HOUSING UNIT AND NATURAL GAS CONSUMPTION?

A. Yes. Table 15 shows that single-family homes, be they one-family attached dwellings or one-family detached dwellings, have distinctly greater natural gas usage than do multi-family homes (setting aside buildings with two to four units). While multi-family units in buildings with five or more units have natural gas usage of 41 MCF, single-family

[40] Low-income status of a zip code is measured by the percentage of population with annual income at or below 150% of Federal Poverty Level. (ACS, 5YR, 2018, Table C17002).

detached homes have gas consumption more than twice that high (97 MCF), while single-family attached homes have usage nearly twice that high (74 MCF).

Table 15. Household Site Fuel Consumption in the Northeast Region, Totals and Averages, British Thermal Units (Btu), Final (2009 RECS Table CE2.2)

Housing Unit Characteristics and Natural Gas Usage Indicators	Per Household (million Btu)	Per Household (thousand CF)
Housing Unit Type		
Single-Family	95.4	93
Single-Family Detached	99.5	97
Single-Family Attached	75.8	74
Multi-Family	55.9	55
Apartments in 2-4 Unit Buildings	76.3	74
Apartments in 5 or More Unit Buildings	41.9	41

Q. IS THERE A RELATIONSHIP BETWEEN LOW-INCOME STATUS AND THE TYPE OF HOUSING UNIT IN THE PECO GAS SERVICE TERRITORY?

A. Yes. The data is set forth in two different tables below. Immediately below, Table 16 shows the relationship between the presence of single-family homes in the PECO Gas service territory and the percentage of low-income population. The relationship in the PECO Gas service territory is what one might expect. While only four (4) zip codes with the highest penetrations of low-income population also have a high penetration of single-family homes, 27 zip codes in the PECO Gas service territory having the lowest percentage of low-income population have the highest penetrations of 1-family homes (blue-shaded cells). In contrast, while 19 of the zip codes in the PECO Gas service territory having a high percentage of low-income households fall within the zip codes with the lowest percentage of 1-family homes, only nine (9) of the zip codes with the lowest penetration of low-income population also represent zip codes with the lowest penetration of 1-family homes (yellow-shaded cells).

Table 16 Low-Income Zip Codes[41] by Percentage of Single-Family Homes

No. of Zip Codes by decile (pct population below 150% FPL)	Number of Zip Codes by Decile (percentage of occupied units 1-family homes) 1	2	3	4	5	6	7	8	9	10	Grand Total
1	1						2	1	2	8	14
2		3					2	4	5	1	15
3	3		2		1	2	1	3	1	2	15
4	1	2	2	2	1	3	1	1	2		15
5			1	5	3	2	2	1		1	15
6		1	1	3	3	2	1	2	2		15
7	3	1	4	1		2		2	2		15
8	1	1	2	3	3	2	2		1		15
9	2	2	2	1	4	1	2			1	15
10	3	5	1			1	2	1		1	14
Grand Total	**14**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**14**	**148**

The same relationship can be seen with multi-family housing in Table 17 below. As the percentage of low-income population declines in a PECO Gas zip code, so, too, does the percentage of multi-family buildings with ten or more units. While 28 zip codes with the lowest percentage of low-income population also have the lowest percentage of multi-family buildings with 10 or more units, only 20 zip codes with the highest penetration of low-income population fall within the four deciles of the lowest penetrations of buildings with 10 or more units (yellow-shaded cells). So, too, are there fewer zip codes with a higher percentage of low-income population and fewer multi-family buildings with 10 or more units. While 26 zip codes fall within the four highest deciles of the percentage of low-income population and high penetrations of buildings with 10 or more units, only 18

[41] Low-income status of a zip code is measured by the percentage of population with annual income at or below 150% of Federal Poverty Level. (ACS, 5YR, 2018, Table C17002).

zip codes fall within the lowest percentage of low-income population and the highest percentage of multi-family buildings with 10 or more units (blue-shaded cells).

Table 17. Low-Income Zip Codes[42] by Percentage of Buildings with 10+ Units

No. of Zip Codes by decile (pct population below 150% FPL)	Number of Zip Codes by Decile (percentage of occupied units multi-family homes with 10+ units)										Grand Total
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	
1	4	6	2			1		1			14
2	2	1	3	2	3	1			1	2	15
3		2	1	2	2	2	1		1	4	15
4	2			1	2	2	1	2	3	2	15
5		1	3	1	1	1	4	3	1		15
6	2			4		2	2	2	3		15
7	2		2		1	2	1	4	1	2	15
8			2	3	3	1	4		2		15
9		3	1	1	2	3	1	1		3	15
10	2	2	1	1	1		1	2	3	1	14
Grand Total	**14**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**14**	**148**

It is clear that the housing stock in the PECO Gas service territory is such that the building types with the lowest natural gas consumption (multi-family buildings, excluding those with only 2-4 units) are found within the lowest income zip codes.

Q. DOES THE DATA FOR PECO GAS CONFIRM WHAT YOU WOULD EXPECT TO FIND WITH RESPECT TO LOW-INCOME USAGE?

A. Yes. Table 18 below shows the relationship between PECO Gas home heating bills and low-income status, when low-income status is measured by the percentage of population in each zip code living with annual income below 150% of the Federal Poverty Level.

[42] Low-income status of a zip code is measured by the percentage of population with annual income at or below 150% of Federal Poverty Level. (ACS, 5YR, 2018, Table C17002).

Based on the discussion above, I would expect to find that the PECO Gas zip codes with higher percentages of low-income population would disproportionately also be zip codes with disproportionately lower PECO Gas home heating bills (and, conversely, zip codes with lower percentages of low-income population would disproportionately also be zip codes with disproportionately higher PECO Gas home heating bills). Indeed, this is precisely what occurs. While 26 of the zip codes in the three deciles with the highest PECO Gas home heating bills have the lowest percentages of low-income population only one (1) zip code with the lowest heating bills also have the lowest penetration of low-income population (yellow-shaded cells). Conversely, while 22 of the zip codes with the highest percentages of low-income population also have amongst the lowest heating bills, only five (5) of the zip codes with the highest penetrations of low-income households fall within the grouping of zip codes with the highest PECO Gas heating bills (blue-shaded cells).

Table 18. Low-Income Zip Codes[43] by Heating Bills											
No. of Zip Codes by decile (level of heating avg bill)	**Number of Zip Codes by Decile (percentage of population < 150% Poverty)**										
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**Grand Total**
1					2	1	3	3	3	2	14
2			1	3		2	3	3	3		15
3				2	1	3	1	1	3	4	15
4				2	2	1	1	3	4	2	15
5	1			1	4	3	1	1		4	15
6		6		3		1	2	2		1	15
7	2	3	5	2	2	1					15
8	3		4		2	2	1	1	1	1	15
9	4	3	2	1	1	1	1	1	1		15
10	4	3	3	1	1		2				14
Grand Total	**14**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**14**	**148**

Q. DOES THIS PATTERN ANALYSIS REMAIN CONSTANT IF YOU DEFINE "LOW-INCOME" IN DOLLAR TERMS RATHER THAN IN TERMS OF POVERTY LEVEL?

A. Yes. Table 19 shows the same pattern when I define "low-income" by referencing households with annual income below $15,000 (rather than defining low-income by reference to the ratio of income to Poverty Level). The Table shows that while six (6) zip codes fall within the group of zip codes having low PECO Gas heating bills and a low percentage of households with annual income less than $15,000, 19 zip codes fall within the group having high heating bills and a low percentage of households with annual income less than $15,000 (yellow-shaded cells). In contrast, while 23 zip codes fall in the group with low PECO Gas heating bills and a high percentage of low-income

[43] Low-income status of a zip code is measured by the percentage of population with annual income at or below 150% of Federal Poverty Level. (ACS, 5YR, 2018, Table C17002).

population, only eight (8) fall within that group of zip codes with high heating bills and a high percentage of population with annual income less than $15,000 (blue-shaded cells).

Table 19. Low-Income Zip Codes[44] by Heating Bills											
No. of Zip Codes by decile (level of heating avg bill)	**Number of Zip Codes by Decile (percentage of population < $15,000 annual income)**										**Grand Total**
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	
1			1		2	2	2	2	3	2	14
2	1	2	1	3				3	4	1	15
3		1		2	1	1	2	2	3	3	15
4			1	1	1	6		1	3	2	15
5	1	1	1		3	3	2	1		3	15
6		3	4	2		2	1	3			15
7	3	2	3	3	3		1				15
8	3	1	3	1	3		3		1		15
9	3	2		2	1		3	2		2	15
10	3	3	1	1	1	1	1	1	1	1	14
Grand Total	**14**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**14**	**148**

Q. DID YOU EXAMINE THE RELATIONSHIP BETWEEN INCOME AND PECO GAS USAGE IN ANY OTHER FASHION?

A. Yes. I finally examined the relationship between PECO Gas home heating bills and the percentage of households who receive Food Stamps (SNAP) and/or cash public assistance. The data is set forth in Table 20 below. The Table shows that while one (1) zip code falls in the bottom three deciles of low-income zip codes measured by the receipt of Food Stamps/public assistance as well as the bottom three deciles of PECO Gas home heating bills, 27 zip codes fall within the group with high heating bills and low percentages of households receiving Food Stamps/public assistance yellow-shaded cells). Conversely, while 29 zip codes falls within the group of zip codes with a high percentage

[44] Low-income status of a zip code is measured by the percentage of population with annual income at or below $15,000.

of Food Stamp/public assistance recipients along with the lowest bills, only two (2) zip codes fall in that group with a high percentage of households receiving Food Stamps/public assistance and high heating bills (blue-shaded cells).

Table 20. Low-Income Zip Codes[45] by Heating Bills

No. of Zip Codes by decile (level of heating avg bill)	**Number of Zip Codes by Decile (percentage of HHs receiving Food Stamps and/or public assistance)**										
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**Grand Total**
1				1			4	1	5	3	14
2			1	2	1	1	1	4	3	2	15
3					2		2	3	3	5	15
4	1		1			2	3	3	3	2	15
5	3	1	2	1	1	3	1	1		2	15
6		1	3	4	3	1	1	2			15
7		1	3	4	5	1	1				15
8	2	4	4			3	1		1		15
9	3	4			2	4	1	1			15
10	5	4	1	3	1						14
Grand Total	**14**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**14**	**148**

Q. HAVE YOU CONSIDERED WHETHER THIS RELATIONSHIP IS ATTRIBUTABLE TO THE FACT THAT LOW-INCOME CUSTOMERS WILL RECEIVE CAP DISCOUNTS?

A. Yes. The delivery of CAP discounts to *some* low-income customers does not account for the consistent patterns that are shown above. According to PECO, in the zip codes that are being studied, PECO Gas serves 426,312 home heating accounts, while serving 20,100 CAP recipients. PECO Gas, in other words serves less than five percent (5%) of its heating customer base through CAP (OCA-III-03). In contrast, if PECO Gas were to serve its home heating customer base in the same proportion as low-income customers

[45] Low-income status of a zip code is measured by the percentage of population receiving Food Stamps (SNAP) and/or cash public assistance.

(with income below 150% of Poverty) are to the total population, PECO Gas would serve nearly 12% of its total home heating customer base through CAP. PECO Gas serves only 40% of its expected income-eligible population. The patterns I identify above are not driven by CAP participation.

Moreover, the data PECO Gas was asked to provide was the average residential home heating bills. (OCA-III-5). PECO Gas gave no indication that its report of these residential home heating bills by zip code reduced home heating bills to reflect CAP credits.

Q. WHAT DO YOU CONCLUDE?

A. Based on the data and discussion presented above, I conclude that low-income households in the PECO Gas service territory are disproportionately and on average likely to live in homes that consume lower levels of natural gas. As a result, the PECO Gas proposal to substantially increase its fixed monthly customer charge will disproportionately impose adverse impacts on low-income customers.

Ultimately, based on this discussion, along with my initial discussion of the adverse impacts that will accrue to low-income customers of PECO Gas, I recommend that the residential customer charge recommended by OCA witness Glenn Watkins be adopted.

Part 3. Allocation of Universal Service Costs.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I recommend that the PECO Gas universal service costs be allocated among all customer classes. Arguments that non-residential customers do not contribute to the need for universal service programs, nor do they benefit from such programs, are demonstrably in error.

Q. WHY SHOULD THE COMMISSION CONSIDER THE ALLOCATION OF UNIVERSAL SERVICE COSTS IN THIS PROCEEDING?

A. In its 2019 Final Policy Statement and Order in the PUC's generic investigation into energy affordability in Pennsylvania (Docket M-2019-3012599),[46] the Commission explicitly acknowledged that, historically, it allocated universal service costs exclusively to residential customers, but then stated that "our review of Pennsylvania's current universal service model in the *Review* and *Energy Affordability* proceedings has provided reasons to reconsider this position. (Final Policy Statement and Order, at 92). The Commission observed that "[t]he current cost-recovery method for universal services, including CAP costs, is putting a significant burden on residential customer bills. . ." (Id.). The Commission's decision to substantially reduce the definition of an "affordable" burden will create even more universal service costs and increase that "significant burden" even more. According to the Commission:

[46] http://www.puc.pa.gov/about_puc/consolidated_case_view.aspx?Docket=M-2019-3012599 (November 5, 2019) (last accessed May 16, 2020).

> Given the significant past increase in EDC universal service spending – and the anticipated increases in both EDC and NGDC universal spending through 2021 – the Commission is concerned that recovering CAP costs (as well as other universal service costs) from only residential ratepayers will continue to make electric and/or natural gas bills increasingly unaffordable for non-CAP customers, especially those with incomes between 151-200% of the FPIG.

(Id., at 95). I agree with these observations. There is a substantial population of PECO Gas customers who have difficulties in paying their utility bills without being sufficiently "low-income" to qualify for CAP. The current CAP costs could prove to be problematic for these customers, and those costs will increase in the future, both for the reasons identified in the Commission's Final Order (pages 94 – 95) and for the reason that the Commission has revised its Final Policy Statement recommending reductions of the percentage of income payments to be charged to CAP customers.[47]

As I will establish below, the Commission reached an appropriate conclusion when it stated in its Final Order that "[t] he Commission agrees that poverty, poor housing stock, and other factors that contribute to households struggling to afford utility service are not just 'residential class' problems. Further, helping low-income families maintain utility service and remain in their homes is also a benefit to the economic climate of a community." (Id., at 96).

The Commission stated in its Final Order that "the Commission finds it appropriate to consider recovery of the costs of CAP costs from all ratepayer classes. Utilities and

[47] While the Office of Consumer Advocate has urged that CAP is designed to address long-term structural poverty, these costs might increase even more to the extent that COVID-19 results in structural job loss. Temporary loss of income due to COVID-19 should be considered to be addressed through a PUC-approved emergency relief program.

stakeholders are advised to be prepared to address CAP cost recovery in utility-specific rate cases consistent with the understanding that the Commission will no longer routinely exempt non-residential classes from universal service obligations. . .” (Id., at 99, notes omitted).[48] The discussion below is consistent with this Commission guidance.

Q. PLEASE EXPLAIN THE CURRENT ALLOCATION OF UNIVERSAL SERVICE COSTS BY PECO GAS.

A. PECO Gas states unequivocally that “Universal Service Costs are allocated to the residential class with no differentiation between gas-heating and non-heating.” (OCA-III-20, see also, OCA-III-21 [“Universal service costs are only allocated to the residential class.”]) This allocation only to the residential class occurs notwithstanding that PECO Gas collects some of its universal service costs in base rates, (OCA-III-21).

A. The Commission-Identified Factors.

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In its September 2019 Final Order quoted above, the Pennsylvania PUC identified several factors that “contribute to households struggling to afford utility service” and indicated that such factors “are not just residential class problems.” Amongst those factors which the PUC identified were “poverty, poor housing stock, and other factors.” In this section of my testimony, I address those specifically-identified factors. In my discussion below, I examine two aspects of “poverty.”

[48] The Commission observed that it was not making “a final precedential decision regarding cost recovery in this docket. We are merely providing that the recovery of CAP costs in particular can be fully explored in utility rate cases henceforth. “ (Id., at note 150).

The first aspect of "poverty" involves customers who are at or below differing ranges at or below PECO Gas' CAP income-eligibility maximum. I estimate these numbers by multiplying the number of customers for each PECO Gas zip code (OCA-III-3) times the percentage of population at the varying population ranges.[49] I then sum the results for each zip code to obtain the number of customers at each Poverty range for the PECO Gas service territory as a whole.[50]

The process I identify above yields an estimate of roughly 62,000 low-income customers.[51] The Census data for PECO Gas zip codes indicates that the PECO Gas service territory has roughly 12.6% of the population in this service area living with income below 150% of Poverty. While this is lower than most geographic areas, it does not present the complete picture.

The second aspect of Poverty I examine involves customers who have income above the maximum income-eligibility established by the PUC for CAP (150% of Poverty), but whose income is sufficiently low that they can reasonably be expected to face difficulties paying their utility bills. I define this population of "near-poor" to include households who have income higher than 150% of Poverty, but lower than 200% of Poverty. An additional roughly 28,000 customers are estimated to live with income between 150%

[49] American Community Survey, Table C17002, available at Data.Census.gov (last accessed December 4, 2020).

[50] The process of matching zip codes to Census Data is explained in more detail in my testimony below.

[51] My estimate is lower than the number of estimated PECO Gas low-income customers reported by BCS in 2019 (74,914).

and 200% of Poverty (5.7%). This population has income that is insufficiently low to qualify for most public assistance programs, but insufficiently high to be able to consistently meet their month-to-month payments.

An additional 8.2% of PECO Gas' customers are estimated to live with income of greater than 150% of Poverty, but less than 200%.

This population is important to examine because these households lack sufficient income to be self-sufficient in the counties served by PECO Gas. The income for a 3-person household can be compared to the income needed to achieve "self-sufficiency" by county within the PECO Gas service territory.[52] Those self-sufficiency incomes for the PECO Gas counties are set forth in the Table below.[53] For space purposes, the self-sufficiency incomes included below are limited to 3-person households with three different types of composition: (1) two adults with 1 school-age child; (2) one adult with one school-age child and one teenager; and (3) one adult with one infant and one school-age child.[54]

[52] The Self-Sufficiency Standard determines the amount of income required for working families to meet basic needs at a minimally adequate level, taking into account family composition, ages of children, and geographic differences in costs.

[53] http://www.selfsufficiencystandard.org/pennsylvania (last accessed December 4, 2020).

[54] In contrast, there are 14 variations of family composition for a 3-person household with one- or two-adults for which self-sufficiency incomes are published.

Table 21. Self-Sufficiency Income (PECO Gas counties) (2018) For 3-person Households with Selected Compositions				
State Name	County1	2 Adults--1 School age child	1 Adult--1 School-Age-1 Teen	1 Adult--1 School-Age-1 Infant
Pennsylvania	Bucks County	$61,979	$54,918	$74,289
Pennsylvania	Chester County	$63,995	$57,053	$79,518
Pennsylvania	Delaware County	$60,509	$53,230	$72,306
Pennsylvania	Lancaster County	$54,440	$47,670	$63,800
Pennsylvania	Montgomery County	$63,800	$56,658	$77,975

For our purposes here, the data in the Table above is significant in two respects. On the one hand, the data shows that the self-sufficiency income in 2018 (the last year for which data is reported) exceeds 200% of Poverty Level for a three-person household ($41,560 in 2018). A three-person household living with income equal to 150% of Poverty Level in 2018 would have had an income of $31,170.[55] On the other hand, the data further shows the substantial variation between geographic areas. For a three-person household (1 adult, 1 school age child, 1 infant), for example, the self-sufficiency income ranges from a low of $63,800 (Lancaster County) to a high of $79,518 (Chester County) in the PECO Gas service territory.

Q. WHAT DO YOU CONCLUDE?

A. For purposes of the PUC's consideration of whether to allocate universal service costs over all customer classes, the most important observation here is that tens of thousands of PECO Gas customers with income at or below 150% of Poverty do not participate in CAP notwithstanding their low-income status. In addition, even ***more*** customers live with incomes that are above the income-eligibility maximum of 150% of Poverty, but

[55] Federal Register, Vol. 83, No. 12, p.2643 (January 18, 2018) (100% of Poverty for 3-person household is $20,780).

less than 200% of Poverty. Allocating universal service costs over all customer classes would help improve the affordability of PECO Gas bills to these low-income and near-poor customers who are income-challenged but not participating in, or not eligible for, PECO Gas' universal service programs.

Q. IS THERE ANY OTHER OF THE PUC-ARTICULATED FACTORS THAT YOU HAVE EXAMINED?

A. Yes. The Commission identified the quality of "housing stock" (i.e., "poor housing stock") as one of the relevant factors to consider. The Census Bureau does not report data on the quality of housing stock. Nonetheless, from an energy perspective, one can use the age of housing as a surrogate for which households have control over their energy consumption. The Table below sets forth the data for the zip codes comprising the PECO Gas service territory.

Table 22. Low-Income Zip Codes[56] by Age of Housing Units

No. of Zip Codes by decile (percent population <150% FPL)	Number of Zip Codes by Decile (percentage of housing units built before 1970)										Grand Total
	1	2	3	4	5	6	7	8	9	10	
1	3	1	1	2	2	1				4	14
2	4	2	1	1		1	1	1	2	2	15
3	3	2			2	3	1	2	1	1	15
4	1	1	1	4	1	2		2	3		15
5		2	2	2	2	1	4	1	1		15
6	2	2	3	2	2	2			2		15
7		1	2	1	3	2	2	1	2	1	15
8		3	2	2		2		3	2	1	15
9		1	2	1	1	1	4	3		2	15
10	1		1		2		3	2	2	3	14
Grand Total	**14**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**14**	**148**

As the Table immediately above shows, the older housing stock in the PECO Gas service territory disproportionately occurs in zip codes with a higher penetration of low-income households. Indeed, 17 of the zip codes with the lowest penetration of older housing stock in the PECO Gas service territory also are zip codes with the lowest percentage of population with income below 150% of Poverty, while only 10 of the zip codes with the lowest percentage of older housing stock correspond to zip codes with a high percentage of low income population (yellow-shaded cells). Conversely, while 18 of the zip codes with the highest percentage of very old housing stock also have the highest percentages of low-income households, only 13 of the zip codes with a high percentage of very old housing stock are also zip codes with lower penetrations of low-income households (blue-shaded cells).

[56] Low-income status of a zip code is measured by the percentage of population with annual income at or below $15,000.

In short, the Commission was correct to be aware of the relationship between low-income status and poorer housing stock. [57]

B. Poverty is Not Just a Residential Class Problem.

Q. PLEASE ADDRESS THE STATEMENT BY THE PUC THAT POVERTY IS "NOT JUST [A] RESIDENTIAL CLASS PROBLEM."

A. I agree with the PUC's observation that poverty is "not just [a] residential class problem." In reaching this conclusion, I examine broad economic factors throughout the PECO Gas service territory, not exclusively associated with the residential class, which contribute to the inability-to-pay of PECO Gas low-income customers.

Q. DO LOW WAGES AFFECT THE PARTICIPATION OF CUSTOMERS IN THE UNIVERSAL SERVICE PROGRAMS OF PECO GAS?

A. Yes. OCA asked PECO Gas to provide the number of CAP participants with wage/salary income for all or part of their income, as well as the number of CAP participants with only public assistance as income. The data is set forth in the Table immediately below. The Table demonstrates that, according to PECO Gas' data, its CAP participation includes a substantial proportion of participants who are eligible notwithstanding the fact that they receive wage or salary income. In contrast, a very small proportion of PECO Gas' CAP participants have income from public assistance only. In 2019, more than one-

[57] This observation is not inconsistent with the discussion above demonstrating that low-income households are, disproportionately and on average, lower use customers. As the U.S. Department of Energy has found, while low-income households tend to live in less efficient housing units (on a per square foot basis), those low-income households (as documented above for the PECO Gas service territory) also tend to live in housing units that are sufficiently smaller that their total usage is lower than non-low-income households.

in-three PECO Gas CAP participants (6,668 / 19,397 = 0.344) received wage income. In 2018, the proportion of CAP participants who received wage income was nearly identical (7,006 / 20,214 = 0.347).

Table 23. CAP Participants with Wage or Salary Income for All or Part of their Income and with Public Assistance as Only Source of Income
(OCA-III-12)

	Wages / Salary	No Wages / Salary	Public Assistance Only	Total
2018	7,006	12,767	441	20,214
2019	6,668	12,295	434	19,397

PECO Gas was further able to provide the average income of CAP participants who received only wages or salaries as their income source. CAP participants in the lowest Poverty bracket (0-50%) not only experienced lower monthly incomes, but experienced a higher rate of part-time (rather than full-time) employment. CAP participants in the middle Poverty bracket (50 – 100%) still had more part-time rather than full-time employment. Even full-time employment, however, resulted in an annualized income of less than $20,000 in the most recent year (through September 2020). The 2020 monthly income of $2,353, which annualizes to an income of $28,236, still results in households having a ratio of income to Federal Poverty Level falling between 101% and 150%.

Table 24. CAP Participants by Wage/Salary Income by Poverty Level (OCA-III-13)

	0-50%		51-100%		101-150%	
	No. Accts	Avg /Month	No. Accts	Avg /Month	No. Accts	Avg /Month
Dec-2018						
Full-time	361	$576	1,283	$1,601	1,588	$2,353
Part-time	1,218	$535	1,626	$1,154	976	$1,598
Dec-2019						
Full-time	337	$567	1,262	$1,610	1,577	$2,326
Part-time	1,239	$553	1,702	$1,134	1,039	$1,600
Sep-2020						
Full-time	321	$621	1,293	$1,604	1,738	$2,275
Part-time	1,283	$556	1,913	$1,097	1,163	$1,549

Q. HAS PECO GAS STUDIED THE ECONOMIC HEALTH OF ITS SERVICE TERRITORY OR CONSIDERED HOW THE ECONOMIC HEALTH AFFECTS UNIVERSAL SERVICE PARTICIPATION?

A. No. When OCA asked PECO Gas for all studies "of the relationship between CAP enrollment and economic trends (e.g., unemployment, housing starts, consumer expenditures)" PECO Gas replied that it "does not have any studies (analyses, memos, evaluations, or other written document) of the relationship between CAP enrollment and economic trends (e.g., unemployment, housing starts, consumer expenditures within the past five years)." (OCA-III-23). Moreover:

- When OCA asked for any studies of the economic health of the PECO Gas service territory, PECO Gas responded that "no studies of the economic health of the Company's service territory have been prepared by or for PECO Gas within the past five years." (OCA-III-24). Nor has PECO Gas developed (OCA-III-25) or applied (OCA-III-26) any metrics by which to measure the economic health of the Company's service territory. When asked for metrics by which to track the economic health of the Company's service territory, PECO Gas responded that it "does not track such metrics and, therefore, does not have any of the requested reports." (OCA-III-26).

- PECO Gas has not provided any discussion or report of the economic health of the Company's service territory to Company management, Board or investors in the last five years. (OCA-III-27).

Q. HAVE YOU HAD OCCASION TO EXAMINE THE VARIOUS UNDERLYING ECONOMIES WITHIN THE PECO GAS SERVICE TERRITORY?

A. Yes. It is important to recognize that the employment and wage data I discuss below predates the COVID-19 health pandemic. With this in mind, I examine wages in the communities comprising the PECO Gas service territory.[58] Using these communities, I find that low wages are prevalent throughout the PECO Gas service territory. Based on this local wage data, I find that the inability-to-pay issues addressed by the universal service programs of PECO Gas are not "caused" by the residential customer class. They are instead broader societal issues that can be attributed to every customer class.

Q. UPON WHAT DO YOU BASE YOUR CONCLUSION THAT LOW WAGES ARE PREVALENT THROUGHOUT THE PECO GAS SERVICE TERRITORY?

[58] For purposes of my testimony here, I define "community" as one of the geographic units listed in the PECO Gas tariff as comprising its service territory. PECO Exhibit JAB-2, page 5 of 83 ("List of Communities Served").

A. The purpose of the discussion below is not to identify the particular communities as having particular problems. Indeed, rather than presenting data on individual communities, I have aggregated the data for all communities in the PECO Gas service territory and examined that data for PECO Gas as a whole (i.e., PECO Gas communities set forth in the PECO Gas tariff).

Q. WHAT DID YOU FIND?

A. A substantial number of employed civilian adults (age 16 or older) in the PECO Gas service territory are employed in occupations that are generally defined to be "low-wage" jobs. In reaching this conclusion, I matched the communities listed in the PECO Gas tariff as comprising its service territory with the corresponding geographic units for which data was reported by the Census Bureau through the American Community Survey (ACS) (2018, 5YR). The Census data (i.e., ACS) I use involves civilian employment and median earnings.[59] The "median earnings" would be the median earnings for a particular occupation in the community for which data is reported. The "percentiles" included in Table 25 refer to the community at that percentile within all PECO Gas communities. A community at the 20th percentile, for example, would be that community with a median earnings (for a given occupation) at which point 20% of all PECO Gas communities have median earnings less than the reported amount, and 80% of PECO Gas communities have median earnings greater than the reported amount. The 50th percentile would be that community in which half of all communities have a median earnings for the particular occupation lower, and the other half of PECO Gas communities have a median earnings

[59] The relevant ACS tables I used included: B24011, B24020, B24021, B24031, B24041, C24050, S2401.

for the particular occupation higher. I report communities at three different percentiles (a lower percentile: 20th; a higher percentile: 80th; and the mid-point: 50th percentile).

Overall, in the service occupations for communities comprising the PECO Gas service territory, the community with the median level of median earnings (i.e., half of all communities have median earnings less, while half have median earnings more) for service occupations was less than $20,000. Even the community with the 80th percentile of median earnings for service occupations only experienced median earnings of $24,281. Particularly low earnings are found in the food preparation and serving, personal care and services, and building and ground maintenance and cleaning occupations in the PECO Gas service territory.

Table 25. Median Earnings for Low Wage Occupations (2018)
(By Community in PECO Gas Service Territory)[60]

Occupations	20th Percentile	50th Percentile	80th Percentile
Service[61]	$14,504	$19,919	$24,281
Service: Health care support	$19,123	$24,342	$30,397
Service: Food preparation and serving	$8,638	$12,975	$18,482
Service: Building and grounds maintenance and cleaning	$14,766	$23,950	$32,273
Service: Personal care and service	$10,993	$16,821	$25,318
Production/transportation & material moving: Material moving	$13,403	$21,793	$30,655

[60] American Community Survey, Table B24011 (Occupation by Median Earnings in the Past 12 Months [in 2018 inflation-adjusted dollars] for the Civilian Employed Population 16 Years and Over).

[61] "Service" occupations include, but are not limited to, the service occupations listed in this Table.

In addition to these specific occupations, persons employed in the retail trade industry had median earnings of only $25,786 in the median PECO Gas community. (ACS Table B24031). Full-time employees in the retail trade industry made up more than 10% of all full-time civilian workers. (ACS Table S2403).

The number of workers (civilian age 16 and older) living with these low wages in the PECO Gas service territory is substantial. In just the four service occupations I identified in the Table above, plus those working in "material moving," nearly 200,000 workers are employed in the PECO Gas service territory. These five limited occupations comprise more than one-of-seven workers employed in this geographic area (i.e., PECO Gas service territory).

Table 26. Civilian Workers Age 16 and Older (2018)
(PECO Gas service territory)

Occupations	Number of Full-Time Workers	Percent of Full-Time Workers
Service[62]	182,599	14.4%
Service: Health care support	32,523	2.6%
Service: Food preparation and serving	61,197	4.8%
Service: Building and grounds maintenance and cleaning	35,36	2.8%
Service: Personal care and service	34,939	2.8%
Production/transportation & material moving: Material moving	23,514	1.9%
Sub-total	187,519	14.8%

Q. WHAT DO YOU CONCLUDE BASED ON THIS DATA?

[62] "Service" occupations include, but are not limited to, the service occupations listed in this Table.

A. I conclude that the Pennsylvania PUC was correct when it observed in September 2019 that Poverty is a broad-based social problem not associated with any particular customer class, including specifically not being associated with the residential class exclusively. I find that a substantial number of wage-earning customers participate in PECO Gas' universal service programs. I find further that one reason that these customers income-qualify for PECO Gas' universal service programs is because a substantial number of people throughout the PECO Gas service territory are working at Poverty level wages.

C. How Universal Service Benefits Business.

Q. HAVE YOU HAD OCCASION TO CONSIDER HOW PROVIDING UNIVERSAL SERVICE BENEFITS BUSINESS?

A. Yes. Any increase in natural gas costs to business from payment of universal service costs would be offset by increases in employee productivity. Poverty produces ill-prepared workers whose lives are easily disrupted by small catastrophes. If the car breaks down, if a child gets sick, it suddenly becomes impossible to be a reliable worker. Poverty also generates poor health among workers, making them less reliable still and raising the cost of employing them. Paying a small increase in costs to help generate these offsetting benefits is a reasonable investment for a business to make.

In addition to generating economic development impacts on their own accord, programs such as Pennsylvania's CAP help contribute to the overall competitiveness of the Pennsylvania economy. This conclusion is not disputed by researchers that consider the impacts of programs such as home energy affordability subsidies on private employers. One comprehensive study published in 2004 concluded:

> Why the under-use of public benefits is a problem. When most people hear about the idea of marketing public benefits through employers, their initial reaction is "why would a company want to get involved with a social service program?"
>
> In fact, employers have good reason to be concerned that large numbers of working people with low family incomes do not take advantage of the public benefits intended to help them and their families achieve economic sufficiency--benefits that also help employers by contributing to the economic stability of their workforces. These public benefits bolster the ability of low-income workers to meet their basic needs, in effect providing a wage supplement to employers.[63]

Note that these conclusions are reached by business stakeholders: the U.S. Chamber of Commerce and the National Association of Manufacturers.

Q. HAS THE CONCLUSION THAT ADDRESSING UNIVERSAL SERVICE PROBLEMS HELPS BUSINESSES BEEN REACHED THROUGH PENNSYLVANIA-SPECIFIC RESEARCH?

A. Yes. Addressing the problems of poverty is a critical element to restoring the competitiveness of Pennsylvania businesses. In its report *Back to Prosperity: A*

[63] Geri Scott (2004). "Private Employers and Public Benefits," Workforce Innovation Networks (WINS): Boston (MA) and Washington D.C. WINS is a collaboration of Jobs for the Future, the Center for Workforce Preparation of the U.S. Chamber of Commerce, and the Center for Workforce Success, The Manufacturing Institute of the National Association of Manufacturers. Available at: https://www.jff.org/resources/private-employers-and-public-benefits/ (last accessed December 13, 2020).

Competitive Agenda for Renewing Pennsylvania,[64] the Brookings Institution Center on Urban and Metropolitan Policy consistently noted the need to address the factors contributing to the decline of communities, large and small, in the state. According to the report, funded by the Heinz Endowment and the William Penn Foundation, neighborhood decline "has become a contagious self-sustaining process in parts of older urban Pennsylvania." Such decline, the report found, triggers a slide in property values, brings negative perceptions, and erodes public health and safety, all of which impede the competitiveness of the state's business and industry. According to this analysis of the competitiveness of Pennsylvania business, and how to "restore prosperity," "the widening social and economic gap between Pennsylvania's older communities and their suburbs has negative implications for the overall health of its regions."

Q. WILL PROGRAMS SUCH AS CAP HELP ADDRESS THESE PROBLEMS?

A. Programs such as CAP, while obviously not a solution standing by themselves, are one *part* of the solution. In addition to addressing utility payment problems, home energy affordability programs can help address trends toward housing abandonment, reductions in educational attainment,[65] and adverse health outcomes for payment-troubled utility customers.[66]

[64] Available at: https://www.brookings.edu/research/back-to-prosperity-a-competitive-agenda-for-renewing-pennsylvania/ (last accessed December 13, 2020).

[65] Roger Colton (1996). "The Road Oft Taken: Unaffordable Home Energy Bills, Forced Mobility And Childhood Education in Missouri," 2 Journal on Children and Poverty 23.Available at: https://www.tandfonline.com/doi/abs/10.1080/10796129608414757 (last accessed December 13, 2020).

[66] See generally, Apprise, Inc. (2018). National Energy Assistance Survey: Final Report, National Energy Assistance Directors' Association: Washington D.C. Available at: http://www.appriseinc.org/resource-library/selected-reports/energy-survey-research-and-policy-analysis/ (last accessed December 13, 2020).

Universal service programs help to control the need to provide local government services, the cost of which is largely borne by non-residential taxpayers. There is a direct connection between unaffordable home energy bills and the costs of providing public health services.[67] There is a documented connection between unaffordable home energy bills and public safety costs.[68] The benefits of mitigating the need to provide these government services redound to the benefit of all taxpayers, including commercial and industrial entities.

Q. HAVE YOU HAD OCCASION TO REVIEW RESEARCH ON THE RELATIONSHIP BETWEEN INABILITY-TO-PAY AND THE MITIGATION OF HARMS TO BUSINESS?

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[67] See generally, Jamal Lewis, et al. (2019). Energy efficiency as energy justice: addressing racial inequities through investments in people and places, available at https://www.greenandhealthyhomes.org/wp-content/uploads/Energy-Efficiency-as-Energy-Justice_Final.pdf (last accessed December 13, 2020); see also, Maheswaran et al. (2004). Socio-economic deprivation and excess winter mortality and emergency hospital admissions in South Yorkshire Coalfields Health Action Zone, UK. Public Health 118. 167 – 176, available at https://pubmed.ncbi.nlm.nih.gov/15003406/ (last accessed December 13, 2020); see also, Frank, D., Neault, N., Skalicky, A., Cook, J., Wilson, J., Levenson, S., Meyers, A., Heeren, T., Cutts, D., Casey, P., Black, M., and Berkowitz, C. (2006). Heat or Eat: Low Income Home Energy Assistance Program and Nutritional Risk Among Children Under 3 Years Old. Pediatrics, available at: https://pubmed.ncbi.nlm.nih.gov/17079530/ (last accessed December 13, 2020); Frank DA, Roos N, Meyers AF, et al., Seasonal variation in weight-for-age in a pediatric emergency room. Public Health Reports, 1996; 111:366-371; Bhattacharya J, DeLeire T, and Currie J. Heat or eat? Cold-weather shocks and nutrition in poor American families. Am. J. Public Health. 2003; 93:1149-1154.

[68] Canadian Housing and Rental Association (February 2005). Affordable & Efficient: Towards a National Energy Efficiency Strategy for Low-Income Canadians, as cited in Environmental Law Centre, University of Victoria, Conserving the Planet without Hurting Low-Income Families, available at: http://www.elc.uvic.ca/press/documents/Conserving-planet-without-hurting-low-income-families-April2010-FINAL.pdf (last accessed December 13, 2020).

A. Yes. A 2014 study by the Consumer Financial Protection Bureau[69] (CFPB) reports that "even when the economy was booming, financial stress was sapping the productivity and hurting the health of millions of American workers."[70] According to the CFPB:

> Multiple surveys offer ample evidence of the impact of financial stress at work. For example, in 2012, roughly one in five employees admitted they had skipped work in the past year to deal with a financial problem. Among workers now in their 30's and 40's – a critical cohort of the American workforce - stress levels are even higher. Many Generation X workers (29%) say their personal finances distract them at work, and a majority (53%) find it stressful to deal with their personal finances. This is a particularly salient finding given that Gen Xers – those born between 1964 and 1980 – are beginning to enter their peak-earning years. If they are financially stressed now, Gen Xers may have more difficulty than other generations finding security in the future. Across workers of all generations, 24% admit their personal finances have been a distraction at work. And, of those workers who are concerned about their finances, 39% spend at least three hours each week either thinking about or dealing with financial problems at work.[71]

According to the CFPB:

> It's not just employees who want help managing financial stress at work. Managers confront this stress every day. In a recent survey, 61% of human resources professionals say financial stress is having some impact on

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[69] CFPB (August 2014). Financial wellness at work: A review of promising practices and policies. https://www.consumerfinance.gov/data-research/research-reports/financial-wellness-at-work/ (last accessed December 13, 2020).

[70] Financial wellness at work, at 6, citing E. Thomas Garman et al., Financial Stress Among American Workers: Final report: 30 Million Workers in America –One in Four—Are Seriously Financially Distressed and Dissatisfied Causing Negative Impacts on Individuals, Families, and Employers, 17 2005).

[71] Id., citing MetLife, Inc., 10th Annual Study of Employee Benefits Trends: Seeing Opportunity in Shifting Tides 51 (2012), available at http://www.winonaagency.com/img/~www.winonaagency.com/10th annual met life study of benefits trends.pdf ("22% of employees admit that they have taken unexpected time off in the past 12 months to deal with a financial issue and/or spent more time than they think they should at work on personal financial issues . . . ."). 15% of Gen Y respondents, 10% of Gen X respondents, 5% of Younger Boomer respondents, and 1% of Older Boomer respondents admitted to the same; PricewaterhouseCoopers, LLC, Employee Financial Wellness Survey 10,11 (2014), available at http://www.pwc.com/en_US/us/private-company-services/publications/assets/pwc-employee-financial-wellness-survey-2014-results.pdf.

employee work performance. Twenty-two percent say worries over personal finances have a "large impact" on employee engagement.[72]

Q. HOW SUBSTANTIAL ARE THE RESULTING COSTS TO EMPLOYERS?

A. The costs to employers can be substantial, and engaging in activities to reduce these costs can be helpful to employers. One white paper presented "an overview of the research literature related to financial stress, how it can affect employee productivity, and real world data regarding the estimated costs to businesses when financially stressed employees are left to struggle on their own."[73]

Indeed, an increase in health care costs is one of the most cited costs imposed on employers due to financial stress. As CFPB reported:

> there is reason to consider whether financial stress may also raise employer health care costs, specifically, the documented link between psychological stress and physical health and well-being. . . [R]esearchers have attempted to quantify the overall cost to employers from all forms of stress, and they have found those costs are not trivial. . . [R]esearchers at Ohio State surveyed 9,200 people between 2005 and 2011 to learn more about their stress levels. The findings of the Consumer Finance Monthly surveys indicate one in five people report debt stress has had a high negative impact on their health. Judging from the available survey evidence, a large share of the American population reports they suffer from chronic financial stress, and they blame that stress for hurting their health.
>
> A recent report in Health Affairs analyzed the health risks and medical expenses of more than 92,000 employees over a three-year period. Those

[72] Id., citing Society for Human Resource Management, SHRM Research Spotlight: Financial Education Initiatives in the Workplace 2 (2012), available at https://www.shrm.org/hr-today/trends-and-forecasting/research-and-surveys/Documents/Financial_Education_Flier_FINAL.pdf (last accessed December 13, 2020).

[73] Martha Brown Menard, Ph.D. (June 2017). Improving Employees' Financial Wellness: Why it Matters and What Employers Can Do About It." https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3011461 (last accessed December 13, 2020).

> reporting high stress were $413 more costly per year on average than workers who were not at risk from stress. By comparison, smoking – a common health risk targeted by corporate wellness programs – was found to raise health care costs by $587 dollars on average. Since financial problems are an important stress factor, it appears employers may be paying a high cost for employee financial stress, but they do not recognize it because a large portion of that expense shows up indirectly as a health care expense.[74]

Moreover, financial stress adversely affects employers both through absenteeism and presenteeism.[75] According to Menard:

> Academic researchers have studied the costs of absenteeism, presenteeism, and employee turnover specifically associated with employee financial stress, and have estimated these costs based on real world data. Absenteeism from work resulting from worrying about personal finances and employee turnover in particular represents a problem that has been well documented in the literature, and higher levels of financial stress are associated with higher levels of absenteeism, particularly among blue-collar workers. A recent survey of over 5,000 US workers by the company Willis Towers Watson found that employees who are worried about their finances are absent on average for 3.5 days annually.[76]

[74] CFPB Financial Wellness at Work, supra, citing, Lucia F. Dunn & Ida A. Mirzaie, Working Paper, Determinants of Consumer Debt Stress: Differences by Debt Type and Gender (2012), available at http://www.chrr.org/content/surveys/cfm/doc/DSI-Working-Paper-07-19-12.pdf (last accessed December 13, 2020); Ron Z. Goetzel et al., Ten Modifiable Health Risk Factors Are Linked To More Than One-Fifth Of Employer-Employee Health Care Spending, 31 Health Affairs 2474 (2012).; Ron Z. Goetzel, et al., The relationship between modifiable health risks and health care expenditures, 40 J. Occup. Environ. Med. 843 (1998) (showing an analysis of the multi-employer HERO health risk and cost database). https://journals.lww.com/joem/Abstract/1998/10000/The_Relationship_Between_Modifiable_Health_Risks.3.aspx (last accessed December 13, 2020). https://www.healthaffairs.org/doi/pdf/10.1377/hlthaff.2011.0819 (last accessed December 13, 2020); Health Poll, AP-AOL/ABT SRBI (2008), http://surveys.associatedpress.com/data/SRBI/AP-AOL%20Health%20Poll%20Topline%20040808_FINAL_debt%20stress.pdf (last accessed December 13, 2020).

[75] "Presenteeism" has long been recognized in both the industry and academic literature. See, e.g., Paul Hemp (October 2004). Presenteeism: At Work but Out of It, Harvard Business Review https://hbr.org/2004/10/presenteeism-at-work-but-out-of-it (last accessed December 13, 2020).

[76] Menard, supra, at 6 (internal notes omitted).

According to Menard, "financially troubled employees bring [their] concerns to work."

Dr. Menard reports:

> The previously mentioned Mercer survey found that 16% of employees reported spending more than 20 working hours each month worrying about money. The average across those surveyed was 13 hours per month. For an individual employee, that is equal to 7.8% of their annual work time spent being distracted as a result of their financial situation. Other estimates are even higher. Garman and colleagues peg financial presenteeism and absenteeism costs at 15-20% of total compensation paid to all employees in the businesses studied. . .The Mercer survey also found that 22 percent of employees report missing at least one day of work to handle financial problems, and a full 20 percent have had to resign from jobs due to financial stress.[77]

Menard's work was confirmed by research of the International Foundation of Employee Benefit Plans ("IFEBP"). That research concluded:

> Financially distressed workers are more likely to miss work—not surprising given persons with financial stress tend to have more physical and mental health problems than those who are financially healthy. In fact, 70% of all job absenteeism has been tied to stress-related illnesses.
>
> Even when employees do show up for work, they are likely to demonstrate some degree of presenteeism due to fatigue and/or an inability to concentrate. Presenteeism occurs when employees come to work but are not functioning up their capabilities. It manifests itself in a host of ways including more time spent on tasks, poor-quality work, impaired social functioning, burnout, anger and low morale.
>
> One in five employees (20%) reports issues with personal finances have been a distraction at work. More than one-third (37%) say they spend three hours or more each week thinking about or dealing with issues related to personal finances.[78]

[77] Menard, supra, at 7 (internal notes omitted).

[78] Patricia Bonner (Nov./Dec. 2016). The Impact of Financial Stress on Your Employees, Plans and Trusts, Vol. 34:6: 18-24. https://www.ifebp.org/inforequest/ifebp/0200354.pdf (last accessed December 13, 2020).

The fact that employee financial problems affect the employer is recognized widely within industry circles. For example, according to one report by the Society for Human Resource Management ("SHRM"), "when employees are stressed financially, their health and productivity can both suffer."[79] According to SHRM, 48 percent of human resource managers report workers are struggling and stressed over "covering basic living expenses." SHRM reports that 60% of employers indicate that personal financial issues affect their "workers inability to focus at work" and 34% report such issues result in "absenteeism and tardiness."

A different survey, this one of employers rather than employees, asked employers about their workers' financial stress. "The survey found that financially stressed employees are not able to check their worries at the door; they typically spend over three hours per week dealing with personal finance at work and lose nearly one month of productive work time (23-31 days per year) over financial concerns." This survey states that "there may be a strong correlation between poverty and financial stress," though it acknowledges that "low wages" are not "completely to blame."[80]

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[79] Stephen Miller (April 2016). Employees' Financial Issues Affect Their Job Performance." Available at: https://www.shrm.org/resourcesandtools/hr-topics/benefits/pages/employees-financial-issues-affect-their-job-performance.aspx (last accessed December 13, 2020).

[80] Dan Macklin (August 2019). Businesses Losing $500 Billion Due to Employees Financial Distress, H.R. Technologist Weekly Newsletter. Available at: https://www.hrtechnologist.com/articles/compensation-benefits/businesses-losing-500-billion-due-to-employees-financial-stress-2/ (last accessed December 13, 2020).

Q. DOES THE REASONING YOU DISCUSS THROUGHOUT THIS SECTION APPLY TO PENNSYLVANIA AND TO PECO GAS?

A. Yes. There is a direct relationship between the offer of a universal service program such as CAP and economic benefits to local commercial and industrial customers. For example:

- Turnover costs businesses money. We know that unaffordable home energy bills lead to the frequent mobility of households.[81]

- Time missed due to family care provision costs businesses money. We know that unaffordable home energy leads to more frequent childhood illnesses.[82]

- Time missed due to lack of employee productivity and employee illness costs businesses money. We know that the inability to stay warm due to unaffordable home energy bills leads to increased illnesses, including pneumonia, influenza, and other infectious diseases.[83]

In sum, increasing employee productivity directly contributes to the increased profitability of firms. With low-wage employees, in particular, unaffordable home energy directly contributes to lowered productivity. Increased personal illness, increased employee turnover, and increased family care responsibilities are but three of the factors contributing to lower employee productivity. The provision of affordable energy through universal service programs such as CAP positively affects each of these productivity factors.

[81] Roger Colton. "A Road Oft Taken: Unaffordable Home Energy Bills, Forced Mobility, and Childhood Education in Missouri," 2 Journal of Children and Poverty 23 (1996). Available at: https://www.tandfonline.com/doi/abs/10.1080/10796129608414757 (last accessed December 13, 2020).

[82] Jayanta Bhattacharya et al. (June 2002). Heat or Eat? Cold Weather Shocks and Nutrition in Poor American Families, National Bureau of Economic Research: Cambridge (MA). Available at: https://ajph.aphapublications.org/doi/10.2105/AJPH.93.7.1149 (last accessed December 13, 2020).

[83] Apprise, Inc. (December 2018). 2018 National Energy Assistance Survey: Final Report, National Energy Assistance Directors' Association (NEADA): Washington D.C. Available at: http://www.appriseinc.org/wp-content/uploads/2019/02/NEADA-2018-LIHEAP-Survey.pdf (last accessed December 13, 2020).

Q. IN ADDITION TO THE SPECIFIC FINANCIAL BENEFITS YOU HAVE DESCRIBED ABOVE, IS THERE A BROADER BENEFICIAL IMPACT ON THE ECONOMY FROM UNIVERSAL SERVICE PROGRAMS?

A. Yes. As a significant contributor to economic development, low-income rate affordability programs provide substantive benefits to all customer classes. Because programs such as CAP contribute to income within the low-income population that can be spent in the general retail economy (on items such as food and clothing), it helps drive additional job creation, income generation, and economic activity.

A study prepared for Entergy Service Corporation, a major electric utility serving the Middle South, found that a low-income rate affordability program would be a significant generator of jobs, economic activity, and income throughout the region. The report found:

> The distribution of energy assistance first creates economic activity for the Entergy states through the direct delivery of benefit dollars. In addition to the dollars of cash benefits, however, the delivery of energy assistance will also free up household dollars that would have been devoted to the costs arising from the payment and behavior consequences of energy bill unaffordability. These dollars, too, can then instead be spent (and circulated) in the local economy.
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> * * *
>
> While the discussion of the economic impacts of energy assistance looks at economic benefits on a statewide basis, in fact, the economic impacts provide particular advantage to low-income communities. Existing research indicates that low-income households tend to shop at local retail establishments. For food in particular, low-income households tend to shop at small, local food stores. Moreover, not only are low-income *households* more likely to shop locally, but the *businesses* serving low-income households are more likely to

shop locally as well. It is clear, therefore, that not only will the provision of energy assistance provide income and employment to low-income households, but the earnings and employment that are delivered to such households will likely be spent, retained and recirculated within the low-income community as well.

The delivery of energy assistance in the four Entergy states accomplishes far more for those states than simply helping low-income residents avoid arrears on home energy bills and preventing the potential loss of home energy service due to nonpayment. The delivery of home energy assistance also serves as a substantial economic stimulant for the economies of the Entergy states. [84]

Q. HAS THIS RELATIONSHIP BETWEEN INABILITY-TO-PAY AND ECONOMIC GROWTH BEEN GENERALLY RECOGNIZED?

A. Yes. Consider, for example, the findings of the U.S. Government Accountability Office (GAO). In its report Poverty in America,[85] GAO found:

> The relationship between poverty and adverse outcomes for individuals is complex, in part because most variables, like health status, can be both a cause and a result of poverty. Regardless of whether poverty is a cause or an effect, however, the conditions associated with poverty can work against the development of human capital—that is the ability of individuals to remain healthy and develop the skills, abilities, knowledge, and habits necessary to fully participate in the labor force. Human capital development is considered one of the fundamental drivers of economic growth. An educated labor force, for example, is better at learning, creating, and implementing new technologies. Economic theory suggests that when poverty affects a significant portion of the population, these effects can extend to the society at large and produce slower rates of growth.[86]

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[84] Roger Colton (August 2003). The Economic Impacts of Home Energy Assistance: The Entergy States. Entergy Services Corp: Little Rock (AR). Available at: http://www.fsconline.com/downloads/Papers/2003%2010%20EApasEconDev.pdf (last accessed May 16, 2020).

[85] GAO (January 2007). Poverty in America: Economic Research Shows Adverse Impacts on Health Status and Other Social Conditions as well as the Economic Growth Rate, GAO Report GAO-07-344. (hereafter GAO Poverty Consequences). Available at: https://www.gao.gov/products/GAO-07-344 (last accessed December 13, 2020).

[86] GAO Poverty Consequences, at 2.

As one can see, in other words, the results I discuss herein are not revolutionary conclusions, nor are they unique to the PECO Gas service territory. The causes and consequences which I have identified are widely recognized as being attributable to broad social forces unrelated to any particular population that happens to fall into a group which someone has seen fit to label as a particular class of utility customers.

Q. DO THE IMPACTS OF COVID-19 CHANGE YOUR CONCLUSIONS ABOUT THE IMPACTS OF UNIVERSAL SERVICE ON BUSINESSES?

A. No. There is no question that businesses in Pennsylvania are being adversely affected by the COVID-19 pandemic. Many businesses have been ordered to close, or to substantially curtail, their operations during this time of public health emergency. However, residential customers are also impacted by the economic difficulties but still are responsible for universal service costs. Many of the residential customers paying the costs of the program are also low-income or near poverty and experiencing a similar economic impact that businesses are experiencing. The economic difficulties faced by business during this health emergency is not reason, unto itself, to decline to allocate universal service costs amongst all customer classes for all the reasons I have outlined above.

D. Allocation of Universal Service Costs and Ratemaking Principles.

Q. IS THE ALLOCATION OF UNIVERSAL SERVICE COSTS CONSISTENT WITH SOUND REGULATORY PRINCIPLES?

A. Yes. One well-accepted tenet of utility ratemaking is that certain expenses incurred by a public utility are for "public goods." Due to the nature of public goods, all customers receive benefits from public goods and, accordingly, the costs of such goods are spread over all customer classes. Each end user makes a financial contribution to the utility's delivery of public goods. The "public goods" doctrine is applied in a variety of settings as a justification to spread designated utility costs over all customer classes.

In economic theory, public goods are those products and services that are valuable to society but which are undersupplied when society relies on private markets to provide them. Because they are needed and will not be made sufficiently available through private markets, the government must supply public goods. Classic examples of public goods include streetlights, city roads, and police protection.

In addition, the "public goods" doctrine is applied in a variety of settings as a justification to spread designated utility costs over all customer classes. Fire hydrants, for example, have been found to be public goods. The basic telecommunications network has also been found to be a "public good" as a justification for spreading network costs over all customer classes.

For these purposes, the Pennsylvania PUC should adopt the definition of "public good" articulated by the National Regulatory Research Institute (NRRI). NRRI stated:

> A public good can be defined as "any publicly induced or provided collective good" that "arise[s] whenever some segment of the public collectively wants and is prepared to pay for a different bundle of goods and services than the unhampered market will produce." (note omitted). In sharp contrast to the private-good model. . ., the emphasis of the public-good model is on the *total* societal benefits—both direct and indirect—associated with network modernization. As applied to the telecommunications network, the public-good model is based upon the premise that the costs of achieving and supporting a modern, state-of-the-art network infrastructure are ultimately borne by the general body of ratepayers as opposed to limited subsets of customers who exhibit a high demand for specific new services. The public-good model is conducive to establishing social policies which provide for a "supply driven definition" of infrastructure.
>
> * * *
>
> Under the public-good model, infrastructure investment[s] that are in the "public interest" are mandated by regulatory commissions, which act as surrogates for marketplace forces for the very reason that those forces break down either because of the enormous risks involved because of uncertainty with respect to costs and demand or both, or because of the intangible or unmeasurable society benefits which are not valued by the marketplace. (emphasis in original).[87]

This NRRI discussion helps guide the PUC's consideration of universal service cost allocations in several ways.

- First, universal service is a "publicly induced or provided collective good" as described by the NRRI.

[87] National Regulatory Research Institute (October 1991). The Public Good/Private Good Framework for Identifying POTS Objectives for the Public Switched Network, NRRI: Columbus (OH). Available at: http://ipu.msu.edu/wp-content/uploads/2016/12/Kravtin-Selwyn-Keller-Pots-Objectives-91-15-Oct-91-1.pdf (last accessed December 13, 2020).

- Second, it is clear from prior Pennsylvania proceedings, that NRRI was correct in referring to such a "collective good" as one that not all ratepayers would choose to pay for. Indeed, the fact that the Pennsylvania General Assembly mandated that a universal service charge be "nonbypassable" indicates that the General Assembly understood this aspect of a "public good" and that it affirmatively decided that ratepayers could not avoid this cost by switching suppliers.

- Third, the Pennsylvania universal service programs are consistent with NRRI's statement that the emphasis is on "the *total* societal benefits." Indeed, these benefits include not simply the benefits to participating customers, but also, in the words of NRRI, the benefits "both direct and indirect." Pennsylvania's CAP programs, as a public good, clearly fit this notion of generating not only direct social benefits, but also a wide range of indirect social benefits to all customer classes. Some of these types of benefits to non-residential customers have been described in detail above.

- Fourth, the finding that universal service is a "public good" has cost allocation implications to it. As NRRI points out, "the costs of achieving and supporting a modern, state-of-the-art network infrastructure are ultimately borne by the general body of ratepayers." While some ratepayer groups would limit the allocation of costs only to those customers who "use" the service of a universal service program, accepting this decision is at fundamental odds with universal service being determined to be a "public good."

Finally, the very fact that the public benefits of Pennsylvania's universal service programs such as CAP are hard to quantify is one of the reasons that universal service should be found to be a public good with costs allocated to all ratepayers. As NRRI points out, the public good approach applies "for the very reason that those [market] forces break down. . .because of . . .the intangible or unmeasurable society benefits which are not valued by the marketplace."

Q. HAS SOMEONE OTHER THAN THE NATIONAL REGULATORY RESEARCH INSTITUTE REACHED THIS SAME CONCLUSION?

A. Yes. It is not merely state utility regulatory commissions that recognize universal service as a "public good." In addition to the National Regulatory Research Institute (NRRI) discussion cited above, the National Association of Attorneys General (NAAG) has reached this same conclusion:

> At its spring 1998 meeting, the National Association of Attorneys General (NAAG) adopted a resolution addressing competition issues in electric utility transactions. . .NAAG endorsed the following principles:. . .(11) Any system benefit charges which are imposed to support public goods such as. . .universal service, and low-income assistance, should be applied in a competitively-neutral and non-avoidable manner.[88]

Q. PLEASE EXPLAIN HOW A "PUBLIC GOOD" CAN BE PROVIDED TO AN INDIVIDUAL.

A. A product can represent a "public good" even though the direct service is provided to an individual. For example, businesses do not go to school, individuals do. Businesses do not go to doctors, individuals do. Businesses do not place their children in day care, individuals do. Despite this, in each of these instances, the direct benefits to business from the affordable provision of these "public goods" have been documented. Affordable health care and child care are all akin to affordable home energy in their nature as public goods which provide direct and substantial benefits to business as well as individuals. Accordingly, businesses, as well as individuals, should be responsible for helping to pay for these public goods.

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[88] Ilene Gotts and Gregory Racz, "Post-Script Regarding Electric Utilities Mergers," in Practising Law Institute, Telecommunications Mergers & Acquisitions 1998: Financing, Regulatory and Business Issues, Corporate Law and Practice Course Handbook Series, at 433, 434 (July 1998). Available at: https://plus.pli.edu/Details/Details?rows=10&fq=title_id~3A2822~229410~2229202B~id~3A282B22~229410-CH10~2229~&facet=true&qt=legal_boolean&mode=Detailed (last accessed December 13, 2020).

Q. HAVE YOU EXAMINED HOW OTHER STATES WITH UNIVERSAL SERVICE PROGRAMS SIMILAR TO PECO GAS ALLOCATED THEIR UNIVERSAL SERVICE COSTS AMONG CUSTOMER CLASSES?

A. Yes. My review examined the states of Maine, Maryland, New Hampshire, New Jersey, Ohio, Illinois, Colorado and Nevada. My review found that all eight states that have PIPP-based programs allocate the cost responsibility for their programs over all customer classes.

Q. IS THERE ANY ANALOGY TO VIEWING UNIVERSAL SERVICE FOR PECO GAS AS A PUBLIC GOOD?

A. Yes. Affordable home energy can be analogized to other public goods. For example, child care is analogous to affordable energy because of the direct benefits it has been found to provide to business. The Committee on Economic Development has quantified the beneficial impacts to business from reducing the causes of employee absenteeism and employee turnover associated with unaffordable child care. According to CED:[89]

> Many businesses also find that helping parents meet their child care needs can potentially reduce absenteeism and employee turnover. The 1990 *National Child Care Survey* (NCCS) found that 15 percent of the mothers in its sample who worked outside the home reported losing some time from work (including arriving late, leaving early, or having to take a full day off) during the previous month because of a failure in their regular child care arrangement. Studies have found that employee turnover produces disruption and inefficiency in the work environment and that the cost of replacing

[89] CED is a national business-academic partnership. One objective of CED is "to unite business judgment and experience with scholarship in analyzing the issues and develop recommendations to resolve the economic problems that constantly arise in a dynamic and democratic society." Objectives of the Committee for Economic Development. The Research and Policy Committee of the CED is directed under the organization's bylaws to "initiate studies into the principles of business policy and of public policy which will foster the full contribution by industry and commerce to the attainment and maintenance" of the objectives of the organization.

> employees is high. For example, Merck & Co., Inc. found that it costs. . . about 75 percent of salary to replace a clerical or technical employee. It also found that it may take considerable time to fill a vacant position and an average of 12.5 months for a new employee to become adjusted to the job.[90]

E. Summary and Recommendation.

Q. WHAT DO YOU CONCLUDE?

A. Based on the data and discussion above, I find that programs such as the Pennsylvania universal service programs, directed toward preserving home energy service and relieving financial stress about a household's capacity to meet its fundamental household needs on a month-to-month basis, address a societal-wide problem that is not limited to the residential customer class. The problems that are related to unaffordable home energy are not "caused" by the residential class. Nor do the PECO Gas universal service programs deliver benefits that are limited to the residential class.

Accordingly, the costs of those programs should be allocated and spread over all of PECO Gas' customer classes. No reason exists for the residential class to be charged with paying the entire cost of programs that have the effect of improving business profitability by reducing business costs, including reducing absenteeism and turnover, and increasing employee productivity.

Q. WHAT DO YOU RECOMMEND?

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[90] Research and Policy Committee (1993). Why Child Care Matters: Preparing Young Children for a More Productive America, A Statement by the Research and Policy Committee of the Committee for Economic Development, at 1, Committee for Economic Development: New York: NY. Available at: https://www.ced.org/pdf/Why_Child_Care_Matters_1993.pdf (last accessed December 13, 2020).

A. I recommend that universal service charges be allocated between customer classes on a competitively neutral basis. The allocation of universal costs among customer classes should be based on the percentage of revenue provided by each customer class at base rates. This approach reflects the fact that these universal service costs are being treated as a distribution-related expense. In addition, many of the benefits and savings of the programs are captured in the distribution component of the base rates. Finally, a cost allocation based on class contribution to total revenues at base rates would be administratively easy to apply. These revenues are identified in the Company's filing.

Part 4. Enhanced Equity Return for Claimed Exemplary Management.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I address the request by PECO Gas to be granted an "enhanced" return on equity based on the Company's claim of exemplary management. (Bradley, PECO Gas St. 1, at 25; Moul, PECO Gas St. 5, at 2, 7, 52). In my testimony, I examine PECO claims that its management results in superior performance with respect to customer satisfaction and customer outreach/education. In addition, I will examine certain performance outcomes regarding customer collections and customer service. I will further examine the interests of ratepayers, which interests should be balanced against the Company's claim for additional profit based on its asserted exemplary management.

A. Customer Satisfaction.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I review PUC-generated data on customer satisfaction. I find that this data does not support Mr. Bradley's claims of superior, or exemplary, management used by PECO to seek an increase to its return on equity.

Q. WHAT DATA DO YOU PRIMARILY RELY UPON IN YOUR REVIEW OF "CUSTOMER SATISFACTION" BY PECO CUSTOMERS?

A. I have reviewed data on PECO's "customer satisfaction" as reported by the PUC in its annual "Customer Service Performance Report." [91] I examine the two most recent years of PUC data (2018, 2019), along with the PUC's 2014 report. I compare the two most recent years to 2014 because PECO witness Bradley chose 2014 as his base year for comparison. (PECO Gas St. 1, at 21; see also, OCA-VIII-15 ["PECO tracks more metrics in reference to customer satisfaction than what were tracked in 2010, and the methodology was changed in 2014. PECO believed providing five years of historical data, 2014-2019, was sufficient to show trends for all available metrics"]).

Rather than relying on internal PECO data regarding customer satisfaction, I instead rely on data generated by the PUC for use by the PUC. The PUC has stated that "in order to establish a means to monitor customer service, the Commission promulgated regulations that specify the information that will be reported to and analyzed by the PUC.

[91] Available at https://www.puc.pa.gov/filing-resources/reports/customer-service-performance-reports/ (last accessed December 10, 2020).

Regulations require the EDCs and NGDCs to report on important components of customer service, including. . .the level of customer satisfaction with the company's handling of recent interactions with its customers." (2019 Customer Service Performance Report, at 1). For PECO to instead use its own internally-generated data would inappropriately involve substituting PECO's decision-making on what data to collect, and how to collect it, for the PUC's decisions to "specify the information that will be reported to and analyzed by the PUC." (Id.) The PUC explicitly states that its information collection, specified by regulation, was developed "in order to establish a means to monitor customer service." Accordingly, I rely upon the information specified by PUC regulation for the purpose for which it was intended.[92]

Q. DO YOU EXAMINE PECO GAS' PERFORMANCE SPECIFICALLY?

A. No. The PUC combines PECO Gas and PECO Electric data into a single metric, and reports that data relative to other electric utilities in Pennsylvania. Accordingly, I use the data for PECO operations as a whole. This does not differ from what PECO, itself, used in Mr. Bradley's testimony. When asked whether the metrics presented in the PECO Gas Direct Testimony were "specific to PECO Gas operations," PECO responded that "this metric is calculated for the entire PECO company (Electric and Gas)." (OCA-VIII-15(c)).

[92] By internal notes in this quotation from the Commission publication, the PUC cites to (1) "Rulemaking on EDC Reporting Requirements for Quality of Service Benchmarks and Standards final on Apr. 24, 1998, at Docket No. L-00970131. Reporting began in 1999"; (2) "Rulemaking on NGDC Reporting Requirements for Quality of Service Benchmarks and Standards Order entered Jan. 14, 2000 at Docket No. L-00000147 final on Jan. 12, 2000. Reporting began in 2001"; and (3) "52 Pa Code §§ 54.151-54.156 for EDCs and 52 Pa Code §§ 62.31-62.37 for NGDCs."

Q. PLEASE EXPLAIN WHAT ELEMENT OF CUSTOMER SATISFACTION YOU PRIMARILY FOCUS ON IN YOUR DISCUSSION BELOW.

A. The PUC reports data on two levels of satisfaction: (1) “somewhat satisfied”; and (2) “very satisfied.” While I present the data on both levels below, I focus primarily (but not exclusively) on the level of customers who are “very satisfied.” I do this because PECO Gas is claiming an equity enhancement not based on adequate management (manifested through adequate customer service), but rather because PECO Gas is claiming an equity enhancement based on superior or exemplary management (manifested through customer service). Customers who are “somewhat satisfied” with their customer service do not support a claim of “superior” management. If customers are “somewhat satisfied” with call center courtesy, or with call center knowledge, for example, those customers are not reporting “exemplary” service. Given the issue placed before the Commission in this case –not the presence of adequate service, but the presence of superior or exemplary service—the question to be considered is the extent of customers who are “very satisfied.”

Q. WHAT IS THE FIRST ELEMENT OF CUSTOMER SATISFACTION YOU CONSIDERED?

A. The first element of customer satisfaction I examine involves customer satisfaction with the ease of being able to reach PECO. The data is set forth in Table 27 below. In this response, and throughout my discussion of the PUC’s reported data on customer satisfaction, I note that the Commission reports data for PECO as a whole, not for PECO as considered from its separate natural gas and electric divisions. As show in the Table below, as recently as 2019, PECO had one-in-three customers who were less than "very satisfied" with the ease of reaching the Company. While PECO saw somewhat of an uptick in the percentage of customers "very satisfied," at the same time, it experienced a downward movement in the portion of customers "somewhat satisfied." PECO's level of satisfaction does not place them at the top of Pennsylvania utilities. Amongst the electric utilities, PECO was in the middle tier of utilities, tied with Penn Power (3-4 of 8) for the proportion of customers "very satisfied" and tied with Duquesne (3-4 of 8) for the proportion either somewhat or very satisfied. PECO's overall performance on the proportion of customers very satisfied did not distinguish the Company. Rather, PECO was grouped in a cluster of five utilities with between 63% and 66% of customers very satisfied with their ease of being able to reach their respective utility.

Table 27. Satisfaction with Ease of Reaching PECO

	Very Satisfied	Somewhat Satisfied	Combined
2014	57%	25%	82%
2018	63%	21%	84%
2019	66%	19%	85%

Q. WHAT IS THE SECOND FACTOR THAT YOU EXAMINED?

A. The second factor of customer satisfaction I examined involves customer satisfaction with the ease of using PECO's automated telephone service. Table 28 sets forth the data for the three years examined: 2014, 2018 and 2019. PECO substantially improved its customer satisfaction with its automated phone system from 2014 to 2019. While in 2014, PECO experienced 49% of its customers being very satisfied with the ease of using the utility's automated phone system, by 2019 that percentage had increased to 59%. At the same time, however, the percentage of customers who were "somewhat satisfied" with the ease of using PECO's automated phone system declined from 28% to only 24%. The increase in the combined satisfaction (somewhat satisfied, very satisfied) was much lower than the increase in the highest score. Overall, however, PECO's data shows that more than two-of-five of its customers (41%) were less than "very satisfied" with their ability to use PECO's automated phone system. When measured against the test of whether PECO's performance exhibits superior management, rather than merely being adequate, the data does not support a finding of superior or exemplary management.

Table 28. Percent of Customers Indicating Satisfaction with Using Automated Phone System (PECO) (2014, 2018, 2019)

	Very Satisfied	Somewhat Satisfied	Combined
2014	49%	28%	77%
2018	58%	21%	70%
2019	59%	24%	83%

Q. WHAT IS THE THIRD FACTOR YOU CONSIDERED?

A. The third factor I examined in the PUC-reported data involved customer satisfaction with the way in which PECO customer service representatives handled a customer-initiated contact with the Company. The data is set forth in Table 29 below. Roughly three-of-four (77%) customers reported being "very satisfied" with the PECO representative's handling of a customer-initiated contact in 2014. PECO's performance improved from 2014 to 2019, but only slightly. At the same time the proportion of customers being "very satisfied" increased by three percent (3%), the proportion of customers who were "somewhat satisfied" declined by two percent (2%). The result was a very slight uptick in the combined proportion of customers who were either "very" or "somewhat" satisfied.

PECO's performance does not place them in a tier of utilities that would support a finding of superior or exemplary management. Rather, PECO's performance ranked them sixth (of eight) utilities in the proportion of customer very satisfied, as well as six of eight on the combined proportion of customers who were either "very" or "somewhat" satisfied. Looking at that combined proportion, rather than distinguishing itself as demonstrating superior or exemplary performance, PECO was simply part of the group of seven utilities with a combined proportion of between 88% and 90%. Rather than demonstrating exemplary or superior performance, PECO's performance was ordinary or typical of the other Pennsylvania utilities.

Table 29. Percent of Customers Indicating Satisfaction with Representative's Handling of Contact (PECO) (2014, 2018, 2019)

	Very Satisfied	Somewhat Satisfied	Combined
2014	74%	14%	88%
2018	75%	14%	89%
2019	77%	12%	89%

Q. WHAT IS THE FOURTH FACTOR YOU CONSIDERED?

A. The fourth factor I examined from the PUC's report on customer satisfaction involves customer satisfaction with the Company's call center representative's "courtesy." The data is set forth in Table 30 below. Being treated "courteously" by Company call center representatives would be one of the most elementary expectations that a customer could expect when making contact with the PECO call center. As recently as 2019, however, nearly one-in-five (18%) of PECO customers reported that PECO call center representatives had been less than "very courteous" in their recent interaction with PECO. While the proportion of customers being treated "very courteous" improved from 2014 (78%) to 2019 (82%), that proportion declined from 2018 (83%) to 2019 (82%).

PECO's management, as manifested by whether call center representatives were reported as being "very courteous" certainly does not place the Company in the upper tiers of customer service. As recently as 2019, only one other Pennsylvania utility had a proportion of customers reporting call center representatives to be "very courteous" that was equal to or lower than PECO's, with the other six utilities reporting higher proportions. Indeed, in 2019, only two utilities had a combined proportion of customers reporting call center representatives to be either "very courteous" or "somewhat courteous" that was lower than PECO's.

Table 30. Satisfaction with Call Center Representative's Courtesy (PECO) (2014, 2018, 2019)

	Very Courteous	Somewhat Courteous	Combined
2014	78%	12%	90%
2018	83%	9%	92%
2019	82%	11%	93%

I find that PECO's customer service does not distinguish the Company from other Pennsylvania utilities. Indeed, when nearly one-in-five customers making contact with the utility report that the call center representative was something less than "very courteous," there should be concern (whether by PECO management, by some other utility's management, or by the PUC). For purposes of this proceeding, however, when the question is not whether service is “adequate,” but rather whether customer service is “superior” or “exemplary,” PECO’s performance does not support a finding of superior or exemplary performance. Rather than exhibiting superior or exemplary performance with respect to this element of customer service, PECO falls into the bottom range of performance amongst the Pennsylvania utilities. This element of customer service does not support PECO’s claim of superior or exemplary management performance.

Q. WHAT IS THE FIFTH FACTOR YOU CONSIDERED?

A. The fifth factor I considered, as reported by the PUC, is the extent to which PECO’s call center representatives were found to be “knowledgeable” in their contacts with customers. The data is set forth in Table 31 below. In addition to being “courteous,” one of the primary expectations that a customer making contact with PECO should be able to rely upon is that the Company’s call center representative will be “knowledgeable” about how to respond to the contact. With PECO, however, nearly one-in-four customers making contact with the Company in 2018 and 2019 (23%), and more than one-in-four making contact with the Company in 2014, were found to be less than “very knowledgeable.” Indeed, in the five years from 2014 to 2019, the percentage of customers reporting that call center representatives were neither “very knowledgeable” or “somewhat knowledgeable” increased from nine percent (2014) to ten percent (2019). A utility, be it PECO or someone else, for whom nearly one-in-ten customers report that the call center representative was neither “very knowledgeable” nor “somewhat knowledgeable” should not be found to be delivering superior service.

Indeed, in 2019, the PUC reported that PECO was tied for the worst performance amongst the electric utilities in the proportion of customers reporting the call center representative(s) with whom they had contact to be “very knowledgeable.” This data certainly does not support a finding that PECO is delivering “superior” or “exemplary” performance sufficient to support an increase in its profit attributable to management performance.

Table 31. Satisfaction with Call Center Representative’s Knowledge (PECO) (2014, 2018, 2019)

	Very Knowledgeable	Somewhat Knowledgeable	Combined
2014	74%	17%	91%
2018	77%	15%	92%
2019	77%	13%	90%

Q. WHAT IS THE LAST FACTOR YOU EXAMINED FROM THE PUC-REPORTED DATA?

A. The sixth and final factor I examined from the PUC reports on “customer service performance” involves customer satisfaction with PECO’s “overall quality of service” during a recent contact with the utility. Table 32 below sets forth the data. As with other customer service factors, while PECO perhaps offers adequate service to its customers, it does not provide exemplary or superior service. More than one-in-four customers, after having made recent contact with PECO, came away feeling less than “very satisfied.” PECO’s performance fell exactly in the middle of Pennsylvania’s (electric) utilities. PECO was tied with West Penn Power (#4 - #5) with 73% of its customers feeling very satisfied with the overall quality of service during a recent contact with PECO. Three utilities had a lower percentage of being very satisfied, while three other utilities had a higher percentage. PECO's satisfaction rating on the extent to which its customers felt "very satisfied" during a recent contact, in other words, hardly demonstrates an exemplary position.

Table 32.Percent of Customers Satisfied with Overall Quality of Service During Recent Contact (PECO) (2014, 2018, 2019)

	Very Satisfied	Somewhat Satisfied	Combined
2014	66%	19%	85%
2018	71%	17%	88%
2019	73%	17%	90%

Q. WHAT DO YOU FIND AND CONCLUDE?

A. Company witness Bradley asserts in his Direct Testimony that PECO has pursued a number of programs in recent years that would enhance the customer service experience when customers have reason to interact with the utility. He asserts that PECO Gas staffs its Customer Care Center to ensure customer demands are met and invests in training programs to improve agent skills on an ongoing basis."(PECO Gas St. 1, at 19 – 21). Witness Bradley concludes that "PECO exhibited, and continues to exhibit, superior management performance. . ." (PECO Gas St. 1, at 25). The data I cite above does not support his conclusion. Using the data which the PUC prescribed to be reported for the explicit purpose of assessing utility customer service performance, I find that while, in many ways, PECO does not perform worse than other Pennsylvania utilities in the realm of customer service, PECO certainly does not perform substantially better than Pennsylvania utilities. Indeed, in many ways the performance of PECO on customer service related factor is toward the bottom level of performance in Pennsylvania. Mr.

Bradley's testimony notwithstanding, PECO cannot lay claim to superior or exemplary management when it relates to customer service.

B. Collection and Customer Service Outcomes.

Q. HAVE YOU HAD OCCASION TO EXAMINE THE ACTUAL OUTCOMES OF PECO GAS MANAGEMENT IN THE AREA OF COLLECTIONS PERFORMANCE AND CUSTOMER SERVICE?

A. Yes. In assessing whether PECO Gas exhibits "exemplary" or "superior" management, the Commission should look not merely at what the Company asserts it does (i.e., activities), but should look also at what results the Company actually generates (i.e., outcomes). In my discussion below, I consider data on collections and customer service outcomes for PECO. My discussion will be based on data that is reported by the Commission, itself. I examine outcomes data published by the PUC in: (1) the PUC's annual Cold Weather Survey; and (2) the annual BCS report on Collections Performance and Universal Service Programs. Based on this PUC-published data, I conclude that PECO does not engage in "superior" or "exemplary" management sufficient to generate outcomes that are outside the middle-of-the-pack for Pennsylvania utilities.

Q. PLEASE DISCUSS WHAT YOU FIND BASED ON THE PUC'S MOST RECENT COLD WEATHER SURVEY.

A. PECO contributes disproportionately to the number of accounts who face serious threats to their cold weather well-being as a result of nonpayment disconnections during non-cold weather months. I reach this conclusion notwithstanding the observation that the

PUC combines PECO data for natural gas and electric customers for reporting as part of the electric data in the PUC's Cold Weather Survey results. I note that PECO has 29.2% of the total number of customers in Pennsylvania, while having 22.8% of the Confirmed Low-Income customers in the state. According to the most recent (2019) Cold Weather Survey,[93] however, PECO contributed:

- 72.9% (4,043 of 5,545) of the "total households without service after completion of the survey" (excluding "households using potentially unsafe heating sources, other central heating sources, and vacant"); and
- 73.2% (4,138 of 5,655) of the "total households without a central heating source due to termination of utility service (includes households using potentially unsafe heating sources and excludes other central heating sources and vacant residences)."

Contrary to other Pennsylvania utilities, who serve from nearly three to more than four times as many customers, PECO's customer service does not rise to the level of ensuring that customers have safe sources of home heating during Pennsylvania's cold weather months.

Moreover, the PUC's most recent Cold Weather Survey shows that PECO has under-performed other Pennsylvania utilities in reducing those customers placed at risk during the cold weather months. According to the Survey, while all (electric) utilities reduced the number of total households without service after completion of the survey by 27%

[93] The PUC's annual Cold Weather Surveys can be accessed at http://www.puc.state.pa.us/filing_resources/gas_and_electric_cold_weather_survey_results.aspx (last accessed on December 9, 2020).

from their 2014-2017 average through 2019, PECO had reduced its number by only 19% (4,043 / 5,008 = 0.81). While all (electric) utilities reduced the number of total households without a central heating source due to termination of utility service" by 28% from their 2014-2017 average through 2019, PECO had reduced its number by only 22% (4,136 / 5,284 = 0.22).

The most recent years have not revealed improvement for PECO. While all (electric) utilities increased their total households without service by only 1.7% from 2018 to 2019, PECO increased its number by more than three times that rate, 5.7%. While all (electric) utilities held their number of total households without central heating virtually constant from 2018 (5,653) to 2019 (5,655), PECO increased its number by 3.2% in that single year (4,005 / 4,138 = 0.968).

I find that PECO does not demonstrate superior or exemplary management when measured by how effectively it provides customer service to help customers who have experienced a nonpayment disconnection have their service reconnected to provide essential home heating service.

Q. PLEASE DISCUSS WHAT YOU FIND BASED ON THE MOST RECENT BCS ANNUAL REPORT ON COLLECTIONS PERFORMANCE AND UNIVERSAL SERVICE PROGRAMS.

A. When measured by the data annually reported by the PUC's Bureau of Consumer Services in the BCS "Report on Universal Service Programs and Collections

Performance," PECO Gas again does not demonstrate superior or exemplary management performance.[94] Consider that the BCS report documents that:

- PECO Gas has "confirmed" the low-income status of 24,977 (BCS, page 6) of its estimated 74,914 (BCS, page 7) low-income customers, a rate of 33.3%. This compares to a statewide confirmation rate of 62.0% (437,905 of 706,823). (BCS, at 6, 7). Indeed, given that PECO Gas' low numbers are included in the statewide total, the difference between the PECO Gas performance and non-PECO Gas performance would be even greater.
- PECO Gas under-performs on payment plans, both for residential customers as a whole and for confirmed low-income customers. BCS emphasizes the importance of payment plans. It states that "one of the stated purposes of the Chapter 56 regulations is to 'provide functional alternatives to termination.' Customers who make a payment arrangement on an outstanding balance have acknowledged that they are aware of the outstanding debt, and have avoided any imminent threat of termination. (BCS, at 17) (internal citations omitted). BCS reports that PECO Gas has a far higher percentage of its residential natural gas customers who are in debt, but are ***not*** on arrangements, than do Pennsylvania natural gas utilities as a whole. While natural gas utilities statewide have roughly one-third of their residential customers who are in debt on an arrangement, PECO Gas has less one-quarter of its residential customers who are in debt on an arrangement. (BCS, at 22).

[94] See, note 31, supra, for the source for the annual BCS reports (last accessed December 20, 2020).

- PECO Gas' performance with respect to moving Confirmed Low-Income customers on to payment arrangements is even worse when contrasted to natural gas utilities statewide. While PECO Gas has 42% of its Confirmed Low-Income customers who are in debt on an arrangement, natural gas utilities statewide have 72% of their Confirmed Low-Income customers who are in debt on an arrangement. (BCS, at 22).
- The difference is not attributable to the dollar level of arrears. PECO Gas under-performs Pennsylvania gas utilities statewide in the percentage of dollars owed which are on agreement. While natural gas utilities statewide have 43.8% of its residential customers in debt on an arrangement, PECO Gas has only 34.6% of its residential customers in debt on an arrangement. (BCS, page 26)
- The difference with Confirmed Low-Income customers is even more dramatic. While PECO Gas has 44.3% of its Confirmed Low-Income dollars owed on an agreement, natural gas utilities statewide have 75.8% of their Confirmed Low-Income dollars owed on an agreement. (BCS, page 27).
- It is not the case that PECO Gas is simply targeting its agreements to customers with the highest arrearages. Indeed, the average PECO Gas arrearages not on an agreement is far higher than the average balance on an agreement ($666.81 vs. $391.28). (BCS, page 28). Not only is PECO Gas failing to place accounts in arrears on an agreement, in other words, but those agreements that it is negotiating involve the smaller levels of arrears that are owed to the Company.

- PECO does not exhibit superior or exemplary outcomes in the number of customers it has with arrearages over $10,000. On this metric, PECO reports its gas and electric customers together. (BCS, page 30). This metric should be considered given that the data reporting is mandated by statute. As the BCS states in presenting the data: "On December 22, 2014, Act 155 became effective, reauthorizing and amending Chapter 14 of the Public Utility Code (66 Pa. C.S. §§ 1401-1419), Responsible Utility Customer Protection. Act 155 implemented a new reporting requirement for the public utilities to report data regarding the number of active (*i.e.* accounts not final billed) residential accounts that exceed $10,000 in arrearages at the end of each calendar year, along with those account balances." (BCS, page 30, internal notes omitted). According to the most recent BCS report, PECO has 82 accounts with balances exceeding $10,000, an increase of 54.7% from 2017 to 2019. While that is not the worst performance, it is also far from being at or toward the best performance. Two (electric) utilities have larger numbers, while four have smaller numbers. (Id., at 30). PECO does perform poorly in terms of the increase in accounts with balances greater than $10,000. PECO's 54.7% increase in the number of these high-balance accounts exceeds the statewide average of 29.7%, as well as exceeds every other (electric) utility, except Penelec (Id., at 30).

Q. WHY IS THIS DATA SIGNIFICANT FROM A MANAGEMENT PERFORMANCE PERSPECTIVE?

A. Ultimately, the PECO Gas performance discussed immediately above leads to higher rates of arrearages and higher costs to all ratepayers. As the PUC explained to the Pennsylvania General Assembly and Governor in its "Sixth Report to the General Assembly and Governor Pursuant to Section 1415 [regarding] Implementation of Chapter 14" (January 30, 2020). (hereinafter "Sixth Chapter 14 Report"), higher rates of arrears yield greater working capital needs.

> Cash working capital is a measurement of the days between when service is rendered and when revenue is received (and conversely when a utility receives a service and when it pays its invoice). For the residential class the days between utility service and payment of the bill are measured as a residential class average. The number of days is then multiplied by the matching operation and maintenance expense or revenue category to find a dollar value that a utility would need to have on hand. The dollar value is included in rate base so that the utility can earn a return on the capital required to bridge the gap between service rendered and revenue collected.[95]

The Commission has stated that moving customers in arrears on to payment arrangements helps the customer retire his/her arrearage more quickly. (see e.g., Sixth Chapter 14 Report, at 131).

Moreover, failing to move accounts in arrears, as well as dollars in arrears, on to payment arrangements has the adverse impact of increasing service disconnections. Moving customers on to payment arrangements helps the customer avoid falling sufficiently far into arrears that the balance is beyond the ability of the customer to retire. (see, e.g., Sixth Chapter 14 Report, at 131). As the PUC told the General Assembly and Governor,

[95] The PUC's Biennial Chapter 14 Reports, along with the annual data updates, can be accessed at: http://www.puc.state.pa.us/filing_resources/biennial_report_pursuant_to_section_1415.aspx (last accessed December 9, 2020).

"Termination of utility service is the most serious consequence of customer nonpayment. The termination of utility service is a last resort when customers fail to meet their payment obligation." (Id.)

Given the discussion above, it thus comes as no surprise that PECO Gas does not exhibit superior or exemplary outcomes when it comes to avoiding the disconnection of service. For residential customers, the PECO Gas termination rate is somewhat higher than the statewide average (PECO Gas: 4.5% vs. gas industry average: 4.0%). The PECO Gas performance is not superior or exemplary, but rather nearly at the statewide average. (BCS, page 13). The same cannot be said for the PECO Gas termination rates for its Confirmed Low-Income customers. Instead, the PECO Gas Confirmed Low-Income termination rate (19.0%) is more than two times higher than the statewide average (9.1%). (BCS, page 14). No other natural gas utility has a Confirmed Low-Income termination rate that is close to PECO Gas (NFG being the closest at 16.4%, with PGW being the next closest at 13.4%). (Id.)

Q. WHAT DO YOU CONCLUDE?

A. The data presented above presents a consistent message. That message is that PECO Gas does not demonstrate superior or exemplary management when it comes to issues involving customer service and collections performance.

Part 5. Proposed Fraud/Theft Investigation Charge.

Q, PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In its proposed tariff, the Company is proposing to add a Section 17.7, to Rule 17, entitled "Theft/Fraud Investigation." The proposed section states the following:

> If the Company's meters or other Company equipment on the customer's premises have been tampered or interfered with by any means whatsoever, the customer being supplied through such equipment whether an applicant or a customer as defined at pa C.S. § 1403 shall pay a theft/fraud investigation charge in addition to any amount that the Company estimates is due for service used, but not registered on the Company's meter. These theft/fraud investigation charges listed below include allocated overheads, all investigative costs and administrative cost deemed necessary by the Company to correct any and all unauthorized conditions at the premise. The Company reserves the right to assess theft/fraud investigation charges as a precedent to reconnection of service as well as the right to assess a separate reconnection charge as described in Rule 17.6.

The current charge is proposed to be $460.00. (Id.)

Q. IS THE PROPOSED PECO TARIFF OBJECTIONABLE?

A. Yes. The proposed tariff language provides the Company with authority to determine the extent to which, if at all, the "Company's meters or other Company equipment" has been "tampered or interfered with." No definition has been provided for either term. No process has been established to determine whether an ***allegation*** that the Company's equipment has been "tampered or interfered with" have a basis in fact. I note that allegations of meter tampering (or "interference" with Company equipment) have a higher standard of proof that must be met than most allegations.[96] There is, with respect to any allegation of fraud, a presumption that the customer acted honestly in good faith.

[96] Colton (1990). "Heightening the Burden of Proof in Utility Shutoff Cases Involving Allegations of Fraud." 33 Howard L. Review 137.

That allegation must be overcome by clear and convincing evidence. The fact the PECO Gas considers an allegation of meter tampering (or interference with other Company equipment) to be a type of "fraud" is evident in the tariff itself (i.e., "The Company reserves the right to assess theft/fraud investigation charges. . ."). Indeed, the Company's own label for its proposed tariff section is "Theft/Fraud Investigation." The PECO Gas tariff does not provide for any process to determine the legitimacy of an allegation that the Company's meters "or other Company equipment" have been "tampered or interfered with," it does not provide a process by which the Company must sustain its allegations by application of the appropriate burden of proof.

Q. IS THERE A SECOND PROBLEM WITH THE COMPANY'S PROPOSED TARIFF CHANGE?

A. Yes. The proposed tariff is irremediably excessively broad. Rather than proposing a specific charge applicable to specifically prescribed actions on the part of a customer, PECO Gas proposes a charge applicable if the Company alleges that its equipment has been interfered with "by any means whatsoever." Not only is there no limit on what PECO might deem to be "interference," but there is no limit on what activities PECO deems to be covered by the charge. Moreover, while the proposed tariff references meter tampering, the charge is not limited to meter tampering. The proposed PECO Gas language covers all allegations of "theft/fraud."

The problem with the over-reach of the tariff, for example, can be seen in a hypothetical applicable to a landlord/tenant situation. Tenant A moves into a rental unit, believing the landlord has provided natural gas service. The landlord allows Tenant A to move in, believing that the Tenant understands his/her obligation to transfer service into the Tenant's name. PECO alleges that the Tenant, who is not a customer of PECO, has committed "fraud," asserting that taking service without applying for service falls within the language of "interfering with equipment by any means whatsoever."

In this (and similar) situations –this hypothetical is not intended to be exclusive, but rather illustrative—what PECO alleges to be "fraud" is seen to be a "mistake" by others. Nonetheless, PECO imposes a fee pursuant to this tariff of $460 for costs, including "all investigative costs," "allocated overheads," and "administrative costs deemed necessary by the Company. . ."

The over-reach of the tariff can be seen in the tariff language further when PECO Gas, in the four corners of its tariff, expands its charges from being applicable to meter tampering (or interference by any means whatsoever), to "theft/fraud," to circumstances which PECO Gas merely alleges involves "unauthorized conditions at the premise."[97] The hypothetical illustration above, in other words, even if not representing meter tampering, may well be alleged to be an "unauthorized condition."

Q. IS IT APPROPRIATE TO APPROVE A CHARGE THAT INCLUDES "ALLOCATED OVERHEADS. . .AND ADMINISTRATIVE COSTS"?

[97] PECO proposes to delete its prior language stating that "in the case of fraud, the reconnection charge will also include allocated overheads, all investigative costs and administrative costs as determined by the Company." PECO Exh. JAB-2, page 29 of 83. That deletion should occur notwithstanding a denial of the proposed "Theft/Fraud Investigation Charge."

A. No. Overhead costs and administrative costs have already been included in base rates. To include these costs in the proposed charge would be allow PECO Gas to recover them twice: once in base rates and again through the proposed new tariffed charge.

Q. IS THE PROPOSED TARIFF LANGUAGE INAPPROPRIATE IN ITS APPLICABILITY?

A. Yes. PECO Gas proposes a tariff charge to be applied even if a household is not a PECO customer. PECO's tariff proposal is to assess the proposed charge to "an applicant" as well as to a customer. The $460 charge may be assessed by PECO Gas whether or not the person had any involvement with, or any responsibility for, whatever objectionable behavior PECO Gas is alleging (whether it be meter tampering, "interference with other equipment by any means whatsoever," "theft/fraud," or "unauthorized conditions").

Whatever the intended breadth of the tariff, the language in the four corners of the tariff language as proposed by PECO Gas is excessive and over-reaching to the extreme. The language within the four corners of the proposed tariff is certainly not limited to meter tampering.

Q. WHAT ARE THE CONSEQUENCES OF IMPOSING THE PROPOSED "THEFT/FRAUD INVESTIGATION CHARGE"?

A. When PECO Gas states that it will apply this charge to "applicants," it seems clear that the Company will refuse to connect service to a new customer unless/until the proposed charge has been paid. In addition, PECO Gas explicitly states that it "reserves the right to assess theft/fraud investigation charges as precedent to reconnection of service." Inherent with reserving that "right," in other words, is the presumed action by PECO to disconnect service, and to leave a premises without service, pending payment of the fee.

Q. WILL LOW-INCOME CUSTOMERS/APPLICANTS LIKELY BE DISPROPORTIONATELY ADVERSELY AFFECTED BY THE PROPOSED CHARGE?

A. Yes. My testimony above documents that low-income customers in the PECO Gas service territory are disproportionately tenants, the housing situation where allegations that usage is "unauthorized" are more likely to occur. In addition, Census data clearly demonstrates that tenants move far more frequently than do homeowners,[98] giving rise to more frequent possibilities that there may be allegations of "unauthorized use."

Q. WHAT DO YOU CONCLUDE?

A. The PECO Gas proposed tariff charge is fatally flawed. It should not be approved.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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[98] See, e.g., Tenure by Year Households Moved into Unit (ACS Table B25038, Table B25039) (ACS 2019 5YR), available at https://data.census.gov/cedsci/all?q=moved-in (last accessed December 17, 2020); see also, Median Year Householder Moved into Unit by Tenure, (ACS Table B25039) (ACS 2019 5YR), available at https://data.census.gov/cedsci/all?q=moved-in (last accessed December 17, 2020).

Colton Schedules

Schedule RDC-1
Proposed COVID-19 Emergency Relief Program

1. COVID-19 EMERGENCY RELIEF PROGRAM Emergency Relief Program ("ERP").
    a. Effective one (1) day after the issuance of the Commission's Final Order in this proceeding, PECO will implement a temporary program to provide bill payment assistance for customers who need temporary relief measures during the pendency, and for a period following the termination of the shutoff restrictions ordered by the Commission.
    b. Enrollment in the ERP may be made online or by phone.
    c. Eligibility.
        i. Any residential customer meeting the following qualifications will be eligible for the program: (i)The customer is a current customer in arrears; and (ii)The customer is not participating or eligible for CAP; and (iii)The customer provides the following:
            1. proof of unemployment benefits filed/received for one or more household members on March 13, 2020; or
            2. proof the customer, or a member of the customer's household, is eligible for, or has received, the first federal COVID-19 relief check in the amount of $1,200.

2. Benefits.
    a. Residential customer ERP benefits shall include:
        i. Upon enrollment, suspension of collection efforts for any amounts due for service beginning as of the March 2020 billing cycle and continuing through the duration of the shutoff restrictions adopted pursuant to paragraph 1; and
        ii. Upon enrollment, a customer shall be entitled to a one-time credit (up to $400) in an amount equal to 25% of the customer's applicable balance as of the ERP Enrollment Termination Date (defined below).
        iii. All ERP customers will be screened for CAP and MEAF eligibility, and those who may be eligible will be encouraged to apply for the most appropriate program to address their needs.
        iv. For customers determined to be ineligible for CAP, any remaining current applicable balance shall be subject to a long-term deferred payment arrangement (including the suspended amount). For purposes of establishing a deferred payment arrangement for applicable balances, the Company shall offer payment arrangement terms consistent with section 1405(b) or 24 months, whichever is longer, unless a shorter arrangement is

affirmatively agreed to by the consumer. Longer payment arrangements may be offered to ERP participants at the discretion of the Company.

3. Cost-recovery. The Company shall track the costs associated with providing the ERP for deferred recovery over ten years (without interest), including but not limited to implementation costs and direct bill credit amounts.

4. Termination and Extension. As the COVID-19 situation is changing rapidly, the extent of federal and state assistance is not fully known, and to protect the Company from an indefinite financial exposure, the ERP Enrollment period will terminate at the end of the December 31, 2021 billing period. No later than 30 days prior to the ERP Enrollment Termination Date, the Company will initiate discussions with the parties to this PECO Gas base rate proceeding to discuss a possible extension of customer benefits provided under the ERP.

5. ERP Enrollment Termination Date. Upon occurrence of the ERP Enrollment Termination Date, enrollment in the ERP will cease except as to customers who initiate enrollment activity prior to the ERP Enrollment Termination Date, unless an extension is agreed upon or ordered by the Commission.

Colton Appendix A: Professional Background

Roger Colton
Fisher, Sheehan & Colton
Public Finance and General Economics
Belmont, MA
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EDUCATION:

J.D. (Order of the Coif), University of Florida (1981)

M.A. (Regulatory Economics), McGregor School, Antioch University (1993)

B.A. Iowa State University (1975) (journalism, political science, speech)

PROFESSIONAL EXPERIENCE:

Fisher, Sheehan and Colton, Public Finance and General Economics: 1985 - present.

As a co-founder of this economics consulting partnership, Colton provides services in a variety of areas, including: regulatory economics, poverty law and economics, public benefits, fair housing, community development, energy efficiency, utility law and economics (energy, telecommunications, water/sewer), government budgeting, and planning and zoning.

Colton has testified in state and federal courts in the United States and Canada, as well as before regulatory and legislative bodies in more than three dozen states. He is particularly noted for creative program design and implementation within tight budget constraints.

PROFESSIONAL AFFILIATIONS:

Past Chair:	Belmont Zoning By-law Review Working Committee (climate change)
Member:	Board of Directors, Massachusetts Rivers Alliance
Columnist:	Belmont Citizen-Herald
Producer:	Belmont Media Center: BMC Podcast Network
Host:	Belmont Media Center: Belmont Journal
Member:	Belmont Town Meeting
Vice-chair:	Belmont Light General Manager Screening Committee
Past Chair:	Belmont Goes Solar
Coordinator:	BelmontBudget.org (Belmont's Community Budget Forum)
Coordinator:	Belmont Affordable Shelter Fund (BASF)
Past Chair:	Belmont Solar Initiative Oversight Committee
Past Member:	City of Detroit Blue Ribbon Panel on Water Affordability
Past Chair:	Belmont Energy Committee
Member:	Massachusetts Municipal Energy Group (Mass Municipal Association)

Past Chair:	Housing Work Group, Belmont (MA) Comprehensive Planning Process
Past Member:	Board of Directors, Belmont Housing Trust, Inc.
Past Chair:	Waverley Square Fire Station Re-use Study Committee (Belmont MA)
Past Member:	Belmont (MA) Energy and Facilities Work Group
Past Member:	Belmont (MA) Uplands Advisory Committee
Past Member:	Advisory Board: Fair Housing Center of Greater Boston.
Past Chair:	Fair Housing Committee, Town of Belmont (MA)
Past Member:	Aggregation Advisory Committee, New York State Energy Research and Development Authority.
Past Member:	Board of Directors, Vermont Energy Investment Corporation.
Past Member:	Board of Directors, National Fuel Funds Network
Past Member:	Board of Directors, Affordable Comfort, Inc. (ACI)
Past Member:	National Advisory Committee, U.S. Department of Health and Human Services, Administration for Children and Families, Performance Goals for Low-Income Home Energy Assistance.
Past Member:	Editorial Advisory Board, International Library, *Public Utility Law Anthology*.
Past Member:	ASHRAE Guidelines Committee, GPC-8, *Energy Cost Allocation of Comfort HVAC Systems for Multiple Occupancy Buildings*
Past Member:	National Advisory Committee, U.S. Department of Housing and Urban Development, Calculation of Utility Allowances for Public Housing.
Past Member:	National Advisory Board: Energy Financing Alternatives for Subsidized Housing, New York State Energy Research and Development Authority.

PROFESSIONAL ASSOCIATIONS:

National Association of Housing and Redevelopment Officials (NAHRO)
National Society of Newspaper Columnists (NSNC)
Association for Enterprise Opportunity (AEO)
Iowa State Bar Association
Energy Bar Association
Association for Institutional Thought (AFIT)
Association for Evolutionary Economics (AEE)
Society for the Study of Social Problems (SSSO)
Association for Social Economics

BOOKS

Colton, *et al.*, ***Access to Utility Service***, National Consumer Law Center: Boston (4th edition 2008).

Colton, *et al.*, ***Tenants' Rights to Utility Service***, National Consumer Law Center: Boston (1994).

Colton, ***The Regulation of Rural Electric Cooperatives***, National Consumer Law Center: Boston (1992).

BOOK CHAPTERS

Colton (2018). The equities of efficiency: distributing energy usage reduction dollars, Chapter in Energy Justice: US and International Perspectives (Edited by Raya Salter, Carmen Gonzalez and Elizabeth Ann Kronk Warner), Edward Elgar Publishing (London, England).

JOURNAL PUBLICATIONS

65 publications in industry and academic journals, primarily involving utility regulation and affordable housing. (list available upon request)

TECHNICAL REPORTS

200 technical reports for public-sector and private-sector clients (list available upon request)

JURISDICTIONS IN WHICH EXPERT WITNESS PROVIDED

1. Maine
2. New Hampshire
3. Vermont
4. Massachusetts
5. Massachusetts
6. Rhode Island
7. Connecticut
8. New Jersey
9. Maryland
10. Pennsylvania
11. Washington D.C.
12. Virginia
13. North Carolina
14. South Carolina
15. Florida (Federal Court)
16. Alabama
17. Mississippi
18. Tennessee
19. Kentucky
20. Ohio
21. Indiana
22. Michigan
23. Wisconsin
24. Illinois
25. Minnesota
26. Iowa
27. Missouri
28. Arkansas
29. Texas (Federal Court)
30. South Dakota
31. North Dakota
32. Montana
33. Colorado
34. New Mexico
35. Arizona
36. Utah
37. Idaho
38. Nevada
39. Washington
40. Oregon
41. California
42. Hawaii

Canadian Provinces

1. Nova Scotia
2. Ontario
3. Manitoba
4. British Columbia

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018929
	:	
PECO Energy Company – Gas Division	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts set forth in my Direct Testimony, OCA Statement 5, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: December 22, 2020
*300678

Signature: ______________________
Roger D. Colton

Consultant Address: Fisher, Sheehan, & Colton
34 Warwick Road
Belmont, MA 02478

OCA Statement 6

R-2020-3018929
2/17/21 JK

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

	:	
PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	
	:	Docket No. R-2020-3018929
PECO ENERGY COMPANY - GAS DIVISION	:	
	:	

DIRECT TESTIMONY
OF
GEOFFREY C. CRANDALL

ON BEHALF OF
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

December 22, 2020

I. QUALIFICATIONS

Q. What is your name and business address?

A. My name is Geoffrey C. Crandall. My business address is MSB Energy Associates, Inc., 6907 University Avenue #162, Middleton, Wisconsin 53562.

Q. On whose behalf are you testifying today?

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

Q. Please describe your background and experience in the field of gas and electric utility regulation.

A. I am a principal and the Vice President of MSB Energy Associates, Inc. I have over 45 years of experience in utility regulatory issues, including resource planning, restructuring, mergers, fuel, purchase power and gas cost recovery and planning analysis, energy efficiency, conservation and load management impacts, program design and other issues. I have provided expert testimony before more than a dozen public utility regulatory bodies throughout the United States. I have provided expert testimony before the United States Congress on several occasions and have previously filed testimony in over a half-dozen cases before the Pennsylvania Public Utility Commission.

My experience includes over 15 years of service on the Staff of the Michigan Public Service Commission. In my tenure at the Michigan Public Service Commission, I served as an analyst in the Electric Division (Rates and Tariff section) involving rate as well as fuel and purchase power cases. I also served as the Technical Assistant to the Chief of Staff, supervisor of the energy conservation section (involving residential and commercial energy efficiency programs). I also served as the Division Director of the Industrial, Commercial and Institutional Division. In that capacity, I was Director of the Division that had responsibility for the energy efficiency and conservation program design, funding, and implementation of Michigan utility and DOE-funded private company implemented programs and initiatives involving Industrial, Commercial and Institutional gas and electric customers throughout Michigan.

In 1990, I became employed by MSB Energy Associates, Inc. and have served clients throughout the United States on numerous projects related to system planning, transmission need and siting, fuel, purchase power and gas cost recovery assessments, energy efficiency and load management program development, electric restructuring, customer impact analyses, and other issues. My vita is attached as Schedule GCC-1.

II. <u>DIRECT TESTIMONY</u>

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

A. The purpose of my testimony is to assess the reasonableness of PECO's proposed Natural Gas (voluntary) Energy Efficiency and Conservation Plan that was included in Docket No. R-2020-3018929. I address a number of operational, cost-effective, programmatic, budget and implementation concerns with PECO's proposed natural gas energy efficiency and conservation programs which were described by Witness Masalta in this docket. I offer specific suggestions to the Administrative Law Judge and the Commission regarding the reasonableness of the proposed programs.

Q. Please identify the important issues that you believe should be addressed by the Commission in this docket.

A. Key concerns and issues that I have with PECO's proposed energy efficiency and conservation plans are:

- Reasonableness of PECO's request to increase the residential annual budget from $2.008 million to $4.5 million. I recommend continuation of the current budget levels of $2,008,000 per year for the residential programs and $28,000 for the commercial programs.
- PECO's estimation of the cost-effectiveness of its proposed energy efficiency and conservation programs.
- PECO has failed to provide OCA with evaluation, measurement and verification (EMV) studies and reports on its 2010-2020 energy efficiency programs either

done internally or (more appropriately) by a third party professional EMV team. Such documentation was not provided even though OCA requested relevant studies. This has impeded OCA's ability to conduct a thorough review of PECO's 2010-2020 energy efficiency and conservation (EE & C) programs. PECO should make those studies available to interested parties in this docket.

- The implementation and customer participation in PECO's 2010-2020 energy efficiency and conservation programs was inadequate.

- I am concerned that PECO is relying primarily on its website and word of mouth to increase customer participation which may not be sufficient to generate more robust customer participation.

- I am also concerned that Commercial gas energy efficiency and conservation program costs are allocated to the marketing budget and PECO does not have a reconciliation mechanism, should the designated funds not be fully utilized.

Q. Please summarize your conclusions.

A. PECO did not demonstrate the cost effectiveness of its proposed programs in its direct case. Through discovery, I obtained PECO's cost effectiveness analyses, which showed that PECO's space and water heating programs were not cost effective from the total resource cost perspective based on PECO's forecast of its avoided gas costs.

I also determined that PECO's evaluation of its proposed new Smart Thermostat program greatly exaggerates the energy savings, such that each thermostat saves more energy annually than the entire annual heat load of a typical home. Correcting that error results in the Smart Thermostat program failing the total resource cost based on PECO's forecast of its avoided gas costs.

I also determined that PECO's avoided cost forecasts understate the avoided costs during the winter heating season, and thus understate the value of the space heating programs (including Smart Thermostats).

I concluded that with the adjustments to the avoided costs, some of the space heating programs which failed under PECO's calculations are likely to pass. Others are marginally failing to pass, but may pass when the avoided costs are fully corrected. Still others are not likely to pass.

PECO did not provide evidence supporting its desire to more than double its residential energy efficiency program budget, while it is currently spending only about half of the money it currently budgets for and collects. PECO could in essence double its energy efficiency program activities within the existing budget.

I believe that increasing budget for programs other than low income that are not cost effective is not appropriate at any time, and even more so during the economic hardship from the COVID pandemic.

I also believe that increasing the budget for programs when PECO is using only slightly more than half its existing budget is inappropriate, especially in light of the economic hardships due to the COVID pandemic.

I have developed an alternative energy efficiency portfolio based on: i) not increasing the energy efficiency program costs charged to ratepayers above current levels; ii) adopting PECO's proposed low-income program to offer services to more vulnerable customers affected by the COVID pandemic; iii) not funding PECO's proposed energy efficiency programs, with the exception of low income, that will not be cost effective; iv) reducing funding for PECO's proposed energy efficiency programs which are not now cost effective but may become so if analyzed using more appropriate avoided costs; and v) funding PECO's programs that are cost effective. My recommended portfolio is below:

Comparison of PECO and OCA Recommended Budgets		
Program/Portfolio	PECO 2021 and beyond Programs	OCA Recommendations
Residential Efficient Furnace	$1,507,500	$518,000
Residential Super-Efficient furnace	$250,000	$75,000
Residential boiler	$150,000	$0
Residential Storage Water Heater	$25,000	$ 0
Residential Smart Thermostat	$332,500	$50,000
Residential Aerators and showerheads	$65,000	$65,000
Low Income S&EHP	$1,000,000	$1,000,000
Residential Emerging Technologies Pilot	$125,000	$0
Commercial Efficient Furnace	$12,000	$12,000
Commercial Efficient Boiler	$10,500	$10,500
Education/Admin/CSP admin	$1,050,625	$300,000
Annual Total	$4,528,125	$2,030,500

I recommend that PECO provide an updated benefit-cost analysis of its energy efficiency programs correcting for the errors identified in my testimony. I reserve the right to update my recommendations based on any updated cost-benefit analysis.

<u>Overview of PECO's Proposal</u>

Q. Please identify the energy efficiency and conservation programs and services that PECO is now offering to its residential and commercial customers.

A. According to PECO's Application and the testimony of Witness Masalta, PECO is currently offering a $300 rebate for an ENERGY STAR® residential furnace replacement, a $50 rebate for an ENERGY STAR® storage water heater, a $300 rebate for an ENERGY STAR® residential boiler, a $300 rebate for an ENERGY STAR® commercial furnace and a $300 rebate for an ENERGY STAR® commercial boiler. PECO St. 9 at 3-4. PECO'S energy efficiency and conservation budget since 2010, as approved in their last base rate case, was included in Docket No. R-2010-2161592 in the amount of $2.008 million/year. PECO St. 9 at 5.

Q. What is PECO proposing to offer its residential and commercial customers in its energy efficiency and conservation programs beginning in 2021?

A. PECO proposes to offer (1) its existing $300 rebate for an ENERGY STAR® residential furnace replacement (having an Annual Fuel Utilization Efficiency (AFUE) of 95% or above), (2) a new $500 rebate for an ENERGY STAR® + residential furnace replacement (having an AFUE of 97% or above and the offer cannot be combined), (3) a new $50 rebate for a smart thermostat, (4) discount pricing on faucet aerators and showerheads, (5) an expanded $100 rebate for an ENERGY STAR® storage water heater, (6) its existing

$300 rebate for an ENERGY STAR® residential boiler, (7) its existing $300 rebate for an ENERGY STAR® commercial furnace and (8) its existing $300 rebate for an ENERGY STAR® commercial boiler. PECO St. 9 at 6-7. PECO is also proposing to offer a low-income program entitled the "Safe and Efficient Heating Program". PECO St. 9 at 7-8. This program enhances energy efficiency (combustion test, filter changeouts, maintenance, etc.) in households that have an income between 0 and 100% of the poverty guideline and are not eligible for the Low-Income Usage Reduction Program (LIURP). PECO has also proposed a residential emerging technologies pilot program to gauge customer interest, assess energy savings and cost reduction technologies including ozone laundry system, gas heat pumps, etc. PECO St. 9 at 8. PECO is proposing an administrative, education and Consumer Services Provider budget component of $1.045 million. PECO St. 9 at 9.

Overall PECO'S residential energy efficiency and conservation budget would result in an increase from $2.008 million/year to $4.5 million/year beginning in 2021. The Company's breakdown of the energy efficiency and conservation budget is summarized in Table 1 below. PECO St. 9 at 9.

Table 1

Expanded Residential Programs	Estimated Funding (Dollars)
Residential Gas High-Efficiency Furnace Rebate	1,507,500
Residential ENERGY STAR®+ Furnace Rebate*	250,000
Residential Gas High-Efficiency Boiler Rebate	150,000
Residential Gas High-Efficiency Water Heater Rebate**	25,000
Residential Gas Heating Smart Thermostat Rebate*	332,500
Residential Gas Water Heating Rebates (aerators and showerheads)*	65,000
Low-Income Safe and Efficient Heating Program (including CSP Admin)*	1,000,000
Residential Emerging Technologies Pilot*	125,000
Education, PECO Admin, CSP Admin	1,045,000
Total	**4,500,000**

* New program
** Increased rebate for existing program

Q. How is the Company proposing to recover the costs of the existing, expanded and new residential energy efficiency and conservation programs?

A. PECO is proposing to recover $4.5 million per year through residential gas distribution base rates. If less than $4.5 million is spent, the difference would be credited to the following year's Universal Service Fund Charge (USFC), as it currently does with its existing residential EE&C budget. PECO St. 9 at 10.

Q. How is the Company proposing to recover the costs of the commercial energy efficiency and conservation programs?

A. PECO's cost recovery of the commercial program expenses is through gas base rates that cover PECO's Marketing Department's budget. According to PECO they do not have a reconciliation mechanism to true up the funds annually or otherwise.

Concerns About Existing Energy Efficiency and Conservation Programs

Q. Before discussing the Company's proposal in this proceeding, can you discuss your concerns with the Company's existing energy efficiency and conservation programs?

A. Yes. As a result of the base rate case settlement agreed to by PECO in 2010, the Commission authorized an annual budget of $2,008,000 so that PECO could provide incentives to its customers for residential furnaces, boilers and residential storage water heaters. Unfortunately, PECO has fallen short of getting robust customer and trade ally participation in its energy efficiency programs which is needed to deliver incentives and encouragement to PECO customers to reduce energy waste and the inefficient use of natural gas. See Schedule GCC-2. As was indicated in response to OCA VII-12, PECO is relying primarily on word-of-mouth and the Company's website to obtain customer participation in the energy efficiency and conservation programs. PECO needs to improve the active participation of more of its residential and commercial customers.

Moreover, even though I requested program impact studies and reports from PECO, on the 2010-2020 programs, they were not made available to me, as of this writing. This impedes my ability to review and assess the existing ratepayer funded programs.

Concerns About Proposed Energy Efficiency and Conservation Programs

Q. In addition to the concerns noted above, are the energy efficiency programs PECO is proposing for residential customers cost-effective?

A. At the portfolio level, PECO has determined that the portfolio of residential programs in aggregate is cost effective under the Total Resource Cost (TRC) test (Table 2 below). PECO also determined that its energy efficiency portfolio is cost effective for the utility cost test, ratepayer impact test, societal cost test and participant cost test.

Table 2

PECO Energy Efficiency Portfolio Cost Effectiveness Under TRC				
	2021	2022	2023	2024
Residential Programs	2.65	2.74	2.86	2.98
Low Income	0.21	0.22	0.22	0.23
Commercial Programs	1.01	1.04	1.09	1.13
Total PECO Portfolio	2.02	2.09	2.18	2.28

Source: Confidential Attachment OCA-VII-26(a), Tab "1-Portfolio Summary"

However, PECO's analysis shows that at the measure and program levels, the furnace/boiler and storage water heater programs fail the TRC.

Q. What are the TRC benefit cost ratios of the programs that fail the TRC test according to PECO's analysis?

A. The ENERGY STAR® Furnace, ENERGY STAR® Boiler and ENERGY STAR® Storage Water Heater programs are existing residential programs, the latter of which is proposed to be expanded with higher rebate levels. The ENERGY STAR®+ Furnace program is a proposed new residential program targeting even higher efficiency furnaces. In addition, the existing commercial ENERGY STAR® Furnace program also fails the TRC. A benefit-cost ratio of less than 1.0 means that the program is not cost effective. Table 3 shows that according to PECO's calculations, PECO's residential proposed space and water heating programs are not cost effective under the TRC. PECO's commercial ENERGY

STAR® Furnace program also does not pass the TRC test, although its impact is small (40 participants).

Table 3

PECO Proposed Programs Not Cost Effective Under TRC				
	2021	2022	2023	2024
Residential ENERGY STAR® Furnace (>= 95% AFUE)	0.67	0.69	0.72	0.75
Residential ENERGY STAR®+ Furnace (>= 97% AFUE)	0.62	0.64	0.67	0.69
Residential ENERGY STAR® Boiler (>= 90% AFUE)	0.40	0.41	0.43	0.44
Residential Storage Water Heater (0.67 EF)	0.18	0.18	0.19	0.20
Commercial ENERGY STAR® Furnace <225 kBTU/hr (>= 90% AFUE)	0.85	0.88	0.92	0.95

Source: Confidential Attachment OCA-VII-26(a), Tab "2-Measure Summary"

Q. How can it be that PECO's total energy efficiency portfolio easily passes the TRC even though five of its mainstay programs are not cost effective?

A. PECO is proposing to add three new programs, the Smart Thermostat, Low Flow Faucet Aerator and the Low Flow Shower Head programs, which it claims are highly cost effective. According to PECO's calculations, they produce significant savings, are low cost and have high participation rates, resulting in high benefit-cost ratios as shown in Table 4. In addition, PECO's existing commercial ENERGY STAR® Boiler program is cost effective but has little impact (35 participants).

Table 4

PECO Proposed Programs That Are Cost Effective Under TRC				
	2021	2022	2023	2024
Residential Smart Thermostat	8.64	8.96	9.40	9.88
Residential Low Flow Faucet Aerator	18.20	18.59	19.01	19.44
Residential Low Flow Shower Head	15.98	16.33	16.70	17.09
Commercial ENERGY STAR® Boiler <300kBTU/hr (>= 90% AFUE)	1.53	1.58	1.64	1.70

Source: Confidential Attachment OCA-VII-26(a), Tab "2-Measure Summary"

Because PECO believes the three new residential programs are highly cost effective, heavy reliance on these programs offsets the programs that are not cost effective and results in PECO's prediction that the overall portfolio is cost effective.

Q. What is the relative energy savings that PECO projects for each measure?

A. Comparing the savings by measure, PECO estimates that one Smart Thermostat will save 62 MCF annually, about five times the amount saved by a residential furnace and about 50 times the amount saved by an efficient storage water heater.

Q. What is the relative dollar savings that PECO projects for each measure?

A. Comparing the savings by measure, PECO estimates that one Smart Thermostat will save $181.35 annually, or a present value of $1,329.89 over its 11-year life, about 3.5 times the money saved by an energy efficient furnace over its 18-year life.

Q. What is the relative dollar savings that PECO projects for each of the seven programs PECO is proposing?

A. The gross savings are dominated by the Smart Thermostats program. Because the relative costs of the Smart Thermostats program are small, the net savings are even more dominated by the Smart Thermostats program. This is summarized in Table 5 as follows.

Table 5

PECO Proposed Programs for 2021 – TRC Analysis				
	Annual Gas $ Saved per Participant	Program Life Cycle Gross Savings PV$	Program Cost PV$	Program Life Cycle Net Savings PV$
Residential ENERGY STAR® Furnace (>= 95% AFUE)	37.08	1,814,930	2,698,425	-883,495
Residential ENERGY STAR®+ Furnace (>= 97% AFUE)	42.02	204,669	329,500	-124,831
Residential ENERGY STAR® Boiler (>= 90% AFUE)	19.14	93,208	234,500	-141,292
Residential Storage Water Heater (0.67 EF)	3.44	7,012	39,750	-32,738
Residential Smart Thermostat	181.35	8,843,749	1,024,100	7,819,649
Residential Low Flow Faucet Aerator	0.82	527,937	29,000	498,937
Residential Low Flow Shower Head	3.42	1,775,376	111,096	1,664,280
Commercial ENERGY STAR® Furnace <225 kBTU/hr (>= 90% AFUE)	37.61	14,654	17,160	-2,506
Commercial ENERGY STAR® Boiler <300kBTU/hr (>= 90% AFUE)	70.05	25,019	16,415	8,676

Source: Confidential Attachment OCA-VII-26(a), Tab “2-Measure Summary”

It should be noted from PECO's analysis that 79% of the portfolio savings come from the Smart Thermostat program, 17% from the Low Flow Shower Head program, 5% from Low Flow Aerator program, and 9% from the commercial Boiler program. With the commercial boiler program as the exception, the proposed space and water heating programs are net losers and reduce the overall portfolio TRC dollar savings.

It should also be noted that the gas energy savings represents only 8% of the Low Flow Faucet Aerator program savings and only 10% of the Low Flow Showerhead program savings. The rest of the savings for these programs are due to the cost of saved water.

Q. **Are you satisfied with PECO's analysis of smart thermostats?**

A. No. It appears that PECO made an error in its analysis. The amount of energy and dollar savings PECO attributes to smart thermostats does not seem reasonable. PECO's cost effectiveness analysis is based on each smart thermostat saving 62.00 MCF per year[1]. (Confidential Attachment OCA-VII-26(a), Tab "4-MICS"). In PECO's analysis, it takes less energy to heat a typical residential home for an entire year than what PECO assumed each smart thermostat would save that year.[2] Clearly, this is an error since the smart

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[1] PECO identified the source of the smart thermostat characteristics as Mid Atlantic TRM V9/PA 2021 TRM. The Mid Atlantic TRM establishes smart thermostat savings to be 6% of the fossil fuel used for space heating, which is far less than the value PECO used in its analysis.

[2] The American Gas Association reported that a typical new home uses 59.6 MMBTU per year, or about 57.5 MCF per year, for space heating. "A Comparison of Energy Use, Operating Costs, and Carbon Dioxide Emissions of Home Appliances 2020 update," EA 2020-04, October 1, 2020, pages 7-8. Thus, PECO's benefit-cost analysis attributed <u>savings</u> of gas used per home per year for space heating resulting from the smart thermostat that is greater than the total gas use per year per average home for space heating.

thermostat cannot save 100% of the space heating load. In contrast, Philadelphia Gas Works estimated that smart thermostats save 8% on home heating usage.[3]

Q. What would be the effect of correcting the savings attributable to the smart thermostat program on the measure, program and portfolio cost effectiveness?

A. It would greatly reduce the benefit cost ratios, i.e., smart thermostats would be less cost effective than PECO proposed.

Philadelphia Gas Works estimated that each smart thermostat would save 5.15 MMBTU per year[4], or about 4.96 MCF[5]. Using the corrected smart thermostat savings in PECO's cost-effectiveness spreadsheet, smart thermostats are no longer cost effective at the measure level and the entire portfolio becomes less cost-effective. See Table 6.

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[3] Philadelphia Gas Works EnergySense Demand Side Management Portfolio, Docket No. P-2014-2459362, Implementation Plan Fiscal Years 2021-2023, May 6, 2020, page 6.

[4] Philadelphia Gas Works EnergySense Demand Side Management Portfolio, Docket No. P-2014-2459362, Implementation Plan Fiscal Years 2021-2023, May 6, 2020, page 23. PGW's projects that its Smart Thermostat program will save 34,089 MMBTU annually from 6,625 smart thermostats installed.

[5] One thousand cubic feet (Mcf) of natural gas equals 1.037 MMBtu equals 10.37 therms.

Table 6

Impact of Corrected Smart Thermostat Savings on TRC Benefit-Cost Ratios 2021			
Savings Per Installation	Measure	Residential Programs (Excluding Low Income)	Total PECO Portfolio (Including Low Income)
62 MCF PECO Calculation	8.64	2.65	2.02
4.96 MCF Corrected Savings	0.69	1.02	0.81

Source: Confidential Attachment OCA-VII-26(a), Tab "1-Portfolio Summary"

Q. Should the Commission reject PECO's proposed Smart Thermostat program because it is not cost effective based on this analysis?

A. No. Although it appears that the Smart Thermostat program is not cost effective using corrected savings values, PECO's method of estimating avoided costs is likely to understate the avoided cost of gas used to evaluate smart thermostats. Using proper avoided costs will increase the avoided costs, and thus increase the benefits attributable to the Smart Thermostat program. I discuss this further in reference to the space and water heating programs.

In addition, PECO's calculation (and my update using revised gas savings in PECO's spreadsheet) includes only the gas savings. Smart thermostats would also be valuable in controlling electric air conditioning loads in the summer, and the value of doing so is not included in PECO's calculations or mine. Philadelphia Gas Works analysis of smart thermostats included significant electric energy savings. Including electric savings in the

PECO Smart Thermostat program, in conjunction with proper avoided costs, would likely result in the program being cost effective, although at a lower benefit cost ratio than projected by PECO. The Smart Thermostat program should be implemented at a lower budget and rigorously evaluated for impacts on both gas and electricity consumption to determine the actual savings. The program should be modified depending on the findings.

Q. Should the Commission reject the space and water heat programs because they are not cost effective?

A. No. Space and water heat programs apply to long-lived measures that are costly to retrofit. Once a home installs a furnace or water heater, it will remain in place, consuming more energy if it is inefficient for a long period of time. In the absence of the space and water heating programs, more customers will opt for inefficient devices and thus lock in the inefficiency and wasteful use of energy for years to come.

Natural gas prices are quite low, and potential future prices are skewed toward higher prices than lower. For example, if the gas price is $2.50/MMBTU, it is more likely that gas prices could increase by $2.00/MMBTU to $4.50/MMBTU than decrease by $2.00 to $0.50/MMBTU. If gas prices increase, the space and water heating programs will be more cost effective. Installing efficient space and water heaters is a hedge against future gas price increases.

Finally, PECO's method of estimating avoided costs is likely to understate the avoided cost of gas used for space heating and to a lesser extent water heating. Using proper avoided costs will increase the avoided costs, and thus the benefits attributable to the space and water heating programs.

Q. Please explain why you believe PECO has underestimated the avoided costs of gas for space and water heating.

A. My concern is that PECO uses an annual levelized avoided cost of natural gas in its cost effectiveness calculations of measures applying to the winter heating season. This levelized cost will be higher than actual cost when gas prices are low (e.g., off-peak months) and will be lower than actual costs when gas prices are high (peak months). That will average out when applied to a device that has steady year-around consumption, such as gas cooking. However, space heat is a driver of winter peak loads, which is also when gas prices tend to be the highest. Thus, an annual levelized cost, applied to space heating loads which occur during periods of high gas prices, will likely understate the actual avoided costs applicable to the space heating programs. It is likely to also understate the avoided costs applicable to water heating. Water heating, while a year-around load, is likely to consume more energy during cold weather because the inlet water temperature is likely to be cooler and because there will be more heat loss within the home (e.g., more heat loss from the hot water system to a house heated to 68 degrees than to one cooled to 76 degrees).

Q. Have you estimated the impact of levelizing the costs on an annual basis?

A. Yes. PECO provided monthly avoided gas costs in Confidential Attachment to OCA XV-8(a). Over the 18-year life of the space heating equipment the levelized costs for the winter space heating months are approximately 1.5 times the annual levelized costs. In other words, accounting for that factor alone would increase the benefits of the space heating programs by 50%. That adjustment alone brings the residential ENERGY STAR® Furnace program TRC to 1.01 and the commercial ENERGY STAR® Furnace program TRC to 1.28, both now passing the TRC test. It also brings the residential ENERGY STAR®+ Furnace program TRC to 0.93 and the corrected Smart Thermostat program TRC to 0.96, both near-passing.

Q. Are there other factors that would increase the gas avoided costs during the heating season?

A. Yes. Another problem with PECO's method is the treatment of avoided pipeline transportation capacity reservation costs and avoided distribution system costs. PECO did not consider the avoided pipeline transportation capacity reservation costs and avoided distribution system costs in the derivation of its avoided costs. Both would apply to the peak conditions, and both would apply selectively to the space and water heating calculations. Failure to include these avoided costs further understates the benefits of the space and water heating programs

Q. Can you suggest a solution to the avoided cost issues you raised?

A. Yes. PECO should identify and calculate the avoided transportation costs and distribution system costs, both of which are driven by the peak day load. PECO should then apply those avoided costs to the peak period, i.e., during the winter months.

PECO should evaluate the smart thermostat and space heating (and to a lesser extent, water heating) programs using the winter strip prices for the avoided natural gas commodity cost and the avoided transportation capacity reservation costs and distribution system costs applied to the winter peak periods

Q. You suggested that the smart thermostat and space and water heating programs should be evaluated using winter seasonal avoided costs for cold-weather loads. How should the low flow aerators and low flow showerheads be evaluated?

A. Generally, any measure that has uniform year around consumption could be evaluated using PECO's levelized annual avoided cost approach.

It is reasonable to use PECO's levelized annual avoided cost method to evaluate low flow shower heads and low flow aerators.

Q. Are PECO's calculations of cost effectiveness tests from perspectives other than the TRC accurate?

A. No. PECO provided a confidential spreadsheet in response to OCA VII-26(a) that appeared to calculate the cost effectiveness under the utility cost test, the societal cost test, the participant test and the ratepayer impact test, in addition to the TRC. I observed that the participant and ratepayer impact tests were improperly calculated. PECO has since clarified that the spreadsheet, while being capable of calculating the other tests, was applied to calculate the TRC. Data required to calculate the participant and rate impact tests was not input, and thus the values reported for those tests are invalid and should not be used.

Q. Please summarize your testimony regarding the cost effectiveness of PECO's proposed energy efficiency programs.

A. I have reached the following conclusions:

- The avoided costs PECO used in its calculations understate the benefits from its space and water heating programs, as well as the Smart Thermostat program that is directly tied to space heating.
- The energy saving and economic benefits of the Smart Thermostat program have not been substantiated by PECO and are much higher under PECO's calculations than would be reasonably expected.
- Correcting the avoided costs applicable to the space heating programs, which are not cost effective under PECO's calculations, will probably make them cost effective or marginally failing the TRC test, except the residential Energy Star® Boiler program.
- Correcting the MCF savings for smart thermostats results in the program failing the TRC using PECO's avoided costs. It is probable that the Smart Thermostat program

would become cost effective if the proper avoided costs, applicable to the space heating season, were used.

Q. What are your recommendations regarding PECO's cost effectiveness calculations?

A. I recommend that the Commission:

1. Require PECO to recalculate the avoided costs to more accurately reflect the peak season gas commodity strip prices and transportation and distribution costs.
2. Require PECO to reassess its anticipated savings from the Smart Thermostat program.
3. Require PECO to calculate the TRC including electric savings for smart thermostats and other programs as applicable.

Q. What information has PECO provided regarding its commercial energy efficiency and conservation programs?

A. Very little. PECO seeks to continue its existing commercial gas high efficiency furnace and boiler programs. (Witness Masalta, Statement 9, pages 4 and 6). Prior to December 17, PECO provided neither a budget nor a cost-effectiveness evaluation of its commercial programs. On December 17, PECO provided a revised response to OCA VII-26(a) in which PECO added the analysis of the commercial programs to its confidential spreadsheet. I've incorporated that information into my testimony.

Q. If the Commission approves PECO's request to continue its commercial programs, what conditions should apply?

A. Because the cost-effectiveness of the commercial space heating programs is uncertain but likely to be cost effective if the avoided costs reflect all of the factors I previously described, approve them if PECO shows them to be cost effective after analysis using the corrected avoided costs. If cost effective and implemented, monitor and evaluate the programs to ensure that they are cost effective, and make program adjustments whenever it is determined that they are not cost effective under the TRC.

Q. How do you recommend that the Commission monitor and evaluate the cost effectiveness of the Company's energy efficiency and conservation programs?

A. For both the residential and commercial programs, every six months PECO should provide an implementation report (Measures installed and status of the implementation) to the Commission and interested parties. In addition, PECO should submit an impact evaluation and submit it to the Commission and interested parties every other year.

Q. Do you have any other concerns about PECO's proposed energy efficiency and conservation programs?

A. Yes. Given PECO's deficient performance implementing its energy efficiency and conservation programs, compounded by the severe economic hardship and pandemic being endured now by PECO's customers in Pennsylvania, the budget for the energy efficiency and conservation program should be capped at its current level of $2,008,000 per year for the residential sector and $28,000 per year for commercial.

BUDGET

Q. What budget levels has PECO proposed?

A. PECO is seeking approval of a Budget to be approximately $4.5 million/year overall for the residential portfolio. Since 2010, PECO has been collecting $2.008 million/year for its residential programs.

PECO disclosed that $28,000 has been earmarked annually for the commercial EE&C programs since 2009. See Schedule GCC-3, the December 17 response to OCA XV-3. It appears that costs are covered when and if incurred as part of PECO's Marketing Department's budget. However, it appears that the continuation of the commercial programs would entail a *de minimis* expense.

Please refer to PECO's response to OCA-VII-19, attached as Schedule GCC-4.

Q. What has PECO actually spent on its energy efficiency programs since 2010?

A. In the years 2010 through 2016, PECO spent an average of $1,495,296 per year on its residential portfolio. That is 74% of the $2,008,000 that it collected annually.

In the years 2017 through 2019, PECO spent an average of $1,101,893 per year on its residential portfolio. That is 55% of the $2,008,000 that it collected annually.

In the years 2010 through 2016, PECO spent an average of $13,170 per year on its commercial portfolio. That is 47% of the $28,000 that it collected annually.

In the 2017-2019 period, PECO's spending dropped to an average of $2,563 per year on its commercial portfolio. That is 9% of the $28,000 that it collected annually.

Please refer to PECO's response to OCA-VII-18, attached as Schedule GCC-5.

Q. Is it reasonable to approve a budget of $4.5 million for its residential programs as proposed by PECO?

A. No. That would represent a quadrupling of actual residential energy efficiency expenditures during the time of COVID-19. It is particularly unreasonable given that in the past three years, PECO has been spending only about half of the energy efficiency budget it had collected from ratepayers to support energy efficiency programs.

Q. Do you have a proposal?

A. Yes. The Commission should limit PECO's budget for residential energy efficiency programs to $2.008 million and the budget for commercial programs to $28,000. I propose that budget should be allocated among the programs as shown in Table 7. Table 7 compares PECO's budget provided in Statement 9 and sponsored by Witness Masalta to the recommendations I am making in my direct testimony.

Table 7

Comparison of PECO and OCA Recommended Budgets		
Program/Portfolio	PECO 2021 and beyond Programs	OCA Recommendations
Residential Efficient Furnace	$1,507,500	$518,000
Residential Super-Efficient furnace	$250,000	$75,000
Residential boiler	$150,000	$0
Residential Storage Water Heater	$25,000	$ 0
Residential Smart Thermostat	$332,500	$50,000
Residential Aerators and showerheads	$65,000	$65,000
Low Income S&EHP	$1,000,000	$1,000,000
Residential Emerging Technologies Pilot	$125,000	$0
Commercial Efficient Furnace	$12,000	$12,000
Commercial Efficient Boiler	$10,500	$10,500
Education/Admin/CSP admin	$1,050,625	$300,000
Annual Total	$4,528,125	$2,030,500

Q. **Please describe the suggested changes to the program budget adjustments as shown on Table 7.**

A. Regarding residential furnaces, I am proposing that the $1,507,500 PECO proposed for its ENERGY STAR® furnaces program be reduced to $518,000. PECO's analysis shows this program fails the TRC, but my assessment is that it will pass when analyzed with appropriate seasonal avoided costs. I am concerned about free ridership rates[6] with the standard Energy Star® furnaces and it will be important to monitor this program for free ridership as it is implemented.

Q. Please explain your suggestions regarding Energy Star®+ residential furnaces.

A. In addition to rebates on the standard Energy Star® furnaces (95% or above), offering a rebate for the <u>more</u> efficient (Energy Star®+ furnaces (97% or above) would send a signal to trade allies and the market that there is increased demand and a consumer desire for the highest tier efficient furnaces. PECO's analysis shows this program fails the TRC, but my assessment is it is likely to pass when analyzed with appropriate seasonal avoided costs. Given the constraints created by the economic downturn and pandemic, the annual budget for the higher efficiency furnaces program (97% +) is recommended to be $75,000.

Q. Please explain your suggestions regarding the residential boiler program.

[6] Free rider is a commonly used term that describes a program participant who takes an action within a program (e.g., receiving a $300 rebate for a high efficiency furnace), but would have taken the same action in the absence of the program.

A. For residential Energy Star® boilers, I am proposing that the budget be eliminated entirely (reduced from $150,000 to $0). PECO's analysis shows this program fails the TRC, and my assessment is that it will not pass even when analyzed using appropriate avoided costs.

Q. Please describe your suggestions regarding residential storage water heaters.

A. I propose that the budget for the residential storage water heater program be eliminated entirely (reduced from $25,000 to $0). PECO's analysis shows this program fails the TRC, and my assessment is that it will not pass even when analyzed using appropriate avoided costs.

Q. What is your recommendation regarding Smart Thermostats?

A. I recommend that the Smart Thermostat program be funded at $50,000 per year. Smart thermostats are a newer technology that appeals to residential customers. Studies in Oregon have shown that nearly 40% of the customers who took advantage of the rebates for a Smart thermostat would have purchased them absent a rebate. Therefore, PECO should be required to monitor the free rider impact to better understand if the program measures, as implemented, are cost effective. PECO's analysis, using the correct energy savings per thermostat shows this program fails the TRC, but my assessment is it is likely to pass when analyzed with appropriate seasonal avoided costs and with the inclusion of electric savings benefits.

Q. Please describe your recommendations regarding the low flow aerator and showerhead programs.

A. I recommend that the aerator and showerhead programs be funded at PECO's proposed level of $65,000. These measures are widely used throughout PECO's residential customer base and save water in addition to gas. The aerators and showerheads typically have a long useful life so they will produce savings for years to come. These programs handily passed the TRC test in PECO's analysis, though the results were driven predominantly by the water rather than the gas savings.

Q. What are your recommendations regarding the low-income program?

A. I recommend that the low-income Safe and Efficient Heating Program be funded at $1,000,000 as PECO proposed. Given the extreme hardship caused by the COVID pandemic, Pennsylvania's unemployment levels and the acute economic hardships being dealt with by Pennsylvania residents, there is a pressing need by PECO's low-income customers to maintain their households, cut costs and reduce the use of natural gas. Establishing this new program would be responsive to customers' needs and would be very beneficial. This program would increase the integrity of housing stock in

Pennsylvania and would be responsive to the heightened need to mitigate economic hardships faced by PECO's residential customers.

Q. Do you have a recommendation regarding the emerging technologies program?

A. Yes. The proposed emerging technologies pilot program would include micro combined heat and power, ozone laundry equipment, gas heat pumps, smart carbon monoxide detectors and demand side management technologies. While interesting and potentially useful, I recommend that this program be eliminated and not funded at this time. There is a constrained budget and a very substantive and pressing need for PECO customers to minimize costs of maintaining their households in Pennsylvania. Therefore, priority must be given to eliminating energy waste and driving household costs down using energy efficiency technology in the living dwellings occupied by PECO's residential customers.

Q. Do you have additional adjustments to PECO's proposed energy efficiency and conservation budget?

A. Yes, I turn my attention now to the proposed Education, Administration and CSP administrative budget items. PECO proposed that this item be funded at $1,045,000 annually ($1,050,625 including the commercial programs). Given the tight economic times and the need to keep utility costs and rates down, I recommend that the budget be reduced from $1,050,625 as PECO proposed to $300,000 per year. I realize that this will require some belt-tightening, but given the economic hardship and the impact of the pandemic in Pennsylvania I believe that a 15% overhead to cover administrative, education and CSP costs for utility programs is not unreasonable and should be adopted.

Q. Schedule GCC-4 indicates that PECO does not have a reconciliation mechanism for its commercial programs. Is that a concern?

A. Yes. PECO has been vague about how the budgets are determined for the commercial programs. It is unclear whether there are commercial program budgets, or if the commercial programs are funded on an as needed basis from budgets generally allocated to another purpose. It was only on December 17 that PECO indicated that it "earmarked" $28,000 annually since 2009 for commercial programs. The actual commercial program expenditures have been small, especially in recent years. PECO indicated that funds for commercial gas EE & C programs emanate from their Marketing Department's budget and that they do not have a reconciliation mechanism for true ups.

However, to maintain accountability, and to put some limits on the budget that PECO can collect for commercial programs, I recommend that a procedure be established to ascertain that the commercial program funds were used for their intended purpose to enhance energy efficiency and conservation. If there are unspent funds, the procedure should ensure that those funds are credited back to commercial customers or used for the benefit of its commercial customers. Even though the unspent funding levels may be low it is important to maintain sound regulatory principles and not allow PECO to keep or use for some other purpose the funds designated for commercial energy efficiency.

Q. What is the impact of your proposed budget on the residential energy and cost savings?

A. I recommend PECO's budget be capped at the existing levels (which are nearly double the actual expenditures PECO made in recent years). The result of the lower budget is that there may be fewer participants and less savings than PECO has projected, corrected for the Smart Thermostat error. My proposal resulted in better benefit cost ratios than PECO's, even though overall savings were less. The comparison of PECO's and my proposals are summarized in Schedule GCC-6.

Schedule GCC-7 is a three-page summary providing more detail of PECO's proposed energy efficiency portfolio each year 2021-2024. Schedule GCC-7 uses PECO's information, with the exception of the correction of the Smart Thermostat error previously discussed.

Schedule GCC-8 is a three-page summary providing more detail of my proposed energy efficiency portfolio each year 2021-2024. Schedule GCC-8 uses my proposed budget and PECO's information to determine the energy and economic impacts. It uses the corrected Smart Thermostat savings value previously discussed.

Schedule GCC-9 is a three-page summary providing more detail of PECO's proposed energy efficiency portfolio as filed each year 2021-2024. Schedule GCC-9 uses PECO's information, including the erroneous Smart Thermostat savings value previously discussed. Because of the error, it is not a viable analysis. However, I provided it to illustrate how significantly one error impacted PECO's analysis.

Q. What should the PAPUC (Commission) do in response to your recommendations?

A. The Commission should specifically address the following recommendations:

- The Commission should adopt my proposed program changes and revised budget**.**
- PECO should provide EMV studies of the impacts and lessons learned from implementing the 2010-2020 EE&C programs.

- PECO should increase its efforts to market and increase customer participation in its energy efficiency and conservation programs.
- If funding that is designated for Commercial ENERGY STAR® furnaces and boilers goes unspent at the end of the year, PECO should credit those funds back to commercial customers.
- PECO should be required to recalculate the avoided costs to more accurately reflect the peak season gas commodity strip prices and transportation and distribution costs.
- PECO should be required to reassess its anticipated savings from the Smart Thermostat program including kWh and kW savings and avoided gas costs that address heating season gas costs, avoided transportation reservation charges and avoided distribution capacity costs.
- PECO should be required to calculate the TRC including electric savings for programs that result in electric savings in addition to the gas savings.

Q. Does that conclude your testimony?

A. Yes.

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Résumé of
Geoffrey C. Crandall
Vice President and Principal

EDUCATION

B.S. in Business and Pre-Law, Western Michigan University, 1974.

Mr. Crandall has also completed courses at Michigan State University Graduate School, the University of Wisconsin-Madison and Wayne State University, in areas of federal taxation, accounting, management and the economics of utility regulation. Mr. Crandall also completed the examination for the National Conference of States on Building Codes and Standards Energy Auditor.

EXPERIENCE

Mr. Crandall joined MSB in January 1990. Mr. Crandall has addressed issues related to fuel and purchase power, natural gas, re-regulation, planning, regulatory issues, residential and low-income issues, energy efficiency and impacts of utility restructuring on customers in California, New York, Colorado, Iowa, and Michigan. He has analyzed and/or designed energy efficiency programs for residential customers in Michigan, Georgia, Wisconsin, Arizona, and New Orleans, and has conducted workshops on system planning, energy efficiency, low-income restructuring and energy efficiency issues in over 20 states, including Washington, Hawaii, Nevada, Kansas, Michigan, Rhode Island, California, Virginia, and New Orleans. Mr. Crandall has analyzed integrated resource plan and or energy efficiency programs in the states of Arizona, Georgia, Hawaii, Illinois, Maine, Michigan, Minnesota, North Carolina, Ohio, Pennsylvania, Utah, Washington State, California, Iowa, Montana, Colorado, Missouri, Virginia, Wisconsin, and Washington D.C.

Prior to joining MSB, Mr. Crandall was employed by the Michigan Public Service Commission from 1974 through 1989, where he served in several capacities including analyst in the rates and tariff section, Technical Assistant to the Chief of Staff, and as the Director of the Demand-Side Management Division. He had responsibilities that included rate and tariff review, rate cases, utilities uncollectible and bad debts, integrated resource planning, the development, implementation and monitoring of government- and utility-sponsored demand-side management, energy-efficiency and load response policies and programs. These activities involved customers in the residential, commercial, industrial and institutional sectors.

Mr. Crandall has dealt with a wide variety of regulatory issues beyond energy efficiency, including utility diversification, incentive regulation, utility billing practices, utility power plant maintenance and management of plant outages.

Mr. Crandall served as Chair of the NARUC Energy Conservation Staff Subcommittee from 1986-1989. He has lectured and made presentations to many groups on demand-side programs and least-cost planning, including two NARUC-sponsored least-cost planning conferences; the 1990 NARUC Regional Workshops on Least-Cost Utility Planning in Newport, Rhode Island and Little Rock, Arkansas; the Wisconsin Public Service Commission's Integrated Resource Planning Workshop; the 1988, 1989, and 1990 Michigan State University Graduate School of Public Utilities and the U.S. Department of Energy.

Mr. Crandall has testified before the: United States Congress, Michigan Legislature, Michigan Public Service Commission, North Carolina Utilities Commission, Public Service Commission of the District of Columbia, Illinois Commerce Commission, Maine Public Utilities Commission, Massachusetts Department of Public Utilities, Public Service Commission of Hawaii, Minnesota Public Service Commission, Iowa Public Service Commission, Georgia Public Service Commission, Public Utility Commission of Ohio, Virginia Public Service Commission, Wisconsin Public Service Commission, and the City Council of the City of New Orleans, Louisiana.

Mr. Crandall has written several articles published in the Public Utilities Fortnightly and Electricity Journal, Natural Gas Magazine, and a number of proceedings for the Biennial Regulatory Information Conference and the American Council for an Energy-Efficient Economy.

TESTIMONY

Case No. U-5531, (8/77), Consumers' Power Company electric rate increase application. Mr. Crandall served as the Staff Witness and recommended that the Applicant initiate the Residential Electric Customers' Information program.

Case No. U-6743, (3/81), Michigan Consolidated Gas Company. Mr. Crandall served as the Staff policy witness and recommended that the Commission approve a surcharge to cover all reasonable and prudent costs associated with Applicant's implementation of the Michigan Residential Conservation Services Program.

Case No. U-6819, (6/81), Michigan Power Company-Gas. Mr. Crandall served as the Staff policy witness and described the basis for the program and the expected level of activity, recommending that the Commission approve a surcharge to cover all reasonable and prudent costs associated with Applicant's implementation of the Michigan Residential Conservation Service Program.

Case No. U-6787, (6/81), Michigan Gas Utilities Company. Served as the Staff policy witness and described the basis for the program and the expected level of activity, recommending that the Commission approve a surcharge to cover all reasonable and prudent costs associated with the implementation of the Michigan Residential Conservation Service Program.

Case No. U-6820, (6/81), Michigan Power Company-Electric. Served as the Staff policy witness and reviewed the Applicant's request to operate the Michigan Residential Conservation Service Program. Although not mandated by federal law, Applicant chose to operate the program in conjunction with its other services offered to residential gas customers. Recommended the establishment of a surcharge to cover all reasonable and prudent costs associated with the operation of that program.

Case No. U-5451-R, (10/82), Michigan Consolidated Gas Company. Served as the Staff policy witness and described the Staff's position regarding Applicant's proposed adjustment of surcharge level. Recommended that the eligibility criteria for customers be adjusted to more accurately reflect proper fuel consumption and to include customers who would be likely to realize a seven-year return on their investment by installing flue-modification devices in conjunction with Applicant's financing program.

Case No. U-6743-R, (10/82), Michigan Consolidated Gas Company. Served as the Staff policy witness regarding the Applicant's proposed expenses and revenues, as well as the reasonableness of activity and expense levels in the company's projected period.

Case No. U-7341, (12/84), Detroit Edison Company, Request for Authority for Certain Non-Utility Business Activities. Represented the Staff's position during settlement discussions and sponsored the settlement agreement.

Case No. U-6787-R, (3/84), Michigan Gas Utilities Company. Served as the Staff witness regarding the Applicant's proposed expenses and revenues. This also included a review of the company's future expenses associated with the Energy Assurance Program, the Specialized Unemployed Energy Analyses, and the Michigan Business Energy Efficiency Program expenses.

Case No. U-8528, (3/87), Commission's Own Motion on the Costs, Benefits, Goals and Objectives of Michigan's Utility Conservation Programs. Represented the Staff on the costs and savings of conservation programs and the other benefits of existing programs and described alternative actions available to the Commission relative to future energy-conservation programs and services and other conservation policy matters.

Case No. U-8871, et al., (4/88), Midland Cogeneration Venture Limited Partnership. For approval of capacity charges contained in a power-purchase agreement with Consumers' Power Company. Served as the Staff witness on Michigan conservation potential and reasonably achievable programs that could be operated by Consumers' Power Company and testified to the potential impact of these conservation programs on the Company's request for use of its converted nuclear plant cogeneration project. Also recommended levels of demand-side management potential for the commercial, industrial and institutional sectors in Consumers' Power service territory.

Case No. U-9172, (1/89), Consumers' Power Company, Power-Supply Cost-Recovery Plan and Authorization of Monthly Power-Supply Cost-Recovery Factors for 1989. Served as Staff witness on the conservation potential and reasonably achievable programs that could be operated by Consumers' Power Company. Testified to the potential impact of these conservation programs on the Company's fuel and purchase practices, its five-year forecast and the fuel factor. Recommended levels of demand-side management potential for the commercial, industrial and institutional sectors in Consumers' Power service territory as an offset to its more-expensive outside and internally generated power. Suggested that CPCO vigorously pursue conservation, demand-side management research, and planning and program implementation.

Case No. U-9263, (4/89), Consumers' Power Company Request to Amend its Gas Rate Schedule to Modify its Rule on Central Metering. Served as a Staff witness on the conservation effect of converting from individual metered apartments to a master meter. Suggested that the Commission continue its moratorium on the master meters, due to the adverse energy-conservation and efficiency impact.

Case No. E-100, (1/90), North Carolina Public Service Commission proceeding on review of the Duke Power Company's least-cost utility plan. Testified on behalf of the North Carolina Consumers' Council regarding utility energy-efficiency and demand-side management programs and the concept of profitability and implementation of demand-side management programs.

Case No. 889, (1/90), Public Service Commission of the District of Columbia. Testified on behalf of the Government of the District of Columbia in the Potomac Electric Power Company's application for an increase in its retail rates (general rate case). Sponsored testimony regarding the design and implementation and overall appropriateness of PEPCO's existing and proposed energy-efficiency and conservation programs.

Case No. 889, (4/90), Public Service Commission of the District of Columbia. Provided supplemental direct testimony and testified on behalf of the Government of the District of Columbia in the Potomac Electric Power Company's application for an increase in its retail rates (general rate case). Offered supplemental testimony regarding a more detailed review of PEPCO's existing pilot and full-scale energy-efficiency and conservation programs. Offered suggestions and recommendations for a future direction for PEPCO to pursue in order to implement more cost-effective and higher-impact energy-efficiency and conservation programs.

Case No. ICC Docket 90-004 and 90-0041, (6/90), Illinois Commerce Commission proceeding to adopt an electric-energy plan for Central Illinois Light Company (CILCO). Testified on behalf of the State of Illinois, Office of Public Counsel and the Small-Business Utility Advocate. Reviewed the CILCO electric least-cost plan filing and the conservation and load-management programs proposed in its filing. Sponsored testimony regarding my analysis of the proposed programs and offered alternative programs for the Company's and the Commission's consideration.

Case No. D.P.U. 90-55, (6/90), Commonwealth of Massachusetts Department of Public Utilities. Testified on behalf of the Commonwealth of Massachusetts, Division of Energy Resources. Reviewed and analyzed Boston Gas' proposed energy-conservation programs that were submitted for pre-approval in its main rate case. In addition, suggested that it might consider implementation of other natural-gas energy- efficiency programs, and not award an economic incentive for energy-efficiency and conservation programs until minimum program-implementation standards are satisfied.

Case No. U-9346, (6/90), Michigan Public Service Commission. Testified on behalf of the Michigan Community Action Agency Association. Reviewed and analyzed the Consumers' Power Company rate-case filing related to energy-efficiency and demand-side management programs. Proposed alternative energy-efficiency programs and recommended program budgets and a cost-recovery mechanism.

Case No. 89-193; 89-194; 89-195; and 90-001, (6/90), Maine Public Utilities Commission. Testified on behalf of the Maine Public Advocate's Office. Reviewed the appropriateness of Bangor Hydro-Electric Company's existing energy-efficiency and demand-side management programs in the context of BHE's main rate case and request for approval to construct the Basin Mills Hydro-Electric dam. Reviewed the overall resource plan and suggested alternative programs to strengthen the energy-efficiency and demand-side management resource efforts.

Case No. 6617, (4/91), Hawaii Public Utility Commission. Testified on behalf of the Hawaii Division of Consumer Advocacy. Described what demand-side management resources are, why they should be included in the integrated resource planning process and proposed the implementation of several pilot projects in Hawaii along with guidelines for the pilot programs.

Case No. E002/GR-91-001, (5/91), Minnesota Public Utilities Commission. Testified on behalf of Minnesotans for an Energy Efficient Economy. Assessed the DSM programs being operated or proposed by Northern States Power Company and made recommendations as to ways in which NSP could improve its DSM efforts.

Case No. 905, (6/91), Public Service Commission of the District of Columbia. Testified on behalf of the District of Columbia Energy Office. Responded to the energy-efficiency and load management aspects of Potomac Electric Company's filing and made several recommendations for DC-PSC action.

Case No. 6690-UR-106, (9/91), Public Service Commission of Wisconsin. Testified on behalf of The Citizens' Utility Board of Wisconsin. Assessed the DSM programs being operated or proposed by the Wisconsin Public Service Corporation, made recommendations as to the WPSCO energy efficiency programs, and suggested ways the company could improve its DSM efforts.

Case No. E002/CN-91-19, (12/91), Minnesota Public Utilities Commission. Testified on behalf of Minnesota Department of Public Service. Assessed the DSM potential and programs being operated or proposed by Northern States Power Company and made recommendations as to the potential for energy efficiency in the NSP service territory and ways in which NSP could improve its DSM efforts.

Case No. 912, (4/92), Public Service Commission of the District of Columbia. Testified on behalf of the Government of the District of Columbia in the Potomac Electric Power Company's application for an increase in its retail rates for the sale of electric energy. Testified regarding the reasonableness of DSM and EUM policy changes, the cost allocation of the DSM and EUM expenses, an examination of the prudence of management regarding the energy-efficiency programs, and an examination of the appropriateness of the costs associated with energy-efficiency programs.

Case No. PUE 910050, (5/92), Virginia State Corporation Commission. Testified on behalf of the Citizens for the Preservation of Craig County regarding the need for the Wyoming-Cloverdale 765 kV transmission line. Specifically, addressed the adequacy of the DSM planning of Appalachian Power Company and Virginia Power/North Carolina Power. Made recommendations as to APCO and VEPCO's energy efficiency programs, and suggested ways the company could improve its DSM efforts.

Case No. EEP-91-8, (5/92), Iowa Utilities Board. Testified on behalf of the Izaak Walton League concerning the adequacy of Iowa Public Service Company's Energy Efficiency Plan. Reviewed the plan and suggested modifications to it.

Case No. 4131-U and 4134-U, (5/92), Georgia Public Service Commission. Testified on behalf of the Georgia Public Service Commission staff regarding the demand-side management portions of Georgia Power Company's and Savannah Electric and Power Company's Integrated Resource Plans. Testimony demonstrated that it is reasonable for the Commission to expect that the utilities can successfully secure substantial amounts of demand-side management resources by working effectively with customers.

Case No. 917, (8/92), Public Service Commission of the District of Columbia. Testified on behalf of the District of Columbia Energy Office in hearings on Potomac Electric

Power Company's Integrated Resource Planning process. Addressed a number of program-specific issues related to PEPCO's demand-side management efforts.

Case No. 4132-U, 4133-U, 4135-U, 4136-U, (10/92), Georgia Public Service Commission. Testified on behalf of the Staff Adversary IRP Team of the Georgia PSC. Provided a critique of Georgia Power Company's and Savannah Electric and Power Company's proposed residential and small commercial DSM programs.

Case No. 4135-U, (3/93), Georgia Public Service Commission. Testified on behalf of the Staff Adversary IRP Team of the Georgia PSC. Provided a critique of Savannah Electric and Power Company's proposed Commercial and Industrial DSM programs.

Case No. R-0000-93-052, (12/93), Arizona Corporation Commission. Testified on behalf of the Arizona Community Action Association. Critiqued and made recommendations regarding the integrated resource plans and demand-side management programs of Arizona Public Service Company and Tucson Electric Power Company.

Case No. 934, (4/94), Public Service Commission of the District of Columbia. Filed testimony on behalf of the District of Columbia Energy Office in hearings concerning the Washington Gas Light Company (WGL) general rate case application to increase existing rates and charges for gas service. Testimony involved critiquing and reviewing WGL's least cost planning efforts and integration of DSM, marketing and gas supply efforts.

Case No. U-10640, (10/94), Michigan Public Service Commission. Testified on behalf of the Michigan Community Action Agency Association concerning the need to integrate DSM and load promotion analysis into MichCon's GCR planning process.

Case No. 05-EP-7, (3/95), Wisconsin Public Service Commission. Testified on behalf of the Citizens' Utility Board on level of utility DSM and program designs and strategies.

Case No. 05-EP-7, (3/95), Wisconsin Public Service Commission. Testified on behalf of the Wisconsin Community Action Program Association on low-income customers and utility DSM programs.

Case No. TVA 2020-IRP, (9/95), Tennessee Valley Authority. Testified on behalf of the Tennessee Valley Energy Reform Coalition. Assessed, critiqued and made recommendations regarding the integrated resource plans and demand-side management programs proposed by the Tennessee Valley Authority.

Case No. R-96-1, (10/95), Alaska Public Utilities Commission. Testified on behalf of the Alaska Weatherization Directors Association regarding the proposed standards and guidelines for integrated resource planning and energy efficiency initiatives under consideration in Alaska.

Case No. D95.9.128, (2/96), Montana Public Service Commission. Testified on behalf of the District XI Human Resources Council concerning the low-income energy efficiency programs offered by the Montana Power Company.

Case No. DPSC Docket No. 95-172, (5/96), Delaware Public Service Commission. Prepared draft testimony on behalf of the Low-Income Energy Consumer Interest Group regarding Delmarva Power & Light Company's application to revise its demand-side programs. The case was settled, with LIECIG obtaining funding for low-income energy efficiency programs, prior to testimony.

Case No. U-11076, (8/96), Michigan Public Service Commission. Testified on behalf of the Michigan Community Action Agency regarding the Michigan Jobs Commission's recommendations regarding electric and gas reform. Discussed the implications of utility restructuring and the needs of residential and low-income households, and proposed regulatory and industry solutions.

Case No. 96-E-0897, (3/97), New York Public Service Commission. Prepared draft testimony for New York's Association for Energy Affordability regarding the impact of proposed utility restructuring plans on low-income customers. The case was settled in Spring 1997.

Case No. R-00973954, (7/97), Pennsylvania Public Utilities Commission. Testified on behalf of the Commission on Economic Opportunity regarding the economics of demand-side measures and programs proposed for implementation by Pennsylvania Power & Light Company.

Case No. 98-07-037, (7/98), California Public Utilities Commission. Testified on the California Alternative Rates for Energy and the Low-Income Energy Efficiency programs regarding the implementation and adoption of revisions to these programs necessitated by the AB 1890 and the Low-Income Governing Board.

Case No. U-12613, (3/01), Michigan Public Service Commission. Testified on behalf of the Michigan Community Action Agency regarding the Wisconsin Public Service Corporation application to implement PA 141 the electricity deregulation law. I reviewed the portions of the filing related to their provision of electric energy efficiency and load management.

Case No. U-12649, (3/01), Michigan Public Service Commission. Testified on behalf of the Michigan Community Action Agency regarding the Wisconsin Electric Power Company and the Edison Sault Electric Company application to implement PA 141 Michigan's electricity deregulation law. I reviewed the portions of the filing related to their provision of electric energy efficiency and load management.

Case No. U-12651, (3/01), Michigan Public Service Commission. Testified on behalf of the Michigan Community Action Agency regarding the Northern States Power Company – Wisconsin application to implement PA 141 the electricity deregulation law. I reviewed the portions of the filing related to their provision of electric energy efficiency and load management.

Case No. U-12652. (3/01), Michigan Public Service Commission. Testified on behalf of the Michigan Community Action Agency regarding the Indiana Michigan Power Company d/b/a American Electric Power application to implement PA 141 the electricity deregulation law. I reviewed the portions of the filing related to their provision of electric energy efficiency and load management.

Case No. U-12725, (4/01), Michigan Public Service Commission. Testified on behalf of the Michigan Community Action Agency regarding the Wisconsin Electric Power Company and the Edison Sault Electric Company application to increase its residential rates. I reviewed the portions of the filing related to their provision of electric energy efficiency and load management and recommended a significant increase in these activities.

Case No. U-13060, (12/01), Michigan Public Service Commission. Testified on behalf of the Michigan Community Action Agency regarding the Michigan Consolidated Gas Company application for Approval of their Gas Cost Recovery Plan and Five-Year gas Forecast. I reviewed the filing and recommended the Commission reject the proposed GCR factor and suggested continuation of the existing GCR factor or adopt an adjusted MCAAA sponsored GCR factor. I also suggested a set-aside allocation be designated for low-income customers to ensure access to alternative gas providers under the applicant's customer choice program.

Case No. 6690-UR-114, (9/02), Wisconsin Public Service Commission. Testified on behalf of the Citizens Utility Board regarding the Wisconsin Public Service Corporation application to increase its electric and natural gas rates. I reviewed the portions of the filing related to their low-income assistance/weatherization and the proposed executive compensation incentive plan.

Case No. U-14401, (04/05), Michigan Public Service Commission. Testified on behalf of the Michigan Community Action Agency regarding the Michigan Consolidated Gas Company application for Approval of their Gas Cost Recovery Plan and Five-Year gas Forecast. I reviewed the filing and recommended the Commission reject the proposed plan and suggested initiation of strategies that would lower the need to acquire expensive and unnecessary gas supplies.

Case No. U-14401-R, (10/05), Michigan Public Service Commission. Testified on behalf of the Michigan Community Action Agency regarding the Michigan Consolidated Gas Company application re-opener Approval of their Gas Cost Recovery Plan and Five-Year gas Forecast. I reviewed the filing and recommended the Commission reject the proposed plan and suggested initiation of strategies that would lower the need to acquire expensive and unnecessary gas supplies.

Case No. U-14701, (02/06), Michigan Public Service Commission. Testified on behalf of the Michigan Environmental Council and The Public Interest Group In Michigan regarding the Consumers Energy Company application for Approval of a Power Supply Cost Recovery Plan and for Authorization of Monthly Power Supply Cost Recovery Factors for calendar year 2006. I reviewed the filing including the application, testimony, exhibits, discovery responses and submitted testimony recommending that the Commission not approve the five-year PSCR plan as filed due to the impacts related to the Palisades sale and the absence of alternative resources in the projected five-year resource portfolio.

Case No. U-14702, (02/06), Michigan Public Service Commission. Testified on behalf of the Michigan Environmental Council and The Public Interest Group In Michigan regarding The Detroit Edison Company application for authority to implement a Power Supply Cost Recovery Plan in its rate schedules for 2006-metered jurisdictional sales of electricity. I reviewed the application; testimony, exhibits and submitted testimony that recommended that the Commission not approve the proposed five-year PSCR plan as filed due because it was deficient in its selection of alternative resources in the projected five-year resource portfolio.

Case No. U-14992, (12/06), Michigan Public Service Commission. Testified on behalf of the Michigan Environmental Council and The Public Interest Group In Michigan regarding The Consumers Energy Company application for approval of the proposed Power Purchase Agreement in connection with the sale of the Palisades Nuclear Power Plant and other assets. The purpose of my testimony was to address the overall soundness of this application and proposal. I reviewed the application, testimony, exhibits and submitted testimony that recommended that the Commission not approve the proposed purchase power agreement and transfer the ownership of the nuclear plant and other assets.

Case No. 06-0800, (3/07), Illinois Commerce Commission. Provided testimony on behalf of the Illinois Citizens Utility Board regarding the Illinois electricity resource auction process. I assessed the existing resource/power supply auction-based bidding process and recommended modifications and improvements to the Illinois resource acquisition mechanism.

Case No. 24505-U, (5/07), Georgia Public Service Commission. Testified on behalf of the Georgia Public Service Commission Advocacy staff regarding the demand-side management portions of Georgia Power Company's Integrated Resource Plans. Testimony demonstrated that it is reasonable for the Commission to approve the five proposed DSM programs and expect that Georgia Power can successfully secure considerably more demand-side management resources by working effectively with its customers.

Case No. U-14992, (11/07), Michigan Public Service Commission. Testified on behalf of the Michigan Environmental Council and The Public Interest Group In Michigan regarding The Consumers Energy Company rate application for approval of a rate increase and the recovery of energy efficiency programs and certain costs in connection with the sale of the Palisades Nuclear Power Plant and other assets. I reviewed the application, testimony, exhibits and submitted testimony that recommended that the Commission not approve the recovery of transaction costs involving the transfer the ownership of the nuclear plant and other assets and on various aspects of its proposed energy efficiency programs and proposed incentives.

Case No. 07-0540, (12/07), Illinois Commerce Commission. Provided testimony on behalf of the Environmental Law and Policy Center regarding the Commonwealth Edison Company application for approval of its proposed Energy Efficiency and Demand Response Plan. I assessed the proposed energy efficiency and demand response plan and recommended modifications and improvements to the proposed plan filing.

Case No. 07-0539, (12/07), Illinois Commerce Commission. Provided testimony on behalf of the Environmental Law and Policy Center regarding the Central Illinois Light Company d/b/a and Ameren CIPS CENTRAL ILLINOIS PUBLIC SERVICE COMPANY and Ameren CIPS ILLINOIS POWER COMPANY d/b/a Ameren IP application for approval of its proposed Energy Efficiency and Demand Response Plan. I assessed the proposed energy efficiency and demand response plan and recommended modifications and improvements to the proposed plan filing.

Case No. U-15415, (2/08), Michigan Public Service Commission. Testified on behalf of the American Association of Retired People regarding The Consumers Power Company application for approval for authority to implement a Purchase Power recovery plan, 5-year forecast, and monthly PSCR factors for the 12-month period calendar year 2008. I reviewed the application, testimony, exhibits and submitted testimony that recommended that the Commission adopt a more effective and less expensive resource acquisition procedure to help keep the cost of energy down in Michigan.

Case No. U-15417, (4/08), Michigan Public Service Commission. Provided testimony on behalf of the American Association of Retired People regarding The Detroit Edison Company for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedule for 2008 Metered Jurisdictional Sales of Electricity. I reviewed the application, testimony, exhibits and submitted testimony that recommended that the Commission adopt a more effective and less expensive resource acquisition procedure to help keep the cost of energy down in Michigan.

Case No. U-15244, (7/08), Michigan Public Service Commission. Provided testimony on behalf of the Michigan Environmental Council and The Public Interest Group In Michigan regarding The Detroit Edison Company request for Authority to increase rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority. I reviewed the application, testimony, and exhibits and submitted testimony that recommended that the Commission direct DECO to make modifications to its Integrate Resource Planning analysis.

Case No. EEP-08-2, (7-08), Iowa Public Utilities Board. Provided testimony on behalf of the environmental interveners regarding the request of the Mid-American Energy Company for approval of an Energy Efficiency Plan. I made an assessment of the proposed energy efficiency and demand response plan and recommended modifications and improvements to the implementation strategy and proposed programs.

Case No. EEP-08-1, (8-08), Iowa Public Utilities Board. Provided testimony on behalf of the environmental interveners regarding the Interstate Power and Light Company request for approval of an Energy Efficiency Plan. I made an assessment of the proposed energy efficiency and demand response plan and recommended modifications and improvements to the proposed programs and implementation strategy.

Case No. 137-CE-147, (2-09), Public Service Commission of Wisconsin. Provided testimony on behalf of PRESERVE OUR RURAL LANDS regarding the Application of American Transmission Company, as an Electric Public Utility, to Construct a new 345 kV Line from the Rockdale Substation to the West Middleton Substation, Dane County, Wisconsin. I suggested modifications of the proposal and rejection of the approval of the line.

Case No. M2009-2093218, (8-09), Pennsylvania Public Utility Commission. Provided testimony on behalf of The Office Of Consumer Advocate regarding the West Penn Power Company d/b/a Allegheny Power Energy Efficiency and Conservation Plan request for plan approval. I analyzed the proposed plan and made an assessment of the proposed energy efficiency and demand response and cost recovery plan. I suggested modifications and improvements to the proposed programs as well as the proposed implementation strategy.

Case No. 09-1947-EL-POR, 09-1948-EL-POR, 09-1949-EL-POR, 09-1942-EL-EEC, 09-1943-EL-EEC, 09-1944-EL-EEC, POR, 09-580-EL-EEC, 09-580-EL-EEC, 09-580-EL-EEC, Public Utilities Commission of Ohio. Provided testimony on behalf of The Office Of The Environmental Law and Policy Center regarding the Ohio Edison Company, The Cleveland Electric Illuminating Company and the Toledo Edison Company for approval of their energy efficiency and peak demand reduction program portfolio and associated cost recovery mechanism and approval of their initial benchmark reports and in the matter of the energy efficiency and peak demand reduction programs. I reviewed, analyzed and assessed the appropriateness of the proposed plans, benchmark reports and proposed peak reduction program portfolio. I suggested modifications and improvements to the proposed programs. I also made recommendations regarding the proposed implementation strategy as well as accounting and program cost tracking.

Case No. U-16412, (10/10), Michigan Public Service Commission. Provided testimony on behalf of the Natural Resources Defense Council, Michigan Environmental Council and The Environmental Law and Policy Center regarding the Consumers Energy Company request to
Amend its natural gas & energy efficiency Energy Optimization Plan. I reviewed the application, testimony, exhibits, discovery responses and submitted testimony that recommended modifications to the proposed Energy Optimization Plan.

Case No. 10-0570, (11/10), Illinois Commerce Commission. Provided testimony on behalf of the Environmental Law and Policy Center regarding the Commonwealth Edison Company application for approval of its proposed Energy Efficiency and Demand Response Plan. Assessed the proposed energy efficiency and demand response plan and recommended modifications and improvements to the proposed plan filing.

Case No. 10-0568, (11/10), Illinois Commerce Commission. Provided testimony on behalf of the Environmental Law and Policy Center regarding the Central Illinois Light Company d/b/a and Ameren CIPS CENTRAL ILLINOIS PUBLIC SERVICE COMPANY and Ameren CIPS ILLINOIS POWER COMPANY d/b/a Ameren IP application for approval of its proposed Energy Efficiency and Demand Response Plan. Assessed the proposed energy efficiency and demand response plan and recommended modifications and improvements to the proposed plan filing.

Case No. 10-0564, (11/10), Illinois Commerce Commission. Provided testimony on behalf of the Environmental Law and Policy Center regarding the People's Gas Light and Coke Company and North Shore Gas Company request for approval of its proposed Energy Efficiency Plan. Assessed the proposed energy efficiency and demand response plan and recommended modifications and improvements to the proposed plan filing.

Case No. 10-0567, (11/10), Illinois Commerce Commission. Provided testimony on behalf of the Environmental Law and Policy Center regarding the Northern Illinois Gas Company application for approval of its proposed Energy Efficiency Plan and approval of Rider 30, Energy Efficiency Plan Cost recovery and related changes to Nicor tariffs. Assessed the proposed energy efficiency and demand response plan and recommended modifications and improvements to the proposed plan filing.

Case No. M-2010-2210316, (3/11), Pennsylvania Public Utility Commission. I provided testimony on behalf of The Office Of Consumer Advocate regarding the UGI Utilities, Inc. Electric Division (UGI-Electric) request for Efficiency and Conservation Plan approval. I analyzed the proposed plan and made an assessment of the proposed energy efficiency and demand response and cost recovery plan. I suggested modifications and improvements to the proposed programs and implementation strategy.

Case No. 11-07026 and 11-07027, (11/11), Public Utilities Commission of Nevada. I provided testimony on behalf of the Bureau of Consumer Protection regarding both the Sierra Pacific Power Company and Nevada Power Company 2011 Annual Demand Side Management Update reports. I reviewed the filings and made recommendations regarding various aspects of demand response resources and demand side management portfolios.

Case No., U-16671 (01/12), Michigan Public Service Commission. I provided testimony on behalf of the Environmental Law and Policy Center regarding the reasonableness of the Detroit Edison Company’s filing and assertions made by a witness regarding a net-to-gross factor relative to the 2010 and 2011 energy efficiency programs implemented in response to Public Act 295 of 2008.

Case Nos. P-2012-2320468, P-2012-2320480, P-2012-2320484, P-2012-2320450, (10/12), Pennsylvania Public Utility Commission. I provided testimony on behalf of The Office Of the Consumer Advocate regarding the application of Metropolitan Edison Company, Pennsylvania Electric Company, West Penn Power, Pennsylvania Power Company on the Energy Efficiency regarding the benchmarks established for the period June 1, 2013 through May 31, 2016.
I analyzed the proposed adjustments of Phase II Energy Efficiency and Conservation target levels and energy efficiency acquisition costs.

Case No. Case Nos. 12-2190-EL-POR, 12-2191-EL-POR, 12-2192-EL-POR, (10/12) Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and the Toledo Edison Company for Approval of their energy efficiency and peak demand reduction program portfolio plan for 2013-2015. I provided testimony on behalf of Ohio Environmental Council and The Environmental Law and Policy Center regarding the Ohio Edison Company, The Cleveland Electric Illuminating Company and the Toledo Edison Company for approval of their 2013-2015 energy efficiency and peak demand reduction program portfolio. I reviewed, analyzed and assessed the appropriateness of the proposed plans, benchmark reports and proposed peak reduction program portfolio. I suggested modifications and improvements to the proposed programs and made recommendations and proposed new approaches to the proposed implementation strategy.

Case No., 12-06052 and 12-06053 (10/12), Public Utilities Commission of Nevada, I provided testimony on behalf of the Attorney General of the State of Nevada, Bureau of Consumer Protection regarding both the Sierra Pacific Power Company and Nevada Power Company 2013-2015 Triennial Integrated Resource Plan covering the period 2013-2032 and Approval of its Energy Supply Plan for the period 2013-2015. I reviewed, analyzed and assessed the appropriateness of the proposed plans and proposed peak reduction portfolio. I suggested modifications and improvements to the proposed programs and made recommendations and proposed new approaches to the implementation strategy.

Case No. U-16434-R, (10/12), Michigan Public Service Commission. Provided testimony on behalf of the Michigan Community Action Agency Association regarding The Detroit Edison Company for Reconciliation of its Power Supply Cost Recovery Plan for 12-month Period Ending December 31, 2011. I reviewed the application, testimony, exhibits and submitted testimony that recommended that the Commission adopt a remedy in regard to several aspects of the Reduced Emission Fuels projects that Detroit Edison was involved in.

Case No. Docket No. M-2012-2334388 (12/12), Pennsylvania Public Utility Commission. I provided testimony on behalf of The Office of the Consumer Advocate regarding the Petition of PPL Electric Utilities Corporation for Approval of an Energy Efficiency and Conservation Plan. I analyzed the proposed plan and made an assessment of the proposed energy efficiency and demand response and cost recovery plan. I suggested modifications to the proposed programs and implementation strategy to enhance its effectiveness.

Case No. U-17097, (03/13) Michigan Public Service Commission. Provided testimony on behalf of the Michigan Community Action Agency Association regarding The Detroit Edison Company filing for Reconciliation of its Power Supply Cost Recovery Plan for 12-month Period Ending December 31, 2013. I reviewed the application, testimony, exhibits and submitted testimony recommending that the Commission adopt a remedy regarding the Reduced Emission Fuels projects that Detroit Edison was participating in.
Case No. U-17095, (04/13) Michigan Public Service Commission. Provided testimony on behalf of the Michigan Community Action Agency Association regarding The

Consumers Electric Company Application for Approval of A Power Supply Cost Recovery Plan and for Authorization of Monthly Power Supply Cost Recovery Factors for 2013. I reviewed the application, testimony, and exhibits and submitted testimony recommending that the Commission reject the proposed five-year resource plan. I also recommend that the Commission prohibit CECO from collecting capital related investments for a pipeline in Zeeland, Michigan. I also recommended that CECO demonstrate to the Commission that the Palisades and MCV generation plants purchase power agreements are cost-effective, being complied with and are in the public interest.

Case No. EEP-2012-0001, (4-13), Iowa Public Utilities Board. Provided testimony on behalf of the environmental interveners regarding the Interstate Power and Light Company 2014-2018 Energy Efficiency Plan. I made an assessment of IPL's proposed resource planning as well their energy efficiency, renewable energy and demand response resources. I recommended modifications and improvements to the proposed programs, implementation and resource measurement strategy.

Case No. U-17131, (04/13), Michigan Public Service Commission. Testified on behalf of the Michigan Community Action Agency regarding the Michigan Consolidated Gas Company application for Approval of their Gas Cost Recovery Plan and Five-Year gas Forecast and approval to implement a reservation charge. I reviewed the filing and recommended the Commission require MichCon to initiate procurement strategies that would reduce the heavy reliance that is being placed on the 75% VCA gas procurement strategy.

Case No. U-17133, (04/13), Michigan Public Service Commission. Testified on behalf of the Michigan Community Action Agency regarding the Consumers Energy Company application for approval of its gas cost recovery plan and authorization of a gas cost recovery factor from April 2013- March 2014. I reviewed the filing and made recommendations regarding the Quartile Fixed Price Purchases Gas purchasing strategy used by CECO.

Case No. EEP-2012-0002, (6/13), Iowa Public Utilities Board. Provided testimony on behalf of the environmental interveners regarding the Mid-American Energy Company 2014-2018 Energy Efficiency Plan. I made an assessment of MidAm's proposed resource planning as well their energy efficiency, renewable energy and demand response resources. I recommended modifications and improvements to the proposed programs, implementation and resource measurement strategy.

Case No. 13-0431-EL-POR (08/13), Public Utility Commission of Ohio. Provided testimony regarding the Application of Duke Energy Ohio, Inc. for Approval of its Energy Efficiency and Peak Demand Reduction Portfolio of Programs.
The testimony was provided on behalf of Ohio Environmental Council and The Environmental Law and Policy Center. Duke Energy Ohio, Inc. was seeking approval of their revised energy efficiency and peak demand reduction program portfolio. I analyzed and reviewed the appropriateness of the revised plan and proposed peak reduction program portfolio. I suggested significant additions and modifications to the proposed

programs. I offered specific program recommendations and new elements be added to their programs and implementation strategy.

Case No. 13-0498, (10/13), Illinois Commerce Commission. Provided testimony on behalf of the Environmental Law and Policy Center regarding the request by Ameren Illinois for approval of its proposed Energy Efficiency and Demand Response Plan 3. Assessed the proposed energy efficiency and demand response plan and recommended modifications and improvements to the proposed plan filing.

Case No. 13-0499 (10/13), Illinois Commerce Commission. Provided testimony on behalf of the Environmental Law and Policy Center regarding the request by The Illinois Department of Commerce and Economic Opportunity for approval of its proposed Energy Efficiency Plan 3. Assessed the proposed energy efficiency plan and recommended modifications and improvements to the proposed plan filing.

Case No. 13-0495 (11/13), Illinois Commerce Commission. Provided testimony on behalf of the Environmental Law and Policy Center regarding the request by Commonwealth Edison application for approval of its proposed third Energy Efficiency Plan. I assessed the proposed energy efficiency plan and recommended modifications and enhancements to the proposed plan.

Case No. 13-0550 (12/13), Illinois Commerce Commission. Provided testimony on behalf of the Environmental Law and Policy Center regarding the request by North Shore Gas Company and The Peoples Gas Light and Coke Company for approval of its proposed second Energy Efficiency Plan. I assessed the proposed energy efficiency plan and recommended modifications and enhancements to the proposed plan.

Case No. 13-0549, (01/14), Illinois Commerce Commission. Provided testimony on behalf of the Environmental Law and Policy Center regarding the Northern Illinois Gas Company D/b/a/ Nicor for approval of its proposed second Energy Efficiency Plan, Cost recovery and related changes to Nicor tariffs. I assessed the proposed energy efficiency plan and recommended modifications and improvements to the proposed plan filing.
Case No. U-17319, (06/14), Michigan Public Service Commission. Provided testimony on behalf of the Great Lakes Renewable Energy Association regarding the DTE Electric Company application for approval of its PSCR Plan 2014 - 2018. I reviewed the filing and made recommendations regarding the PSCR five-year forecast and plan.

Case No. U-17317, (08/14), Michigan Public Service Commission. Provided testimony on behalf of the Great Lakes Renewable Energy Association regarding the Consumers Energy Company application for approval of its PSCR Plan 2014 - March 2018. I reviewed the filing and made recommendations regarding the PSCR five-year forecast and plan.

Case No. U-17680, (03/15), Michigan Public Service Commission. Provided testimony on behalf of the Great Lakes Renewable Energy Association regarding the DTE Electric

Company application for approval of its PSCR Plan 2015 - 2019. I reviewed the filing and made recommendations regarding the PSCR five-year forecast and plan.

Case No. U-17678, (04/15), Michigan Public Service Commission. Provided testimony on behalf of the Great Lakes Renewable Energy Association regarding the Consumers Energy Company application for approval of its 2015 – 2019 PSCR Plan. I reviewed the application, filing and related documents and offered suggestions to improve the proposed five-year PSCR forecast and plan.

Case No. U-17735, (04/15), Michigan Public Service Commission. Provided testimony on behalf of the Michelle Rison and the Residential Consumer Group regarding aspects of the Consumers Energy Company general rate case application for authority to increase its rates for the generation and distribution of electricity and other relief. I reviewed the general rate case application, filing and related documents regarding CECO's reliance on and implementation of an Advanced Metering Infrastructure to deliver services to its customers. I offered specific recommendations regarding tariffs and policies related to Advanced metering infrastructure.

Case No. U-17767, (05/15), Michigan Public Service Commission. Provided testimony on behalf of a number of residential customers of DTE Electric under the nomenclature of Dominic and Lillian Cusumano and the Residential Customer Group. I provided testimony regarding DTE Electric's general rate case application for authority to increase its rates for the generation and distribution of electricity and other relief. I reviewed the general rate case filing and issues related to DTE Electric's reliance on and implementation of an Advanced Metering Infrastructure. I offered specific suggestions to improve DTE Electric's tariffs, policies and procedures related to implementation of an advanced metering infrastructure.

Case No. Docket No. P-2014-2459362 (06/15), Pennsylvania Public Utility Commission. I provided testimony on behalf of The Office of the Consumer Advocate regarding the Petition of Philadelphia Gas Works for Approval of Demand-Side Management Plan for FY 2016-2020; and Philadelphia Gas Works Universal Service and Energy Conservation Plan for 2014-2016 52 Pa Code Section 62.4- Request for Waivers. I analyzed the proposed five-year DSM plan and made an assessment of the proposed plan emphasizing the proposed conservation adjustment mechanism and the proposed performance incentives mechanisms. I suggested extensive modifications to the proposed Plan.

Case No. U-17792 (08/15), Michigan Public Service Commission. Provided testimony on behalf of the Great Lakes Renewable Energy Association. I provided testimony and exhibits regarding Consumers Energy Company proposed 2015 Biennial Renewable Energy Plan. I reviewed the Biennial Renewable Energy Plan, testimony, exhibits and supporting information related to Consumers Energy Company renewable resource strategy resulting from the enabling statute (Public Act 295 of 2008). I offered my opinion and assessment of the reasonableness of the proposed plan as well as specific recommendations to improve the 2015 Biennial Renewable Energy Plan as well as Consumers Energy Company's electric resource planning procedures.

Case No. U-17793 (08/15), Michigan Public Service Commission. Provided testimony on behalf of the Great Lakes Renewable Energy Association. I provided testimony and exhibits regarding the proposed DTE Electric Company 2015 Biennial Renewable Energy Plan. I reviewed the proposed Biennial Renewable Energy Plan, testimony, exhibits and supporting information related to the DTE Electric Company renewable resource strategy resulting from Public Act 295 of 2008. I offered my opinion and assessment of the reasonableness of the proposed plan and made specific recommendations for improvement of the 2015 Biennial Renewable Energy Plan as well as DTE Electric Company's annual PSCR plan development and electric resource planning procedures.

Case No. M-2015-2514767 (01/16). I provided testimony on behalf of The Office of the Consumer Advocate regarding the joint Petition of the First Energy Companies serving customers in Pennsylvania. I reviewed the proposed five-year Energy Efficiency and Conservation Plan and offered suggestions to modify and improve various programs proposed for the 2016-2020 Plans.

Case No. M-2015-2515691 (01/16). I provided testimony on behalf of The Office of the Consumer Advocate regarding the joint Petition of the PECO Energy Company serving customers in Pennsylvania. I reviewed the proposed five-year Energy Efficiency and Conservation Plan and offered suggestions to modify and improve various programs proposed for the Act 129 related Energy Efficiency and Conservation Plan for 2016 – 2020.

Case No. U-17920, (03/16), Michigan Public Service Commission. Provided testimony on behalf of the Great Lakes Renewable Energy Association regarding the DTE Electric Company application for approval of its PSCR Plan 2016 – 2020. I reviewed the filing and made recommendations regarding the PSCR five-year forecast and plan.

Case No. U-17918, (03/16), Michigan Public Service Commission. Provided testimony on behalf of the Great Lakes Renewable Energy Association regarding the Consumers Energy Company application for approval of its PSCR Plan 2016 – 2020. I reviewed the application, filing and supporting materials and made recommendations regarding the PSCR five-year forecast and plan.

Case No. U-18014, (07/16), Michigan Public Service Commission. Provided testimony on behalf of the Great Lakes Renewable Energy Association regarding the DTE Electric Company general rate case application for approval to raise rates. I reviewed the filing and made recommendations regarding inclusion of a corporate tax deferred debit, policies and tariffs related to smart meters and DTE's transition to an automated meter infrastructure.

Case No. U-17087 (Remand), (08/16), Michigan Public Service Commission. Provided testimony on behalf of the Residential Consumer Group regarding the Consumers Energy Company application to increase its rates for the generation and distribution of electricity. I reviewed the filing regarding the support and substantiation for the opt-out tariff that is included and approved for Consumers Energy Company. I made a series of specific recommendations regarding the lack of substantiation for the up-front and monthly charges (both existing and proposed) contained within the non-transmitting meter tariff (among other tariffs) and policies related to smart meters and DTE's transition to an automated meter infrastructure.

Case No. U-18111, (08/16), Michigan Public Service Commission. The purpose of my testimony was to address the reasonableness of Detroit Edison Company's (DTE) requested changes to its Biennial Renewable Energy Plan which had been previously approved in Case No. U-17793. I also recommended procedural changes in an effort to enhance the review, assessment and ultimately the integration of additional renewable resources into DTE's provision of electricity to its customers in the future.

Case No. U-18090, (10/16), Michigan Public Service Commission. Provided testimony on behalf of the Great Lakes Renewable Energy Association regarding the Consumers Energy response to the Commission's own Motion to establish a method and avoided cost for comply with the Public Utilities Regulatory Policy Act of 1978, 16 USC 2601 et seq. I reviewed the filing including Consumers Energy proposal for their preferred avoid cost methodology and made recommendations as to an appropriate approach and methodology for deriving avoided costs to be relied upon by Qualifying Facilities in Michigan.

Case No. U-18402 (04/18), I provided testimony on behalf of the Great Lakes Renewable Energy Association regarding Consumers Energy Company PSCR application, 2018-2022 five-year plan and filing materials. Based on my review I offered suggestions and recommendations regarding the PSCR level, impacts of residential, commercial and industrial customer owned renewable resources in its 2018-2022 PSCR resource mix.

Case No. M-2017-2640306 (04/18), The Pennsylvania Office of Consumer Advocate regarding a Peoples Natural Gas Company proposed the Energy Efficiency and Conservation Plan. I reviewed the proposed five-year Combined Heat and Power, Energy Efficiency and Conservation Plan proposed by Peoples Natural Gas Company. I sponsored direct, rebuttal and surrebuttal testimony, which addressed the design of the programs due to the deficiencies that were embodied in the proposed Plan.

Case No. U-18403 (04/18), I provided testimony on behalf of the Great Lakes Renewable Energy Association regarding the Application of DTE Electric Company for authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules For 2018 Metered Jurisdictional Sales of Electricity. Based on my review I offered recommendations regarding the reasonableness of its PSCR factor level and resource mix proposed for its 2018-2022 PSCR resource mix.

Case No. U-18231 (04/18), I provided testimony on behalf of the Great Lakes Renewable Energy Association regarding Consumers Energy Company Renewable Energy Plan application. I reviewed the proposed renewable energy plan and related filing materials. Based on my review I offered suggestions and recommendations regarding to improve the REP Plan development process. I recommended that the REP Plan development process be coordinated with Act 304 as well as Integrated Resource Planning processes and general rate proceedings to result in a more beneficial resource mix to better serve CECO ratepayers.

Case No. U-18232 (07/18), I provided testimony on behalf of the Great Lakes Renewable Energy Association regarding The Detroit Edison Company Biennial Renewable Energy Plan application. I reviewed the proposed renewable energy plan and related filing materials. Based on my review I offered suggestions and recommendations regarding to improve the REP Plan development process. I recommended that the REP Plan development process be coordinated with Act 304 as well as Integrated Resource Planning processes and general rate proceedings to result in a more beneficial resource mix which would benefit Detroit Edison Company ratepayers.

Case No. M-2017-2640306 (09/18), The Pennsylvania Office of Consumer Advocate regarding a Peoples Natural Gas Company proposed the Energy Efficiency and Conservation Plan. I reviewed the proposed five-year Combined Heat and Power, Energy Efficiency and Conservation Plan proposed by Peoples Natural Gas Company. I offered Supplemental Surrebuttal testimony with suggestions for energy efficiency program and plan improvements.

Case No. M-2017-2640195 (09/18), The Pennsylvania Office of Consumer Advocate regarding an Application of Transource Pennsylvania, LLC for approval of the Siting and Construction of the 230 kV Transmission Line Associated with the Independence Energy Connection - East and West Projects in portions of York and Franklin Counties, Pennsylvania. I reviewed the proposed transmission project and plan. I offered suggestions for utilization of energy efficiency programs and improvements to the transmission plan.

Case No. U-20219 (05/19), Michigan Public Service Commission. Provided testimony on behalf of the Michelle Rison and the Residential Consumer Group regarding aspects of the Consumers Energy Company PSCR Plan application seeking authorization to increase its rates for the generation and distribution of electricity and other relief. I reviewed the PSCR Plan application, filing and related documents. I reviewed, assessed and offered suggestions to improve the PSCR Plan and 5-year forecast that Consumers Energy Company (CECO) provided and to made recommendations to improve the PSCR Plan. I pointed out concerns regarding lack of benefits emanating from the Tax Cut and Jobs Act of 2017 (TCJA), leasing the Zeeland plant interconnection pipeline, and the gas management services contract terms for acquisition of natural gas at its Zeeland, Jackson and Karn plants.

Case No. U-20561 (11/19), Michigan Public Service Commission. Provided testimony on behalf of Michelle Rison and the Residential Consumer Group regarding aspects of THE DTE ELECTRIC COMPANY rate case seeking authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority. I reviewed the application, supporting testimony, exhibits and work papers and related documents. I addressed the issue of the appropriateness of a projected test period compared to a historic test period. In addition, I addressed the issue of the initiation and modification of DTE's advanced metering infrastructure .

Case No. U-20209 (03/20) Michigan Public Service Commission. Provided testimony on behalf of Michelle Rison and the Residential Consumer Group regarding aspects of the application of CONSUMERS ENERGY COMPANY reconciliation portion of the case dealing with implementation of its approved gas cost recovery plan for the 12-month period of April 1, 2018 through March 31, 2019. I reviewed the filing including the application, testimony, exhibits, work papers and other supporting documentation. I highlighted several concerns regarding the lack of GCR customer benefits that should have been derived from implementation of the Tax Cut and Jobs Act of 2017, leasing arrangements regarding an interconnection pipeline, and failure to identify or quantify GCR customer benefits resulting from the gas management services that CECO subcontracted out for its Zeeland, Jackson and Karn plants.

Case No. U-20525 (06/20) Michigan Public Service Commission. Provided testimony on behalf of Michelle Rison and the Residential Customer Group regarding the application of CONSUMERS ENERGY COMPANY for approval of a power Supply cost Recovery Plan for the 12 months ending December 31, 2020. I reviewed the filing including the application, testimony, exhibits, work papers and supporting documents. I highlighted several concerns regarding the lack of GCR customer benefits that should have been derived from implementation of the Tax Cut and Jobs Act of 2017, leasing arrangements regarding an interconnection pipeline, and failure to identify or quantify GCR customer benefits resulting from the gas management services that CECO subcontracted out relative to the Zeeland, Jackson and Karn facilities.

Case No. U-20220 (12/20) Michigan Public Service Commission. Provided testimony on behalf of Michelle Rison and the Residential Customer Group regarding the application of CONSUMERS ENERGY COMPANY for reconciliation of its power Supply cost Recovery Plan for the 12 months ending December 31, 2019. I reviewed the case filing including the application, testimony, exhibits, work papers and supporting documents. I identified and defended several concerns regarding the deficiency of GCR customer benefits regarding the implementation of the Tax Cut and Jobs Act of 2017, leasing arrangements regarding an interconnection pipeline as well as the failure to identify or quantify GCR customer benefits resulting from the gas management services that CECO subcontracted out.

In addition, I have served the following public sector clients since 1990.

Client	**Nature of Service**
Alaska Housing Finance Corporation	Analysis of energy efficiency, system planning and applicability of Energy Policy Act standards to Alaska resource selection process.
California Low Income Governing Board	In conjunction with AB 1890 the state's restructuring statute provided analyses of options to deliver energy efficiency and assistance programs to low-income households in a restructured utility environment. Assisted the CPUC and Low-Income Governing Board in de low-income energy assistance and energy efficiency programs, implementation methods and procedures under interim utility administration.
Conservation Law Foundation of New England	Provided technical support to the collaborative working groups with Boston Edison, United Illuminating, Eastern Utilities Association, and Nantucket Electric regarding system planning approaches, energy efficiency programs and resource screening.
District of Columbia Public Service Commission	Testimony regarding demand-side management, least cost planning principles.
Germantown Settlement, Philadelphia	Analysis and technical support regarding business structure and market to aggregate load and/or provide energy efficiency and energy assistance services to low-income households.
City of New Orleans	Developed least cost planning rules, guided a public working group to develop demand-side programs, and developed a low income, senior citizens energy efficiency program.

Oak Ridge National Laboratory	Prepared an economic analysis of the customer impact from various electricity restructuring configurations for the State of Ohio
Ohio Office of Consumer Council	Analyzed two utilities' long-range plans and energy efficiency resource options. Analyzed the Dominion East Gas Company application to be relieved of the merchant function.
Ontario Energy Board	Developed demand-side management programs and evaluated need for natural gas integrated resource planning rules.
U.S. Environmental Protection Agency	Developed handbook, "Energy Efficiency and Renewable Energy: Opportunities from Title IV of the Clean Air Act", which focuses on how energy efficiency and renewables relate to acid rain compliance strategies.
U.S. Environmental Protection Agency and U.S. Department of Energy	Analyzed and compared utility supply- and demand-side resource selection for Clean Air Act compliance on the Pennsylvania-New Jersey-Maryland (PJM) interconnection.
Washington State Weatherization Directors	Natural Gas energy conservation program design involving Cascade Natural Gas Company

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set VII

Response Date: 11/19/2020

OCA-VII-12

Is PECO currently relying primarily on word-of-mouth and its website to stimulate awareness of both residential and commercial programs? If so, does PECO intend to continue this program marketing and outreach strategy? If not, what marketing, awareness building and outreach strategies does PECO intend to implement for its natural gas EE&C programs?

RESPONSE:

PECO is currently relying primarily on word-of-mouth and the company's website for gas rebate programs. In addition, PECO will implement new education campaigns to raise awareness of the expanded offerings. For example, the company may use bill inserts, emails, social media, events, informational sheets, and website updates as forms of expanded customer engagement.

Responsible Witness: Doreen Masalta

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set XV

Response Date: 12/17/2020

OCA-XV-3

Please refer to discovery response OCA-VII-19. The costs of PECO's commercial gas EE&C programs are recovered through base rates as a part of PECO's Marketing Department budget. Provide the amount of money PECO budgeted each year 2009 through 2019 for its commercial gas EE&C programs.

RESPONSE:

$28,000 has been earmarked annually for the commercial gas EE&C programs since 2009. This amount includes both incentive and administration costs.

Responsible Witness: Doreen Masalta

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set VII

Response Date: 11/19/2020

OCA-VII-19

Please provide a detailed description of the cost recovery mechanism for PECO's residential and commercial gas EE&C programs, including how under recovery and over recovery of costs is handled. What adjustment mechanism, if any, is there given that the costs are recovered through the gas distribution base rates which apparently change infrequently?

RESPONSE:

In accordance with PECO's 2010 Gas Rate Case Settlement (Docket R-2010-2161592), $2.008M per year is recovered through base rates to fund PECO's residential gas EE&C programs. PECO determines the actual costs of delivering the residential gas EE&C programs to customers on an annual basis. If the annual costs are less than the $2.008M, PECO reconciles the difference by providing a credit to residential customers through the "E-factor" portion of the Universal Services Funds Charge (USFC). PECO is not entitled to additional rate recovery if it spends more than the $2.008M in a given year. PECO closely monitors the annual program spend to ensure that the costs are not exceeded and thus there is no over recovery.

For PECO's commercial gas EE&C programs, the costs are recovered through base rates as part of PECO's Marketing Department's budget and PECO does not have a reconciliation mechanism.

Responsible Witness: Doreen Masalta

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2020-3018929

Response of PECO Energy Company
To Interrogatories of the
Office of Consumer Advocate
OCA Set VII

Response Date: 11/19/2020

OCA-VII-18

Please provide the annual PECO EE&C program expenditures for each year since 2009 and the annual savings increment associated with the expenditures.

RESPONSE:

Refer to Attachment OCA-VII-18(a)

Responsible Witness: Doreen Masalta

PECO EE&C Expenditure & Savings 2009-2019				
	Expenditure		Annual MCF Savings	
Year	Residential	Commercial	Residential	Commercial
2009	$1,471,809	$ 27,320	47,071	886
2010	$1,799,973	$ 34,133	75,415	1,756
2011	$1,960,896	$ 15,390	86,961	807
2012	$1,374,548	$ 17,160	39,873	550
2013	$1,348,407	$ 6,180	41,215	196
2014	$1,427,767	$ 5,835	42,819	100
2015	$1,434,046	$ 9,210	43,404	162
2016	$1,121,434	$ 4,283	28,008	128
2017	$1,128,229	$ 3,368	34,299	108
2018	$1,055,656	$ 1,538	31,615	49
2019	$1,121,793	$ 2,783	33,895	118

COMPARISON OF PECO AND OCA ENERGY EFFICIENCY PORTFOLIOS 2021				
	PECO Proposed w Smart Thermostat Correction		**OCA Proposed with Smart Thermostat Correction**	
	Participants	MCF Savings	Participants	MCF Savings
ENERGY STAR® Furnace (>= 95% AFUE)	5,025	56,838	1,727	19,531
ENERGY STAR®+ Furnace (>= 97% AFUE)	500	6,410	150	1,923
ENERGY STAR® Boiler (>= 90% AFUE)	500	2,919	0	0
Storage Water Heater (0.67 EF)	250	282	0	0
Smart Thermostat	6,650	30,984	1,000	4,960
Low Flow Faucet Aerator	7,250	2,088	7,250	2,088
Low Flow Shower Head	7,200	8,617	7,200	8,617
Residential Program Total	**27,375**	**110,138**	**17,327**	**37,116**
Low income Home Audit	289	3,529	289	3,529
Low Income Total	**289**	**3,529**	**289**	**3,529**
ENERGY STAR® Furnace <225 kBty/hr (>= 90% AFUE)	40	459	40	459
ENERGY STAR® Boiler <300kBTU/hr (>= 90% AFUE)	35	732	35	732
Commercial Program Total	**75**	**1,191**	**75**	**1,191**
Portfolio Total	**27,739**	**114,857**	**17,691**	**41,838**

COMPARISON OF PECO AND OCA ENERGY EFFICIENCY PORTFOLIO BENEFIT COST RATIOS 2021								
	PECO Proposed w Smart Thermostat Correction				**OCA Proposed with Smart Thermostat Correction**			
	Residential	Low Income	Commercial	**Portfolio**	Residential	Low Income	Commercial	**Portfolio**
Present Value TRC Benefits	$5,131,000	$211,000	$40,000	**$5,381,000**	$3,095,000	$211,000	$40,000	**$3,412,000**
Present Value Costs	$5,011,000	$1,000,000	$39,000	**$6,676,000**	$1,405,000	$1,000,000	$34,000	**$2,722,000**
Net Present Value TRC Benefits	$119,000	-$789,000	$1,000	**-$1,294,000**	$1,690,000	-789,000	$6,000	**685,000**
Total Resource Cost Test Benefit-Cost Ratio	1.02	0.21	1.01	**0.81**	2.20	0.21	1.18	**1.25**
Utility Cost Test Benefit-Cost Ratio	1.06	0.11	1.41	**0.70**	1.26	0.11	1.77	**0.57**

PECO PROPOSAL with Smart Thermostat Correction

Program Year 2021

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	5,025	56,838	$1,507,500
ENERGY STAR Furnace (>=97% AFUE)	500	6,410	$250,000
ENERGY STAR Boiler (>=90 AFUE)	500	2,919	$150,000
Storage Hot Water Heater (0.67 EF)	250	282	$25,000
Smart Thermostat	6,650	32,984	$332,500
Low Flow Faucet Aerator (<=1.5 GPM)	7,250	2,088	$29,000
Low Flow Showerhead (<=2.0 GPM)	7,200	8,617	$36,000
Residential Program Total	**27,375**	**110,138**	**$2,330,000**
Low Income Home Audit	289	3,529	$883,866
Low Income Program Total	**289**	**3,529**	**$883,866**
ENERGY STAR Furnace <225 kBTU/h (>=90% AFU	40	459	$12,000
ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE	35	732	$10,500
Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**27,739**	**114,857**	**$3,236,366**

Program Year 2022

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	5,025	56,838	$1,507,500
ENERGY STAR Furnace (>=97% AFUE)	500	6,410	$250,000
ENERGY STAR Boiler (>=90 AFUE)	500	2,919	$150,000
Storage Hot Water Heater (0.67 EF)	250	282	$25,000
Smart Thermostat	6,650	32,984	$332,500
Low Flow Faucet Aerator (<=1.5 GPM)	7,250	2,088	$29,000
Low Flow Showerhead (<=2.0 GPM)	7,200	8,617	$36,000
Residential Program Total	**27,375**	**110,138**	**$2,330,000**
Low Income Home Audit	289	3,529	$883,866
Low Income Program Total	**289**	**3,529**	**$883,866**
ENERGY STAR Furnace <225 kBTU/h (>=90% AFU	40	459	$12,000
ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE	35	732	$10,500
Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**27,739**	**114,857**	**$3,236,366**

Program Year 2023

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	5,025	56,838	$1,507,500
ENERGY STAR Furnace (>=97% AFUE)	500	6,410	$250,000
ENERGY STAR Boiler (>=90 AFUE)	500	2,919	$150,000
Storage Hot Water Heater (0.67 EF)	250	282	$25,000
Smart Thermostat	6,650	32,984	$332,500
Low Flow Faucet Aerator (<=1.5 GPM)	7,250	2,088	$29,000
Low Flow Showerhead (<=2.0 GPM)	7,200	8,617	$36,000
Residential Program Total	**27,375**	**110,138**	**$2,330,000**
Low Income Home Audit	289	3,529	$883,866
Low Income Program Total	**289**	**3,529**	**$883,866**
ENERGY STAR Furnace <225 kBTU/h (>=90% AFU	40	459	$12,000
ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE	35	732	$10,500
Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**27,739**	**114,857**	**$3,236,366**

Program Year 2024

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	5,025	56,838	$1,507,500
ENERGY STAR Furnace (>=97% AFUE)	500	6,410	$250,000
ENERGY STAR Boiler (>=90 AFUE)	500	2,919	$150,000
Storage Hot Water Heater (0.67 EF)	250	282	$25,000
Smart Thermostat	6,650	32,984	$332,500
Low Flow Faucet Aerator (<=1.5 GPM)	7,250	2,088	$29,000
Low Flow Showerhead (<=2.0 GPM)	7,200	8,617	$36,000
Residential Program Total	**27,375**	**110,138**	**$2,330,000**
Low Income Home Audit	289	3,529	$883,866
Low Income Program Total	**289**	**3,529**	**$883,866**
ENERGY STAR Furnace <225 kBTU/h (>=90% AFU	40	459	$12,000
ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE	35	732	$10,500
Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**27,739**	**114,857**	**$3,236,366**

PECO PROPOSAL with Smart Thermostat Correction

Program Year 2021				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	27,375	110,138	$2,875,000	$2,330,000	$0	$545,000	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$28,125	$22,500	$0	$5,625	$0
Admin and Education	N/A	N/A	$500,000	$0	$0	$0	$500,000
Emerging Technologies Pilots	N/A	N/A	$125,000	$0	$0	$0	$125,000
Portfolio Total	**27,739**	**114,857**	**$4,528,125**	**$2,352,500**	**$883,866**	**$666,759**	**$625,000**

Program Year 2022				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	27,375	110,138	$2,875,000	$2,330,000	$0	$545,000	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$28,125	$22,500	$0	$5,625	$0
Admin and Education	N/A	N/A	$500,000	$0	$0	$0	$500,000
Emerging Technologies Pilots	N/A	N/A	$125,000	$0	$0	$0	$125,000
Portfolio Total	**27,739**	**114,857**	**$4,528,125**	**$2,352,500**	**$883,866**	**$666,759**	**$625,000**

Program Year 2023				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	27,375	110,138	$2,875,000	$2,330,000	$0	$545,000	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$28,125	$22,500	$0	$5,625	$0
Admin and Education	N/A	N/A	$500,000	$0	$0	$0	$500,000
Emerging Technologies Pilots	N/A	N/A	$125,000	$0	$0	$0	$125,000
Portfolio Total	**27,739**	**114,857**	**$4,528,125**	**$2,352,500**	**$883,866**	**$666,759**	**$625,000**

Program Year 2024				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	27,375	110,138	$2,875,000	$2,330,000	$0	$545,000	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$28,125	$22,500	$0	$5,625	$0
Admin and Education	N/A	N/A	$500,000	$0	$0	$0	$500,000
Emerging Technologies Pilots	N/A	N/A	$125,000	$0	$0	$0	$125,000
Portfolio Total	**27,739**	**114,857**	**$4,528,125**	**$2,352,500**	**$883,866**	**$666,759**	**$625,000**

PECO PROPOSAL with Smart Thermostat Correction

Program Year 2021

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$5,131	$5,011	$119	1.02	1.06
Low Income	$211	$1,000	-$789	0.21	0.11
Commercial	$40	$39	$1	1.01	1.41
Portfolio Total	**$5,381**	**$6,676**	**-$1,294**	**0.81**	**0.70**

Program Year 2022

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$5,276	$5,011	$264	1.05	1.09
Low Income	$217	$1,000	-$783	0.22	0.11
Commercial	$41	$39	$2	1.05	1.46
Portfolio Total	**$5,533**	**$6,676**	**-$1,142**	**0.8**	**0.7**

Program Year 2023

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$5,450	$5,011	$438	1.09	1.14
Low Income	$223	$1,000	-$777	0.22	0.12
Commercial	$43	$39	$3	1.09	1.51
Portfolio Total	**$5,716**	**$6,676**	**-$960**	**0.86**	**0.76**

Program Year 2024

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$5,638	$5,011	$627	1.13	1.19
Low Income	$230	$1,000	-$770	0.23	0.12
Commercial	$44	$39	$5	1.13	1.57
Portfolio Total	**$5,913**	**$6,676**	**-$763**	**0.89**	**0.79**

OCA PROPOSAL with Smart Thermostat Corrected

Program Year 2021

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	1,727	19,531	$518,000
ENERGY STAR Furnace (>=97% AFUE)	150	1,923	$75,000
ENERGY STAR Boiler (>=90 AFUE)	0	0	$0
Storage Hot Water Heater (0.67 EF)	0	0	$0
Smart Thermostat	1,000	4,960	$50,000
Low Flow Faucet Aerator (<=1.5 GPM)	7,250	2,088	$29,000
Low Flow Showerhead (<=2.0 GPM)	7,200	8,617	$36,000
Residential Program Total	**17,327**	**37,118**	**$708,000**
Low Income Home Audit	289	3,529	$883,866
Low Income Program Total	**289**	**3,529**	**$883,866**
ENERGY STAR Furnace <225 kBTU/h (>=90% AFU	40	459	$12,000
ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE	35	732	$10,500
Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**17,691**	**41,838**	**$1,614,366**

Program Year 2022

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	1,727	19,531	$518,000
ENERGY STAR Furnace (>=97% AFUE)	150	1,923	$75,000
ENERGY STAR Boiler (>=90 AFUE)	0	0	$0
Storage Hot Water Heater (0.67 EF)	0	0	$0
Smart Thermostat	1,000	4,960	$50,000
Low Flow Faucet Aerator (<=1.5 GPM)	7,250	2,088	$29,000
Low Flow Showerhead (<=2.0 GPM)	7,200	8,617	$36,000
Residential Program Total	**17,327**	**37,118**	**$708,000**
Low Income Home Audit	289	3,529	$883,866
Low Income Program Total	**289**	**3,529**	**$883,866**
ENERGY STAR Furnace <225 kBTU/h (>=90% AFU	40	459	$12,000
ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE	35	732	$10,500
Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**17,691**	**41,838**	**$1,614,366**

Program Year 2023

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	1,727	19,531	$518,000
ENERGY STAR Furnace (>=97% AFUE)	150	1,923	$75,000
ENERGY STAR Boiler (>=90 AFUE)	0	0	$0
Storage Hot Water Heater (0.67 EF)	0	0	$0
Smart Thermostat	1,000	4,960	$50,000
Low Flow Faucet Aerator (<=1.5 GPM)	7,250	2,088	$29,000
Low Flow Showerhead (<=2.0 GPM)	7,200	8,617	$36,000
Residential Program Total	**17,327**	**37,118**	**$708,000**
Low Income Home Audit	289	3,529	$883,866
Low Income Program Total	**289**	**3,529**	**$883,866**
ENERGY STAR Furnace <225 kBTU/h (>=90% AFU	40	459	$12,000
ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE	35	732	$10,500
Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**17,691**	**41,838**	**$1,614,366**

Program Year 2024

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	1,727	19,531	$518,000
ENERGY STAR Furnace (>=97% AFUE)	150	1,923	$75,000
ENERGY STAR Boiler (>=90 AFUE)	0	0	$0
Storage Hot Water Heater (0.67 EF)	0	0	$0
Smart Thermostat	1,000	4,960	$50,000
Low Flow Faucet Aerator (<=1.5 GPM)	7,250	2,088	$29,000
Low Flow Showerhead (<=2.0 GPM)	7,200	8,617	$36,000
Residential Program Total	**17,327**	**37,118**	**$708,000**
Low Income Home Audit	289	3,529	$883,866
Low Income Program Total	**289**	**3,529**	**$883,866**
ENERGY STAR Furnace <225 kBTU/h (>=90% AFU	40	459	$12,000
ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE	35	732	$10,500
Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**17,691**	**41,838**	**$1,614,366**

OCA PROPOSAL with Smart Thermostat Corrected

Program Year 2021				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	17,327	37,118	$792,960	$708,000	$0	$84,960	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$22,500	$22,500	$0	$0	$0
Admin and Education	N/A	N/A	$215,040	$0	$0	$0	$215,040
Emerging Technologies Pilots	N/A	N/A	$0	$0	$0	$0	$0
Portfolio Total	**17,691**	**41,838**	**$2,030,500**	**$730,500**	**$883,866**	**$201,094**	**$215,040**

Program Year 2022				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	17,327	37,118	$792,960	$708,000	$0	$84,960	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$22,500	$22,500	$0	$0	$0
Admin and Education	N/A	N/A	$215,040	$0	$0	$0	$215,040
Emerging Technologies Pilots	N/A	N/A	$0	$0	$0	$0	$0
Portfolio Total	**17,691**	**41,838**	**$2,030,500**	**$730,500**	**$883,866**	**$201,094**	**$215,040**

Program Year 2023				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	17,327	37,118	$792,960	$708,000	$0	$84,960	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$22,500	$22,500	$0	$0	$0
Admin and Education	N/A	N/A	$215,040	$0	$0	$0	$215,040
Emerging Technologies Pilots	N/A	N/A	$0	$0	$0	$0	$0
Portfolio Total	**17,691**	**41,838**	**$2,030,500**	**$730,500**	**$883,866**	**$201,094**	**$215,040**

Program Year 2024				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	17,327	37,118	$792,960	$708,000	$0	$84,960	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$22,500	$22,500	$0	$0	$0
Admin and Education	N/A	N/A	$215,040	$0	$0	$0	$215,040
Emerging Technologies Pilots	N/A	N/A	$0	$0	$0	$0	$0
Portfolio Total	**17,691**	**41,838**	**$2,030,500**	**$730,500**	**$883,866**	**$201,094**	**$215,040**

OCA PROPOSAL with Smart Thermostat Corrected

Program Year 2021

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$3,095	$1,405	$1,690	2.20	1.26
Low Income	$211	$1,000	-$789	0.21	0.11
Commercial	$40	$34	$6	1.18	1.77
Portfolio Total	**$3,346**	**$2,654**	**$692**	**1.26**	**0.57**

Program Year 2022

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$3,171	$1,405	$1,766	2.26	1.31
Low Income	$217	$1,000	-$783	0.22	0.11
Commercial	$41	$34	$7	1.22	1.82
Portfolio Total	**$3,428**	**$2,654**	**$775**	**1.3**	**0.6**

Program Year 2023

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$3,257	$1,405	$1,852	2.32	1.36
Low Income	$223	$1,000	-$777	0.22	0.12
Commercial	$43	$34	$9	1.27	1.89
Portfolio Total	**$3,523**	**$2,654**	**$869**	**1.33**	**0.61**

Program Year 2024

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$3,349	$1,405	$1,944	2.38	1.42
Low Income	$230	$1,000	-$770	0.23	0.12
Commercial	$44	$34	$11	1.32	1.97
Portfolio Total	**$3,624**	**$2,654**	**$970**	**1.37**	**0.64**

PECO PROPOSAL as Filed with Smart Thermostat Error

Program Year 2021

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	5,025	56,838	$1,507,500
ENERGY STAR Furnace (>=97% AFUE)	500	6,410	$250,000
ENERGY STAR Boiler (>=90 AFUE)	500	2,919	$150,000
Storage Hot Water Heater (0.67 EF)	250	282	$25,000
Smart Thermostat	6,650	412,300	$332,500
Low Flow Faucet Aerator (<=1.5 GPM)	7,250	2,088	$29,000
Low Flow Showerhead (<=2.0 GPM)	7,200	8,617	$36,000
Residential Program Total	**27,375**	**489,454**	**$2,330,000**
Low Income Home Audit	289	3,529	$883,866
Low Income Program Total	**289**	**3,529**	**$883,866**
ENERGY STAR Furnace <225 kBTU/h (>=90% AFU	40	459	$12,000
ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE	35	732	$10,500
Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**27,739**	**494,173**	**$3,236,366**

Program Year 2022

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	5,025	56,838	$1,507,500
ENERGY STAR Furnace (>=97% AFUE)	500	6,410	$250,000
ENERGY STAR Boiler (>=90 AFUE)	500	2,919	$150,000
Storage Hot Water Heater (0.67 EF)	250	282	$25,000
Smart Thermostat	6,650	412,300	$332,500
Low Flow Faucet Aerator (<=1.5 GPM)	7,250	2,088	$29,000
Low Flow Showerhead (<=2.0 GPM)	7,200	8,617	$36,000
Residential Program Total	**27,375**	**489,454**	**$2,330,000**
Low Income Home Audit	289	3,529	$883,866
Low Income Program Total	**289**	**3,529**	**$883,866**
ENERGY STAR Furnace <225 kBTU/h (>=90% AFU	40	459	$12,000
ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE	35	732	$10,500
Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**27,739**	**494,173**	**$3,236,366**

Program Year 2023

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	5,025	56,838	$1,507,500
ENERGY STAR Furnace (>=97% AFUE)	500	6,410	$250,000
ENERGY STAR Boiler (>=90 AFUE)	500	2,919	$150,000
Storage Hot Water Heater (0.67 EF)	250	282	$25,000
Smart Thermostat	6,650	412,300	$332,500
Low Flow Faucet Aerator (<=1.5 GPM)	7,250	2,088	$29,000
Low Flow Showerhead (<=2.0 GPM)	7,200	8,617	$36,000
Residential Program Total	**27,375**	**489,454**	**$2,330,000**
Low Income Home Audit	289	3,529	$883,866
Low Income Program Total	**289**	**3,529**	**$883,866**
ENERGY STAR Furnace <225 kBTU/h (>=90% AFU	40	459	$12,000
ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE	35	732	$10,500
Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**27,739**	**494,173**	**$3,236,366**

Program Year 2024

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	5,025	56,838	$1,507,500
ENERGY STAR Furnace (>=97% AFUE)	500	6,410	$250,000
ENERGY STAR Boiler (>=90 AFUE)	500	2,919	$150,000
Storage Hot Water Heater (0.67 EF)	250	282	$25,000
Smart Thermostat	6,650	412,300	$332,500
Low Flow Faucet Aerator (<=1.5 GPM)	7,250	2,088	$29,000
Low Flow Showerhead (<=2.0 GPM)	7,200	8,617	$36,000
Residential Program Total	**27,375**	**489,454**	**$2,330,000**
Low Income Home Audit	289	3,529	$883,866
Low Income Program Total	**289**	**3,529**	**$883,866**
ENERGY STAR Furnace <225 kBTU/h (>=90% AFU	40	459	$12,000
ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE	35	732	$10,500
Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**27,739**	**494,173**	**$3,236,366**

PECO PROPOSAL as Filed with Smart Thermostat Error

Program Year 2021				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	27,375	489,454	$2,875,000	$2,330,000	$0	$545,000	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$28,125	$22,500	$0	$5,625	$0
Admin and Education	N/A	N/A	$500,000	$0	$0	$0	$500,000
Emerging Technologies Pilots	N/A	N/A	$125,000	$0	$0	$0	$125,000
Portfolio Total	**27,739**	**494,173**	**$4,528,125**	**$2,352,500**	**$883,866**	**$666,759**	**$625,000**

Program Year 2022				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	27,375	489,454	$2,875,000	$2,330,000	$0	$545,000	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$28,125	$22,500	$0	$5,625	$0
Admin and Education	N/A	N/A	$500,000	$0	$0	$0	$500,000
Emerging Technologies Pilots	N/A	N/A	$125,000	$0	$0	$0	$125,000
Portfolio Total	**27,739**	**494,173**	**$4,528,125**	**$2,352,500**	**$883,866**	**$666,759**	**$625,000**

Program Year 2023				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	27,375	489,454	$2,875,000	$2,330,000	$0	$545,000	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$28,125	$22,500	$0	$5,625	$0
Admin and Education	N/A	N/A	$500,000	$0	$0	$0	$500,000
Emerging Technologies Pilots	N/A	N/A	$125,000	$0	$0	$0	$125,000
Portfolio Total	**27,739**	**494,173**	**$4,528,125**	**$2,352,500**	**$883,866**	**$666,759**	**$625,000**

Program Year 2024				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	27,375	489,454	$2,875,000	$2,330,000	$0	$545,000	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$28,125	$22,500	$0	$5,625	$0
Admin and Education	N/A	N/A	$500,000	$0	$0	$0	$500,000
Emerging Technologies Pilots	N/A	N/A	$125,000	$0	$0	$0	$125,000
Portfolio Total	**27,739**	**494,173**	**$4,528,125**	**$2,352,500**	**$883,866**	**$666,759**	**$625,000**

PECO PROPOSAL as Filed with Smart Thermostat Error

Program Year 2021

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$13,267	$5,011	$8,256	2.65	3.89
Low Income	$211	$1,000	-$789	0.21	0.11
Commercial	$40	$39	$1	1.01	1.41
Portfolio Total	**$13,518**	**$6,676**	**$6,842**	**2.02**	**2.50**

Program Year 2022

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$13,722	$5,011	$8,711	2.74	4.03
Low Income	$217	$1,000	-$783	0.22	0.11
Commercial	$41	$39	$2	1.05	1.46
Portfolio Total	**$13,980**	**$6,676**	**$7,304**	**2.1**	**2.6**

Program Year 2023

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$14,308	$5,011	$9,297	2.86	4.22
Low Income	$223	$1,000	-$777	0.22	0.12
Commercial	$43	$39	$3	1.09	1.51
Portfolio Total	**$14,574**	**$6,676**	**$7,899**	**2.18**	**2.71**

Program Year 2024

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$14,947	$5,011	$9,936	2.98	4.43
Low Income	$230	$1,000	-$770	0.23	0.12
Commercial	$44	$39	$5	1.13	1.57
Portfolio Total	**$15,222**	**$6,676**	**$8,546**	**2.28**	**2.85**

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018929
	:	
PECO Energy Company – Gas Division	:	

VERIFICATION

I, Geoffrey C. Crandall, hereby state that the facts set forth in my Direct Testimony, OCA Statement 6, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: December 22, 2020
*300681

Signature: Geoffrey C Crandall
Geoffrey C. Crandall

Consultant Address: MSB Energy Associates, Inc.
6907 University Ave # 162
Middleton, WI 53562

OCA Statement No. 3R

R-2020-3018929
2/17/21 JK

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**DOCKET NO. R-2020-3018929**
	:	
PECO ENERGY COMPANY – GAS DIVISION	:	

REBUTTAL TESTIMONY OF

KEVIN W. O'DONNELL, CFA

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

January 19, 2021

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Kevin W. O'Donnell. I am President of Nova Energy Consultants, Inc ("Nova"). My business address is 1350 SE Maynard Rd., Suite 101, Cary, North Carolina 27511.

Q. ON WHOSE BEHALF ARE YOU PRESENTING REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA"). The OCA represents consumers before the Pennsylvania Public Utility Commission ("the Commission").

Q. MR. O'DONNELL, DID YOU PREVIOUSLY SUBMIT WRITTEN DIRECT TESTIMONY ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE IN THIS CASE?

A. Yes. I presented testimony as part of the OCA's alternative recommendation in the event the Commission does not adopt the OCA's primary position as described by OCA witness Scott Rubin.

Q. MR. O'DONNELL, WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. To review the testimony of Christopher Keller, Fixed Utility Financial Analyst with the Pennsylvania Bureau of Investigation and Enforcement ("I&E").

Q. DO YOU AGREE WITH MR. KELLER'S RECOMMENDATION TO ALLOW PECO ENERGY – GAS DIVISION A RETURN ON EQUITY OF 10.24%?

A. No. A 10.24% ROE is not reflective of current market conditions, and if accepted by the Commission, will allow PECO Energy – Gas Division ("PECO Gas" or "the Company") to over-earn, at the expense of consumers, in a market reflective of much lower capital costs.

Q. PLEASE EXPLAIN WHY YOU BELIEVE MR. KELLER'S RECOMMENDATION TO ALLOW PECO GAS A 10.24% ROE IS EXCESSIVE AND UNWARRANTED.

A. The last rate case order from this Commission involving PECO Energy – Gas Division was Docket No. R-2010-2161592. In the Company's 2010 rate case, a ROE of 11.75% was requested, along with a common equity to total capital structure of 53.18%. The case was ultimately settled and approved by the Commission on December 16, 2010.[1] PECO Energy – Electric Division's most recent rate case was under Docket No. R-2018-3000164. That rate filing made by the Company's electric utility affiliate was made on March 29, 2018, included a 10.95% ROE request, and was ultimately settled and approved by the Commission on December 20, 2018.[2] However, subsequent to each of these rate cases, the financial markets across the country have undergone tremendous change.

[1] S&P Global Rate Case History (Past Rate Cases); Years: All; Service Type: All; Company List: PECO Energy Co.; States: Pennsylvania; Date Accessed: October 19, 2020. The Settlement resolved all issues, but one issue regarding cost allocation, which is not materially relevant for the purposes of this testimony.
[2] *Id.*

Q. HOW HAVE INTEREST RATES CHANGED SINCE THE COMPANY'S MOST RECENT RATE CASES?

A. On December 16, 2010, which was the date of the final order in the last PECO Gas case, the yield on 30-year US Treasury bonds closed at the end of the day at 4.57%. On December 20, 2018, which is the date of the last PECO Electric final order, the yield on 30-year US Treasury bonds closed at the end of the day at 3.02%. Subsequently, on January 14, 2021, the yield on 30-year US Treasury bonds closed at the end of the day at 1.88%. As such, the yield on 30-year US Treasury bonds has fallen 269-basis points and 114-basis points from the settlement dates of each of the Company's two previous rate cases.[3] As such, interest rates have fallen notably over the periods outlined above.

Q. HOW HAVE EQUITY MARKETS CHANGED SINCE THE COMMISSION'S ORDER IN THE COMPANY'S MOST RECENT RATE CASES?

A. On December 16, 2010, the Dow Jones Utility Average ("DJUA") closed at 396.70 and on December 20, 2018, the DJUA closed at 729.42. Subsequently, on January 14, 2021, the DJUA closed at the end of the day at 851.26.[4] As such, this change represents approximate increases of 115% and 17% in the DJUA since the last PECO Gas case in 2010 and PECO Electric case in 2018. Such a strong upward movement in the utility equity market is indicative of investors accepting a lower cost of capital on their investments.

[3] https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

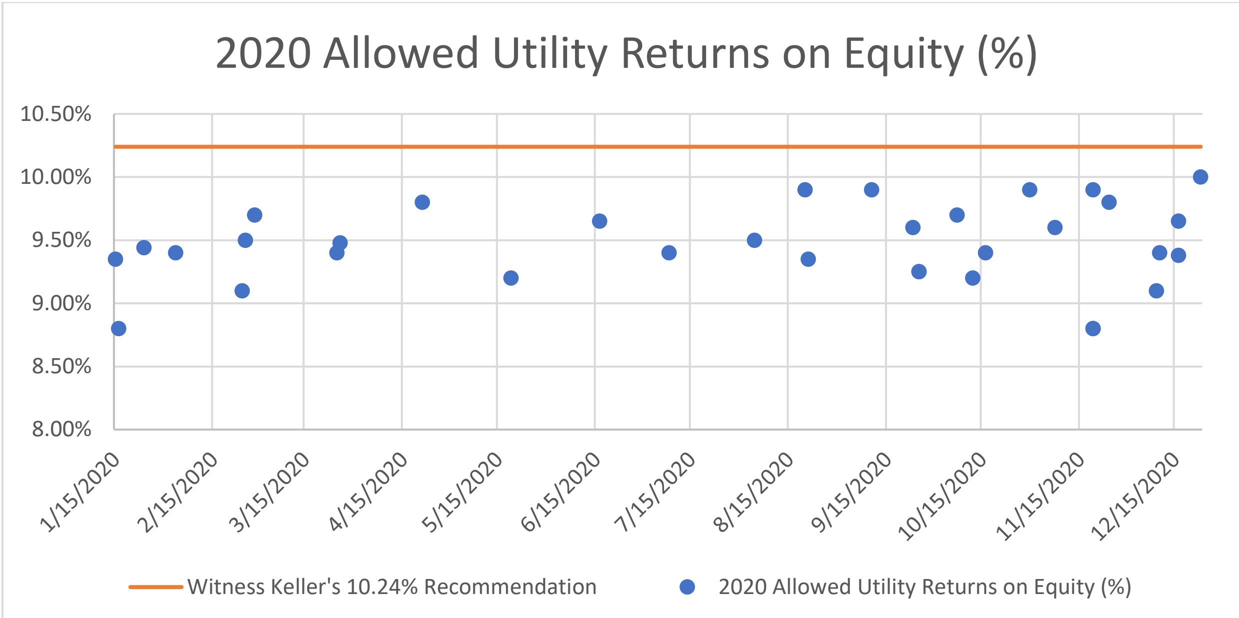
[4] https://finance.yahoo.com/quote/%5EDJU/history?period1=1292371200&period2=1609200000&interval=1d&filter=history&frequency=1d&includeAdjustedClose=true

Q. HOW DOES MR. KELLER'S RECOMMENDED ROE OF 10.24% COMPARE TO THE NATIONAL AVERAGE ROE GRANTED BY STATE REGULATORS ACROSS THE COUNTRY DURING 2020?

A. As of the end of 2020, the overall allowed ROE for natural gas utilities was 9.46%, which was down slightly from the 9.71% allowed by state regulators for natural gas utilities in 2019.[5] Mr. Keller's recommended ROE of 10.24% is well above the 9.46% average across the United States in 2020. Additionally, of the 34 completed natural gas cases reported during 2020 that comprised the 9.46% average for the year, there were no rate cases with an allowed return higher than 10.00%[6], which is in contrast to Mr. Keller's recommended ROE in this case of 10.24%. See **Chart 1** below for reference:

[5] S&P Global Market Intelligence Rate Case Statistics; Frequency: Annually; Date Range: 01/01/2019 – 12/31/2020; Service Type: Natural Gas; Chart Items: Return on Equity (%); Date Accessed: January 8, 2021.
[6] S&P Global Market Intelligence Rate Case Statistics; Company List: All; Date Range: 01/01/2020 – 12/31/2020; Service Type: Natural Gas; Chart Items: Return on Equity (%); Date Accessed: January 8, 2021.

Chart 1: 2020 US Allowed Utility Returns on Equity (%)[7]



Q. WHAT ARE THE PRIMARY DIFFERENCES BETWEEN YOUR ROE RECOMMENDATION OF 8.75% AND I&E'S RECOMMENDATION OF 10.24% IN THE CURRENT RATE CASE?

A. The following points below drive the difference between my recommendation in this current rate case, and that of I&E Witness Keller:

- Mr. Keller noted that his recommended ROE is 10.24% as this is the exact value produced by his DCF model.[8] I have instead placed the greatest weight on the results produced by my DCF model and decided upon my ultimate recommendation based upon a variety of data inputs. I also used the CAPM and CEA methods as checks on the results produced by the DCF[9];

[7] S&P Global Market Intelligence Rate Case Statistics; Company List: All; Date Range: 01/01/2020 – 12/31/2020; Service Type: Natural Gas; Chart Items: Return on Equity (%); Date Accessed: January 8, 2021.
[8] I&E Witness Keller's Direct Testimony, page 23: line 7.
[9] Witness O'Donnell's Direct Testimony, page 54: lines 1 – 3.

- Mr. Keller removed New Jersey Resources Corp., Southwest Gas Holdings, and UGI Corp. from the comparable proxy group used throughout his analysis whereas I retained these companies in my proxy group and presented the results with and without the high growth rate associated with Northwest Natural Gas;[10]
- Mr. Keller's DCF result (*i.e.*, 10.24%)[11] was derived from a proxy group that ultimately was comprised of 7 companies,[12] utilized an average of a spot dividend yield and a 52-week dividend yield (*i.e.*, sourced from *Barron's* and *Value Line*) for the dividend yield value (*i.e.*, 3.38%) of his comparable proxy group companies,[13] and utilized 5-year earnings growth forecasted values for his proxy group companies (*i.e.*, sourced from *Yahoo Finance*, *Zacks*, *Morningstar*, and *Value Line*) to develop the average growth rate (*i.e.*, 6.86%) for use within his DCF model.[14] I used a proxy group of 10 companies, dividend yields that ranged from 1-week to 13-weeks, and a variety of historical and forecasted earnings ("EPS"), dividend ("DPS"), and book value ("BPS") growth rates[15]; and
- Mr. Keller's CAPM result (*i.e.*, 9.08%)[16] was derived using a risk-free rate of return of 1.23% based upon various 10-year treasury note yields,[17] an overall average expected market return of 10.46% based upon *Value Line* estimates and *S&P 500* estimates from *Barron's* and *Morningstar*,[18] a resulting equity risk premium of 9.23%, and an average Beta value for his 7-company proxy group

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[10] I&E Witness Keller's Direct Testimony, page 9: line 3.
[11] I&E Witness Keller's Direct Testimony, I&E Exhibit No. 2, Schedule 1, Page 1.
[12] I&E Witness Keller's Direct Testimony, I&E Exhibit No. 2, Schedule 4, Page 1.
[13] *Id.*
[14] I&E Witness Keller's Direct Testimony, I&E Exhibit No. 2, Schedule 5, Page 1.
[15] Witness O'Donnell's Direct Testimony: Exhibit KWO-2.
[16] I&E Witness Keller's Direct Testimony, I&E Exhibit No. 2, Schedule 10, Page 1.
[17] I&E Witness Keller's Direct Testimony, I&E Exhibit No. 2, Schedule 8, Page 1.
[18] I&E Witness Keller's Direct Testimony, I&E Exhibit No. 2, Schedule 9, Page 1.

sourced from *Value Line* (*i.e.*, 0.85).[19] In contrast, I surveyed market forecasts based on historical returns, as well as professional investment firms estimates of future returns.[20]

Q. HOW DOES YOUR PROXY GROUP DIFFER FROM THAT OF MR. KELLER?

A. As referenced in my pre-filed direct testimony, the number of available gas utilities has been dwindling due to various acquisitions and mergers seen across the industry. As such, I have opted to use the full 10 company comparable proxy group as provided by *Value Line*. In contrast Mr. Keller opted to remove New Jersey Resources, Southwest Gas Holdings, and UGI Corp from his comparable proxy group.[21] In his direct testimony, Mr. Keller noted that he removed New Jersey Resources and Southwest Gas Holdings from his proxy group as these companies did not meet his "*first criterion that fifty percent or more of the company's revenues must be generated from the regulated gas utility industry*."[22]

I have decided not to perform a similar removal of companies from my comparable proxy group as that of Mr. Keller largely given the limited number of 10 companies provided for the natural gas industry through *Value Line*. Throughout my 35 years of experience providing rate of return testimony across the United States, I have always found analysts' removal of certain companies within a proxy group to be inherently subjective. In addition, removing companies from a group that is already small can result in data integrity issues. As such, I have consistently maintained that within the

[19] I&E Witness Keller's Direct Testimony, I&E Exhibit No. 2, Schedule 7, Page 1.
[20] Witness O'Donnell's Direct Testimony, pages 78 – 81.
[21] I&E Witness Keller's Direct Testimony, page 9: line 3.
[22] I&E Witness Keller's Direct Testimony, page 10: lines 10 – 11.

natural gas industry, unless a company is currently going through bankruptcy, or a merger/acquisition type transaction, it should be included within a proxy group for transparency purposes.

Additionally, please note that in reference to my proxy group, I am aware UGI Corp. recently announced on December 30, 2020 their plan to purchase Mountaineer Gas in West Virginia.[23] However, as my direct testimony was filed on December 22, 2020, the data that I based my recommendation upon was sourced prior to UGI Corp's merger announcement. As a result, I do not find it necessary to adjust my proxy group or the information included within my direct testimony for this case given the date that my analysis was performed, and the testimony was filed.

Q. HOW DOES YOUR DCF ANALYSIS DIFFER FROM MR. KELLER'S?

A. In Mr. Keller's DCF analysis shown within **I&E Exhibit No. 2 – Schedule 5**, the results for his 7 company comparable proxy group were derived from his calculated dividend yield *(Average of (1) Spot Price Dividend Yield and (2) Average 52-Week Dividend Yield) + Average EPS Growth Rate*.[24] Note however, that Mr. Keller removed a single growth rate for Northwest Natural Gas Co. ("Northwest") as provided by *Value Line* as he deemed that this projected growth rate was "*extremely inconsistent and would have an unreasonable and unwarranted impact*"[25] on his DCF analysis. As such, the growth rate specific to the portion of Mr. Keller's DCF analysis sourced from *Value Line* is therefore only based upon analyst projections for 6 proxy group companies rather than 7. This

[23] https://www.ugicorp.com/investors/press-releases/press-releases-details/2020/UGI-to-Acquire-Mountaineer-Gas-Company/default.aspx
[24] I&E Witness Keller's Direct Testimony, I&E Exhibit No. 2, Schedule 6, Page 1.
[25] I&E Witness Keller's Direct Testimony, page 22: lines 12 – 13.

ultimately increased the weight given to the *Value Line* analyst EPS growth rate projections for these 6 companies.

In contrast, my DCF analysis reflected additional data points given that I utilized the full range of gas utilities followed by *Value Line* and then also considered EPS, DPS and BPS growth rates from both a historical and forecasted perspective. By considering these additional data points, my approach balanced out any undue influence that a growth rate for a single company would have on my DCF analysis due to the breadth of other data sources considered. Specifically, I derived my DCF results by first utilizing Forecasted Annualized Dividend Yields based on three separate time periods (*i.e.*, 13-weeks, 4-weeks, and 1-week) provided by *Value Line*, plus the following growth rates for my 10-company comparable proxy group:

- Historical EPS, DPS, and BPS growth rates over a 10-year period and a 5-year period provided by *Value Line*;
- Forecasted EPS, DPS, and BPS growth rates from *Value Line*;
- Average plowback growth rates (*i.e.*, percent retained to common equity) provided by *Value Line*;
- 3-year projected EPS growth rates provided by the *Center for Financial Research and Analysis* ("*CFRA*"); and
- 3 to 5-year EPS growth rate provided by *Charles Schwab* ("*Schwab*").

I have also included such results specific to Exelon as Exelon represents the overall parent company for PECO Energy. My DCF results are presented within **Exhibit KWO-2, Exhibit KWO-5** and **Exhibit KWO-6** to my originally pre-filed direct testimony. Within my pre-filed direct testimony, I have included my reasoning for why I have utilized each of the above referenced dividend yields and historical/forecasted growth rates.

Q. HOW DOES YOUR DCF DIVIDEND YIELD COMPARE TO THAT USED BY MR. KELLER?

A. As referenced within my direct testimony, a DCF result is built from two primary data sources, (1) a dividend yield, and (2) a forecasted growth rate. The dividend yield utilized by Mr. Keller within his DCF Model of 3.38% is derived by computing the average of the spot price for the week ending December 3, 2020 and the 52-week average for the period ending December 3, 2020. In contrast, I have presented dividend yields over three separate time periods of 3.7%, 3.5%, and 3.6% (*i.e.*, the 13-week, 4-week, and 1-week periods ending December 18, 2020) for my proxy group. As such, the primary differences between my DCF Analysis and that of Mr. Keller's relates to the growth rates used, given that Mr. Keller included a more limited number of companies within his proxy group and also singularly employed EPS growth rate forecasts.

Q. HOW DO YOUR DCF GROWTH RATES COMPARE TO THOSE USED BY MR. KELLER?

A. I do not disagree with the specific data used as inputs by Mr. Keller in his DCF model as his calculations approximate a portion of my own. However, where I disagree with Mr. Keller, is in regard to the data he utilized being sufficient to base the entirety of his DCF analysis and overall recommendation on. Simply put, I do not agree with Mr. Keller's sole reliance upon earnings growth forecasts within his DCF model.[26]

On Page 99 within my direct testimony, I explained why I believe analysts should utilize more than just forecasted EPS growth rates for each proxy group company included within their DCF analysis. There have been various academic articles and journals that specifically call into question the accuracy of earnings predictions and forecasts. Accordingly, I believe that placing undue reliance upon forecasted EPS growth rates produces unrealistically high returns on equity numbers that cannot be sustained indefinitely. As such, I maintain that additional data points should be considered within one's DCF analysis, such as forecasted DPS and BPS growth rates, as well as historical EPS, DPS, and BPS growth rates. In considering this additional data, an analyst is providing a more complete picture of the scenario based on all of the available data.

Q. WHY DO YOU BELIEVE IN THE IMPORTANCE OF ALSO UTILIZING HISTORICAL GROWTH RATES WITHIN YOUR DCF ANALYSIS?

A. As referenced in my pre-filed direct testimony, I strongly believe that historical growth rates should be used as part of the basis for an analyst's recommendation. Forecasted growth rates are also very important, but they are just that, in that they represent forecasts and estimates. I also believe that in light of the COVID-19 pandemic, the use of historical growth rates is more critical than ever given the inherent uncertainties beset by the pandemic. Mr. Keller's 10.24% cost of equity recommendation is highly influenced by his narrow reliance on analysts' projected EPS growth rates for the companies in his

[26] I&E Witness Keller's Direct Testimony, page 20: line 11.

proxy group. Mr. Keller's approach excludes information about other growth rates which are publicly available that, if included, would have provided a broader foundation for a more comprehensive DCF analysis to support an appropriate cost of equity for PECO Gas.

Q. WAS MR. KELLER'S REMOVAL OF NORTHWEST GAS' FORECASTED EPS GROWTH NECESSARY AND REASONABLE?

A. No. Mr. Keller overlooked the benefit that historical growth rates provide. Mr. Keller noted in his testimony that he removed a forecasted EPS growth rate of 24.50% for Northwest Natural Gas Co. from his analysis and that he was "*unable to find any explanation or justification of why this estimate was so high*".[27] However, if one were to examine the historical growth rates for Northwest, they would see that the 10-Year Historical EPS Growth Rate for Northwest was -11.00% and the 5-Year Historical EPS Growth Rate was -17.00%.

Provided this context, the increased level of Northwest's forecasted EPS growth rate at 24.50% as provided by *Value Line* makes sense given the fact that Northwest is recovering from negative growth on a 10-year and 5-year historical basis. Such knowledge could not be gained without analyzing all available growth rates. As illustrated by Northwest, actual low or negative historic growth rates are a possibility, information excluded from Mr. Keller's approach.

My approach of using historical and forecasted growth rates allows for the Commission to view all of the available data from both a historical and forecasted

[27] I&E Witness Keller's Direct Testimony, page 22: lines 20 – 21.

perspective. The fact that Northwest had ($2.94) earnings per share in 2017 is reflected in my DCF analysis, as well as *Value Line's* projected earnings per share for Northwest of $3.20 for 2023, 2024, and 2025. I recognize the value that forecasted growth rates provide, but viewing these growth rates in the proper context alongside the corresponding historical growth rates is vital to most appropriately determine the proper ROE for the company under analysis. In doing so in the current case, my use of both historical and forecasted growth rates applied to a larger proxy group afforded me the ability not to require the outright exclusion of the Northwest forecasted EPS growth rate from *Value Line*.

Q. HOW DOES YOUR CAPM ANALYSIS DIFFER FROM MR. KELLER'S?

A. In Mr. Keller's CAPM analysis, he performed his calculation using a risk-free rate of return based on 10-year treasury bonds of 1.23%, an overall average expected market return of 10.46%, a resulting equity risk premium of 9.23%, and an average Beta value for his 7-company proxy group of 0.85. The end-result of Mr. Keller's CAPM was a ROE of 9.08%[28] as compared to my CAPM range of 5.50% to 7.75%.[29]

In contrast, as shown in **Exhibit KWO-7** to my originally pre-filed direct testimony, I've developed a range from which I determined my CAPM results by utilizing a one year period of 30-year treasury bonds for a risk-free rate averaging 1.61% (*i.e.*, with a high value of 2.39% and a low value of 0.99% over the previous annual period examined), an equity risk premium range from 4.25% to 6.25%, and an average

[28] I&E Witness Keller's Direct Testimony, I&E Exhibit No. 2, Schedule 10, Page 1.
[29] Witness O'Donnell's Direct Testimony, Exhibit KWO-1.

Beta value for my proxy group comprised of the average Beta provided for my 10 company proxy group over the most recent quarter (*i.e.*, 0.89).

The first difference in my CAPM analysis and that of Mr. Keller is my use of the current quarter Betas for my proxy group comprised of 10 companies, and Mr. Keller's use of the average of Betas from different time periods for his proxy group comprised of 7 companies. This led to the Beta that I utilized in my CAPM analysis being 0.89, in contrast to Mr. Keller's of 0.85.[30]

Secondly, another difference that led to the variance between my CAPM results, and those of Mr. Keller, is that for his risk-free rate, Mr. Keller utilized forecasted 10-year treasury bond yields from Q1'21 – Q1'22 and from 2022 – 2026[31], while I utilized historical 30-year treasury bond yields over the previous one-year period as shown in **Exhibit KWO-7**. Our respective analyses led Mr. Keller to use a risk-free rate in his CAPM of 1.23%, whereas I utilized an average of 1.61% (with a low to high annual range of 0.99% to 2.39%).

Lastly, Mr. Keller's results were influenced greatly by his estimated overall market return of 10.46%, thus leading to his use of 9.23% as the equity premium, in comparison to my 4.25% to 6.25% range for the equity premium. I have utilized this 4.25% to 6.25% equity premium range as it embodies the approximate range of the historical and forecasted growth rates found in **Exhibit KWO-2**. In contrast, Mr. Keller's overall market return of 10.46% is an average of, (1) the 9.79% return over the next 3 to 5 year index appreciation for *Value Line's* 1700 stocks, and (2) the 11.13% over a 5-year period for the S&P 500 dividend yield and growth rates as provided by *Barron's* and

[30] I&E Witness Keller's Direct Testimony, I&E Exhibit No. 2, Schedule 7, Page 1.
[31] I&E Witness Keller's Direct Testimony, I&E Exhibit No. 2, Schedule 8, Page 1.

Morningstar.[32] I do not find the use of 10.46% as the overall market return to be realistic given the current economic situation, or even when examining market trends prior to the impacts of the COVID-19 pandemic.

Additionally, as I demonstrated in my pre-filed direct testimony, in its response to discovery request **OCA-IV-20**, PECO Gas' parent company Exelon has only assumed a 7% expected return on its pension assets.[33] Also as noted within my pre-filed direct testimony, various market experts, such as Grantham Mayor Van Otterloo, Morningstar Investment Management, Research Affiliates, and Vanguard, are not expecting the market to earn double-digit returns in the future either.

I&E witness Keller's CAPM analysis is flawed due to the inputs used and therefore does not provide a meaningful check on what DCF-based cost of equity is appropriate for PECO Gas.

Q. ARE THERE ANY OTHER DIFFERENCES IN YOUR ANALYSIS VERSUS THAT OF MR. KELLER?

A. Yes. I disagree with Mr. Keller's decision to accept the Company's proposed, end of the FPFTY cost of debt of 3.97%, long-term debt capital structure of 46.62%, and common equity capital structure of 53.38%.[34] I have instead recommended that the Company's cost of debt should be set at 3.84% based on the adjustments made in **Exhibit KWO-8** from my direct testimony, and that the Company's capital structure be set at a 50% - 50%

[32] I&E Witness Keller's Direct Testimony, I&E Exhibit No. 2, Schedule 9, Page 1.
[33] PECO Witness Stefani response to Question No. **OCA-IV-20**.
[34] I&E Witness Keller's Direct Testimony, page 6: line 10.

ratio between overall debt and common equity as noted within **Exhibit KWO-1** of my pre-filed direct testimony.

Q. IS MR. KELLER'S ACCEPTANCE OF THE COMPANY'S PROPOSED COST OF DEBT REASONABLE?

A. No. Mr. Keller accepted the Company's projected cost rate of long-term debt of 3.97% because this rate fell within his "…*proxy group's implied long-term debt cost range of 3.14% to 5.82%, with an average implied long term debt cost of 4.91% (I&E Exhibit No. 2, Schedule 3).*"[35] Mr. Keller appears to have overlooked updated information specific to PECO Gas' cost of debt. Specifically, the cost rates for PECO's March 2021, September 2021, and March 2022 anticipated "First and Refunding Mortgage Bonds" debt issuances have decreased from the levels previously estimated by Mr. Moul, as described in my direct testimony. Additionally, Mr. Keller did not address whether Mr. Moul's prime rate forecasts are reasonable. In my direct, I explain why the Prime Rate forecasts for PECO Gas' variable rate Trust Preferred Capital Securities should be adjusted downward. I have factored each of these adjustments into my analysis in **Exhibit KWO-8** to my direct testimony, which supported my recommendation that the Commission set the Company's cost of debt rate at 3.84%. The Company's forecasted 3.97% cost of long-term debt is overstated and not reasonable.

Q. DO YOU AGREE WITH MR. KELLER'S CAPITAL STRUCTURE RECOMMENDATION?

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[35] I&E Witness Keller's Direct Testimony, page 13: lines 4 – 7.

A. No, I do not. Mr. Keller accepted the Company's proposed capital structure as "*…it falls within the range of my proxy group's 2019 capital structures*".[36] Mr. Keller's test does not consider whether PECO Gas has provided support for its forecasted end of FPFTY capital structure ratios. Mr. Keller's approach does not consider the revenue requirement difference in the cost of debt versus equity.

Within **Section V** of my pre-filed direct testimony, I recommended that the Commission deny PECO Gas' projected end of the FPFTY capital structure with 46.62% long-term debt and 53.38% common equity as speculative and unreasonable for ratemaking. In place of Company's forecasted end of FPFTY capital structure, I recommended that the Commission set rates based upon capital structure ratios of 50% debt and 50% equity. This capital structure is closer to the actual capital structure ratios granted by utility regulators across the nation and is closer to the average of the 2019 equity ratios for my proxy group of 50.70% and 50.40% for Exelon.[37] The Company's projected capital structure has more equity than is reasonable in these current economic conditions, between the pandemic and low cost of borrowing.

Q. CAN YOU SUMMARIZE WHY YOU DO NOT FEEL IT APPROPRIATE FOR THE I&E POSITION TO BE ADOPTED?

A. Yes. Should the Commission proceed to review the PECO base rate filing on a standard ratemaking basis, I believe that the I&E's proposed capital structure for ratemaking purposes is too costly as the ROE, equity capital structure ratio, and cost of debt are all set at levels that are not indicative of what is currently reflected in capital markets. In

[36] I&E Witness Keller's Direct Testimony, page 12: lines 3 – 4.

contrast, I believe that the following points should be adopted as outlined within my direct:

- The proper capital structure to use in this proceeding is 50.00% common equity and 50.00% long-term debt;
- My recommendation of a cost of debt of 3.84% should be adopted to reflect the changes in the capital markets in contrast to what was included within Mr. Moul's pre-filed direct testimony and what was accepted by Mr. Keller;
- The Company's allowed return on equity should be set at 8.75%, based primarily upon the results of my DCF analysis; and
- The overall rate of return that PECO should be allowed to earn in this proceeding is 6.30%.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018929
	:	
PECO Energy Company – Gas Division	:	

<u>VERIFICATION</u>

I, Kevin W. O'Donnell, hereby state that the facts set forth in my Rebuttal Testimony, OCA Statement 3-R, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: January 19, 2021
*302478

Signature: ____________________
Kevin W. O'Donnell

Consultant Address: Nova Energy Consultants, Inc.
1350 SE Maynard Road
Suite 101
Cary, NC 27511

OCA Statement No. 4R

R-2020-3018929
2/17/21 JK

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
v.	)	Docket No. R-2020-3018929
	)	
	)	
PECO ENERGY COMPANY –	)	
GAS DIVISION	)	

REBUTTAL TESTIMONY
OF
GLENN A. WATKINS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JANUARY 19, 2021

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 6377 Mattawan Trail, Mechanicsville, Virginia 23116.

Q. HAVE YOU PREVIOUSLY FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes. I pre-filed direct testimony in this proceeding on December 22, 2020, which was designated as OCA Statement No. 4

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of this testimony is to respond to the direct testimonies of I&E witness Ethan Cline, Philadelphia Area Industrial Energy Users Group ("PAIEUG") witness Billie Laconte, and OSBA witness Robert Knecht on issues concerning class cost of service and revenue allocations.

II. CLASS COST OF SERVICE ("CCOSS")

Q. DOES I&E WITNESS CLINE INDICATE WHETHER HE EVALUATED THE REASONABLENESS OF CLASS COST OF SERVICE IN THIS CASE?

A. No. On page 26 of his direct testimony, Mr. Cline simply acknowledges that the Company provided a CCOSS in this case and that his revenue allocations and rate design recommendations are based on the Company's corrected CCOSS that was provided in response to OSBA Data Request I-2.[1] I will discuss Mr. Cline's reliance on the Company's CCOSS later in my testimony.

Q. PLEASE SUMMARIZE PAIEUG WITNESS LACONTE'S POSITION CONCERNING CCOSS IN THIS CASE.

[1] Cline direct testimony, page 26.

A. Although Ms. Laconte supports a classification of distribution mains as partially customer-related and partially demand-related, she did not provide an alternative study in this case. However, she has accepted the Company's CCOSS for purposes of determining her recommended class revenue allocations in this case.

Q. DID OSBA WITNESS KNECHT CONDUCT AN ALTERNATIVE CCOSS FOR THE COMMISSION'S CONSIDERATION IN THIS CASE?

A. Yes. Mr. Knecht made several adjustments to the Company's corrected CCOSS. Although some of Mr. Knecht's adjustments are very minor (and coincide with the minor adjustments I made in my CCOSS), his three significant adjustments relate to: (1) using a different weighting factor for the average portion and excess portion within the Average & Excess ("A&E") method to allocate distribution mains; (2) adjustments to various classes' peak demands, and to a lesser degree, throughput; and, (3) the treatment of some Interruptible classes differently than the Company within his A&E approach.

Q. PLEASE EXPLAIN MR. KNECHT'S ALTERNATIVE WEIGHTING FACTOR FOR THE AVERAGE PORTION AND EXCESS PORTION WITHIN THE A&E METHOD.

A. Similar to my direct testimony, Mr. Knecht provides a thorough discussion and explanation of the A&E method on pages 23 and 24 of his direct testimony. Of particular importance is Mr. Knecht's correct observation that for NGDCs, the A&E method is:

> typically more similar in magnitude to a peak demand allocator than to a P&A allocator. However, this observation depends on the weighting factor used to derive the A&E factor. Under specific conditions, namely when the weighting factor is based on the system load factor and there is no diversity of demand across classes, the P&A allocator is arithmetically identical to the A&E factor.[2]

Q. BEFORE YOU CONTINUE, DOES IT APPEAR THERE IS A TYPOGRAPHICAL ERROR IN MR. KNECHT'S STATEMENT ABOVE?

[2] Knecht direct testimony, page 23, lines 4 through 8.

A. Yes. In the last part of Mr. Knecht's statement above where he states: "the P&A allocator is arithmetically identical to the A&E factor," I am certain he meant to say peak demand instead of P&A. In this regard, Mr. Knecht corrects himself later on page 23 wherein he states: "the A&E allocator used by the Company produces results that are nearly identical to those that would result from a peak demand allocator."

Q. PLEASE CONTINUE WITH YOUR EXPLANATION OF MR. KNECHT'S AVERAGE AND EXCESS WEIGHTING FACTOR.

A. Although I noted in my direct testimony that PECO witness Ding incorrectly applied the A&E methodology in her analysis,[3] Mr. Knecht correctly observed that PECO's CCOSS utilized a weighting factor of 25.23% towards average demand and 74.77% "excess" demand. Furthermore, Mr. Knecht observed that an average demand weighting factor of 24.48% would result in an A&E allocator identical to a peak demand allocator; i.e., 100% demand weight.[4]

In order to place more weight on the average component, Mr. Knecht used a variant of the A&E methodology in which he simply weighted average demand at 50% and excess demand at 50%.

Q. IS "EXCESS" DEMAND THE SAME AS PEAK DEMAND?

A. No, and this is a very important point to understand. Excess demand is defined as peak demand minus average demand such that customers with low load factors will have high "excess" demands relative to customers with high load factors.

Q. WITH THE ABOVE UNDERSTANDING, IS THERE A WAY TO DETERMINE THE WEIGHTS GIVEN TO PEAK DEMAND WITHIN THE VARIOUS WITNESSES' CCOSS?

[3] Watkins direct testimony, pages 18 and 19.

[4] Knecht direct testimony, page 25, footnote 38.

A. Yes. As a matter of arithmetic, we can calculate the actual weights given to average demand (annual use) and peak demand. The following table provides the Company's weightings between average and peak demand:

TABLE 1-R

		Percent Weighting	
Party	Witness	Average	Peak
PECO	Ding [5]	17.4%	82.6%
OSBA	Knecht	33.4%	66.6%
OCA	Watkins	50.0%	50.0%

A mathematical proof utilizing Mr. Knecht's approach is provided in my Schedule GAW-1R. These different weightings have a material impact on the total cost of service assigned to individual classes.

Q. HAS THIS COMMISSION PROVIDED CLEAR GUIDANCE AS TO THE APPROPRIATE WEIGHTING THAT SHOULD BE GIVEN TO AVERAGE DEMAND AND PEAK DEMAND?

A. Not specifically. As I discussed in my direct testimony, for many years, this Commission approved P&A methodologies that were weighted 50% on peak demand and 50% on average demand. Furthermore, as noted in my direct testimony on page 13, as well as Mr. Knecht's direct testimony on page 23, line 26 through page 24, line 1, the Commission more recently found in a 2007 Philadelphia Gas Works ("PGW") rate case that:

> . . . the allocation of distributions Mains investment costs should be done using both annual and peak demands.[6]

In the PGW case, the Commission did not specify a percentage weighting between annual and peak demands. However, based on the many years of an explicit practice approving a

[5] Because of the inappropriate application of Ms. Ding's A&E method, this weighting varies across classes and the amount represented is for the Rate R and Rate GC classes.

[6] Pa. PUC v. Philadelphia Gas Works, Docket No. R-00061931, Order, at page 80.

50%/50% weighting, I have continued to utilize a 50% annual (average demand) and 50% peak demand weighting.

Finally, and as noted in my direct testimony, in the pending Columbia Gas of Pennsylvania rate case, the Administrative Law Judge recommends the approval of the P&A methodology using a 50% peak demand and 50% average demand weighting.[7]

Q. ON PAGE 23 OF HIS DIRECT TESTIMONY, MR. KNECHT ASSERTS THERE IS COMMISSION PRECEDENT FOR USING THE A&E ALLOCATION METHOD. DO YOU AGREE WITH MR. KNECHT'S ASSERTION?

A. No. Mr. Knecht's assertion that there is a precedent that the A&E method must be used is nothing more than form over function. Ratemaking should not be a rigid recipe from a cookbook such that utility rates are derived simply from a single set of rigid formulas. With this being said, it is most important to understand the circumstances of the two cases cited by Mr. Knecht as precedent setting, as well as the context under which the class cost of service studies were approved by this Commission.

The first case Mr. Knecht refers to is a 2006 rate case involving PPL Gas (Docket No. R-00061398). In that case, Mr. Knecht and I participated. Mr. Knecht and I both recommended various adjustments to Company witness Paul Herbert's CCOSS study that utilized a modified A&E approach to allocate mains. With respect to my testimony in the 2006 PPL Gas case, I accepted Mr. Herbert's allocation of mains because his modified A&E approach was not materially different than the results that would be obtained under the P&A method utilizing a 50%/50% weighting between peak and average demands. Therefore, in order to avoid bickering over two methods that produce very similar results, I focused my attention on other issues within Mr. Herbert's CCOSS.[8] At the same time, Mr. Knecht rejected Mr. Herbert's modified A&E approach and recommended that mains be allocated to classes based upon number of customers (28%) and peak day demands

[7] Pa. PUC v. Columbia Gas of Pennsylvania, Inc., Docket No. R-2020-3018835, Recommended Decision, at page 395.

[8] My adjustments in the 2006 PPL Gas case included different approaches to allocate storage, storage facilities, income taxes, low income (CAP) costs, miscellaneous revenue, uncollectibles, records and collections, and sharing of the revenue associated with discounted rates across all customer classes.

(72%). Furthermore, Mr. Knecht made adjustments to Mr. Herbert's class peak day demands. In its Opinion and Order, the Commission accepted the Administrative Law Judge's ("ALJ") recommendation and stated:

> The ALJ determined that the record does not demonstrate that the A&E allocator as calculated by PPL Gas is incorrect and that the OSBA failed to support its conclusion by explaining or demonstrating how the definition of the A&E methodology used by the Company is wrong. Finding that the A&E allocator is supported by the evidence, and that the OSBA modification to replace the A&E allocator with a peak demand allocator is not supported by the evidence, the ALJ recommended approval of the Company's A&E allocator. (Order, p. 114)

Because the only controversy surrounding the allocation of mains in the 2006 PPL Gas case concerned Mr. Knecht's proposal to allocate mains based on customers and peak day demand, which was rejected and the fact that I did not object to Mr. Herbert's modified A&E approach because it produced very similar results to those that would be obtained under the P&A method, I do not consider the Commission's findings in this case as precedential -- at least in terms of advocating the A&E approach. The only thing that can be determined from this Order is that the Commission rejected the allocation of mains based partially on number of customers and partially on peak day demands.

Q. PLEASE DISCUSS THE SECOND CASE THAT MR. KNECHT ASSERTS AS BEING PRECEDENTIAL AS IT RELATES TO THE ALLOCATION OF NGDC MAINS COSTS.

A. The second case Mr. Knecht refers to as precedential concerns the 2007 Philadelphia Gas Works ("PGW") general rate case (Docket No. R-00061931). As was the case in the PPL Gas case, the most controversial cost allocation issue concerned the allocation of mains investment. Company witness Howard Gorman conducted his CCOSS based upon an allocation approach in which mains were allocated 25% based on number of customers and 75% based on peak day demand. OCA witness Richard Galligan and Office of Trial Staff (now I&E) witness Joseph Kubas opposed the Company's allocation approach. OCA witness Galligan conducted an alternative CCOSS in which mains had no customer component and allocated mains with a weight of 20% on peak day demand and

80% on average day demands. Witness Kubas agreed conceptually with Mr. Galligan that there should be no customer component within the allocation of mains and stated on page 14 of his direct testimony as follows:

> the A&E method reflects the fact that mains are built to deliver volumes of gas during both average and peak times. Therefore, an equal amount of weight should be given to both events.

However, Mr. Kubas claimed to have used a modified A&E approach. Because Mr. Kubas' detailed workpapers are no longer available, it cannot be determined if the weighting mechanism he utilized in fact gave equal weight to peak and average day demands. In this case, the ALJ agreed with OCA and OTS concerning the two most relevant factors as it relates to the allocation of mains. First, the ALJ recommended that the Company's proposal to allocate mains based on number of customers and peak day demands be rejected. In its Opinion and Order, the Commission agreed with the ALJ's recommendation and found "PGW's proposal to allocate a percentage of the costs of the distribution mains as a customer cost not to be acceptable." Perhaps most important as it relates to any "precedential" value of the A&E approach, the Commission found: "Reviewing the record, we find that the allocation of distribution mains investment costs should be done using both annual and peak demands."[9]

While I did not participate in the 2007 PGW rate case, I did participate in PGW's 2010 general rate case (Docket No. R-2009-2139884). In the 2010 case, Company witness Howard Gorman utilized a modified A&E approach that when evaluated against the traditional P&A method, produced no material differences.[10]

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING MR. KNECHT'S ASSERTION THAT THE A&E METHOD IS NOW THE COMMISSION PREFERRED APPROACH TO ALLOCATE MAINS INVESTMENT COSTS.

A. When the record of the two so-called "precedential" cases are carefully examined along with a clear understanding of the arithmetic involved within the A&E approach, I

[9] Order at page 80.

[10] Docket R-2009-2139884, OCA Statement No. 4 (Watkins' direct testimony, page 12).

can find no evidence of the Commission endorsing the A&E method as its preferred, or allowable, allocation methodology. Indeed, in both of these cases, a "modified" A&E mathematical approach was utilized that gave significant weight to average and peak demands. These findings are entirely consistent with the Commission's long-standing practice of weighting mains allocation based 50% on peak demand and 50% on average demand. With this in mind, it is important to consider the weighting schemes utilized by Ms. Ding and Mr. Knecht in the present case. Ms. Ding's A&E approach is almost entirely weighted on peak day demand while Mr. Knecht's A&E approach results in a 67% peak demand weighting. In my opinion, Ms. Ding's and Mr. Knecht's "modified" A&E approaches place too much weight on peak demand and not enough on average demand. Hence, I continue to support and recommend the use of the much more straight-forward 50% peak/50% average method that is easily understood and less prone to arbitrary manipulations than a "modified" A&E approach.

Q. PLEASE SUMMARIZE MR. KNECHT'S ADJUSTMENTS TO VARIOUS CLASS' PEAK DAY DEMANDS, AND TO A LESSER DEGREE, THROUGHPUT.

A. Mr. Knecht conducted a rather thorough examination of the Company's forecasted class design day demands based on actual historical usage patterns. In conducting his examination, Mr. Knecht used statistical linear regressions in evaluating the reasonableness of PECO's estimated design day demands by class. In these regards, Mr. Knecht observed that the Company's 3.2% implicit load factor for Rate L is nonsensical for a so-called large high load factor service rate schedule. Mr. Knecht's analysis led him to conclude that a more reasonable load factor for Rate L is approximately 40.2%. Next, Mr. Knecht observed that the implicit load factors for Rate Schedules GR and GC are the same (20.9%) under PECO's estimated design days and his statistical analysis led him to conclude that the load factor for the Residential class (Rate GR) is slightly less than that for the Commercial and Industrial class (Rate GC). As a result, Mr. Knecht recommends implicit load factors of 20.1% for Rate GR and 22.5% for Rate GC. Mr. Knecht's statistical analysis also resulted in an increase in the implicit load factor for Firm Transportation Service (Rate TS-F) from the Company's 36.8% to 51.6%. Mr. Knecht's recommended changes in class load factors were then mathematically applied to annual throughput, which resulted in his alternative class design day demands. Finally, Mr. Knecht observed that the Company failed to reduce the Rate TS-F demands associated with those customers whose distribution mains are directly-assigned within the CCOSS.

Q. HAVE YOU REVIEWED MR. KNECHT'S ANALYSES THAT SERVE AS THE BASIS FOR HIS ALTERNATIVE CLASS DESIGN DAY DEMANDS?

A. Yes. Mr. Knecht provided his detailed analysis in Excel format in his Workpaper RDK WP2-PECO 2021 GCOSS RDK Direct.xlsx.

Q. BASED ON YOUR REVIEW, WHAT ARE YOUR CONCLUSIONS REGARDING MR. KNECHT'S ANALYSIS OF CLASS DESIGN DAY DEMANDS?

A. First, it should be understood that class design day demands are merely estimates and that there are a myriad of accepted statistical techniques used to develop such estimates. With this being said, I have concluded that Mr. Knecht's alternative design day demands are more reasonable than those utilized by Ms. Ding in her CCOSS.

Q. PLEASE SUMMARIZE MR. KNECHT'S TREATMENT OF INTERRUPTIBLE CLASS DEMANDS WITHIN HIS A&E APPROACH.

A. Although PECO witness Ding assigned no "excess" demands to any of the Interruptible rate schedules, Mr. Knecht has treated the Temperature Control (Rate TCS) and Interruptible Sales (Rate IS) classes as firm service. With regard to Interruptible Transportation service (Rate TS-I), Mr. Knecht did recognize the inferior quality of this service relative to firm service such that he did not assign any "excess" demand to this rate schedule.[11]

[11] The remaining Interruptible rate schedule (Rate MV-I) has a 100% load factor such that there is no "excess" demand associated with this class.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING MR. KNECHT'S TREATMENT OF RATE "TCS" AND RATE "IS" THE SAME AS FIRM SERVICE?

A. I disagree with Mr. Knecht's treatment of these two Interruptible rate schedules being essentially the same as firm service. While it may be true that these two rates are rarely, if ever, interrupted, there is no doubt that this is an inferior quality of service to that of firm service. As such, it is my opinion that these rate schedules should not be treated the same as a firm service rate schedule. As discussed in my direct testimony, my P&A approach assigns some mains cost responsibility to these rate schedules but recognizes the inferior quality of service for these rate schedules by not assigning any peak portion within the development of the class P&A allocators.

Q. WHAT ARE YOUR OVERALL CONCLUSIONS REGARDING MR. KNECHT'S ALTERNATIVE CCOSS ANALYSIS?

A. I agree that Mr. Knecht's estimates of class design day demands are more reasonable than those portrayed by PECO witness Ding. However, I disagree with Mr. Knecht on two points. First, I disagree with his "modified" A&E approach that effectively assigns mains cost responsibility based on 67% peak demand and 33% average demand (annual throughput). Second, I disagree with Mr. Knecht's treatment of Rates TCS and IS the same as firm service.

Q. SINCE YOU HAVE FOUND MR. KNECHT'S ESTIMATED CLASS DESIGN DAY DEMANDS TO BE MORE REASONABLE THAN THOSE PORTRAYED BY PECO AND ALSO THOSE UTILIZED IN YOUR DIRECT TESTIMONY, HAVE YOU CONDUCTED A REVISED CCOSS TO INCORPORATE MR. KNECHT'S ESTIMATED CLASS DESIGN DAY DEMANDS?

A. Yes.

Q. PLEASE EXPLAIN YOUR REVISED CCOSS.

A. I utilized the same approach and methods as were performed in my direct testimony and presented in my Schedule GAW-3. That is, I utilized the P&A method to allocate mains using a 50%/50% weighting between peak and average demands. My revised CCOSS is identical except that I have utilized Mr. Knecht's recommended class design day demands and throughputs.

Q. WHAT ARE THE RESULTS OF YOUR REVISED CCOSS THAT INCORPORATES MR. KNECHT'S CLASS DESIGN DAY DEMANDS AND THROUGHPUT VOLUMES?

A. The following table provides a comparison of class RORs at current rates under my initial and revised CCOSS:

TABLE 2-R
Comparison of OCA Initial and Revised
P&A RORs At Current Rates

Rate Schedule		Initial Distribution ROR @ Current Rates	Revised Distribution ROR @ Current Rates
GR	Resid.	4.93%	4.84%
GC	Gen. Svc.	8.75%	9.12%
L	Lg. High LF	0.17%	16.54%
MV-F	Mtr. Veh. Firm	3.50%	3.26%
MV-I	Mtr. Veh. Interrupt	25.04%	24.67%
IS	Interruptible	3.24%	3.24%
TCS	Temp. Controlled	25.21%	25.21%
TS-F	Transportation Firm	4.56%	4.56%
TS-I	Transportation Interrupt.	3.13%	3.13%
Total Company		5.73%	5.73%

As can be seen in the table above, the only material difference is Rate L in which my revised CCOSS produces a ROR for this class substantially higher than the system average. This material difference is due to my acceptance of Mr. Knecht's peak demands for Rate L. The details of my revised CCOSS are provided in my Schedule GAW-2R.

III. CLASS REVENUE ALLOCATIONS

Q. BASED ON YOUR REVISED CCOSS, DO YOU RECOMMEND A REVISED CLASS REVENUE ALLOCATION UNDER A "BUSINESS AS USUAL" SCENARIO?

A. Yes. Based on the material change in the Rate L ROR, I now recommend no change in this class's rate revenues. This recommendation is consistent with my recommendation relating to Rate GC.

Q. PLEASE PROVIDE YOUR REVISED ALTERNATIVE "BUSINESS AS USUAL" CLASS REVENUE ALLOCATIONS?

A. The following table provides my revised alternative "business as usual" revenue allocation proposal while the details are provided in my Schedule GAW-3R:

TABLE 3-R

OCA Revised "Business As Usual" Class Revenue Allocation

Rate Schedule	Current Distribution Revenue	Total Increase Before GPC & MFC Reduction	GPC Reduction	MFC Reduction	Net Increase Amount	Net Increase Percent
GR	$233,528,109	$61,466,303	($693,000)	($800,000)	$59,973,303	25.68%
GC	$100,578,711	$0	($370,000)	($66,000)	($436,000)	-0.43%
OL	$423	$0			$0	0.00%
L	$75,475	$0			$0	0.00%
MV-F	$474,506	$135,266	($7,000)		$128,266	27.03%
MV-I	$5,022	$0			$0	0.00%
IS	$34,964	$9,967			$9,967	28.51%
TCS	$689,833	$0			$0	0.00%
TS-F	$16,719,224	$4,400,622			$4,400,622	26.32%
TS-I	$9,508,783	$2,710,632			$2,710,632	28.51%
Total Rate Revenue	$361,615,052	$68,722,789	($1,070,000)	($866,000)	$66,786,789	18.47%
Other Revenue	$1,528,291	$88,491			$88,491	5.79%
Total Company	$363,143,343	$ 68,811,280	($1,070,000)	($866,000)	$66,875,280	18.42%

Q. PLEASE PROVIDE A COMPARISON OF THE VARIOUS PARTIES' PROPOSED CLASS REVENUE ALLOCATIONS FOR THIS CASE.

A. The following table provides a comparison of each parties' proposed "business as usual" class revenue increases based on the Company's proposed overall revenue increase:

TABLE 4-R
Comparison of Proposed "Business As Usual" Class Revenue Increases[12]
($000)

		Initial OCA	Revised OCA	OSBA[13]	PAIEUG[14]	I&E[15]
Before GPC &MFC Changes:						
GR	Resid.	$61,440	$61,466	$64,430	$55,243	$66,662
GC	Gen. Svc.	$0	$0	$436	$9,555	($1,818)
L	Lg. High LF	$29	$0	$0	$35	$35
MV-F	Mtr. Veh. Firm	$135	$135	$139	$0	($14)
MV-I	Mtr. Veh. Interrupt	$0	$0	$1	$0	$0
IS	Interruptible	$10	$10	$0	$13	$0
TCS	Temp. Controlled	$0	$0	$56	$0	($30)
TS-F	Transp. Firm	$4,399	$4,401	$1,570	$3,021	$2,549
TS-I	Transp. Interrupt.	$2,711	$2,711	$2,094	$903	$1,338
Total Distribution Rate Rev.		$68,723	$68,723	$68,723	$68,769	$68,724
GPC & MFC Changes:						
GR Residential		($1,493)	($1,493)	($1,493)		
GC Gen. Svc.		($436)	($436)	($436)		
MV-F Mtr. Veh. Firm		($7)	($7)	($7)		
Total Base Rate Revenue		$66,787	$66,787	$66,787		
Other Revenue		$88	$88	$88		
Total Company		$66,875	$66,875	$66,875		

In order to interpret the table above, it is my understanding that PAIEUG and I&E did not address or take a position on PECO's proposed reductions to GPC and MFC charges while OCA and OSBA do not oppose these proposed reductions. Therefore, the above table is

[12] PECO's proposed class revenue allocations is unknown as it is Mr. Watkins' understanding that PECO will propose a significantly different class revenue allocation in its rebuttal testimony as a result of the Company's corrections to its as-filed CCOSS.

[13] It is my understanding that OSBA witness Knecht does not oppose the Company's reduction to GPC/MFC charges such that his revenue allocation recommendation is net of the Company's proposed reductions to GPC/MFC charges.

[14] It appears that PAIEUG's proposed revenue allocation is before a reduction to MFC and GPC revenues.

[15] It appears that I&E's proposed revenue allocation is before a reduction to MFC and GPC revenues.

bifurcated in order to show the Company's increases before and after GPC and MFC reductions.

Q. PLEASE COMMENT ON PAIEUG WITNESS LACONTE'S PROPOSED "BUSINESS AS USUAL" CLASS REVENUE ALLOCATION.

A. Although Ms. Laconte considered gradualism in her proposed class revenue allocations, I do not support her recommendation for two major reasons. First, Ms. Laconte's allocation does not comply with the Settlement Agreement from Docket No. R-2008-2028394 in which the parties agreed to move Rate GC and Rate L to cost of service by this case. While Ms. Laconte's recommended $9.6 million increase to Rate GC does slightly move this rate schedule somewhat closer to cost of service (based on PECO's corrected CCOSS), it is my opinion that a much more equitable solution is to authorize no increase to Rate GC. Second, and based on Mr. Knecht's investigation and adjustment to Rate L's design day demands, Ms. Laconte's recommended 47% increase[16] to Rate L is unwarranted.

Q. PLEASE COMMENT ON MR. KNECHT'S PROPOSED "BUSINESS AS USUAL" CLASS REVENUE ALLOCATION.

A. With the exception of Rates GC and TS-F, Mr. Knecht's and my "business as usual" revenue allocations are fairly similar. That is, while I recommend a $60.0 million "business as usual" increase to Rate GR, Mr. Knecht recommends an increase of $62.9 million. Conversely, I recommend a $4.4 million increase to Rate TS-F while his recommendation results in a $1.6 million increase to this rate schedule.

Q. PLEASE EXPLAIN THE APPROACH MR. KNECHT USED TO DEVELOP HIS RECOMMENDED CLASS REVENUE ALLOCATION.

A. Conceptually, Mr. Knecht and I used similar approaches in developing our recommended class revenue allocations. That is, we both relied on our respective CCOSS results as a guide in evaluating class revenue responsibility. We both placed a constraint

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[16] $35 ÷ $75 ($000).

that no class should enjoy a rate reduction. Moreover, classes that are currently overearning (under our respective CCOSS) received no increase in base rates and capped significantly underearning classes at 150% of the system average percentage increase.

Q. PLEASE EXPLAIN WHY MR. KNECHT'S AND YOUR REVISED REVENUE ALLOCATIONS DIFFER BETWEEN RATES GR AND TS-F.

A. As best I can tell, the primary reason for this difference relates to differences in our CCOSS results as it relates to Rate TS-F. That is, while Mr. Knecht's CCOSS indicates that the TS-F ROR at current rates is higher than the system average, my CCOSS indicates that this rate schedule's current ROR is somewhat below the system-wide ROR. As a result, Mr. Knecht assigned less than the system average percentage increase to Rate TS-F while I assigned the same percentage increase to this rate schedule as the Residential class; i.e., the remaining increase after recognition of no increases to some classes and larger percentage increases for significantly deficient classes.

Q. PLEASE COMMENT ON I&E WITNESS CLINE'S PROPOSED CLASS REVENUE ALLOCATION.

A. As noted earlier in this testimony, Mr. Cline indicates that he utilized the Company's corrected CCOSS as the basis for his proposed revenue allocations. In this regard, Mr. Cline recommends reducing Rates GC, MV-F and TCS revenues. With regard to his proposed reduction to Rate GC revenues, it appears that Mr. Cline attempts to, for all intents and purposes, bring this class to the Company's corrected calculated cost of service. With regard to Rates MV-F and TCS, it appears that Mr. Cline's proposed revenue reductions are the result of the very high relative rates of return produced from the Company's corrected CCOSS. However, I do not fully understand Mr. Cline's logic for other classes. For example, Mr. Cline proposes a 14.1% increase to Rate TS-I even though the Company's corrected CCOSS indicates that this class is currently producing a relative ROR of 154%, which is even higher than the Rate GC relative ROR of 141% wherein he recommends a rate reduction to Rate GC.

Nonetheless, I have three comments regarding Mr. Cline's proposed revenue allocation. First, given the economic hardships all customers are currently experiencing, I do not believe it is fair and equitable to provide rate reductions to some classes, and at the same time, recommend large percentage increases for other customer classes. Second, Mr. Cline relied heavily on the Company's corrected A&E CCOSS in developing his recommended revenue allocations. I have set forth my criticisms and concerns regarding the Company's A&E approach in this testimony as well as in my direct testimony. In a recent Peoples Natural Gas rate case (Docket No. R-2018-3006818), Mr. Cline was I&E's witness on CCOSS, revenue allocations and rate design. In that case, Mr. Cline explicitly recommended that CCOSS be conducted based on the P&A method to allocate mains-related costs.[17] Had Mr. Cline conducted a CCOSS utilizing his recommended P&A method, he would have arrived at different conclusions. Third, and as discussed earlier in this testimony, I have determined that OSBA witness Knecht's evaluation of the Company's estimated class peak demands is largely correct and that when more reasonable peak demand estimates are used, there is a significant shift in cost responsibility for Rate L.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes.

302535

[17] Cline direct testimony, Docket No. R-2018-3006818, page 15.

PECO ENERGY COMPANY
Peak Demand Weighting Under OSBA A&E Approach

	Total	Resid. (GR)	Gen. Svc. (GC)	Large (L)	MV Firm (MV-F)	MV Inter. (MVF-I)	Interruptible (IS)	Temp. Control (TCS)	Transp. Firm (TS-F)	Transp. Inter (TS-I)
Average Day Demand	230,717	114,982	61,374	45	1,211	2	110	489	25,052	27,451
Avg. Demand Pct	100.0000%	49.8370%	26.6013%	0.0197%	0.5250%	0.0008%	0.0476%	0.2121%	10.8585%	11.8981%
Peak Demand Exclude Interrupt.	924,575	572,676	272,453	113	1,211	2	517	1,564	48,588	27,451
Excess Demand	693,858	457,693	211,080	67	0	0	407	1,075	23,536	0
Excess Demand Pct	100.0000%	65.9635%	30.4212%	0.0097%	0.0000%	0.0000%	0.0587%	0.1549%	3.3920%	0.0000%
A&E Weighting Factor	50.00%									
A&E Factor	100.0000%	57.9003%	28.5112%	0.0147%	0.2625%	0.0004%	0.0531%	0.1835%	7.1252%	5.9491%

<u>Determination of A&E Peak Demand Weight</u>:

A = (W*Class Pct. of Average Demand)+[(1 - W)*Class Pct. of Excess Demand]
B = Class Pct. of Peak Demand
C = Class Pct. of Average Demand
W = Avg. Weighting Factor

A = Bx + C(1 - x) ---> A = Bx + C - Cx ---> A - C = Bx - Cx ---> x = (A - C)/(B - C)

	Total	Resid. (GR)	Gen. Svc. (GC)	Large (L)	MV Firm (MV-F)	MV Inter. (MVF-I)	Interruptible (IS)	Temp. Control (TCS)	Transp. Firm (TS-F)	Transp. Inter (TS-I)
A	100.0000%	57.9003%	28.5112%	0.0147%	0.2625%	0.0004%	0.0531%	0.1835%	7.1252%	5.9491%
B	100.0000%	61.9394%	29.4680%	0.0122%	0.1310%	0.0002%	0.0559%	0.1692%	5.2552%	2.9690%
C	100.0000%	49.8370%	26.6013%	0.0197%	0.5250%	0.0008%	0.0476%	0.2121%	10.8585%	11.8981%
Demand Weighting (x):		**66.6256%**	**66.6256%**	**66.6256%**	**66.6256%**	**66.6256%**	**66.6256%**	**66.6256%**	**66.6256%**	**66.6256%**

Proof										
Demand Weight		66.6256%	66.6256%	66.6256%	66.6256%	66.6256%	66.6256%	66.6256%	66.6256%	66.6256%
Class Peak Demand Pct.		61.9394%	29.4680%	0.0122%	0.1310%	0.0002%	0.0559%	0.1692%	5.2552%	2.9690%
Class Weighted Peak Demand Pct.	**66.6256%**	41.2675%	19.6332%	0.0081%	0.0873%	0.0001%	0.0373%	0.1127%	3.5013%	1.9781%
Average Weight		33.3744%	33.3744%	33.3744%	33.3744%	33.3744%	33.3744%	33.3744%	33.3744%	33.3744%
Class Avg. Pct.		49.8370%	26.6013%	0.0197%	0.5250%	0.0008%	0.0476%	0.2121%	10.8585%	11.8981%
Class Weighted Avg.	**33.3744%**	16.6328%	8.8780%	0.0066%	0.1752%	0.0003%	0.0159%	0.0708%	3.6239%	3.9709%
Total Class A&E Factor	**100.0000%**	57.9003%	28.5112%	0.0147%	0.2625%	0.0004%	0.0531%	0.1835%	7.1252%	5.9491%

PECO Energy Company
Revised Peak & Average Gas Class Cost of Service Study
(Summary)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
SUMMARY AT PRESENT RATES												
DEVELOPMENT OF RETURN EXCLUDING PURCHASED GAS												
OPERATING REVENUE												
Sales of Gas Revenue - Base	SCH , LN		$361,576	$233,489	$100,579	$75	$475	$5	$35	$690	$16,719	$9,509
Other Operating Revenue	SCH , LN		$1,528	$1,098	$320	$0	$2	$0	$0	$2	$65	$41
TOTAL OPERATING REVENUE			$363,104	$234,587	$100,899	$76	$477	$5	$35	$691	$16,785	$9,551
OPERATING EXPENSES												
Operation and Maintenance Expense Excl Pur Gas	SCH , LN		$144,391	$105,380	$28,035	$17	$212	$1	$16	$88	$6,417	$4,225
Depreciation and Amortization Expense	SCH , LN		$88,959	$60,314	$20,064	$9	$165	$1	$12	$69	$4,802	$3,524
Taxes Other Than Income Taxes-General	SCH , LN		$7,545	$5,223	$1,635	$1	$13	$0	$1	$5	$401	$266
Taxes Other Than Income Taxes-Distribution GRT	SCH , LN		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Income Taxes	SCH , LN		$18,763	$16,539	($614)	($6)	$66	($1)	$5	($78)	$1,478	$1,375
TOTAL OPERATING EXPENSES			$222,133	$154,378	$50,349	$33	$324	$2	$24	$240	$10,142	$6,641
OPERATING INCOME (RETURN)			$140,971	$80,208	$50,550	$43	$153	$3	$11	$451	$6,643	$2,910
DEVELOPMENT OF RATE BASE EXCL PURCHASED GAS												
Gas Plant in Service	SCH , LN		$3,537,670	$2,378,042	$811,265	$357	$6,675	$20	$475	$2,651	$202,597	$135,588
Less: Accumulated Depreciation	SCH , LN		$893,447	$607,870	$206,468	$85	$1,546	$5	$106	$675	$43,209	$33,482
Plus: Rate Base Additions Excl Purchased Gas	SCH , LN		$167,673	$117,964	$37,533	$23	$225	$1	$17	$89	$7,019	$4,802
Less: Rate Base Deductions	SCH , LN		$353,635	$229,976	$88,058	$35	$679	$2	$48	$275	$20,715	$13,847
TOTAL RATE BASE EXCL PURCHASED GAS	SCH , LN		$2,458,260	$1,658,161	$554,273	$260	$4,674	$13	$337	$1,790	$145,693	$93,060
RATE OF RETURN EXCL PURCHASED GAS (PRESENT)			5.73%	4.84%	9.12%	16.54%	3.26%	24.67%	3.24%	25.21%	4.56%	3.13%
INDEX RATE OF RETURN EXCL PURCHASED GAS (PRESENT)			100%	84%	159%	288%	57%	430%	56%	440%	80%	55%
EQUALIZED RETURN AT PROPOSED ROR OF 7.70%												
DEVELOPMENT OF RETURN EXCL PURCHASED GAS (EQUALIZED RATE)												
Rate Base Excluding Purchased Gas	SCH S, LN 81		$2,458,260	$1,658,161	$554,273	$260	$4,674	$13	$337	$1,790	$145,693	$93,060
Change in Operating Income (Rate Base * (7.70% - ROR (Present)))	1.97%		$48,315	$47,470	($7,871)	($23)	$207	($2)	$15	($313)	$4,576	$4,256
			7.70%	7.70%	7.70%	7.70%	7.70%	7.70%	7.70%	7.70%	7.70%	7.70%
OPERATING REVENUES												
Change in Revenue (Change in Return * 1.414)	1.41376		$68,305	$67,111	($11,127)	($32)	$293	($3)	$21	($443)	$6,469	$6,017
Distribution Rate Revenue (Present Rates) Incl. Other Non-Gas Revenue	SCH S, LN 62		$363,104	$234,587	$100,899	$76	$477	$5	$35	$691	$16,785	$9,551
Total Dist Rate Revenue (Proposed Rate) Incl. Other Non-Gas Revenue	CALCULATED		$431,409	$301,698	$89,772	$43	$770	$2	$56	$248	$23,254	$15,567
Less: Forfeited Discounts Revenue Increase	REV_487	137	$88	$67	$17	$0	$0	$0	$0	$0	$3	$1
TOTAL REQUIRED BASE RATE REVENUES			$429,793	$300,533	$89,434	$43	$768	$2	$56	$247	$23,186	$15,524
OPERATING EXPENSES												
Operation and Maintenance Expense Excl Pur Gas	SCH S, LN 67		$144,391	$105,380	$28,035	$17	$212	$1	$16	$88	$6,417	$4,225
Depreciation and Amortization Expense	SCH S, LN 68		$88,959	$60,314	$20,064	$9	$165	$1	$12	$69	$4,802	$3,524
Additional Bad Debt Expense	0.0034724		$237	$233	($39)	($0)	$1	($0)	$0	($2)	$22	$21
Additional PUC / OTS & SBA Fee Expense	0.0030802567		$210	$207	($34)	($0)	$1	($0)	$0	($1)	$20	$19
Taxes Other Than Income Taxes-General	SCH S, LN 69		$7,545	$5,223	$1,635	$1	$13	$0	$1	$5	$401	$266
Taxes Other Than Income Taxes-Distribution GRT	SCH S, LN 70		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL OPERATING EXPENSES BEFORE TAXES			$241,343	$171,357	$49,662	$27	$392	$1	$29	$159	$11,662	$8,055
State and Federal Income Taxes @ Effective Tax Rate	SCH S, LN 71		$18,763	$16,539	($614)	($6)	$66	($1)	$5	($78)	$1,478	$1,375
State and Federal Income Taxes @ Statutory Rates	CALCULATED		($19,631)	($19,282)	$3,189	$9	($84)	$1	($6)	$127	($1,858)	($1,727)
TOTAL OPERATING EXPENSES			$240,475	$168,614	$52,237	$30	$373	$2	$28	$208	$11,282	$7,702
NET OPERATING INCOME EXCL PURCHASED GAS			$190,934	$133,084	$37,535	$13	$397	$0	$29	$40	$11,971	$7,865
BASE RATE SALES EXCL PUR GAS @ EQUALIZED ROR 7.70%			$431,409	$301,698	$89,772	$43	$770	$2	$56	$248	$23,254	$15,567

PECO Energy Company
Revised Peak & Average Gas Class Cost of Service Study
(Summary)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
TOTAL REVENUE INCREASE EXCL PUR GAS			$68,305	$67,111	($11,127)	($32)	$293	($3)	$21	($443)	$6,469	$6,017
Less: Forfeited Discounts Revenue Increase			$88	$67	$17	$0	$0	$0	$0	$0	$3	$1
Required Base Rate Revenue Increase			$68,217	$67,044	($11,144)	($32)	$293	($3)	$21	($443)	$6,466	$6,015
BASE RATE REVENUE INCREASE EXCL PUR GAS REVENUES (%)			18.87%	28.71%	-11.08%	-42.98%	61.77%	-62.39%	60.84%	-64.25%	38.68%	63.25%
OCA "Business As Usual" Base Rate Increase			$68,723	$61,440	$0	$29	$135	$0	$10	$0	$4,399	$2,711
OCA Increase to Forfeited Discounts			$88	$67	$17	$0	$0	$0	$0	$0	$3	$1
Total OCA Revenue Increase			$68,811	$61,506	$17	$29	$135	$0	$10	$0	$4,401	$2,712
Revenue Conversion Factor			1.4138	1.4138	1.4138	1.4138	1.4138	1.4138	1.4138	1.4138	1.4138	1.4138
OCA Operating Income Increase			$48,673	$43,506	$12	$20	$96	$0	$7	$0	$3,113	$1,918
OCA Operating Income @ OCA Proposed Rates			$189,644	$123,714	$50,562	$63	$248	$3	$18	$451	$9,756	$4,828
Rate Base			$2,458,260	$1,658,161	$554,273	$260	$4,674	$13	$337	$1,790	$145,693	$93,060
ROR @ OCA "Business As Usual" Proposed Increase			7.71%	7.46%	9.12%	24.36%	5.31%	24.67%	5.33%	25.22%	6.70%	5.19%
Indexed ROR			100%	97%	118%	316%	69%	320%	69%	327%	87%	67%

PECO Energy Company
Revised Peak & Average Gas Class Cost of Service Study
(Rate Base)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
GAS PLANT IN SERVICE												
INTANGIBLE PLANT												
301-Organization	TOTPLT	43	$18,229	$12,254	$4,180	$2	$34	$0	$2	$14	$1,044	$699
303-Miscellaneous Intangible Plant	TOTPLT	43	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL INTANGIBLE PLANT			$18,229	$12,254	$4,180	$2	$34	$0	$2	$14	$1,044	$699
PRODUCTION PLANT (LPG)												
305-Land and Land Rights	DPKDAYP	1	$1,206	$816	$388	$0	$2	$0	$0	$0	$0	$0
311- Liquefied Petroleum Gas Equipment	DPKDAYP	1	$14,334	$9,698	$4,614	$2	$21	$0	$0	$0	$0	$0
320-Other Equipment (SNG Plant)	DPKDAYP	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL PRODUCTION PLANT			$15,539	$10,513	$5,002	$2	$22	$0	$0	$0	$0	$0
STORAGE PLANT (LNG)												
360-Land and Land Rights	ESTORAGE	16	$16	$11	$5	$0	$0	$0	$0	$0	$0	$0
361-Structures and Improvements	ESTORAGE	16	$14,919	$9,974	$4,613	$3	$1	$0	$0	$0	$145	$184
362-Gas Holders.	ESTORAGE	16	$7,084	$4,736	$2,190	$1	$0	$0	$0	$0	$69	$87
363-Purification Equipment	ESTORAGE	16	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
363-1 Liquefaction Equipment	ESTORAGE	16	$50,409	$33,702	$15,586	$10	$3	$0	$0	$0	$489	$620
TOTAL STORAGE PLANT			$72,428	$48,423	$22,394	$14	$4	$0	$0	$0	$702	$891
TRANSMISSION PLANT												
371- Transmission Related Plant	DTRAN	3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL TRANSMISSION PLANT			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DISTRIBUTION PLANT												
374-Land & Land Rights	DDISTPLT	49	$3,637	$2,015	$1,010	$1	$12	$0	$1	$4	$357	$237
375-Structures & Improvements	DDISTPLT	49	$15,745	$8,724	$4,375	$2	$51	$0	$4	$16	$1,545	$1,028
376-Mains												
General	P&A	138	$1,756,701	$987,810	$495,350	$281	$5,774	$7	$418	$1,863	$160,691	$104,507
Direct Assignment	DAMAINS	5	$15,289	$0	$0	$0	$0	$0	$0	$0	$8,219	$7,070
Total Account 376			$1,771,990	$987,810	$495,350	$281	$5,774	$7	$418	$1,863	$168,910	$111,578
378-Measuring & Regulating Station Equip-General	PLT_376	55	$24,652	$13,743	$6,891	$4	$80	$0	$6	$26	$2,350	$1,552
379-Measuring & Regulating Station Equip-City Gate												
City Gate	PLT_376	55	$65,778	$36,668	$18,388	$10	$214	$0	$16	$69	$6,270	$4,142
Direct Assignment	DAMR	9	$11,382	$0	$0	$0	$0	$0	$0	$0	$6,292	$5,090
Total Account 379			$77,160	$36,668	$18,388	$10	$214	$0	$16	$69	$12,562	$9,232
380-Services	CSERVICE	19	$1,111,048	$959,749	$146,489	$26	$49	$7	$13	$102	$3,031	$1,581
381-Meters	CMETERS	20	$163,858	$114,453	$42,012	$4	$155	$2	$4	$226	$3,856	$3,145
Direct Assignment	CMETERSDA	21	$232	$0	$0	$0	$0	$0	$0	$0	$232	$0
Total Account 381			$164,090	$114,453	$42,012	$4	$155	$2	$4	$226	$4,088	$3,145
382-Meter Installations	CMETERS	20	$220,402	$153,948	$56,510	$6	$208	$3	$6	$304	$5,187	$4,230
Direct Assignment	CMETINSTDA	22	$681	$0	$0	$0	$0	$0	$0	$0	$681	$0
Total Account 382			$221,083	$153,948	$56,510	$6	$208	$3	$6	$304	$5,868	$4,230
387-Other Equipment	DISTPLT	41	$2,118	$1,423	$482	$0	$4	$0	$0	$2	$124	$83
388-Asset Retirement Costs for Distribution Plant	DISTPLTXAR	44	$1,454	$977	$331	$0	$3	$0	$0	$1	$85	$57
TOTAL DISTRIBUTION PLANT			$3,392,978	$2,279,510	$771,839	$335	$6,551	$20	$467	$2,613	$198,920	$132,723
GENERAL PLANT												
389-Land and Land Rights	SALWAGES	121	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
390-Structures and Improvements	SALWAGES	121	$10,387	$7,378	$2,118	$1	$17	$0	$1	$6	$521	$344
391-Office Furniture & Equipment	SALWAGES	121	$6,858	$4,871	$1,399	$1	$11	$0	$1	$4	$344	$227
393-Store Equipment	SALWAGES	121	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
394-Tools, Shop & Garage Equip.	SALWAGES	121	$16,155	$11,475	$3,294	$2	$26	$0	$2	$10	$810	$535
395-Laboratory Equipment	SALWAGES	121	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
397-Communication Equipment	SALWAGES	121	$4,872	$3,461	$994	$1	$8	$0	$1	$3	$244	$161
398-Miscellaneous Equipment	SALWAGES	121	$223	$158	$45	$0	$0	$0	$0	$0	$11	$7
TOTAL GENERAL PLANT			$38,495	$27,343	$7,850	$5	$63	$0	$5	$24	$1,931	$1,275
TOTAL GAS PLANT IN SERVICE			$3,537,670	$2,378,042	$811,265	$357	$6,675	$20	$475	$2,651	$202,597	$135,588

PECO Energy Company
Revised Peak & Average Gas Class Cost of Service Study
(Rate Base)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
LESS: ACCUMULATED DEPRECIATION												
INTANGIBLE PLANT ACCUMULATED DEPRECIATION	INTPLT	37	$16,737	$11,250	$3,838	$2	$32	$0	$2	$13	$958	$641
PRODUCTION PLANT ACCUMULATED DEPRECIATION	PRODPLT	38	$13,221	$8,944	$4,255	$2	$19	$0	$0	$0	$0	$0
STORAGE PLANT ACCUMULATED DEPRECIATION	STORPLT	39	$31,273	$20,908	$9,669	$6	$2	$0	$0	$0	$303	$385
TRANSMISSION PLANT ACCUMULATED DEPRECIATION	TRANPLT	40	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DISTRIBUTION PLANT ACCUMULATED DEPRECIATION												
374-Land Rights	PLT_374	50	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
375-Structures & Improvements	PLT_375	51	$5,864	$3,249	$1,629	$1	$19	$0	$1	$6	$575	$383
376-Mains												
General	PLT_376G	52	$363,344	$204,312	$102,455	$58	$1,194	$1	$86	$385	$33,236	$21,616
Direct Assignment	DAMAINSAD	6	$2,147	$0	$0	$0	$0	$0	$0	$0	$54	$2,094
Total Account 376			$365,491	$204,312	$102,455	$58	$1,194	$1	$86	$385	$33,290	$23,709
378-Measuring & Regulating Station Equip-General	PLT_378	56	$8,285	$4,619	$2,316	$1	$27	$0	$2	$9	$790	$522
379-Measuring & Regulating Station Equip-City Gate												
City Gate	PLT_379CG	57	$22,178	$12,363	$6,200	$4	$72	$0	$5	$23	$2,114	$1,396
Direct Assignment	DAMRAD	10	$2,689	$0	$0	$0	$0	$0	$0	$0	$58	$2,631
Total Account 379			$24,867	$12,363	$6,200	$4	$72	$0	$5	$23	$2,172	$4,028
380-Services	PLT_380	60	$262,159	$226,459	$34,565	$6	$12	$2	$3	$24	$715	$373
381-Meters	CMETERS	20	$71,643	$50,042	$18,369	$2	$68	$1	$2	$99	$1,686	$1,375
Direct Assignment	CMETERSDA	21	$3	$0	$0	$0	$0	$0	$0	$0	$3	$0
Total Account 381			$71,646	$50,042	$18,369	$2	$68	$1	$2	$99	$1,689	$1,375
382-Meter Installations	CMETERS	20	$75,785	$52,935	$19,431	$2	$72	$1	$2	$105	$1,784	$1,454
Direct Assignment	CMETERSDA	21	$8	$0	$0	$0	$0	$0	$0	$0	$8	$0
Total Account 382			$75,793	$52,935	$19,431	$2	$72	$1	$2	$105	$1,791	$1,454
387-Other Equipment	PLT_387	63	$1,428	$959	$325	$0	$3	$0	$0	$1	$84	$56
388-Asset Retirement Costs for Distribution Plant	PLT_388	64	$555	$373	$126	$0	$1	$0	$0	$0	$33	$22
TOTAL DISTRIBUTION PLANT ACCUMULATED DEPRECIATION			$816,087	$555,310	$185,416	$74	$1,467	$5	$102	$652	$41,138	$31,922
GENERAL PLANT ACCUMULATED DEPRECIATION	GENLPLT	42	$16,131	$11,457	$3,289	$2	$26	$0	$2	$10	$809	$534
TOTAL ACCUMULATED DEPRECIATION			$893,447	$607,870	$206,468	$85	$1,546	$5	$106	$675	$43,209	$33,482
NET GAS PLANT IN SERVICE			$2,644,222	$1,770,173	$604,797	$272	$5,129	$14	$368	$1,976	$159,388	$102,106
ADDITIONS AND DEDUCTIONS TO RATE BASE												
PLUS: ADDITIONS TO RATE BASE												
COMMON PLANT	SALWAGES	121	$136,770	$97,147	$27,890	$16	$224	$1	$17	$85	$6,860	$4,530
WORKING CAPITAL												
Cash Working Capital - Purchased Gas	SCH RBC, LN 37		$3,679	$2,753	$894	$1	$16	$0	$0	$14	$0	$0
Cash Working Capital	SCH RBC, LN 22		($456)	($150)	($14)	$1	($2)	$0	($0)	$4	($168)	($127)
Gas Storage Inventory	ESTORAGE	16	$30,870	$20,639	$9,545	$6	$2	$0	$0	$0	$299	$380
Materials and Supplies	TOTPLT	43	$489	$329	$112	$0	$1	$0	$0	$0	$28	$19
TOTAL WORKING CAPITAL			$34,582	$23,571	$10,538	$8	$17	$0	($0)	$18	$159	$272
TOTAL ADDITIONS TO RATE BASE EXCL PURCHASED GAS			$167,673	$117,964	$37,533	$23	$225	$1	$17	$89	$7,019	$4,802
TOTAL ADDITIONS TO RATE BASE			$171,352	$120,717	$38,428	$24	$241	$1	$17	$103	$7,019	$4,802
LESS: DEDUCTIONS TO RATE BASE												
Customer Deposits	CUSTDEP	23	$13,418	$4,654	$8,461	$0	$3	$0	$0	$6	$194	$101
Customer Advances for Construction	CUSTADV	135	$1,334	$1,106	$228	$0	$0	$0	$0	$0	$0	$0
Deferred Income Taxes and Credits												
Plant	TOTPLT	43	$383,270	$257,636	$87,892	$39	$723	$2	$51	$287	$21,949	$14,690
Common Plant	SALWAGES	121	$6,582	$4,675	$1,342	$1	$11	$0	$1	$4	$330	$218

PECO Energy Company
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(Rate Base)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
Pension Assets / (Liability)	SALWAGES	121	($35,059)	($24,902)	($7,149)	($4)	($57)	($0)	($4)	($22)	($1,759)	($1,161)
ML Non-Conforming	TOTPLT	43	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Contributions in Aid of Construction (CIAC)	CUSTADV	135	($15,909)	($13,193)	($2,716)	$0	$0	$0	$0	$0	$0	$0
Total Deferred Income Taxes and Credits			$338,883	$224,216	$79,369	$35	$677	$2	$48	$269	$20,521	$13,746
TOTAL DEDUCTIONS TO RATE BASE			$353,635	$229,976	$88,058	$35	$679	$2	$48	$275	$20,715	$13,847
TOTAL PURCHASED GAS RATE BASE			$3,679	$2,753	$894	$1	$16	$0	$0	$14	$0	$0
TOTAL RATE BASE EXCLUDING PURCHASED GAS			$2,458,260	$1,658,161	$554,273	$260	$4,674	$13	$337	$1,790	$145,693	$93,060
TOTAL RATE BASE			$2,461,939	$1,660,914	$555,167	$261	$4,690	$13	$337	$1,803	$145,693	$93,060
CASH WORKING CAPITAL (LEAD LAG)												
TOTAL EXCLUDING PURCHASED GAS												
O&M EXPENSE RELATED CASH WORKING CAPITAL												
Payroll (Distribution Only)	SALWAGES	121	$42,209	$29,981	$8,607	$5	$69	$0	$5	$26	$2,117	$1,398
Pension	SALWAGES	121	$2,513	$1,785	$513	$0	$4	$0	$0	$2	$126	$83
Other Expenses												
Other Expenses	OMXPPPP	114	$97,082	$71,494	$18,484	$10	$134	$0	$10	$56	$4,149	$2,745
BSC	EBSC	18	$25,090	$16,201	$8,648	$6	$164	$2	$0	$69	$0	$0
Purchase of Recievables (POR)	REV_POR	136	$63,454	$45,995	$17,258	$0	$81	$1	$0	$118	$0	$0
TOTAL EXPENSES			$230,350	$165,456	$53,511	$22	$452	$3	$16	$271	$6,392	$4,226
TOTAL EXPENSES PER DAY			$631	$453	$147	$0	$1	$0	$0	$1	$18	$12
CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	5.2329		$3,302	$2,372	$767	$0	$6	$0	$0	$4	$92	$61
AVERAGE PREPAYMENTS			$2,047	$1,459	$453	$1	$4	$0	$0	$2	$81	$48
DISTRIBUTION ACCRUED TAXES			$189	$50	$141	$0	($0)	$0	($0)	$2	$3	($6)
INTEREST PAYMENTS	TOTPLT	43	($5,995)	($4,030)	($1,375)	($1)	($11)	($0)	($1)	($4)	($343)	($230)
NET CASH WORKING CAPITAL EXCL PUR GAS REQUIREMENT			($456)	($150)	($14)	$1	($2)	$0	($0)	$4	($168)	($127)
PURCHASED GAS												
O&M EXPENSE RELATED CASH WORKING CAPITAL												
Commodity Purchased - Contract Purchases	EGAS	17	$201,620	$150,877	$49,021	$70	$892	$9	$0	$750	$0	$0
Commodity Purchased - Spot Market Purchases	ETHRUPUTF	14	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL EXPENSES			$201,620	$150,877	$49,021	$70	$892	$9	$0	$750	$0	$0
TOTAL EXPENSES PER DAY			$552	$413	$134	$0	$2	$0	$0	$2	$0	$0
PP CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	6.65938		$3,679	$2,753	$894	$1	$16	$0	$0	$14	$0	$0
PURCHASED GAS ACCRUED TAXES	ETHRUPUTF	14	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NET PURCHASED GAS CASH WORKING CAPITAL REQUIREMENT			$3,679	$2,753	$894	$1	$16	$0	$0	$14	$0	$0
TOTAL NET CASH WORKING CAPITAL			$3,222	$2,603	$881	$2	$15	$0	($0)	$17	($168)	($127)

PECO Energy Company
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DISTRIBUTION ACCRUED TAXES												
Federal Income Tax	EBT	115	$15,181	$6,524	$8,098	$9	$0	$1	($0)	$98	$489	($37)
State Income Tax	EBT	115	$101,908	$43,793	$54,357	$58	$0	$5	($0)	$659	$3,283	($248)
PURTA Taxes	TOTPLT	43	($159,522)	($107,231)	($36,582)	($16)	($301)	($1)	($21)	($120)	($9,136)	($6,114)
PA Capital Stock Tax	TOTPLT	43	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PA & Local Use Taxes	TOTPLT	43	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PA Property tax	TOTPLT	43	$111,596	$75,015	$25,591	$11	$211	$1	$15	$84	$6,391	$4,277
TOTAL ACCRUED TAXES			$69,163	$18,100	$51,465	$62	($90)	$5	($6)	$722	$1,027	($2,121)
TOTAL ACCRUED TAXES PER DAY			$189	$50	$141	$0	($0)	$0	($0)	$2	$3	($6)
DISTRIBUTION AVERAGE PREPAYMENTS												
AGA Membership Dues	SALESREV	122	$187	$121	$52	$0	$0	$0	$0	$0	$9	$5
EAPA & NGA Membership Dues	SALESREV	122	$49	$32	$14	$0	$0	$0	$0	$0	$2	$1
PUC Assess - Gas	CLAIMREV	132	$759	$545	$179	$1	$2	$0	$0	$1	$22	$10
Cellent Gas Meter Reading	PLT_381	61	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Gas Software Maintenance	DISTPLT	41	$13	$9	$3	$0	$0	$0	$0	$0	$1	$1
Customer and Research	CUSTBILLS	34	$38	$35	$3	$0	$0	$0	$0	$0	$0	$0
VEBA Adjustment	SALWAGES	121	$55	$39	$11	$0	$0	$0	$0	$0	$3	$2
Facility Contracts	DISTPLT	41	$18	$12	$4	$0	$0	$0	$0	$0	$1	$1
IT License & Maintenance	TOTPLT	43	$630	$423	$144	$0	$1	$0	$0	$0	$36	$24
Fleet Activities	GENLPLT	42	$76	$54	$15	$0	$0	$0	$0	$0	$4	$3
Prepared Rent	DISTPLT	41	$60	$40	$14	$0	$0	$0	$0	$0	$3	$2
Postage	CUSTBILLS	34	$162	$149	$13	$0	$0	$0	$0	$0	$0	$0
TOTAL AVERAGE PREPAYMENTS			$2,047	$1,459	$453	$1	$4	$0	$0	$2	$81	$48

PECO Energy Company
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(Expenses)

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OPERATION & MAINTENANCE EXPENSE												
PRODUCTION EXPENSE												
Manufactured Gas Production Expense												
Operation												
710-Operations Labor	DPKDAYP	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
717-Liquefied Petroleum Gas Expenses	DPKDAYP	1	$80	$54	$26	$0	$0	$0	$0	$0	$0	$0
Total Operation			$80	$54	$26	$0	$0	$0	$0	$0	$0	$0
Maintenance												
741-Maintenance of Structures and Improvements.	DPKDAYP	1	$53	$36	$17	$0	$0	$0	$0	$0	$0	$0
742-Maintenance of Production Equipment	DPKDAYP	1	$133	$90	$43	$0	$0	$0	$0	$0	$0	$0
Total Maintenance			$186	$126	$60	$0	$0	$0	$0	$0	$0	$0
Total Manufactured Gas Production Expense			$266	$180	$86	$0	$0	$0	$0	$0	$0	$0
Other Gas Supply Expense												
Operation												
804-Natural Gas Purchases-PGC	EGAS	17	$201,620	$150,877	$49,021	$70	$892	$9	$0	$750	$0	$0
804-Natural Gas Purchases-BSC	EBSC	18	$25,090	$16,201	$8,648	$6	$164	$2	$0	$69	$0	$0
805-Other Natural Gas Purchases	ETHRUPUT	13	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
807-Purchased Gas Expenses	ESTORAGE	16	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
808.1 Gas withdrawn from storage—Debt.	ETHRUPUT	13	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
808.1 Gas withdrawn from storage—Direct	ETHRUPUTT	15	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Gas Supply Expense			$226,710	$167,079	$57,668	$77	$1,056	$11	$0	$819	$0	$0
TOTAL PRODUCTION EXPENSE			$226,976	$167,259	$57,754	$77	$1,056	$11	$0	$819	$0	$0
NATURAL GAS STORAGE EXPENSE												
Operation												
840-Operation Supervision and Engineering	ESTORAGE	16	$252	$169	$78	$0	$0	$0	$0	$0	$2	$3
841-Operation Labor & Expenses - Training	ESTORAGE	16	$812	$543	$251	$0	$0	$0	$0	$0	$8	$10
Total Operation			$1,065	$712	$329	$0	$0	$0	$0	$0	$10	$13
Maintenance												
843-Maintenance Expense	ESTORAGE	16	$4,414	$2,951	$1,365	$1	$0	$0	$0	$0	$43	$54
Total Maintenance			$4,414	$2,951	$1,365	$1	$0	$0	$0	$0	$43	$54
Total Natural Gas Storage Expense			$5,479	$3,663	$1,694	$1	$0	$0	$0	$0	$53	$67
TRANSMISSION EXPENSES												
Operation Expense	TRANPLT	40	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Maintenance Expense	TRANPLT	40	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL TRANSMISSION EXPENSE			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DISTRIBUTION EXPENSES												
Operation												
870-Operation Supervision and Engineering	SALWAGDO	116	$1,094	$802	$211	$0	$2	$0	$0	$1	$47	$31
874-Mains and Services Expenses	PLT_376380	66	$16,959	$11,456	$3,775	$2	$34	$0	$3	$12	$1,011	$666
875-Measuring & Reg. Station Exp.-General	PLT_378	56	$1,036	$577	$289	$0	$3	$0	$0	$1	$99	$65
877-Measuring & Reg. Station Exp.-City Gate Sta.	PLT_379	59	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0
878-Meter & House Regulator Expenses	PLT_3815	69	$5,979	$4,166	$1,529	$0	$6	$0	$0	$8	$155	$114
879-Customer Installations Expenses	CUSTINSTALL	25	$5,158	$4,726	$425	$0	$0	$0	$0	$0	$4	$2
880-Other Expenses	DISTPLT	41	$13,512	$9,078	$3,074	$1	$26	$0	$2	$10	$792	$529
Total Distribution Operation			$43,737	$30,805	$9,304	$4	$71	$0	$5	$32	$2,108	$1,408

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Maintenance												
887-Maintenance of Mains	PLT_376	55	$17,505	$9,758	$4,893	$3	$57	$0	$4	$18	$1,669	$1,102
889-Maint. of Measuring & Reg. Station Equip.-Gen	PLT_378	56	$1,014	$565	$284	$0	$3	$0	$0	$1	$97	$64
892-Maintenance of Services	PLT_380	60	$1,445	$1,248	$191	$0	$0	$0	$0	$0	$4	$2
893-Maint. of Meters & House Regulators	PLT_3815	69	$418	$291	$107	$0	$0	$0	$0	$1	$11	$8
894-Maintenance of Other Equipment	DISTPLT	41	$879	$590	$200	$0	$2	$0	$0	$1	$52	$34
Total Distribution Maintenance			$21,261	$12,454	$5,674	$3	$63	$0	$5	$21	$1,832	$1,211
TOTAL DISTRIBUTION PLANT O&M EXPENSES			$64,998	$43,259	$14,978	$7	$134	$0	$9	$53	$3,940	$2,618
TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)			$297,453	$214,181	$74,426	$85	$1,190	$12	$9	$872	$3,993	$2,685
CUSTOMER ACCOUNTS EXPENSES												
902-Meter Reading	CMETRDG	26	$199	$182	$16	$0	$0	$0	$0	$0	$0	$0
903-Customer Records and Collection Expense	CUSTREC	27	$14,723	$12,963	$1,294	$2	$5	$0	$1	$4	$297	$157
904-Uncollectible Accounts	EXP_904	133	$2,263	$2,046	$205	$0	$1	$0	$0	$1	$6	$4
904-Uncollectible Accounts - PPA	EXP_904PPA	134	$322	$322	$0	$0	$0	$0	$0	$0	$0	$0
905-Miscellaneous CA	CUSTCAM	28	$2,152	$1,971	$177	$0	$0	$0	$0	$0	$2	$1
TOTAL CUSTOMER ACCTS EXPENSE			$19,658	$17,484	$1,692	$2	$6	$0	$1	$6	$305	$161
CUSTOMER SERVICE & SALES EXPENSES												
908-Customer Assistance	CUSTASST	29	$7,742	$7,482	$217	$0	$0	$0	$0	$0	$28	$14
908-Customer Assistance	CUSTASSTDA	30	$500	$0	$499	$0	$0	$0	$0	$0	$0	$0
909-Advertisement	CUSTADVT	31	$309	$298	$9	$0	$0	$0	$0	$0	$1	$1
910-Miscellaneous CS	CUSTCSM	32	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
912-Demonstrating and Selling Expenses	CUSTSALES	33	$2,810	$2,716	$79	$0	$0	$0	$0	$0	$10	$5
916 Miscellaneous Sales Expenses	CUSTSALES	33	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CUSTOMER SERVICE & SALES EXP			$11,361	$10,496	$804	$0	$0	$0	$0	$1	$39	$21
TOTAL OPER & MAINT EXCL A&G			$328,472	$242,161	$76,923	$87	$1,197	$12	$11	$878	$4,337	$2,867
ADMINISTRATIVE & GENERAL EXPENSE												
920-Administrative Salaries	SALWAGES	121	$9,261	$6,578	$1,888	$1	$15	$0	$1	$6	$465	$307
921-Office Supplies & Expense	SALWAGES	121	$1,454	$1,033	$297	$0	$2	$0	$0	$1	$73	$48
923-Outside Service Employed	SALWAGES	121	$16,942	$12,033	$3,455	$2	$28	$0	$2	$11	$850	$561
924-Property Insurance	PSTDGPLT	46	$75	$51	$17	$0	$0	$0	$0	$0	$4	$3
925-Injuries and Damages	SALWAGES	121	$273	$194	$56	$0	$0	$0	$0	$0	$14	$9
926-Employee Pensions & Benefits	SALWAGES	121	$10,139	$7,202	$2,068	$1	$17	$0	$1	$6	$509	$336
928-Regulatory Commission	CLAIMREV	132	$2,717	$1,952	$640	$2	$6	$0	$0	$4	$78	$36
929-Duplicate Charges-Credit	CLAIMREV	132	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
930.1-General Advertising	CLAIMREV	132	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
930.2-Miscellaneous General	SALWAGES	121	$545	$387	$111	$0	$1	$0	$0	$0	$27	$18
932-Maintenance of General Plant	GENLPLT	42	$1,222	$868	$249	$0	$2	$0	$0	$1	$61	$40
TOTAL A&G EXPENSE			$42,629	$30,298	$8,781	$7	$71	$0	$5	$29	$2,080	$1,358
TOTAL OPERATION & MAINTENANCE EXPENSES			$371,101	$272,459	$85,704	$94	$1,268	$12	$16	$907	$6,417	$4,225
TOTAL PURCHASED GAS O&M EXPENSES			$226,710	$167,079	$57,668	$77	$1,056	$11	$0	$819	$0	$0
TOTAL O&M EXPENSES EXCLUDING PURCHASED GAS			$144,391	$105,380	$28,035	$17	$212	$1	$16	$88	$6,417	$4,225

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DEPRECIATION / AMORTIZATION EXPENSE												
INTANGIBLE PLANT EXPENSE	INTPLT	37	$10,333	$6,946	$2,370	$1	$19	$0	$1	$8	$592	$396
PRODUCTION PLANT EXPENSE	PRODPLT	38	$117	$79	$38	$0	$0	$0	$0	$0	$0	$0
LOCAL STORAGE PLANT EXPENSE	STORPLT	39	$1,729	$1,156	$535	$0	$0	$0	$0	$0	$17	$21
TRANSMISSION PLANT EXPENSE	TRANPLT	40	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DISTRIBUTION PLANT EXPENSE												
374-Land Rights	PLT_374	50	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
375-Structures & Improvements	PLT_375	51	$345	$191	$96	$0	$1	$0	$0	$0	$34	$23
376-Mains												
General	PLT_376G	52	$30,455	$17,125	$8,588	$5	$100	$0	$7	$32	$2,786	$1,812
Direct Assignment	DAMAINSDE	7	$155	$0	$0	$0	$0	$0	$0	$0	$54	$101
Total Account 376			$30,610	$17,125	$8,588	$5	$100	$0	$7	$32	$2,840	$1,913
378-Measuring & Regulating Station Equip-General	PLT_378	56	$508	$283	$142	$0	$2	$0	$0	$1	$48	$32
379-Measuring & Regulating Station Equip-City Gate												
City Gate	PLT_379CG	57	$1,361	$759	$380	$0	$4	$0	$0	$1	$130	$86
Direct Assignment	DAMRDE	11	$160	$0	$0	$0	$0	$0	$0	$0	$58	$102
Total Account 379			$1,521	$759	$380	$0	$4	$0	$0	$1	$188	$188
380-Services	PLT_380	60	$22,906	$19,787	$3,020	$1	$1	$0	$0	$2	$62	$33
381-Meters	CMETERS	20	$5,389	$3,764	$1,382	$0	$5	$0	$0	$7	$127	$103
Direct Assignment	CMETERSDA	21	$3	$0	$0	$0	$0	$0	$0	$0	$3	$0
Total Account 381			$5,392	$3,764	$1,382	$0	$5	$0	$0	$7	$129	$103
382-Meter Installations	CMETERS	20	$4,382	$3,061	$1,124	$0	$4	$0	$0	$6	$103	$84
Direct Assignment	CMETERSDA	21	$8	$0	$0	$0	$0	$0	$0	$0	$8	$0
Total Account 382			$4,390	$3,061	$1,124	$0	$4	$0	$0	$6	$111	$84
387-Other Equipment	PLT_378387	70	$133	$66	$33	$0	$0	$0	$0	$0	$19	$14
388-Asset Retirement Costs for Distribution Plant	PLT_388	64	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL DISTRIBUTION PLANT EXPENSE			$65,805	$45,037	$14,764	$6	$118	$0	$8	$50	$3,432	$2,389
GENERAL PLANT EXPENSE	GENLPLT	42	$1,723	$1,224	$351	$0	$3	$0	$0	$1	$86	$57
COMMON PLANT DEPRECIATION/AMORTIZATION	SALWAGES	121	$6,439	$4,574	$1,313	$1	$11	$0	$1	$4	$323	$213
NET MANUFACTURED GAS PLANT EXP	ETHRUPUT	13	$2,812	$1,298	$693	$1	$14	$0	$1	$6	$353	$447
TOTAL DEPRECIATION / AMORTIZATION EXPENSE			$88,959	$60,314	$20,064	$9	$165	$1	$12	$69	$4,802	$3,524

PECO Energy Company
Revised Peak & Average Gas Class Cost of Service Study
(Expenses)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
OTHER OPERATING EXPENSES												
TAXES OTHER THAN INCOME TAXES												
General Taxes												
PURTA Taxes	TOTPLT	43	$2,050	$1,378	$470	$0	$4	$0	$0	$2	$117	$79
Capital Stock	TOTPLT	43	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Payroll Related	SALWAGES	121	$3,776	$2,682	$770	$0	$6	$0	$0	$2	$189	$125
Real Estate Tax	TOTPLT	43	$1,568	$1,054	$360	$0	$3	$0	$0	$1	$90	$60
PA and Local Use Tax	CLAIMREV	132	$152	$109	$36	$0	$0	$0	$0	$0	$4	$2
Total General Taxes			$7,545	$5,223	$1,635	$1	$13	$0	$1	$5	$401	$266
Franchise and Revenue Taxes												
Retail Revenue			$0									
Forfeited Discounts			$0									
Less: Bad Debt			$0									
Total Revenue	CALCULATED		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Distribution @ GRT Rate 0.00%	CALCULATED		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Franchise and Revenue Taxes			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL TAXES OTHER THAN INCOME			$7,545	$5,223	$1,635	$1	$13	$0	$1	$5	$401	$266

PECO Energy Company
Revised Peak & Average Gas Class Cost of Service Study
(Revenues)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
OPERATING REVENUES												
SALES REVENUES												
Sales of Gas Revenues - Base		DIR	$361,576	$233,489	$100,579	$75	$475	$5	$35	$690	$16,719	$9,509
Sales Revenues - Purchased Gas-PGC	EGAS	17	$201,635	$150,889	$49,024	$70	$892	$9	$0	$750	$0	$0
Sales Revenues - Balancing Service Charge-BSC	EBSC	18	$25,075	$16,192	$8,643	$6	$164	$2	$0	$69	$0	$0
TOTAL SALES OF GAS			$588,286	$400,569	$158,245	$152	$1,531	$16	$35	$1,509	$16,719	$9,509
OTHER OPERATING REVENUES												
487-Forfeited Discounts	REV_487	137	$838	$634	$163	$0	$1	$0	$0	$1	$25	$14
488-Miscellaneous Service Revenues	OX_904	106	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
489-Transport of Gas of Others Revenue	PLT_376	55	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
494-Interdepartmental Rents	DISTPLT	41	$691	$464	$157	$0	$1	$0	$0	$1	$40	$27
TOTAL OTHER OPERATING REV			$1,528	$1,098	$320	$0	$2	$0	$0	$2	$65	$41
TOTAL OPERATING REVENUES			$589,814	$401,667	$158,566	$152	$1,533	$16	$35	$1,510	$16,785	$9,551

PECO Energy Company
Revised Peak & Average Gas Class Cost of Service Study
(Labor)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
DEVELOPMENT OF SALARIES & WAGES ALLOCATION FACTOR												
PRODUCTION SALARIES & WAGES EXPENSE												
Manufactured Gas Production Expense												
Operation - Acct 717	OX_PRODM	83	$48	$32	$15	$0	$0	$0	$0	$0	$0	$0
Maintenance - Accts 741-742	MX_PRODM	84	$112	$76	$36	$0	$0	$0	$0	$0	$0	$0
Total Manufactured Gas Production Expense			$160	$108	$51	$0	$0	$0	$0	$0	$0	$0
Other Gas Supply Expense												
Operation - Accounts 804-808	OX_PRODO	85	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Gas Supply			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL PRODUCTION S&W EXP			$160	$108	$51	$0	$0	$0	$0	$0	$0	$0
STORAGE SALARIES & WAGES EXPENSE												
Operation - Accts 840-841	OX_STOR	86	$541	$362	$167	$0	$0	$0	$0	$0	$5	$7
Maintenance - Acct 843	MX_STOR	87	$1,672	$1,118	$517	$0	$0	$0	$0	$0	$16	$21
TOTALSTORAGE S&W EXP			$2,213	$1,479	$684	$0	$0	$0	$0	$0	$21	$27
TRANSMISSION SALARIES & WAGES EXPENSE												
Operation	OX_TRAN	88	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Maintenance	MX_TRAN	89	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL TRANSMISSION S&W EXP			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DISTRIBUTION SALARIES & WAGES EXPENSE												
Operation												
874-Mains and Services Expenses	OX_874	92	$5,809	$3,924	$1,293	$1	$12	$0	$1	$4	$346	$228
875-Measuring & Reg. Station Exp.-General	OX_875	93	$714	$398	$200	$0	$2	$0	$0	$1	$68	$45
878-Meter & House Regulator Expenses	OX_878	94	$1,217	$848	$311	$0	$1	$0	$0	$2	$31	$23
879-Customer Installations Expenses	OX_879	95	$3,662	$3,355	$302	$0	$0	$0	$0	$0	$3	$2
880-Other Expenses	OX_880	96	$2,695	$1,810	$613	$0	$5	$0	$0	$2	$158	$105
Total Operation			$14,096	$10,335	$2,719	$1	$21	$0	$1	$9	$607	$403
Maintenance												
887-Maintenance of Mains	MX_887	97	$9,628	$5,367	$2,691	$2	$31	$0	$2	$10	$918	$606
889-Maint. of Measuring & Reg. Station Equip.-Gen	MX_889	98	$494	$275	$138	$0	$2	$0	$0	$1	$47	$31
892-Maintenance of Services	MX_892	99	$710	$614	$94	$0	$0	$0	$0	$0	$2	$1
893-Maint. of Meters & House Regulators	MX_893	100	$285	$199	$73	$0	$0	$0	$0	$0	$7	$5
894-Maintenance of Other Equipment	MX_894	101	$116	$78	$26	$0	$0	$0	$0	$0	$7	$5
Total Distribution Maintenance			$11,234	$6,533	$3,023	$2	$34	$0	$2	$11	$981	$648
TOTAL DISTRIBUTION S&W EXP			$25,330	$16,868	$5,741	$3	$54	$0	$4	$20	$1,588	$1,052
TOTAL OPER & MAINT S&W EXP (PROD, STOR, TRAN,& DIST)			$27,702	$18,456	$6,477	$3	$54	$0	$4	$20	$1,609	$1,079
CUSTOMER ACCOUNTS EXPENSES												
902-Meter Reading	CMETRDG	26	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
903-Customer Records and Collection Expense	CUSTREC	27	$5,897	$5,192	$518	$1	$2	$0	$0	$2	$119	$63
904-Uncollectible Accounts	EXP_904	133	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
904-Uncollectible Accounts - PPA	EXP_904	133	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
905-Miscellaneous CA	CUSTCAM	28	$291	$266	$24	$0	$0	$0	$0	$0	$0	$0
TOTAL CUSTOMER ACCTS S&W EXPENSE			$6,188	$5,459	$542	$1	$2	$0	$0	$2	$119	$63

PECO Energy Company
Revised Peak & Average Gas Class Cost of Service Study
(Labor)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
CUSTOMER SERVICE & SALES EXPENSES												
908-Customer Assistance	CUSTASST	29	$226	$219	$6	$0	$0	$0	$0	$0	$1	$0
909-Advertisement	CUSTADVT	31	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
910-Miscellaneous CS	CUSTCSM	32	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
912-Demonstrating and Selling Expenses	CUSTSALES	33	$388	$375	$11	$0	$0	$0	$0	$0	$1	$1
916 Miscellaneous Sales Expenses	CUSTSALES	33	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CUST SERVICE & SALES S&W EXP			$615	$594	$17	$0	$0	$0	$0	$0	$2	$1
TOTAL OPER & MAINT S&W EXP EXCL A&G			$34,505	$24,509	$7,036	$4	$56	$0	$4	$22	$1,731	$1,143
ADMINISTRATIVE & GENERAL EXPENSE												
920-Administrative Salaries	SALWAGXAG	120	$7,398	$5,255	$1,509	$1	$12	$0	$1	$5	$371	$245
921-Office Supplies & Expense	SALWAGXAG	120	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
923-Outside Service Employed	SALWAGXAG	120	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
924-Property Insurance	PSTDGPLT	46	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
925-Injuries and Damages	SALWAGXAG	120	$129	$92	$26	$0	$0	$0	$0	$0	$6	$4
926-Employee Pensions & Benefits	SALWAGXAG	120	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
928-Regulatory Commission	CLAIMREV	132	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
929-Duplicate Charges-Credit	CLAIMREV	132	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
930.1-General Advertising	SALWAGXAG	120	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
930.2-Miscellaneous General	SALWAGXAG	120	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
932-Maintenance of General Plant	GENLPLT	42	$177	$126	$36	$0	$0	$0	$0	$0	$9	$6
TOTAL A&G S&W EXPENSE			$7,704	$5,472	$1,571	$1	$13	$0	$1	$5	$386	$255
TOTAL OPER & MAINTENANCE SALARIES & WAGES EXP			$42,209	$29,981	$8,607	$5	$69	$0	$5	$26	$2,117	$1,398

PECO Energy Company
Revised Peak & Average Gas Class Cost of Service Study
(Income Taxes)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
DEVELOPMENT OF INCOME TAXES												
TOTAL OPERATING REVENUES EXCL PURCHASED GAS			$363,104	$234,587	$100,899	$76	$477	$5	$35	$691	$16,785	$9,551
LESS:												
OPER. & MAINT. EXP. EXCL PURCHASED GAS	SCH , LN		$144,391	$105,380	$28,035	$17	$212	$1	$16	$88	$6,417	$4,225
DEPRECIATION AND AMORTIZATION EXPENSE	SCH , LN		$88,959	$60,314	$20,064	$9	$165	$1	$12	$69	$4,802	$3,524
TAXES OTHER THAN INCOME TAXES	SCH , LN		$7,545	$5,223	$1,635	$1	$13	$0	$1	$5	$401	$266
NET OPERATING INCOME BEFORE TAXES			$122,209	$63,670	$51,164	$49	$87	$4	$6	$529	$5,165	$1,535
LESS:												
INTEREST EXPENSE (Rate Base * 1.85% Weighted Cost of Debt)			$45,478	$30,676	$10,254	$5	$86	$0	$6	$33	$2,695	$1,722
BASE TAXABLE DISTRIBUTION INCOME EXCL PURCHASED GAS			$76,731	$32,994	$40,910	$44	$0	$4	($0)	$496	$2,470	($186)
FEDERAL & STATE TAX ADJUSTMENTS												
Regulatory Asset Prog M-1 (Pension & Post Ret)	SALWAGES	121	$3,054	$2,169	$623	$0	$5	$0	$0	$2	$153	$101
Other Property Basis Adjustment (CIAC/ICM)	DISTPLT	41	$12,276	$8,247	$2,793	$1	$24	$0	$2	$9	$720	$480
Removal Costs/Software	TOTPLT	43	$9,120	$6,130	$2,091	$1	$17	$0	$1	$7	$522	$350
AFUDC Equity	TOTPLT	43	$5,482	$3,685	$1,257	$1	$10	$0	$1	$4	$314	$210
Permanent Adjustments	TOTPLT	43	($775)	($521)	($178)	($0)	($1)	($0)	($0)	($1)	($44)	($30)
Repair Allowance Deduction	TOTPLT	43	$132,540	$89,094	$30,394	$13	$250	$1	$18	$99	$7,590	$5,080
TOTAL FEDERAL & STATE TAX ADJUSTMENTS			$161,697	$108,805	$36,980	$16	$305	$1	$22	$121	$9,255	$6,191
CALCULATION OF PA STATE INCOME TAXES												
BASE TAXABLE INCOME	SCH , LN		$76,731	$32,994	$40,910	$44	$0	$4	($0)	$496	$2,470	($186)
LESS:												
State Tax Depreciation (Over) Under Book	TOTPLT	43	($25,538)	($17,167)	($5,856)	($3)	($48)	($0)	($3)	($19)	($1,463)	($979)
Total Tax Adjustments	SCH , LN		$161,697	$108,805	$36,980	$16	$305	$1	$22	$121	$9,255	$6,191
PA STATE TAXALBE DISTRIBUTION INCOME			($59,428)	($58,645)	$9,786	$30	($256)	$3	($18)	$394	($5,323)	($5,399)
PA STATE INCOME TAXES @ Tax Rate 9.99%			($5,937)	($5,859)	$978	$3	($26)	$0	($2)	$39	($532)	($539)
PLUS: DEFERRED STATE INCOME TAXES												
Net Operating Loss Utilization	CALCULATED		$5,937	$5,859	($978)	($3)	$26	($0)	$2	($39)	$532	$539
TOTAL STATE INCOME TAX			$0									
Deferred Taxes on Timing Differences - State	TOTPLT	43	($1,531)	($1,029)	($351)	($0)	($3)	($0)	($0)	($1)	($88)	($59)
Deferred Taxes on State NOL	TOTPLT	43	$5,947	$3,998	$1,364	$1	$11	$0	$1	$4	$341	$228
TOTAL STATE INCOME TAX EXPENSE			$4,416	$2,968	$1,013	$0	$8	$0	$1	$3	$253	$169
CALCULATION OF FEDERAL INCOME TAXES												
BASE TAXABLE INCOME	SCH , LN		$76,731	$32,994	$40,910	$44	$0	$4	($0)	$496	$2,470	($186)
LESS:												
PA State Income Taxes	SCH , LN		$0									
Federal Tax Depreciation (Over) Under Book	TOTPLT	43	($33,615)	($22,596)	($7,709)	($3)	($63)	($0)	($5)	($25)	($1,925)	($1,288)
Total Tax Adjustments	SCH , LN		$161,697	$108,805	$36,980	$16	$305	$1	$22	$121	$9,255	$6,191
FEDERAL TAXALBE DISTRIBUTION INCOME			($51,351)	($53,215)	$11,638	$31	($241)	$3	($17)	$400	($4,860)	($5,089)
FEDERAL INCOME TAXES @ Tax Rate 21.00%			$10,784	$11,175	($2,444)	($6)	$51	($1)	$4	($84)	$1,021	$1,069

PECO Energy Company
Revised Peak & Average Gas Class Cost of Service Study
(Income Taxes)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
DEVELOPMENT OF INCOME TAXES CONTINUED												
FEDERAL INCOME TAXES @ Tax Rate 21.00%	SCH , LN		$10,784	$11,175	($2,444)	($6)	$51	($1)	$4	($84)	$1,021	$1,069
PLUS: DEFERRED FEDERAL INCOME TAXES												
Deferred Taxes on Timing Differences - Federal	TOTPLT	43	$998	$671	$229	$0	$2	$0	$0	$1	$57	$38
Excess Deferred Amortization	TOTPLT	43	$3,455	$2,322	$792	$0	$7	$0	$0	$3	$198	$132
FIT Expense on Flow Through Adjustments	TOTPLT	43	($953)	($640)	($218)	($0)	($2)	($0)	($0)	($1)	($55)	($37)
LESS: OTHER FEDERAL TAX ADJUSTMENTS												
Amortization of ITC - Gas Plant	TOTPLT	43	($64)	($43)	($15)	($0)	($0)	($0)	($0)	($0)	($4)	($2)
TOTAL FEDERAL INCOME TAX EXPENSE			$14,347	$13,571	($1,627)	($6)	$57	($1)	$4	($81)	$1,225	$1,205
TOTAL INCOME TAX EXPENSE EXCLUDING PURCHASED GAS			$18,763	$16,539	($614)	($6)	$66	($1)	$5	($78)	$1,478	$1,375
DEVELOPMENT OF PURCHASED GAS TAXES												
PURCHASED GAS OPERATING REVENUES			$226,710	$167,080	$57,667	$77	$1,056	$11	$0	$819	$0	$0
LESS:												
OPERATION & MAINTAINENCE EXPENSE			$226,710	$167,079	$57,668	$77	$1,056	$11	$0	$819	$0	$0
NET OPERATING INCOME BEFORE TAXES			$0	$2	($2)	$0	($0)	($0)	$0	$0	$0	$0
LESS:												
INTEREST EXPENSE (Rate Base * 1.85% Weighted Cost of Debt)			$68	$51	$17	$0	$0	$0	$0	$0	$0	$0
BASE TAXABLE PURCHASED GAS INCOME			($68)	($49)	($18)	($0)	($0)	($0)	$0	($0)	$0	$0
LESS:												
PA STATE PURCHASED GAS INCOME TAXES @ Tax Rate 9.99%			($7)	($5)	($2)	($0)	($0)	($0)	$0	($0)	$0	$0
Net Operating Loss Utilization	CALCULATED		$7	$5	$2	$0	$0	$0	$0	$0	$0	$0
TOTAL STATE INCOME TAX			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
EQUALS:												
FEDERAL PURCHASED GAS INCOME TAXES @ Tax Rate 21.00%			$14	$10	$4	$0	$0	$0	$0	$0	$0	$0
TOTAL PA INCOME TAX EXPENSE			$4,416	$2,968	$1,013	$0	$8	$0	$1	$3	$253	$169
TOTAL FEDERAL INCOME TAX EXPENSE			$14,362	$13,581	($1,623)	($6)	$57	($1)	$4	($81)	$1,225	$1,205
TOTAL INCOME TAX EXPENSE			$18,777	$16,549	($610)	($6)	$66	($1)	$5	($78)	$1,478	$1,375
TOTAL OTHER TAX EXPENSE			$7,545	$5,223	$1,635	$1	$13	$0	$1	$5	$401	$266
TOTAL TAX EXPENSE			$26,323	$21,772	$1,025	($5)	$79	($1)	$6	($73)	$1,879	$1,640

PECO Energy Company
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DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
Capacity Production - Design Peak Day Sendout	DPKDAYP	1	846,453	572,676	272,453	113	1,211	0	0	0	0	0
Capacity Storage - Design Peak Day Sendout	DPKDAYS	2	846,453	572,676	272,453	113	1,211	0	0	0	0	0
Capacity Transmission - Design Peak Day Sendout	DTRAN	3	846,453	572,676	272,453	113	1,211	0	0	0	0	0
Capacity Distribution Mains (A&E) Excess Demand	DEXCESS	4	0									
Capacity Distribution Mains (Direct Assign Plant)	DAMAINS	5	15,289	0	0	0	0	0	0	0	8,219	7,070
Capacity Distribution Mains (Direct Assign Acc Dep)	DAMAINSAD	6	2,147	0	0	0	0	0	0	0	54	2,094
Capacity Distribution Mains (Direct Assign Dep Exp)	DAMAINSDE	7	155	0	0	0	0	0	0	0	54	101
Capacity Distribution (Des Peak Day Sendout)	DESDAY	8	0									
Capacity Distribution M&R (Direct Assign Plant)	DAMR	9	11,382	0	0	0	0	0	0	0	6,292	5,090
Capacity Distribution M&R (Direct Assign Acc Dep)	DAMRAD	10	2,689	0	0	0	0	0	0	0	58	2,631
Capacity Distribution M&R (Direct Assign Dep Exp)	DAMRDE	11	159	0	0	0	0	0	0	0	58	102
Capacity Avg Daily Del excl Direct	DAVGDD	12	0									
Annual Gas Deliveries - Thruput (Mcf)	ETHRUPUT	13	90,892,982	41,968,538	22,401,370	16,559	442,071	670	40,050	178,588	11,394,081	14,451,056
Annual Gas Deliveries - Firm	ETHRUPUTF	14	76,222,618	41,968,538	22,401,370	16,559	442,071	0	0	0	11,394,081	0
Annual Gas Deliveries - Transportation Only	ETHRUPUTT	15	25,845,137	0	0	0	0	0	0	0	11,394,081	14,451,056
Commodity Gas Storage	ESTORAGE	16	100.00%	66.86%	30.92%	0.02%	0.01%	0.00%	0.00%	0.00%	0.97%	1.23%
Annual Gas Cost (PGC)	EGAS	17	$201,635	$150,889	$49,024	$70	$892	$9	$0	$750	$0	$0
Commodity - Balancing Service Charge (BSC)	EBSC	18	$25,075	$16,191	$8,642	$6	$164	$2	$0	$69	$0	$0
380-Services	CSERVICE	19	$3,347,375	$2,891,540	$441,344	$80	$149	$20	$40	$308	$9,131	$4,765
381-Meters (Avg Cost per meter)	CMETERS	20	$215,514	$150,533	$55,257	$6	$204	$3	$6	$297	$5,072	$4,136
381-Meters Direct Assignment	CMETERSDA	21	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
382-Meters Installations Direct Assignment	CMETINSTDA	22	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
Customer Deposits	CUSTDEP	23	$12,465	$4,323	$7,860	$0	$3	$0	$0	$5	$180	$94
Customer Deposits Interest	CUSTDEPINT	24	$351	$216	$130	$0	$0	$0	$0	$0	$3	$2
879-Customer Installation Expense	CUSTINSTALL	25	$539,593	$494,391	$44,450	$4	$15	$2	$2	$31	$459	$239
902-Meter Reading Expense	CMETRDG	26	$539,593	$494,391	$44,450	$4	$15	$2	$2	$31	$459	$239
903-Customer Records and Collections	CUSTREC	27	100.00%	88.05%	8.79%	0.02%	0.03%	0.00%	0.01%	0.03%	2.02%	1.06%
905-Miscellaneous Customer Accounts	CUSTCAM	28	$539,593	$494,391	$44,450	$4	$15	$2	$2	$31	$459	$239
908-Customer Assistance	CUSTASST	29	100.00%	96.64%	2.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.36%	0.19%
908-Customer Assistance - Direct Assignment	CUSTASSTDA	30	$44,498	$0	$44,450	$0	$15	$2	$0	$31	$0	$0
909-Informational and Instructional Advertising	CUSTADVT	31	$310	$299	$9	$0	$0	$0	$0	$0	$1	$1
910-Miscellaneous Customer Service	CUSTCSM	32	100.00%	96.64%	2.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.36%	0.19%
916-Miscellaneous Sales Expense	CUSTSALES	33	100.00%	96.64%	2.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.36%	0.19%
Number of Bills	CUSTBILLS	34	6,475,119	5,932,690	533,403	48	180	24	24	372	5,505	2,873
Number of Customers (Average Annual)	CUST	35	539,593	494,391	44,450	4	15	2	2	31	459	239
INTERNALLY DEVELOPED ALLOCATION FACTORS		36										
Intangible Plant	INTPLT	37	$18,229	$12,254	$4,180	$2	$34	$0	$2	$14	$1,044	$699
Production Plant	PRODPLT	38	$15,539	$10,513	$5,002	$2	$22	$0	$0	$0	$0	$0
Storage Plant	STORPLT	39	$72,428	$48,423	$22,394	$14	$4	$0	$0	$0	$702	$891
Transmission Plant in Service	TRANPLT	40	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution Plant in Service	DISTPLT	41	$3,389,406	$2,277,110	$771,026	$335	$6,544	$20	$467	$2,610	$198,710	$132,584
General Plant in Service	GENLPLT	42	$38,495	$27,343	$7,850	$5	$63	$0	$5	$24	$1,931	$1,275
Total Gas Plant In Service	TOTPLT	43	$3,537,670	$2,378,042	$811,265	$357	$6,675	$20	$475	$2,651	$202,597	$135,588
Distribution Plant Excl Asset Retirement	DISTPLTXAR	44	$3,391,524	$2,278,533	$771,508	$335	$6,548	$20	$467	$2,612	$198,834	$132,666
Total Transmission and Distribution Plant	TDPLT	45	$3,392,978	$2,279,510	$771,839	$335	$6,551	$20	$467	$2,613	$198,920	$132,723
Total Prod, Stor, Trans, Dist & Gen Plant	PSTDGPLT	46	$3,519,441	$2,365,789	$807,084	$356	$6,640	$20	$472	$2,637	$201,553	$134,889
Total Distribution and General Plant	DGPLT	47	$3,431,473	$2,306,853	$779,688	$340	$6,614	$20	$472	$2,637	$200,851	$133,998
Rate Base	RATEBASE	48	$2,461,939	$1,660,914	$555,167	$261	$4,690	$13	$337	$1,803	$145,693	$93,060
Distribution Plant in Service - Capacity Related	DDISTPLT	49	$1,873,803	$1,038,222	$520,629	$295	$6,069	$7	$439	$1,958	$183,822	$122,362
Account 374	PLT_374	50	$3,637	$2,015	$1,010	$1	$12	$0	$1	$4	$357	$237
Account 375	PLT_375	51	$15,745	$8,724	$4,375	$2	$51	$0	$4	$16	$1,545	$1,028
Account 376-General	PLT_376G	52	$1,756,701	$987,810	$495,350	$281	$5,774	$7	$418	$1,863	$160,691	$104,507

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Account 376-General Average	PLT_376GA	53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Account 376-DA	PLT_376DA	54	$15,289	$0	$0	$0	$0	$0	$0	$0	$8,219	$7,070
Account 376	PLT_376	55	$1,771,990	$987,810	$495,350	$281	$5,774	$7	$418	$1,863	$168,910	$111,578
Account 378	PLT_378	56	$24,652	$13,743	$6,891	$4	$80	$0	$6	$26	$2,350	$1,552
Account 379-City Gate	PLT_379CG	57	$65,778	$36,668	$18,388	$10	$214	$0	$16	$69	$6,270	$4,142
Account 379-Joint	PLT_379DA	58	$11,382	$0	$0	$0	$0	$0	$0	$0	$6,292	$5,090
Account 379	PLT_379	59	$77,160	$36,668	$18,388	$10	$214	$0	$16	$69	$12,562	$9,232
Account 380	PLT_380	60	$1,111,048	$959,749	$146,489	$26	$49	$7	$13	$102	$3,031	$1,581
Account 381	PLT_381	61	$164,090	$114,453	$42,012	$4	$155	$2	$4	$226	$4,088	$3,145
Account 382	PLT_382	62	$221,083	$153,948	$56,510	$6	$208	$3	$6	$304	$5,868	$4,230
Account 387	PLT_387	63	$2,118	$1,423	$482	$0	$4	$0	$0	$2	$124	$83
Account 388-Asset Retirement Costs for Distribution	PLT_388	64	$1,454	$977	$331	$0	$3	$0	$0	$1	$85	$57
Accounts 376, 378 & 379 - Mains & M&R	PLT_376379	65	$1,873,803	$1,038,222	$520,629	$295	$6,069	$7	$439	$1,958	$183,822	$122,362
Accounts 376 & 380 - Mains & Services	PLT_376380	66	$2,883,038	$1,947,560	$641,839	$307	$5,824	$14	$431	$1,965	$171,940	$113,159
Accounts 380 & 381 - Services & Meters	PLT_380381	67	$1,275,138	$1,074,202	$188,502	$31	$204	$9	$18	$328	$7,119	$4,726
Accounts 374 & 375 - Land & Structures	PLT_374375	68	$19,382	$10,739	$5,385	$3	$63	$0	$5	$20	$1,901	$1,266
Accounts 381 through 385	PLT_3815	69	$385,173	$268,400	$98,523	$10	$363	$6	$10	$530	$9,957	$7,375
Accounts 378, 379, & 387	PLT_378387	70	$103,931	$51,834	$25,761	$15	$299	$0	$22	$97	$15,036	$10,867
Residential	DPLTRES	71	$1,161,281	$1,161,281	$0	$0	$0	$0	$0	$0	$0	$0
Small Commercial and Industrilal	DPLTCI	72	$232,169	$0	$232,169	$0	$0	$0	$0	$0	$0	$0
Large High Load Factor	DPLTLHLF	73	$55	$0	$0	$55	$0	$0	$0	$0	$0	$0
Motor Vehicle - Firm	DPLTMVF	74	$713	$0	$0	$0	$713	$0	$0	$0	$0	$0
Motor Vehicle - Interruptible	DPLTMVI	75	$10	$0	$0	$0	$0	$10	$0	$0	$0	$0
Interruptible Service	DPLTIS	76	$54	$0	$0	$0	$0	$0	$54	$0	$0	$0
Temperature Control	DPLTTC	77	$492	$0	$0	$0	$0	$0	$0	$492	$0	$0
Transportation Service - Firm	DPLTTSF	78	$34,593	$0	$0	$0	$0	$0	$0	$0	$34,593	$0
Transportation Service - Interruptible	DPLTTSI	79	$24,742	$0	$0	$0	$0	$0	$0	$0	$0	$24,742
Account 717	OX_717	80	$80	$54	$26	$0	$0	$0	$0	$0	$0	$0
Account 741	MX_741	81	$53	$36	$17	$0	$0	$0	$0	$0	$0	$0
Account 743	MX_743	82	$133	$90	$43	$0	$0	$0	$0	$0	$0	$0
Manufactured Gas Production Operation Expense	OX_PRODM	83	$80	$54	$26	$0	$0	$0	$0	$0	$0	$0
Manufactured Gas Production Maintenance Expense	MX_PRODM	84	$186	$126	$60	$0	$0	$0	$0	$0	$0	$0
Other Production Operation Expense	OX_PRODO	85	$226,710	$167,079	$57,668	$77	$1,056	$11	$0	$819	$0	$0
Storage Operation Expense	OX_STOR	86	$1,065	$712	$329	$0	$0	$0	$0	$0	$10	$13
Storage Maintenance Expense	MX_STOR	87	$4,414	$2,951	$1,365	$1	$0	$0	$0	$0	$43	$54
Transmission Operation Expense	OX_TRAN	88	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission Maintenance Expense	MX_TRAN	89	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission Salaries & Wages Accounts 511-567	SALWAGTO	90	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission Salaries & Wages Accounts 569-574	SALWAGTM	91	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Account 874	OX_874	92	$16,959	$11,456	$3,775	$2	$34	$0	$3	$12	$1,011	$666
Account 875	OX_875	93	$1,036	$577	$289	$0	$3	$0	$0	$1	$99	$65
Account 878	OX_878	94	$5,979	$4,166	$1,529	$0	$6	$0	$0	$8	$155	$114
Account 879	OX_879	95	$5,158	$4,726	$425	$0	$0	$0	$0	$0	$4	$2
Account 880	OX_880	96	$13,512	$9,078	$3,074	$1	$26	$0	$2	$10	$792	$529
Account 887	MX_887	97	$17,505	$9,758	$4,893	$3	$57	$0	$4	$18	$1,669	$1,102
Account 889	MX_889	98	$1,014	$565	$284	$0	$3	$0	$0	$1	$97	$64
Account 892	MX_892	99	$1,445	$1,248	$191	$0	$0	$0	$0	$0	$4	$2
Account 893	MX_893	100	$418	$291	$107	$0	$0	$0	$0	$1	$11	$8
Account 894	MX_894	101	$879	$590	$200	$0	$2	$0	$0	$1	$52	$34
O&M Accounts 874-880	OX_DIST	102	$42,643	$30,003	$9,093	$4	$70	$0	$5	$32	$2,061	$1,376
O&M Accounts 887-894	MX_DIST	103	$3,756	$2,696	$781	$0	$5	$0	$0	$2	$163	$108
Account 902	OX_902	104	$199	$182	$16	$0	$0	$0	$0	$0	$0	$0

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Account 903	OX_903	105	$14,723	$12,963	$1,294	$2	$5	$0	$1	$4	$297	$157
Account 904	OX_904	106	$2,263	$2,046	$205	$0	$1	$0	$0	$1	$6	$4
O&M Accounts 902-905	OX_CA	107	$19,658	$17,484	$1,692	$2	$6	$0	$1	$6	$305	$161
Account908	OX_908	108	$7,742	$7,482	$217	$0	$0	$0	$0	$0	$28	$14
Account909	OX_909	109	$309	$298	$9	$0	$0	$0	$0	$0	$1	$1
Account910	OX_910	110	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M Accounts 908-910	OX_CS	111	$8,550	$7,780	$726	$0	$0	$0	$0	$0	$29	$15
Accounts 901-910	X_CACS	112	$31,019	$27,980	$2,497	$3	$6	$0	$1	$6	$344	$182
Total O&M less Purchased Gas	OMXPP	113	$144,391	$105,380	$28,035	$17	$212	$1	$16	$88	$6,417	$4,225
Total O&M less Purchased Gas, Payroll, & Pension	OMXPPPP	114	$86,740	$63,877	$16,515	$9	$119	$0	$9	$50	$3,707	$2,452
Base Taxable Income	EBT	115	$76,663	$32,944	$40,892	$44	$0	$4	($0)	$496	$2,470	($186)
Salaries & Wages Accounts 870-880	SALWAGDO	116	$14,096	$10,335	$2,719	$1	$21	$0	$1	$9	$607	$403
Salaries & Wages Accounts 887-894	SALWAGDM	117	$11,234	$6,533	$3,023	$2	$34	$0	$2	$11	$981	$648
Salaries & Wages Accounts 902-905	SALWAGCA	118	$6,188	$5,459	$542	$1	$2	$0	$0	$2	$119	$63
Salaries & Wages Accounts 908-910	SALWAGCS	119	$226	$219	$6	$0	$0	$0	$0	$0	$1	$0
Salaries & Wages Excluding Admin & Gen	SALWAGXAG	120	$34,505	$24,509	$7,036	$4	$56	$0	$4	$22	$1,731	$1,143
Total Salaries and Wages Expense	SALWAGES	121	$42,209	$29,981	$8,607	$5	$69	$0	$5	$26	$2,117	$1,398
Base Rate Sales Revenue	SALESREV	122	$361,576	$233,489	$100,579	$75	$475	$5	$35	$690	$16,719	$9,509
Residential	SREVRES	123	$233,489	$233,489	$0	$0	$0	$0	$0	$0	$0	$0
Small Commercial and Industrilal	SREVCI	124	$100,579		$100,579							
Large High Load Factor	SREVLHLF	125	$75			$75						
Motor Vehicle - Firm	SREVMVF	126	$475				$475					
Motor Vehicle - Interruptible	SREVMVI	127	$5					$5				
Interruptible Service	SREVIS	128	$35						$35			
Temperature Control	SREVTC	129	$690							$690		
Transportation Service - Firm	SREVTSF	130	$16,719								$16,719	
Transportation Service - Interruptible	SREVTSI	131	$9,509									$9,509
Claimed Rate Sales Revenue	CLAIMREV	132	$656,974	$471,938	$154,803	$445	$1,392	$13	$34	$948	$18,742	$8,659
Total Write-Offs	EXP_904	133	100.00%	90.40%	9.07%	0.00%	0.04%	0.00%	0.00%	0.06%	0.27%	0.16%
Total Write-Offs	EXP_904PPA	134	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Customer Advances for Construction	CUSTADV	135	1,004	832	171	0	0	0	0	0	0	0
Purchase of Receivables	REV_POR	136	63,454	45,995	17,258	0	81	1	0	118	0	0
487-Forfeited Discounts	REV_487	137	838	634	163	0	1	0	0	1	25	14
P&A Allocator	P&A	138	100.00%	56.23%	28.20%	0.02%	0.33%	0.00%	0.02%	0.11%	9.15%	5.95%
Average Day Throughput Excl. Direct Assignment			230,717	114,982	61,374	45	1,211	2	110	489	25,052	27,451
Design Day Demand.			914,453	572,676	272,453	113	1,211	0	0	0	68,000	0
Memo: Development of P&A Allocator												
Average Day Demand Pct.			100.00%	49.84%	26.60%	0.02%	0.52%	0.00%	0.05%	0.21%	10.86%	11.90%
Design Day Demand Pct.			100.00%	62.62%	29.79%	0.01%	0.13%	0.00%	0.00%	0.00%	7.44%	0.00%
P&A Allocator			100.00%	56.23%	28.20%	0.02%	0.33%	0.00%	0.02%	0.11%	9.15%	5.95%

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Capacity Production - Design Peak Day Sendout	DPKDAYP	1	100.00%	67.66%	32.19%	0.01%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Capacity Storage - Design Peak Day Sendout	DPKDAYS	2	100.00%	67.66%	32.19%	0.01%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Capacity Transmission - Design Peak Day Sendout	DTRAN	3	100.00%	67.66%	32.19%	0.01%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Capacity Distribution Mains (A&E) Excess Demand	DEXCESS	4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Capacity Distribution Mains (Direct Assign Plant)	DAMAINS	5	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	53.76%	46.24%
Capacity Distribution Mains (Direct Assign Acc Dep)	DAMAINSAD	6	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.51%	97.49%
Capacity Distribution Mains (Direct Assign Dep Exp)	DAMAINSDE	7	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	34.76%	65.24%
Capacity Distribution (Des Peak Day Sendout)	DESDAY	8	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Capacity Distribution M&R (Direct Assign Plant)	DAMR	9	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	55.28%	44.72%
Capacity Distribution M&R (Direct Assign Acc Dep)	DAMRAD	10	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.15%	97.85%
Capacity Distribution M&R (Direct Assign Dep Exp)	DAMRDE	11	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	36.17%	63.83%
Capacity Avg Daily Del excl Direct	DAVGDD	12	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Annual Gas Deliveries - Thruput (Mcf)	ETHRUPUT	13	100.00%	46.17%	24.65%	0.02%	0.49%	0.00%	0.04%	0.20%	12.54%	15.90%
Annual Gas Deliveries - Firm	ETHRUPUTF	14	100.00%	55.06%	29.39%	0.02%	0.58%	0.00%	0.00%	0.00%	14.95%	0.00%
Annual Gas Deliveries - Transportation Only	ETHRUPUTT	15	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	44.09%	55.91%
Commodity Gas Storage	ESTORAGE	16	100.00%	66.86%	30.92%	0.02%	0.01%	0.00%	0.00%	0.00%	0.97%	1.23%
Annual Gas Cost (PGC)	EGAS	17	100.00%	74.83%	24.31%	0.03%	0.44%	0.00%	0.00%	0.37%	0.00%	0.00%
Commodity - Balancing Service Charge (BSC)	EBSC	18	100.00%	64.57%	34.47%	0.03%	0.65%	0.01%	0.00%	0.27%	0.00%	0.00%
380-Services	CSERVICE	19	100.00%	86.38%	13.18%	0.00%	0.00%	0.00%	0.00%	0.01%	0.27%	0.14%
381-Meters (Avg Cost per meter)	CMETERS	20	100.00%	69.85%	25.64%	0.00%	0.09%	0.00%	0.00%	0.14%	2.35%	1.92%
381-Meters Direct Assignment	CMETERSDA	21	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
382-Meters Installations Direct Assignment	CMETINSTDA	22	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
Customer Deposits	CUSTDEP	23	100.00%	34.68%	63.06%	0.00%	0.02%	0.00%	0.00%	0.04%	1.44%	0.75%
Customer Deposits Interest	CUSTDEPINT	24	100.00%	61.53%	37.14%	0.00%	0.01%	0.00%	0.00%	0.03%	0.85%	0.44%
879-Customer Installation Expense	CUSTINSTALL	25	100.00%	91.62%	8.24%	0.00%	0.00%	0.00%	0.00%	0.01%	0.09%	0.04%
902-Meter Reading Expense	CMETRDG	26	100.00%	91.62%	8.24%	0.00%	0.00%	0.00%	0.00%	0.01%	0.09%	0.04%
903-Customer Records and Collections	CUSTREC	27	100.00%	88.05%	8.79%	0.02%	0.03%	0.00%	0.01%	0.03%	2.02%	1.06%
905-Miscellaneous Customer Accounts	CUSTCAM	28	100.00%	91.62%	8.24%	0.00%	0.00%	0.00%	0.00%	0.01%	0.09%	0.04%
908-Customer Assistance	CUSTASST	29	100.00%	96.64%	2.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.36%	0.19%
908-Customer Assistance - Direct Assignment	CUSTASSTDA	30	100.00%	0.00%	99.89%	0.00%	0.03%	0.00%	0.00%	0.07%	0.00%	0.00%
909-Informational and Instructional Advertising	CUSTADVT	31	100.00%	96.45%	2.90%	0.00%	0.00%	0.00%	0.00%	0.00%	0.32%	0.32%
910-Miscellaneous Customer Service	CUSTCSM	32	100.00%	96.64%	2.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.36%	0.19%
916-Miscellaneous Sales Expense	CUSTSALES	33	100.00%	96.64%	2.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.36%	0.19%
Number of Bills	CUSTBILLS	34	100.00%	91.62%	8.24%	0.00%	0.00%	0.00%	0.00%	0.01%	0.09%	0.04%
Number of Customers (Average Annual)	CUST	35	100.00%	91.62%	8.24%	0.00%	0.00%	0.00%	0.00%	0.01%	0.09%	0.04%
INTERNALLY DEVELOPED ALLOCATION FACTORS		36										
Intangible Plant	INTPLT	37	100.00%	67.22%	22.93%	0.01%	0.19%	0.00%	0.01%	0.07%	5.73%	3.83%
Production Plant	PRODPLT	38	100.00%	67.66%	32.19%	0.01%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Storage Plant	STORPLT	39	100.00%	66.86%	30.92%	0.02%	0.01%	0.00%	0.00%	0.00%	0.97%	1.23%
Transmission Plant in Service	TRANPLT	40	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Distribution Plant in Service	DISTPLT	41	100.00%	67.18%	22.75%	0.01%	0.19%	0.00%	0.01%	0.08%	5.86%	3.91%
General Plant in Service	GENLPLT	42	100.00%	71.03%	20.39%	0.01%	0.16%	0.00%	0.01%	0.06%	5.02%	3.31%
Total Gas Plant In Service	TOTPLT	43	100.00%	67.22%	22.93%	0.01%	0.19%	0.00%	0.01%	0.07%	5.73%	3.83%
Distribution Plant Excl Asset Retirement	DISTPLTXAR	44	100.00%	67.18%	22.75%	0.01%	0.19%	0.00%	0.01%	0.08%	5.86%	3.91%
Total Transmission and Distribution Plant	TDPLT	45	100.00%	67.18%	22.75%	0.01%	0.19%	0.00%	0.01%	0.08%	5.86%	3.91%
Total Prod, Stor, Trans, Dist & Gen Plant	PSTDGPLT	46	100.00%	67.22%	22.93%	0.01%	0.19%	0.00%	0.01%	0.07%	5.73%	3.83%
Total Distribution and General Plant	DGPLT	47	100.00%	67.23%	22.72%	0.01%	0.19%	0.00%	0.01%	0.08%	5.85%	3.90%
Rate Base	RATEBASE	48	100.00%	67.46%	22.55%	0.01%	0.19%	0.00%	0.01%	0.07%	5.92%	3.78%
Distribution Plant in Service - Capacity Related	DDISTPLT	49	100.00%	55.41%	27.78%	0.02%	0.32%	0.00%	0.02%	0.10%	9.81%	6.53%

PECO Energy Company
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(Allocation Percent)

DESCRIPTION	ALLOCATION BASIS	TAI Alloc No.	TOTAL GAS DIVISION	RESID	GC	LARGE	MOTOR VEHICLE FIRM	MOTOR VEHICLE INTER	INTER SERV	TEMP CONTROL	TRANSP SERV FIRM	TRANSP SERV INTER
Account 374	PLT_374	50	100.00%	55.41%	27.78%	0.02%	0.32%	0.00%	0.02%	0.10%	9.81%	6.53%
Account 375	PLT_375	51	100.00%	55.41%	27.78%	0.02%	0.32%	0.00%	0.02%	0.10%	9.81%	6.53%
Account 376-General	PLT_376G	52	100.00%	56.23%	28.20%	0.02%	0.33%	0.00%	0.02%	0.11%	9.15%	5.95%
Account 376-General Average	PLT_376GA	53	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Account 376-DA	PLT_376DA	54	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	53.76%	46.24%
Account 376	PLT_376	55	100.00%	55.75%	27.95%	0.02%	0.33%	0.00%	0.02%	0.11%	9.53%	6.30%
Account 378	PLT_378	56	100.00%	55.75%	27.95%	0.02%	0.33%	0.00%	0.02%	0.11%	9.53%	6.30%
Account 379-City Gate	PLT_379CG	57	100.00%	55.75%	27.95%	0.02%	0.33%	0.00%	0.02%	0.11%	9.53%	6.30%
Account 379-Joint	PLT_379DA	58	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	55.28%	44.72%
Account 379	PLT_379	59	100.00%	47.52%	23.83%	0.01%	0.28%	0.00%	0.02%	0.09%	16.28%	11.96%
Account 380	PLT_380	60	100.00%	86.38%	13.18%	0.00%	0.00%	0.00%	0.00%	0.01%	0.27%	0.14%
Account 381	PLT_381	61	100.00%	69.75%	25.60%	0.00%	0.09%	0.00%	0.00%	0.14%	2.49%	1.92%
Account 382	PLT_382	62	100.00%	69.63%	25.56%	0.00%	0.09%	0.00%	0.00%	0.14%	2.65%	1.91%
Account 387	PLT_387	63	100.00%	67.18%	22.75%	0.01%	0.19%	0.00%	0.01%	0.08%	5.86%	3.91%
Account 388-Asset Retirement Costs for Distribution	PLT_388	64	100.00%	67.18%	22.75%	0.01%	0.19%	0.00%	0.01%	0.08%	5.86%	3.91%
Accounts 376, 378 & 379 - Mains & M&R	PLT_376379	65	100.00%	55.41%	27.78%	0.02%	0.32%	0.00%	0.02%	0.10%	9.81%	6.53%
Accounts 376 & 380 - Mains & Services	PLT_376380	66	100.00%	67.55%	22.26%	0.01%	0.20%	0.00%	0.01%	0.07%	5.96%	3.92%
Accounts 380 & 381 - Services & Meters	PLT_380381	67	100.00%	84.24%	14.78%	0.00%	0.02%	0.00%	0.00%	0.03%	0.56%	0.37%
Accounts 374 & 375 - Land & Structures	PLT_374375	68	100.00%	55.41%	27.78%	0.02%	0.32%	0.00%	0.02%	0.10%	9.81%	6.53%
Accounts 381 through 385	PLT_3815	69	100.00%	69.68%	25.58%	0.00%	0.09%	0.00%	0.00%	0.14%	2.58%	1.91%
Accounts 378, 379, & 387	PLT_378387	70	100.00%	49.87%	24.79%	0.01%	0.29%	0.00%	0.02%	0.09%	14.47%	10.46%
Residential	DPLTRES	71	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Small Commercial and Industrilal	DPLTCI	72	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Large High Load Factor	DPLTLHLF	73	100.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Motor Vehicle - Firm	DPLTMVF	74	100.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Motor Vehicle - Interruptible	DPLTMVI	75	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
Interruptible Service	DPLTIS	76	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%
Temperature Control	DPLTTC	77	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%
Transportation Service - Firm	DPLTTSF	78	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
Transportation Service - Interruptible	DPLTTSI	79	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Account 717	OX_717	80	100.00%	67.66%	32.19%	0.01%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Account 741	MX_741	81	100.00%	67.66%	32.19%	0.01%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Account 743	MX_743	82	100.00%	67.66%	32.19%	0.01%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Manufactured Gas Production Operation Expense	OX_PRODM	83	100.00%	67.66%	32.19%	0.01%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Manufactured Gas Production Maintenance Expense	MX_PRODM	84	100.00%	67.66%	32.19%	0.01%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
Other Production Operation Expense	OX_PRODO	85	100.00%	73.70%	25.44%	0.03%	0.47%	0.00%	0.00%	0.36%	0.00%	0.00%
Storage Operation Expense	OX_STOR	86	100.00%	66.86%	30.92%	0.02%	0.01%	0.00%	0.00%	0.00%	0.97%	1.23%
Storage Maintenance Expense	MX_STOR	87	100.00%	66.86%	30.92%	0.02%	0.01%	0.00%	0.00%	0.00%	0.97%	1.23%
Transmission Operation Expense	OX_TRAN	88	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transmission Maintenance Expense	MX_TRAN	89	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transmission Salaries & Wages Accounts 511-567	SALWAGTO	90	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transmission Salaries & Wages Accounts 569-574	SALWAGTM	91	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Account 874	OX_874	92	100.00%	67.55%	22.26%	0.01%	0.20%	0.00%	0.01%	0.07%	5.96%	3.92%
Account 875	OX_875	93	100.00%	55.75%	27.95%	0.02%	0.33%	0.00%	0.02%	0.11%	9.53%	6.30%
Account 878	OX_878	94	100.00%	69.68%	25.58%	0.00%	0.09%	0.00%	0.00%	0.14%	2.58%	1.91%
Account 879	OX_879	95	100.00%	91.62%	8.24%	0.00%	0.00%	0.00%	0.00%	0.01%	0.09%	0.04%
Account 880	OX_880	96	100.00%	67.18%	22.75%	0.01%	0.19%	0.00%	0.01%	0.08%	5.86%	3.91%
Account 887	MX_887	97	100.00%	55.75%	27.95%	0.02%	0.33%	0.00%	0.02%	0.11%	9.53%	6.30%
Account 889	MX_889	98	100.00%	55.75%	27.95%	0.02%	0.33%	0.00%	0.02%	0.11%	9.53%	6.30%

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Account 892	MX_892	99	100.00%	86.38%	13.18%	0.00%	0.00%	0.00%	0.00%	0.01%	0.27%	0.14%
Account 893	MX_893	100	100.00%	69.68%	25.58%	0.00%	0.09%	0.00%	0.00%	0.14%	2.58%	1.91%
Account 894	MX_894	101	100.00%	67.18%	22.75%	0.01%	0.19%	0.00%	0.01%	0.08%	5.86%	3.91%
O&M Accounts 874-880	OX_DIST	102	100.00%	70.36%	21.32%	0.01%	0.16%	0.00%	0.01%	0.07%	4.83%	3.23%
O&M Accounts 887-894	MX_DIST	103	100.00%	71.76%	20.79%	0.01%	0.15%	0.00%	0.01%	0.07%	4.34%	2.88%
Account 902	OX_902	104	100.00%	91.62%	8.24%	0.00%	0.00%	0.00%	0.00%	0.01%	0.09%	0.04%
Account 903	OX_903	105	100.00%	88.05%	8.79%	0.02%	0.03%	0.00%	0.01%	0.03%	2.02%	1.06%
Account 904	OX_904	106	100.00%	90.40%	9.07%	0.00%	0.04%	0.00%	0.00%	0.06%	0.27%	0.16%
O&M Accounts 902-905	OX_CA	107	100.00%	88.94%	8.61%	0.01%	0.03%	0.00%	0.01%	0.03%	1.55%	0.82%
Account908	OX_908	108	100.00%	96.64%	2.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.36%	0.19%
Account909	OX_909	109	100.00%	96.45%	2.90%	0.00%	0.00%	0.00%	0.00%	0.00%	0.32%	0.32%
Account910	OX_910	110	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
O&M Accounts 908-910	OX_CS	111	100.00%	90.99%	8.49%	0.00%	0.00%	0.00%	0.00%	0.01%	0.33%	0.18%
Accounts 901-910	X_CACS	112	100.00%	90.20%	8.05%	0.01%	0.02%	0.00%	0.00%	0.02%	1.11%	0.59%
Total O&M less Purchased Gas	OMXPP	113	100.00%	72.98%	19.42%	0.01%	0.15%	0.00%	0.01%	0.06%	4.44%	2.93%
Total O&M less Purchased Gas, Payroll, & Pension	OMXPPPP	114	100.00%	73.64%	19.04%	0.01%	0.14%	0.00%	0.01%	0.06%	4.27%	2.83%
Base Taxable Income	EBT	115	100.00%	42.97%	53.34%	0.06%	0.00%	0.00%	0.00%	0.65%	3.22%	-0.24%
Salaries & Wages Accounts 870-880	SALWAGDO	116	100.00%	73.32%	19.29%	0.01%	0.15%	0.00%	0.01%	0.06%	4.31%	2.86%
Salaries & Wages Accounts 887-894	SALWAGDM	117	100.00%	58.16%	26.91%	0.01%	0.30%	0.00%	0.02%	0.10%	8.73%	5.77%
Salaries & Wages Accounts 902-905	SALWAGCA	118	100.00%	88.21%	8.76%	0.02%	0.03%	0.00%	0.01%	0.03%	1.92%	1.02%
Salaries & Wages Accounts 908-910	SALWAGCS	119	100.00%	96.64%	2.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.36%	0.19%
Salaries & Wages Excluding Admin & Gen	SALWAGXAG	120	100.00%	71.03%	20.39%	0.01%	0.16%	0.00%	0.01%	0.06%	5.02%	3.31%
Total Salaries and Wages Expense	SALWAGES	121	100.00%	71.03%	20.39%	0.01%	0.16%	0.00%	0.01%	0.06%	5.02%	3.31%
Base Rate Sales Revenue	SALESREV	122	100.00%	64.58%	27.82%	0.02%	0.13%	0.00%	0.01%	0.19%	4.62%	2.63%
Residential	SREVRES	123	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Small Commercial and Industrilal	SREVCI	124	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Large High Load Factor	SREVLHLF	125	100.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Motor Vehicle - Firm	SREVMVF	126	100.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Motor Vehicle - Interruptible	SREVMVI	127	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
Interruptible Service	SREVIS	128	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Temperature Control	SREVTC	129	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%
Transportation Service - Firm	SREVTSF	130	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
Transportation Service - Interruptible	SREVTSI	131	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Claimed Rate Sales Revenue	CLAIMREV	132	100.00%	71.84%	23.56%	0.07%	0.21%	0.00%	0.01%	0.14%	2.85%	1.32%
Total Write-Offs	EXP_904	133	100.00%	90.40%	9.07%	0.00%	0.04%	0.00%	0.00%	0.06%	0.27%	0.16%
Total Write-Offs	EXP_904PPA	134	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Customer Advances for Construction	CUSTADV	135	100.00%	82.93%	17.07%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Purchase of Receivables	REV_POR	136	100.00%	72.49%	27.20%	0.00%	0.13%	0.00%	0.00%	0.19%	0.00%	0.00%
487-Forfeited Discounts	REV_487	137	100.00%	75.65%	19.46%	0.00%	0.09%	0.00%	0.00%	0.13%	2.97%	1.69%
P&A Allocator	P&A	138	100.00%	56.23%	28.20%	0.02%	0.33%	0.00%	0.02%	0.11%	9.15%	5.95%
Average Day Throughput Excl. Direct Assignment			100.00%	49.84%	26.60%	0.02%	0.52%	0.00%	0.05%	0.21%	10.86%	11.90%
Design Day Demand.			100.00%	62.62%	29.79%	0.01%	0.13%	0.00%	0.00%	0.00%	7.44%	0.00%
Memo: Development of P&A Allocator												
Average Day Demand Pct.			100.00%	49.84%	26.60%	0.02%	0.52%	0.00%	0.05%	0.21%	10.86%	11.90%
Design Day Demand Pct.			100.00%	62.62%	29.79%	0.01%	0.13%	0.00%	0.00%	0.00%	7.44%	0.00%
P&A Allocator			100.00%	56.23%	28.20%	0.02%	0.33%	0.00%	0.02%	0.11%	9.15%	5.95%

PECO ENERGY COMPANY
OCA Alternative "Business As Usual" Class Revenue Allocation

Rate Schedule		P&A @ Current Rates ROR	P&A @ Current Rates Indexed ROR	Current Distribution Revenue 2/	Required Increase @ 7.70% ROR	Total Requested Increase	Step 1 Percent of System Average Increase	Step 1 Increase Amount	Step 2 Increase	Total Increase Before GPC & MFC Reduction	GPC Reduction 6/	MFC Reduction 6/	Net Increase Amount	Net Increase Percent
GR	Resid.	4.84%	84%	$233,528,109	$67,111,016		--	--	$61,466,303 5/	$61,466,303	($693,000)	($800,000)	$59,973,303	25.68%
GC	Gen. Svc.	9.12%	159%	$100,578,711	($11,127,268)		0%	$0		$0	($370,000)	($66,000)	($436,000)	-0.43%
OL	Outdoor Light	9.12% 1/	159% 1/	$423	$0 1/		0%	$0		$0			$0	0.00%
L	Lg. High LF	16.54%	288%	$75,475	($32,447)		0%	$0		$0			$0	0.00%
MV-F	MV Firm	3.26%	57%	$474,506	$293,168		150%	$135,266		$135,266	($7,000)		$128,266	27.03%
MV-I	MV Inter.	24.67%	430%	$5,022	($3,132)		0%	$0		$0			$0	0.00%
IS	Interruptible	3.24%	56%	$34,964	$21,272		150%	$9,967		$9,967			$9,967	28.51%
TCS	Temp. Control	25.21%	440%	$689,833	($443,099)		0%	$0		$0			$0	0.00%
TS-F	Transp. Firm	4.56%	80%	$16,719,224	$6,469,021		--	--	$4,400,622 5/	$4,400,622			$4,400,622	26.32%
TS-I	Transp. Inter.	3.13%	55%	$9,508,783	$6,016,563		150%	$2,710,632		$2,710,632			$2,710,632	28.51%
Total Rate Revenue		5.73%	100%	$361,615,052	$68,305,094 4/	$68,722,789 4/		$2,855,864	$65,866,925	$68,722,789	($1,070,000)	($866,000)	$66,786,789	18.47%
Other Revenue				$1,528,291 3/	$88,491 3/	$88,491				$ 88,491			$88,491	5.79%
Total Company				$363,143,343	$68,393,585	$68,811,280				$ 68,811,280	($1,070,000)	($866,000)	$66,875,280	18.42%

1/ Outdoor Lighting is included within the GC class per response to OCA-I-4.
2/ Per Exhibits JAB-1 and JAB-4.
3/ Per Witness Ding's corrected CCOSS provided in response to OSBA-I-2.
4/ The total required increase in PECO's CCOSS does not match the total requested increase in Exhibit JAB-1.
5/ Equal percentage of remaining required increase.
6/ Per Exhibit JAB-1.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018929
	:	
PECO Energy Company – Gas Division	:	

VERIFICATION

I, Glenn A. Watkins, hereby state that the facts set forth in my Rebuttal Testimony, OCA Statement 4-R, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: January 19, 2021
*302480

Signature: ______________________
Glenn A. Watkins

Consultant Address: Technical Associates, Inc.
6377 Mattawan Trail
P.O. Box 1690
Mechanicsville, VA 23116

OCA Statement No. 5R

R-2020-3018929
2/17/21 JK

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2020-3018929
PECO Energy Company –Gas Division	:	

Rebuttal Testimony of
Roger D. Colton

On Behalf of:
Office of Consumer Advocate
Statement No. 5R

January 19, 2021

Table of Contents

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, MA.

Q. ARE YOU THE SAME ROGER COLTON WHO PREVIOUSLY PREPARED DIRECT TESTIMONY FOR THE OFFICE OF CONSUMER ADVOCATE IN THIS PROCEEDING?

A. Yes.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR REBUTTAL TESTIMONY.

A. The purpose of my Rebuttal Testimony is to respond to the Direct Testimony of Mitchell Miller submitted on behalf of CAUSE-PA in this proceeding. More specifically, I respond to the following recommendations of Mr. Miller:

- First, I respond to Mr. Miller's recommendation that PECO Gas be directed to immediately decrease home energy burdens as part of this proceeding;
- Second, I respond to Mr. Miller's recommendation that there should be an in-CAP arrearage forgiveness program because of findings that the Fixed Credit Option (FCO) CAP operated by PECO Gas was subsequently found to impose unaffordable burdens; and
- Finally, I will respond to Mr. Miller's recommended plan to increase CAP enrollment by 50%.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Based on the data and discussion presented below, I recommend as follows:

1. That the recommendation that PECO Gas be directed to immediately decrease home energy burdens be deferred to the pending proceeding regarding PECO's Universal Service and Energy Conservation Plan (USECP);
2. That the recommendation that PECO Gas be directed to implement an in-CAP arrearage forgiveness program as part of this proceeding not be approved and deferred to the pending USECP; and
3. That the recommendation that PECO develop a plan to increase CAP enrollment by 50% be consolidated into PECO's currently pending proceeding regarding the Company's USECP.

Part 1. Immediate Decrease in Home Energy Burdens.

Q. PLEASE EXPLAIN THE RECOMMENDATION IN MR. MILLER'S DIRECT TESTIMONY THAT YOU ADDRESS IN THIS PART?

A. Mr. Miller stated in his Direct Testimony that "PECO's CAP rates should be adjusted now, in the context of this proceeding, to ensure that CAP customers are receiving a just and reasonable rate." (CAUSE-PA St. 1, at 31). Mr. Miller's reference to "CAP Rates" is a reference to the percentage of income burdens that underlie CAP bills. I recommend that this proposal be deferred to a different proceeding outside of this rate case.

Q. WHEN YOU SAY "A DIFFERENT PROCEEDING," IS THERE ANY OTHER PENDING PROCEEDING WHICH IS NOW CONSIDERING THE IMPLEMENTATION OF REVISED ENERGY BURDENS FOR PECO'S CAP CUSTOMERS?

A. Yes, there are two proceedings now pending before the Commission that directly present the question of when, if at all, PECO should implement the revised energy burdens recommended in the PUC's Revised CAP Policy Statement.

- First, there is a specific, separate, pending proceeding, initiated as a complaint proceeding by the Tenant Union Representative Network (TURN) in which TURN sought a retroactive reduction of both the electricity and the natural gas home energy burdens used in the PECO Energy CAP. (TURN v. PECO Energy, Docket C-2020-3021557). CAUSE-PA, on whose behalf Mr. Miller is testifying in this rate proceeding, has intervened in that complaint case.
- In addition, PECO has filed a revised Universal Service and Energy Conservation Plan (USECP) with the Commission. The PECO USECP has been docketed for review by the Commission. (Docket M-2018-3005795). In its proposed revised USECP, PECO states that "Beginning no later than 8 months after Commission approval of the Company's 2019-2024 USECP, PECO will implement its CAP PIPP program." (Proposed Revised USECP, at 3). PECO has proposed to incorporate the revised home energy burdens in that "CAP PIPP program."

Q. HOW DOES THE TURN COMPLAINT PROCEEDING RELATE TO MR. MILLER'S RECOMMENDATION IN THIS PROCEEDING?

A. As part of the TURN complaint proceeding I reference above, I submitted testimony noting that according to the PUC (Docket M-2019-3012599),[1] the revised CAP energy burdens (along with other amendments) "should be operational by or before January 1,

[1] http://www.puc.pa.gov/about_puc/consolidated_case_view.aspx?Docket=M-2019-3012599 (November 5, 2019) (hereafter "Final Order").

2021." (Final Order, at 100). Even this language, however, does not mandate utility compliance with the revised burdens. The PUC provided utilities considerable flexibility, but focused on incorporating the revised burdens through revised USECPs. The PUC's Final Order stated:

> We strongly urge the EDCs and NGDCs to incorporate these CAP Policy Statement amendments ***in their USECPs*** as fully and quickly as possible so that all stakeholders will have a basis for meaningful input in the Universal Service Rulemaking. We suggest that the first 16 CAP Policy Statement amendments should be operational by or before January 1, 2021.

(Final Order, at 100) (emphasis added); see also, 2019 Amendments to Policy Statement on Customer Assistance Program, 52 Pa. Code § 69.261-69.267, Docket No. M-2019-3012599, Order on Reconsideration and Clarification at 8 (Pa. PUC Feb. 6, 2020) (EAP Reconsideration Order).

The revised energy burdens were included in "the first 16 CAP Policy Statement amendments" referenced by the PUC at this point of the Final Order. This expected timeframe predated the COVID-19 pandemic which not only resulted in the closure of PUC and OCA offices, but also resulted in the closure of PECO offices. Work-from-home decisions were disruptive to everyone's pre-COVID-19 schedules.

Note that in amending its CAP Policy Statement, the PUC explicitly "urged" utilities to incorporate the CAP Policy Statement amendments, including the revised energy burdens, "in their USECPs." The importance of this is that there is a specific process established for revised USECPs. That process does not involve base rate proceedings.

To incorporate Mr. Miller's recommendation in this proceeding would thus create the potential for three inconsistent implementation dates, resulting from three different proceedings all now pending before the proceeding: (1) retroactive to November 2019 (as requested by TURN in Docket C-2020-3021557); (2) "no later than eight months after Commission approval of the Company's 2019-2024 USECP" (as proposed by PECO in Docket No. M-2018-3005795); or (3) the effective date of rates determined in this proceeding.

Without deciding for purposes here which date is most appropriate, it is nonetheless possible to reach two reasonable conclusions: (1) had the Commission contemplated implementation of the revised energy burdens in a base rate case, it would have said so in its Final Order setting forth the Revised CAP Policy Statement. After all, when the PUC contemplated inserting aspects of the Revised CAP Policy Statement into base rate proceedings, it explicitly said so (e.g., Final Order, at 7 ["Utilities should be prepared to address recovery of CAP costs (and other universal service costs) from any ratepayer classes in their individual rate case filing."]); and (2) the most appropriate date should not be established due to the exigencies of which case happens to be decided first. The implementation date of the revised energy burdens should not be subject to a race-to-the-finish for a final order in one of the three competing now-pending proceedings involving PECO.

Q. IS THERE A SECOND REASON YOU RECOMMEND DEFERRING A DECISION ON WHEN TO ADOPT THE REVISED ENERGY BURDENS?

A. Yes. Mr. Miller's recommendation does not take into account the fact that PECO's CAP program serves not only natural gas customers, but serves electric customers as well. Indeed, while PECO provides only electric service within the City of Philadelphia, it has customers who take both electricity and natural gas in the Philadelphia suburbs. It is thus not clear how Mr. Miller would have PECO implement his recommendation to PECO's combination electric and natural gas CAP customers. Given that this is only a natural gas proceeding, the PUC would not have the ability to direct PECO to implement both the revised electric CAP burdens and the revised natural gas CAP burdens in this proceeding. As a result, those PECO CAP customers who take both electricity and natural gas service from the Company would receive service for gas under the revised burdens, but service for electricity under the existing burdens. The potential for customer confusion would be high.

Q. IS THERE A THIRD REASON TO DEFER THIS ISSUE TO THE PENDING PECO USECP PROCEEDING?

A. While Mr. Miller's testimony focuses on the impact of the revised energy burdens on CAP participants, his testimony does not address the impact of the revised energy burdens on other ratepayers not participating in CAP who may have difficulty paying their home energy bills.

The costs of universal service are borne by all non-participating residential customers, but, many of those residential customers are low-income (or "near-poor") customers themselves. In making this observation, I mean to distinguish between the low-income (or "poor") and the "near-poor." A low-income non-participating customer would be a customer who is income-eligible (i.e., at or below 150% of Poverty) for CAP, but who for whatever reason does not participate. One reason an income-eligible customer may not participate in PECO's CAP, for example, would be that PECO has simply not identified that customer as being income-eligible. According to the most recent (2019) Bureau of Consumer Services (BCS) annual report on Universal Service Programs and Collections Performance,[2] for example, while PECO (electric) has 111,124 CAP participants (page 51), it has 393,662 estimated low-income customers (page 5). At the same time, while PECO (gas) has 19,358 CAP participants (page 51), PECO (gas) has 74,914 estimated low-income customers (page 51). Those low-income customers (i.e., customers with income less than 150% of Poverty) who do not participate in CAP pay for the cost of providing benefits to those low-income customers who do participate in CAP.

In addition to those customers who are eligible for, but who do not participate in, CAP are those customers who are "near-poor." Customers who are near-poor are those customers who do not have income sufficiently low to be eligible for CAP, but who also do not have income sufficiently high to have sufficient resources to meet their day-to-day needs. The "near-poor" can be considered in light of Pennsylvania's Self-Sufficiency Standard.

The data on Pennsylvania's self-sufficiency standard in the PECO (gas) counties demonstrates that customers may not be "low-income" as per the PUC's definition, but

[2] BCS (annual). Universal Service Programs and Collections Performance. available at: http://www.puc.state.pa.us/filing_resources/universal_service_reports.aspx (last accessed January 3, 2021).

still may have insufficient household resources to consistently pay their daily expenses. I consider the five counties which PECO (gas) lists in its Tariff as comprising (in whole or part) its service territory (Bucks, Chester, Delaware, Lancaster, Montgomery counties).[3] In this assessment, I consider the self-sufficiency incomes, limited to three-person households, for these five PECO Gas counties. In the PECO (gas) service territory, the lowest self-sufficiency income for a 3-person household is $33,686 (Lancaster County: 1 adult, 2 teenagers) (162% of Poverty), while the highest self-sufficiency income for a 3-person household in the PECO Gas counties is $87,363 (Chester County: 1 adult; 2 infants) (420% of Poverty). The biggest portion of 3-person self-sufficiency incomes in the PECO (gas) counties, however, fall between 200% of Poverty and 330% of Poverty (n=47 of 75). A significant number of 3-person self-sufficiency incomes in the PECO (gas) counties fall between 200% and 300% of Poverty (n=31 of 75). As can be seen, there is a substantial population who falls within this group of concern (i.e., those who are below a Self-Sufficient income but above the CAP income eligibility line).

In sum, I conclude that there is no single population of income-challenged customers served by PECO. As always, the provision of assistance by PECO to CAP participants must simply be balanced against the obligation of income-eligible non-participants, as well as the obligation of the near-poor, to pay the costs of such assistance.

[3] http://www.selfsufficiencystandard.org/pennsylvania (last accessed January 3, 2021).

Part 2. In-CAP Arrearage Forgiveness Program.

Q. PLEASE EXPLAIN THE RECOMMENDATION IN MR. MILLER'S DIRECT TESTIMONY THAT YOU ADDRESS IN THIS PART?

A. Mr. Miller recommends "rolling debts accrued through the pandemic into pre-program arrearages. . ." (CAUSE-PA St. 1, at 40). He reasons that "PECO's current CAP is not providing affordable bills, and the pandemic has exacerbated the economic struggle for low-income households across the board." (Id.). It is important to note that Mr. Miller's recommendation in this regard is limited to existing CAP customers.

- If a customer is ***newly*** enrolled in CAP, all pre-program arrears would be subject to arrearage forgiveness whether those arrears were incurred during the pandemic or otherwise. Mr. Miller's recommendation would not apply.
- If a customer is ***not income-eligible*** for CAP –remember that my Direct Testimony regarding the impacts of COVID-19 discussed low-wage customers, not necessarily low-income customers—there would be no CAP arrearage forgiveness to be modified as suggested by Mr. Miller. Mr. Miller's recommendation would not apply.
- If a customer is income-eligible for, but ***not participating in*** CAP, the customer is earning no arrearage forgiveness through the program (irrespective of when those arrears were incurred). Mr. Miller's recommendation would not apply.

In sum, as can be seen, the customers Mr. Miller seeks to reach are customers who participated in CAP throughout the pandemic.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO MR. MILLER'S PROPOSED IN-CAP ARREARAGE FORGIVENESS?

A. I recommend that consideration of Mr. Miller's recommendation for an in-CAP arrearage forgiveness be deferred to PECO's pending USECP proceeding. The recommendation Mr. Miller makes represents a substantive change to the PECO CAP. It should be considered within the context of all other changes being recommended for the PECO CAP.

In addition, deferring Mr. Miller's recommendation to the USECP proceeding would allow Mr. Miller to provide important details that do not exist in his Direct Testimony in this proceeding. This lack of detail demonstrates that Mr. Miller's current proposal does not represent a proposal that could reasonably be implemented by PECO Gas as presented.

Q. CAN YOU ILLUSTRATE THE TYPE OF DETAIL THAT MR. MILLER'S RECOMMENDATION IS MISSING IN THE CURRENT PROCEEDING?

A. Yes. Without limitation, examples of programmatic details that are missing from Mr. Miller's recommendation, which makes it impossible to know precisely what his full recommendation is, include:

- What is the start and end date of the in-CAP arrears that would be subject to in-CAP forgiveness?

- Would in-program arrears that had been incurred prior to the beginning of the pandemic (and thus not possibly be related to the pandemic) be subject to his proposal?
- Given that Mr. Miller's recommendation applies only to "debts accrued through the pandemic" because "the pandemic has exacerbated the economic struggle for low-income households," would a CAP participant need to demonstrate or document a pandemic-induced economic harm in order to qualify for the recommended in-program arrears?

Aside from these program details, there are operational details that Mr. Miller did not present. Accordingly, it is not possible to know precisely what Mr. Miller is asking the Commission to approve in his testimony. Without limitation, operational details would include:

- When Mr. Miller recommends that in-CAP arrears be "rolled into" pre-program arrearage forgiveness, is he recommending that: (1) the in-program arrears be forgiven over however many months remain for pre-program forgiveness, or (2) is he recommending that a new arrearage forgiveness period begin for all arrears subject to forgiveness; or (3) is he recommending that two separate period of forgiveness be tracked by PECO Gas, one for pre-program arrears and the other for in-CAP arrears;
- Given that CAP programs, including PECO's CAP, require minimum payments irrespective of income, would in-CAP arrearage forgiveness apply only to arrears that exceed the minimum payment required in PECO's CAP?

Q. ARE YOUR OBSERVATIONS ABOVE INTENDED TO BE A CRITICISM OF WHAT MR. MILLER HAS RECOMMENDED?

A. No. In this proceeding, since Mr. Miller has not made recommendations, I take no position on what the appropriate responses to any of the questions presented above might be. I offer the observations above for two reasons. First, Mr. Miller has not presented a complete proposal on which a decision can be made in this proceeding. Second, to consider a complete proposal would involve both policy and operational decisions that are best presented in, and considered in, a review of a PECO USECP. Given that (as I discuss above) PECO now has pending a proposed revised USECP, any recommendation for a modification in CAP along the lines of that which Mr. Miller proposes should be presented in that review.

Q. DO YOU HAVE ANY FURTHER CONCLUSION?

A. Yes. Mr. Miller's testimony does support the conclusion that the proposed PECO COVID-19 emergency relief recommended in my Direct Testimony should be adopted.

Part 3. Increasing CAP Enrollment by 50%.

Q. PLEASE EXPLAIN THE RECOMMENDATION IN MR. MILLER'S DIRECT TESTIMONY THAT YOU ADDRESS IN THIS PART?

A. Mr. Miller recommends in his Direct Testimony that "PECO be required to develop a plan to increase CAP enrollment by 50% by 2025." (CAUSE-PA St. 1, at 33). I agree that the PECO Gas CAP is "under-enrolled." Indeed, in my Direct Testimony in this proceeding, I stated that "The under-enrollment of the PECO confirmed low-income population into CAP, as discussed above, is significant because the Company's confirmed low-income population has substantially greater payment difficulties than does the residential population as a whole." (OCA St. 5, at 34). Moreover, when PECO Gas asked OCA in discovery for the factual foundation of my conclusion that the PECO Gas CAP was under-enrolled, OCA provided that foundation. OCA's response to that PECO Gas discovery request is appended to Rebuttal Testimony as Schedule RDC-1R.

It is, however, not clear what Mr. Miller seeks as a remedy. Mr. Miller states that "Rather than [prescribe] the specific methods for improved enrollment through this proceeding, the Commission should require PECO to work with its stakeholders to identify the most workable solutions to achieve measurable improvements in CAP enrollment." (CAUSE-PA St. 1, at 33). Mr. Miller's recommendation closely mirrors the conclusions of the PUC in adopting the PUC's Revised CAP Policy Statement. In its Final Order, the PUC stated in relevant part that "Utilities should work with stakeholders to develop Consumer Education and Outreach Plans." (Final Order, at 7). Moreover, the PUC stated in that Final Order that:

> While there is no specific regulatory mandate that each utility must enroll a certain percentage of low-income households in CAP, the near uniform disparity between the total number of potential income-qualified households and those actually receiving assistance calls into question the overall adequacy of consumer education and outreach. Consumer Education and Outreach Plans are paramount to customer awareness of, and enrollment in, universal service programs. Therefore, we are expanding the current CAP Policy Statement in order to provide more guidance on this central matter.

(Final Order, at 78). The PUC continued on to state:

> Historically, within Pennsylvania, only 30% of eligible households have been enrolled in their utility's CAP – regardless of likely correlates such as

> economic performance, unseasonably hotter summers, or unemployment rates. This fact pattern does not convince us that needs are being met, but rather it illuminates the need for increased awareness. We have noted in various USECP proceedings the necessity for utilities to develop more robust efforts to reach customers, particularly the very marginal, for enrollment in universal service programs.
>
> Utilities should develop enhanced Consumer Education and Outreach Plans with input from stakeholders and submit them as part of their addendums initially and their proposed USECP filings going forward. While utilities have flexibility as to the contents of their plans, the plans should reflect focused consumer education and outreach efforts, tailored to the demographics of their individual service territories, spanning the duration of the universal service plan period. In particular, these plans should identify efforts to educate and enroll eligible and interested customers at or below 50% of the FPIG. The Consumer Education and Outreach Plans will be reviewed by BCS and by the Commission's Office of Communications.

(Final Order, at 78 – 79, internal notes omitted). It is not clear what additional obligations Mr. Miller seeks the Commission to impose above and beyond what the Commission provided in the Final Order setting forth the Revised CAP Policy Statement. As I discuss above, PECO has now submitted a proposed revised USECP. That USECP has been docketed for review by the Commission. (Docket M-2018-3005795). It would appear that this now-pending review of PECO's USECP is precisely the appropriate place to address the problems identified by Mr. Miller and the "under-enrollment" identified in my Direct Testimony.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

PECO ENERGY COMPANY
Docket No. R-2020-3018929
Interrogatories of PECO Energy Company to
The Office of Consumer Advocate
Set III

PECO-OCA-III-8. Refer to OCA Statement No. 5, page 33, lines 26-28, please set forth the factual basis for the statement that "PECO Gas under-enrolls its confirmed low-income customer population into its CAP Program".

Response:

To review the context of the cited Statement, Mr. Colton does not make this statement in the context of recommending or proposing changes to the PECO Gas CAP program. Rather, the statement is made in the context of noting that many low-income PECO Gas low-income customers, including many PECO Gas Confirmed Low-Income customers, will not be protected by CAP participation from the harms of the PECO Gas proposed increase to its residential customer charge (i.e., the question and answer is presented in Subsection B, titled "Harms to Low-Income from Increased Customer Charge").

A review of a variety of factors leads to the conclusion that "PECO Gas under-enrolls its confirmed low-income customer population into its CAP Program." Consider that according to the BCS annual report on Universal Service Programs and Collections Performance:

For 2017 through 2019, the monthly average number of PECO (gas) CAP participants, number of estimated low-income customers, and number of Confirmed Low-Income customers was as follows:

PECO Gas	2017	2018	2019
Estimated LI	73,381	74,121	74,914
Confirmed LI	27,784	25,704	24,977
CAP participants	21,898	20,238	19,427

While it might appear, at first blush, that PECO Gas enrolls a high percentage of its Confirmed Low-Income population into CAP, a closer look indicates that conclusion to be misleading. PECO Gas confirms the low-income status of a relatively small percentage of its estimated low-income population. The fact that its CAP participation rate is as high as it is indicates that PECO Gas tends to use the same criteria to enroll customers in CAP as it uses to "confirm" the low-income status of customers. Given this overlap, the CAP participation rate would be expected to be higher than it is as a percentage of the Confirmed Low-Income population.

Moreover, PECO Gas has an extraordinary termination rate for its Confirmed Low-Income population. While the statewide average Confirmed Low-Income termination rate is 9.1%, the PECO Gas Confirmed Low-Income termination rate in 2019 as 19.0% (in 2018, it was 19.4%, with the statewide average being 8.8%). Rather than enrolling Confirmed Low-Income customers into CAP and having arrears made subject to potential arrearage forgiveness, PECO Gas is terminating nearly 1-in-5 of its Confirmed Low-Income customers for nonpayment.

BCS reports that, too, that more than half of all PECO Gas dollars owed by Confirmed Low-Income customers are not on an agreement. Nearly 60% of its Confirmed Low-Income customers in debt are not on a payment arrangement. PECO Gas has, by far, the worst performance on this metric of any Pennsylvania natural gas distribution company. Rather than enrolling Confirmed Low-Income customers in arrears into CAP, in other words, PECO experiences a high percentage of Confirmed Low-Income customers not on an arrangement.

The same is true if one considers dollars of arrears rather than accounts in arrears. In 2019, more than half (55.7%) of the dollars owed by Confirmed Low-Income customers were not on an arrangement. Rather than addressing those arrears by enrolling customers in CAP, and allowing arrears to be made subject to arrearage forgiveness, PECO Gas carries dollars of arrears for Confirmed Low-Income customers without an arrangement.

PECO Gas under-enrolls its lowest income customers into its CAP. According to BCS, the percentage of PECO Gas CAP participants with income at or below 50% of Poverty was 23.4% in 2017; 23.5% in 2018; and 23.4% in 2019. In contrast, 27.9% of PECO Gas' low-income population has income at or below 50% of Poverty. PECO Gas's under-enrollment involves not merely how many customers it enrolls in CAP, but which customers it enrolls in CAP.

Finally, under-enrollment might occur not simply because of a lack of initial enrollment, but also because of a removal of customers due to a failure to recertify. There is a concern about the removal of PECO Gas customers due to a failure to recertify. According to PECO data, the average PECO Gas CAP participation in 2018 was 20,361 while in 2019, it was 19,475. (CAUSE-PA-1-6(a)). This participation was as low as it is, however, due to the very high number of CAP participants removed from the program due to a failure to recertify. According to PECO Gas data (CAUSE-1-8(a)), in 2018, a total of 9,344 CAP participants were removed due to a failure to recertify, while in 2019, 10,046 were removed due to a failure to recertify.

Witness: Roger D. Colton
Dated: 01/08/2021

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018929
	:	
PECO Energy Company – Gas Division	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts set forth in my Rebuttal Testimony, OCA Statement 5-R, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: January 19, 2021
*302479

Signature: ______________________
Roger D. Colton

Consultant Address: Fisher, Sheehan, & Colton
34 Warwick Road
Belmont, MA 02478

OCA Statement 1-SR

R-2020-3018929
2/17/21 JK

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pa. Public Utility Commission v. PECO Energy Co. – Gas Division	: : : :	Docket No. R-2020-3018929

Surrebuttal Testimony of
Scott J. Rubin

ON BEHALF OF
THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

February 9, 2021

Table of Contents

List of Schedules and Attachments

Introduction

Q. Please state your name.

A. My name is Scott J. Rubin. I previously submitted direct testimony on behalf of the Office of Consumer Advocate ("OCA") identified as OCA Statement 1.

Q. What is the purpose of your surrebuttal testimony?

A. First, I will provide an update to pandemic-related information that I discussed in my direct testimony. Second, I will provide a brief response to portions of the rebuttal testimony of PECO Energy Company ("PECO" or "Company") witness Paul Hibbard (PECO St. 11-R).

Q. Do you have any preliminary matters to discuss?

A. Yes. Mr. Hibbard's rebuttal testimony discussed issues I addressed at length in my direct testimony. I am not attempting to respond to every assertion made in his testimony. Rather, I am focusing on those items where I feel that the record needs to be clarified. My failure to respond to a statement should not be taken as assent; rather it represents an area where I already responded to the issue in my direct testimony.

Updates to Pandemic-Related Information

Q. How has the pandemic affected Pennsylvania and PECO's service area since your direct testimony was prepared in mid-December and pre-filed on December 22, 2020?

A. Since my testimony was prepared, additional data have become available concerning the effects of the pandemic on public health and the economies of Pennsylvania and PECO's service area. As I am preparing this surrebuttal in the first week of February, the following is a summary of the most recent information available to me:

- I have updated Figures 3 through 5 and Schedule SJR-1 in my direct testimony to reflect the most recent information available. The updated figures and schedule are provided as Schedule SJR-7S.

- I have prepared Schedule SJR-8S which shows the change in county-level data for COVID-19 cases and unemployment since my direct testimony was filed.

- I also prepared Schedules SJR-9S and SJR-10S to provide the most recent information on income loss and expectations from the U.S. Census Bureau's Household Pulse Survey for Pennsylvania, similar to the information provided in Schedules SJR-4 and SJR-5 in my direct testimony.

- Initial unemployment claims in Pennsylvania have declined since peaking in late March at more than 400,000 claims in one week. When I filed my testimony in December, unemployment claims were ranging between about 20,000 and 25,000 new claims per week statewide. Since then, however, the number of new weekly unemployment claims has almost doubled statewide, averaging approximately 40,000 per week for the past seven weeks.

- Since the pandemic started affecting Pennsylvanians in mid-March, almost half of Pennsylvania's workforce has filed an unemployment claim.

- On pages 13-15 of my direct testimony, I cited the U.S. Census Bureau's Household Pulse Survey as showing that through the two-week period ending November 23 about 45-50% of households in Pennsylvania have lost at least some of their employment income. Those figures have not changed appreciably as of the most recent survey for the two-week period ending January 18, 2021.

- The outlook for small business is slightly worse than it was when I prepared my initial testimony. On pages 15-16 of OCA Statement 1, I summarized the results of the Census Bureau's Small Business Pulse Survey for Pennsylvania. At the end of November, that survey reported that 48% of Pennsylvania's small businesses expected it to take six months or more to return to a normal level of operations, with another 10% saying their business would never fully recover. These figures have not changed significantly as of the most recent survey for the week ending January 10.

- After peaking at more than 1,800 cases per day in early April, Pennsylvania's incidence of COVID-19 declined to fewer than 350 cases per day in early June. In late June, case counts began rising again to 500 or more per day. During July and August, the situation worsened further, with Pennsylvania reporting more than 1,000 new infections per day, resulting in the Secretary of Health and the Governor imposing new restrictions on social gatherings, certain businesses, and requiring the wearing of masks. Infections continued at that level for most of 2020, but since Thanksgiving, new infections in the Commonwealth have numbered in the thousands per day, peaking at more than 10,000 per day in early- to mid-December.

- Around the time that new COVID-19 infections were peaking in December, vaccines started to become available in the Commonwealth. As of the end of January, about 200,000 Pennsylvanians had received both doses of the vaccine, with another 800,000 having received the first dose. As a greater percentage of the population becomes vaccinated, it is hoped that will hasten the return to a more normal economy, workplace, and educational environment.

Q. Have your opinions about the pandemic and its effect on PECO's customers and the Commonwealth changed in the six or seven weeks since your direct testimony was prepared?

A. No. Daily case counts remain very high, businesses and organizations continue to be unable to operate anywhere near their capacity, many local schools and universities remain closed to most students, businesses are closing, and people are dying. At this point, there have been more than 100,000 cases and more than 5,000 deaths from the virus in the counties served (in whole or in part) by PECO Gas.

Of course, none of us knows what the future will bring, but it looks as if it might take several months, if not longer, for public health and the economy to return to a pre-pandemic "normal" level.

Q. Do the updated data affect your conclusions and recommendations about the appropriate regulatory response to a pandemic?

A. No. I continue to recommend that the Commission should not approve any rate increase at this time.

Response to Mr. Hibbard (PECO St. 11-R)

Q. Have you reviewed the rebuttal testimony of Mr. Hibbard, PECO Statement 11-R?

A. Yes.

Q. Mr. Hibbard states on pages 4-5 that there are always customers "who struggle with paying energy bills, and … businesses that struggle to stay solvent." He suggests that these issues can be addressed through various assistance programs, and it would be "inappropriate and unwarranted" to deny a rate increase in its entirety because of these concerns. How do you respond?

A. While Mr. Hibbard agrees that the pandemic has had a severe impact on people and businesses (page 3), he does not believe this should have any effect on this rate case. Indeed, at the top of page 5, he states "these concerns are appropriately addressed in other ways." But he does not explain what those "other ways" should be and he does not propose any regulatory response other than deciding this case as if there were nothing unusual happening in the world.

As I made clear in my direct testimony, I reject this "business as usual" approach to ratemaking during this devastating public health and economic crisis. Ratemaking is a government function that is to be undertaken in the public interest to protect captive customers of monopoly business enterprises. The government sets rates because the price cannot be set by a competitive market. That does not mean, however, that the economy and business climate are irrelevant to ratemaking. Indeed, as I discussed in my direct testimony and as I explain further below, commissions and courts have ruled for many decades that utilities must not be insulated from real-world economic conditions.

Q. At the top of page 5, Mr. Hibbard states that your recommendation is an "out-of-hand rejection of a proposed increase in the Company's revenue requirement" and that the increase "is needed for [PECO] to be made whole." Has he properly characterized your testimony?

A. No, he has not. My recommendation was not made "out-of-hand." It was made after careful consideration of the effects of the pandemic on PECO's gas service area and an evaluation of the effect on PECO of denying a rate increase at this time. On page 24 of my direct testimony, I explain -- using PECO's own numbers -- that the Company earned a return on equity of 10.87% during the 12 months ending June 30, 2020 -- a period that included the first few months of the pandemic when nearly half of Pennsylvania households suffered a significant loss of income. The Company projects that its equity return will decline to 7.27% in the 12 months ending June 30, 2022 (a 12-month period that has not even started yet) if there is no rate increase. Mr. Hibbard does not address these facts, and I do not know how he defines being "made whole." In my opinion, equity returns in the 7% to 11% range in the midst of a pandemic ought to be sufficient for utility investors.

Q. On page 13, lines 11-18, Mr. Hibbard appears to agree with you that market forces and technological change can affect a utility's ability to charge rates that satisfy its

investors. He then states, however, that if this occurs, the result should be that the utility files a case to increase its rates. Do you agree?

A. No, Mr. Hibbard misses the point. He seems to think that lower-than-expected returns are to be made up by increasing customers' rates. In fact, courts and utility regulators have recognized for more than 100 years that there are circumstances when low returns (or even negative returns ultimately leading to business failure) are an integral part of utility regulation. Specifically, if economic or technological conditions change such that there is no longer a demand for the utility's service, or that the price of comparable services has declined significantly, or that people cannot afford to pay the rates that would be determined by traditional ratesetting formulas, then regulators cannot allow the utility to charge a price that is fully consistent with investors' expectations. I cited to one example of this in my direct testimony -- a case from Massachusetts dating from the 1918-1919 influenza pandemic.

The classic case in this regard is the *Market Street Railway* case[1] where the U.S. Supreme Court upheld a regulatory commission's reduction in streetcar fares because the service was becoming obsolete due to competing modes of transportation. It is noteworthy that the Court's holdings included the following: "To the extent that the Commission was influenced by considerations of the value of the service in this case, we find nothing that denies the Company any rights possessed under the Federal Constitution."[2]

[1] *Market Street Railway Co. v. Railroad Commission of Calif.*, 324 U.S. 548, 65 S.Ct. 770, 89 L.Ed. 1171 (1945).
[2] Id., 324 U.S. at 563-64, 65 S.Ct. at 778, 89 L.Ed. at 1183.

Further, the Court made clear the inherent limitation of utility regulation. Thus, the Court held:

> Without analyzing rate cases in detail, it may be safely generalized that the due process clause never has been held by this Court to require a commission to fix rates on the present reproduction value of something no one would presently want to reproduce, or on the historical valuation of a property whose history and current financial statements showed the value no longer to exist, or on an investment after it has vanished, even if once prudently made, or to maintain the credit of a concern whose securities already are impaired. <u>The due process clause has been applied to prevent governmental destruction of existing economic values. It has not and cannot be applied to insure values or to restore values that have been lost by the operation of economic forces.</u>[3]

Q. How does the Court's ruling in *Market Street Railway* relate to Mr. Hibbard's conclusions?

A. Mr. Hibbard seems to be of the opinion that any reduction in a utility's revenues should lead to a new rate case. In fact, the Supreme Court ruled that utility regulation does <u>not</u> insulate utilities from the operation of economic forces. If a utility's revenues decline, or the value of its property is diminished, because of larger forces at work in the economy, then the utility has realized one of the risks of doing business. Utility customers are not the guarantors of success for the business, and regulation is not supposed to ignore what is happening in the economy as a whole.

Q. How does this affect the current case?

A. As I explained in my direct testimony, the economy is experiencing a severe economic disruption at the present time. Utility regulators should not be attempting to make utility

[3] <u>Id.</u>, 324 U.S. at 567, 65 S.Ct. at 779-80, 89 L.Ed. at 1184-85 (emphasis added).

investors "whole" (however Mr. Hibbard defines that term) at the same time businesses and families are struggling to survive. It is permissible -- indeed I suggest it is required -- for utility regulators to use the *Market Street Railway* principles and say, "now is not the time." As the Supreme Court stated in that case, utility regulation must consider the real impacts on people and what is happening in the larger economy.

Q. What is the practical effect of setting rates while considering the economic devastation caused by the pandemic?

A. There are many possible outcomes. As Mr. Hibbard correctly notes, some utility commissions have chosen to essentially ignore the pandemic and set utility rates without regard to how much people are struggling. In Pennsylvania, most utilities that had rate cases pending during the pandemic settled the cases by making significant concessions. Other utilities and regulators have withdrawn rate increase proposals or temporarily reduced rates (or modified rate structures) to provide some relief to customers during the pandemic, as I discussed in my direct testimony. Other possible approaches can include delaying a rate case significantly without compensation to the utility (where legally permissible) or denying any rate increase without restricting the utility's ability to file a new case to "start the clock" again.

Q. Are you aware of any utility rate cases where the utility agreed to significantly delay a rate case without compensation?

A. Yes. I am an expert witness for AARP in a rate case for Dominion Energy South Carolina that is currently pending before the South Carolina Public Service Commission. A few weeks ago, in the middle of evidentiary hearings, the utility agreed to postpone the entire case for six months because of the pandemic.[4] That utility heard the concerns of its customers and consumer representatives and decided that it could postpone any rate increase it might otherwise receive for six months. The parties in South Carolina hope that by the end of summer, the economy will be recovering sufficiently that utility rates can be set under "business as usual" conditions. Of course, if that does not occur, then a different outcome may result.

Q. On pages 15-17 of PECO Statement 11-R, Mr. Hibbard disagrees with your characterization of rate cases as being focused on the utility interest. He states at the top of page 16 that the "entire process is an exercise in 'defining the consumer interest' by "limiting what the utility can charge consumers." Is he correct?

A. No, he is not correct. Setting a reasonable profit level for investors is an important part of a utility rate case, but it is not the same as determining what rates customers can afford to pay or whether customers perceive the rates as being consistent with the value of service they are receiving from the utility.

Q. At the bottom of page 16, Mr. Hibbard states that you implied that the amount of effort spent on determining a reasonable rate of return "is a bad thing from the consumers' perspective." Is that what you said?

A. No, that is not what I said. I never suggested or implied that utility rate cases should no longer consider evidence of a reasonable rate of return. I agree with Mr. Hibbard that this is an important part of the traditional ratemaking equation. What I did suggest, though, is

[4] No Dominion rate hike in SC for at least 6 months as company agrees to hearing delay, *The State (Columbia, SC)*, Jan. 11, 2021, https://www.thestate.com/news/politics-government/article248419600.html.

that the consumer interest is at least as important -- that is, considering what price is reasonable given the value and quality of service received by customers and their ability to pay for that service. Given the circumstances of this case -- setting rates while hundreds (if not thousands) of businesses in the service area are on the brink of failure and many households have suffered a significant loss of income -- the consumer interest must be given full and careful consideration.

Q. In the last paragraph of his testimony (on page 27), Mr. Hibbard concludes by stating your recommendation represents "an inappropriate and unwarranted major departure from ratemaking practices." How do you respond?

A. I disagree. Utility ratemaking does not exist in a vacuum, and it never has. When the government sets rates for monopoly services, it has always considered what is happening in society and the larger economy. In every rate case, commissions evaluate how comparable businesses are performing in order to determine authorized rates of return on equity. Every case includes a consideration of the interest rate environment, reasonable wage rates, inflation levels, and so on. Economic conditions are an integral part of utility ratemaking.

With rare exceptions, we have been fortunate for most of the past century that we have not needed to think about over-arching economic dislocations when setting utility rates. But our luck has run out. We are now faced with economic issues that are much larger than looking at interest rates or profit levels for other large utility companies. Many segments of the economy are in turmoil and peoples' lives and livelihoods are being destroyed. In the past -- during the 1918-1919 pandemic, during the Great

Depression, during times of dramatic technological change -- regulatory commissions have responded to severe economic challenges by recognizing that utilities are part of, and affected by, the larger economy. Regulation is not supposed to protect utilities from those market forces. As the Supreme Court stated, regulation “has not and cannot be applied to insure values or to restore values that have been lost by the operation of economic forces.”

There are several ways in which commissions can choose to respond. I am recommending one that is consistent with past actions of regulators and that recognizes the unusual and severe conditions affecting PECO’s service area. Thankfully, these conditions are rare, but they are not unprecedented. While Mr. Hibbard suggests that utility regulators should ignore what is happening in the world, my recommendations are consistent with actions regulators have taken in the past (and are taking right now) to address what we hope is a once-in-a-lifetime occurrence.

Conclusion

Q. Do the updates to information about the pandemic and economy change any of your conclusions and recommendations?

A. No.

Q. Does anything in Mr. Hibbard’s rebuttal testimony cause you to change any of your conclusions and recommendations?

A. No.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

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Figure 3: Percentage of Pennsylvania Households Experiencing Loss in Employment Income Since March 13, 2020 (updated 2/9/2021)

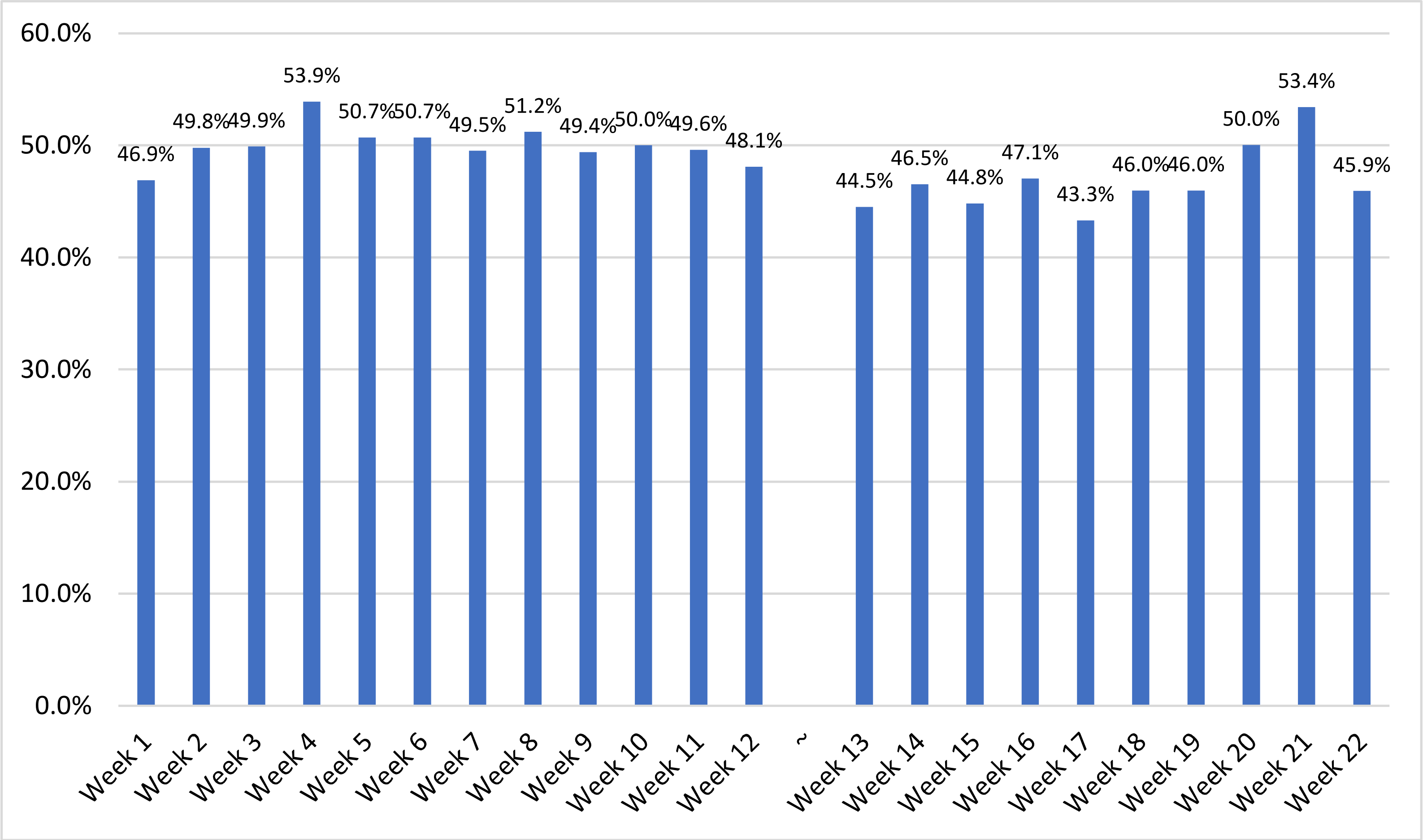


Figure 4: Percentage of Small Businesses in Pennsylvania Expecting it to Take at Least Six Months to Return to Usual Level of Operations (updated on 2/9/2021 with data through January 10, 2021)

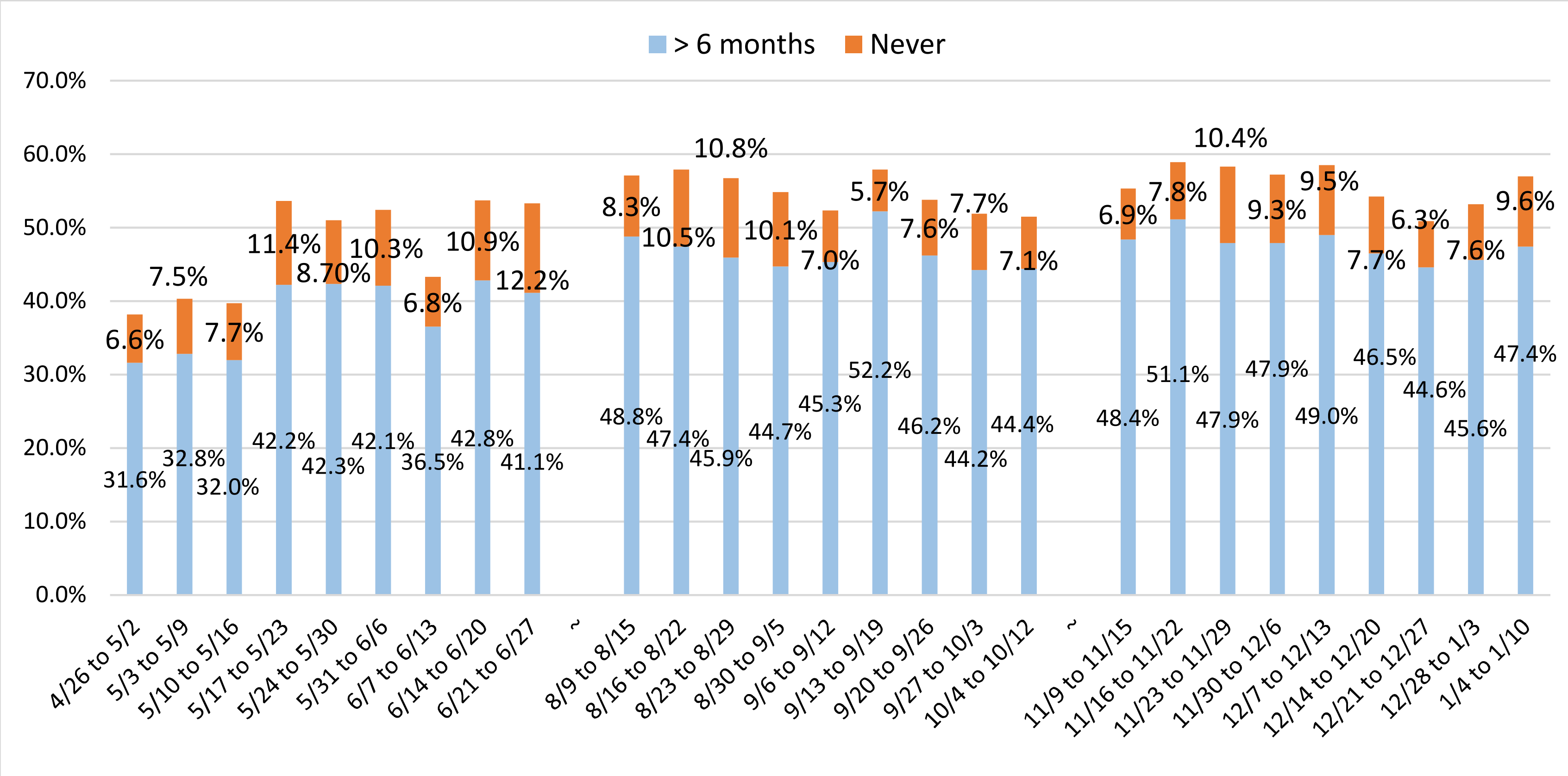
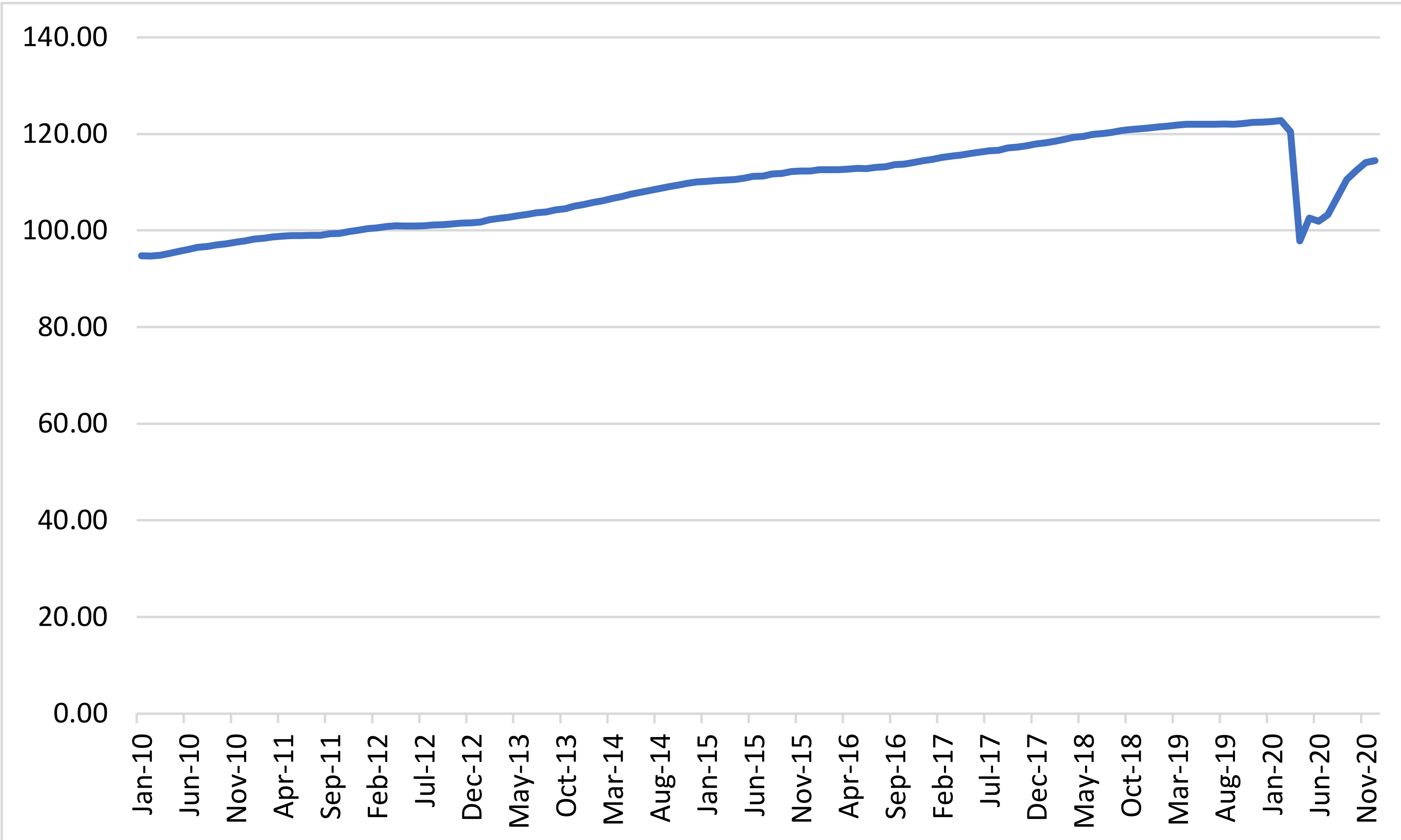


Figure 5: Federal Reserve Bank Coincident Index (Measure of Economic Activity) in Pennsylvania January 2010 to December 2020 (updated 2/9/2021)



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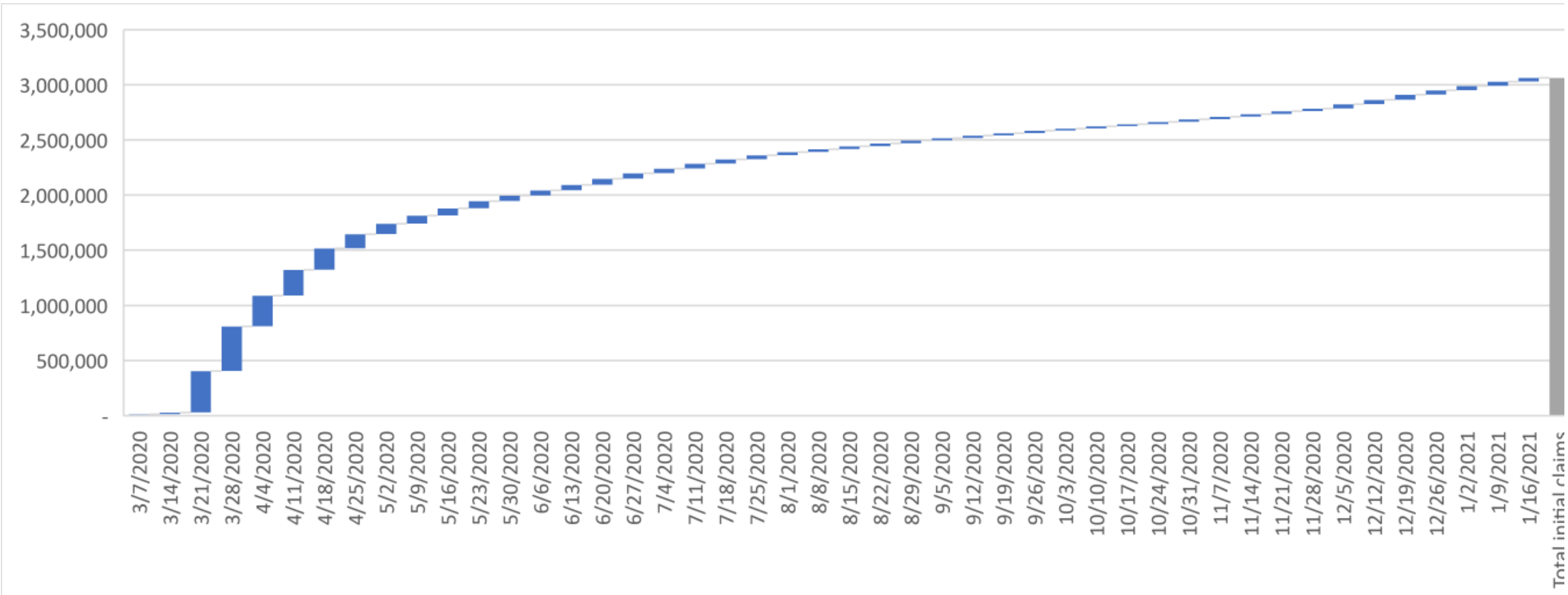
Schedule SJR-1
Updated 2/9/2021

Initial Unemployment Claims in Pennsylvania: Weeks Ending March 7 to January 16, 2021



Source: U.S. Department of Labor, Weekly Unemployment Report, http://oui.doleta.gov/unemploy/archive.asp

Pa. PUC v. PECO Energy Co.
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Week ending:	Initial Unemployment Claims	Week ending:	Initial Unemployment Claims
3/7/2020	12,227	8/8/2020	27,094
3/14/2020	15,439	8/15/2020	25,584
3/21/2020	377,451	8/22/2020	27,510
3/28/2020	404,677	8/29/2020	24,883
4/4/2020	277,640	9/5/2020	22,626
4/11/2020	234,868	9/12/2020	21,747
4/18/2020	194,594	9/19/2020	22,762
4/25/2020	127,896	9/26/2020	22,955
5/2/2020	94,445	10/3/2020	19,844
5/9/2020	75,557	10/10/2020	20,251
5/16/2020	64,078	10/17/2020	19,223
5/23/2020	66,980	10/24/2020	19,974
5/30/2020	48,930	10/31/2020	23,742
6/6/2020	48,827	11/7/2020	23,051
6/13/2020	49,197	11/14/2020	22,756
6/20/2020	54,083	11/21/2020	26,983
6/27/2020	49,986	11/28/2020	23,878
7/4/2020	44,086	12/5/2020	40,833
7/11/2020	44,798	12/12/2020	39,258
7/18/2020	37,986	12/19/2020	47,305
7/25/2020	35,808	12/26/2020	38,279
8/1/2020	29,371	1/2/2021	38,647
		1/9/2021	41,424
		1/16/2021	32,921
		Total	3,062,454

Update in Pandemic-related data for counties served by PECO Gas
(Note: PECO Gas does not serve entire population of all counties listed)

County	Population (2018)	COVID-19 Cases as of 12/7/2020	COVID-19 Cases as of 1/28/2021	Percent Change in COVID-19 Cases	Unemployment Rate as of October 2020	Unemployment Rate as of November 2020
Bucks	626,370	21,146	38,977	84.3%	6.4	5.7
Chester	517,156	14,178	26,744	88.6%	4.9	4.4
Delaware	563,527	22,470	36,636	63.0%	7.2	6.5
Lancaster	538,347	19,426	36,945	90.2%	5.3	4.7
Montgomery	821,301	25,277	47,100	86.3%	5.9	5.3
Total	3,066,701	102,497	186,402	82.7%	6.0	5.3

Sources:

Population:	US Census Bureau, American Community Survey, Table B01003 Total Population (5-year estimate, 2014-2018)
COVID-19 cases:	https://www.health.pa.gov/topics/disease/coronavirus/Pages/Cases.aspx
Unemployment:	Pa. Dept. of Labor & Industry, seasonally adjusted unemployment rates (2nd week in each month) https://www.workstats.dli.pa.gov/MediaCenter/MonthlyNews/Pages/default.aspx

Experienced loss of employment income since mid-March, and expected income loss in the next four weeks, Pennsylvania households by selected characteristics, as of the two-week period ending January 18, 2021

	Lost income since mid-March	Expect to lose income in next 4 weeks
Hispanic origin and Race		
Hispanic or Latino (may be of any race)	64.6%	37.6%
White alone, not Hispanic	44.1%	21.0%
Black alone, not Hispanic	45.2%	31.6%
Asian alone, not Hispanic	26.5%	24.4%
Education		
Less than high school	50.3%	33.4%
High school or GED	44.6%	21.3%
Some college/associate's degree	54.8%	28.0%
Bachelor's degree or higher	39.4%	20.2%
Household income		
Less than $25,000	50.2%	28.6%
$25,000 - $34,999	57.6%	33.1%
$35,000 - $49,999	33.2%	18.5%
$50,000 - $74,999	50.2%	29.5%
$75,000 - $99,999	55.7%	21.7%
$100,000 - $149,999	45.1%	19.7%
$150,000 - $199,999	49.4%	13.0%
$200,000 and above	27.6%	15.6%
All households in Pennsylvania	**45.9%**	**23.3%**

Source: U.S. Census Bureau Household Pulse Survey, Week 22 (two weeks ending Jan. 18, 2021). Employment Table 1. Experienced and Expected Loss of Employment Income, by Select Characteristics: Pennsylvania

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Schedule SJR-10S

How Pennsylvania households who lost employment income since mid-March paid their bills in the past 7 days, as of the two weeks ending January 18, 2021

Regular income sources like those used before the pandemic	41.5%
Credit cards or loans	51.1%
Money from savings or selling assets	63.9%
Borrowing from friends or family	80.0%
Unemployment insurance (UI) benefit payments	98.0%
Stimulus (economic impact) payment	60.1%
Money saved from deferred or forgiven payments (to meet spending needs)	46.1%
Supplemental Nutrition Assistance Program (SNAP)	70.8%
Did not report	41.4%

Source: U.S. Census Bureau Household Pulse Survey, Week 22 (two weeks ending Jan. 18, 2021). Employment Table 1. Experienced and Expected Loss of Employment Income, by Select Characteristics: Pennsylvania

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018929
	:	
PECO Energy Company – Gas Division	:	

VERIFICATION

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

DATED: February 9, 2021
*303585

Signature: Scott J. Rubin
Scott J. Rubin

Consultant Address: 333 Oak Lane
Bloomsburg, PA 17815

OCA Statement No. 2-SR

R-2020-3018929
2/17/21 JK

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
	)	**Docket No. R-2020-3018929**
v.	**)**	
	)	
PECO Energy Company - Gas Division	**)**	

SURREBUTTAL TESTIMONY

OF

LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

February 9, 2021

PUBLIC VERSION

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

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INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lafayette K. Morgan, Jr. My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland, 21044. I am a Public Utilities Consultant working with Exeter Associates, Inc. (Exeter). Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. ARE YOU THE SAME LAFAYETTE K. MORGAN, JR. WHO SUBMITTED PRE-FILED DIRECT TESTIMONY ON DECEMBER 22, 2020 IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to address the issues discussed in the rebuttal testimonies of PECO witnesses Ronald A. Bradley, Robert J. Stefani and Michael J. Trzaska which were filed on January 19, 2021.

Q. ARE YOU INCLUDING UPDATED SCHEDULES SUMMARIZING THE OCA'S CURRENT REVENUE REQUIREMENT POSITION IN THIS PROCEEDING?

A. Yes. I have attached Surrebuttal Schedules LKM-1 to LKM-31 to this surrebuttal testimony which present the OCA's updated position after taking the Company's rebuttal position on certain issues into account.

Q. PLEASE SUMMARIZE THE OCA'S UPDATED RECOMMENDATION AS A RESULT OF THE CHANGES DISCUSSED IN THIS TESTIMONY.

A. In this testimony, I respond to PECO witnesses' rebuttal testimonies on various adjustments I recommended in my direct testimony. I have considered the issues addressed in their rebuttal testimonies and, in some instances, I have modified my adjustments where necessary. As a result of these changes, if the Commission finds a revenue increase is warranted in this proceeding, my recommended total revenue requirement results in a decrease in revenues of $11,475,000 instead of the $24,930,000 decrease that I recommended in my direct testimony.

To the extent that the Company has rebutted my position on an issue that I challenged in my direct testimony, but I did not address in this surrebuttal testimony, it should not be construed that I am in agreement with the Company.

Plant in Service

Q. PLEASE SUMMARIZE MR. BRADLEY'S RESPONSE TO YOUR ADJUSTMENT TO PLANT IN SERVICE.

A. In my direct testimony, I explained that there is evidence that there were construction delays, and explained that the impact of the delays was not reflected in the FPFTY Plant in Service balances. I explained that because the rate base balances are cumulative, PECO's FPFTY rate base assumes that all planned additions to Plant in Service for the FTY occurred and the FPFTY plant additions were simply added to the FTY projected balances. I explained why this approach is unreasonable because it does not recognize any construction delays.

Mr. Bradley disagrees with my adjustment. Although he admits there were construction delays, he states that:

> While the COVID-19 emergency delayed certain construction activities during the historic test year ("HTY") ended June 30, 2020, the Company has accelerated subsequent work and fully expects the plant in service projected for the FPFTY to be placed into service by June 30, 2022. During the first half of 2020, PECO maintained some main construction installation activities and similar work, thereby mitigating the impact of the pandemic-related delays. The remainder of the delayed work to be completed is limited to tie-ins and some repaving and final restoration work which will be in the first half of

> 2021. Put another way, there will be no continual delay or "catch up" beyond the middle of 2021, and no impact to the FPFTY capital program.[1]

Q. PLEASE RESPOND TO MR. BRADLEY'S ASSERTION ON THE PROJECTED PLANT IN SERVICE BALANCES.

A. Mr. Bradley's statement is not based on any evidence. Mr. Bradley is simply making an assertion that "the Company has accelerated subsequent work and fully expects the plant in service projected for the FPFTY to be placed into service by June 30, 2022."[2] The Company has provided no evidence to support this claim. In fact, the Company's responses to the OCA data requests have been evasive and lacking any detailed information.

In OCA-II-3 the Company was asked to provide a copy of the capital budget by plant account for the FTY and the FPFTY and list all projects expected to be completed in the FTY and the FPFTY.[3] The request also asked the Company to provide a description of the projects, the initial estimated completion dates and any revised completion date and to provide the current status of each project. The response to that data request was a workpaper that lacked any of the detailed information sought. What the Company provided was a summary grouping of projects with completion dates beyond the end of the FPFTY. The total plant additions did not match the amounts presented on Exhibit MJT-1, Schedule C-2, Page 16 or Exhibit MJT-2, Schedule C-2, Page 16.

In OCA-XIII-3, the OCA followed up the initial data request and asked the Company to provide a detailed project listing for each of the categories presented on

[1] PECO Statement 1-R at 4.
[2] PECO Statement 1-R at 4.
[3] OCA Statement 2, App. B at 2-3.

Attachment OCA-II-3(a), and to show the projected in-service dates, current status of each project, and identify any project that has been suspended, delayed or cancelled.[4] In the response, the Company stated "[n]one of the projects or programs listed below have been suspended, delayed, or cancelled." This is in direct contradiction to Mr. Bradley's rebuttal testimony where he acknowledges delays.[5] The Company also did not provide the in-service dates for many of the costs it is claiming.

In OCA-XIII-2, the Company was asked to provide management's budget guidelines/instructions issued for development of the O&M and Capital budgets for the periods applicable to the FTY and FPFTY.[6] Rather than provide the information, the Company responded by stating, "[r]efer to PECO Statement No. 2 (Direct Testimony of Robert Stefani), pp. 10-12 for a description of the Company's budgeting process, which was utilized for the development of the O&M and Capital budgets for the periods applicable to the FTY and FPFTY". That section of Mr. Stefani's testimony does not provide the information requested. The information sought would have provided the specific instructions managers would use to prepare their budgets. Certain assumptions to be used when developing the budgets would have been given in the instructions. For example, wage increase percentages, expected growth in plant, or O&M expenses, etc. This information should have been readily available for the Company to provide and is common practice for companies of this size that are part of a holding company structure. By not providing these data, I was unable to determine the reasonableness of the Company's claims.

The Company's claim that no projects were delayed or postponed, and its failure to substantiate its budget data is sufficient reason for the Commission to deny

[4] OCA Statement 2, App. B at 23-24.
[5] Witness Bradley Rebuttal Testimony at page 4, lines 8-11; see also OCA Statement 1, App. B at 16.
[6] OCA Statement 1, App. B at 22.

the inclusion of these costs in rate base. Even absent of the COVID-19 pandemic, it has been my experience that one would normally find that certain changes will have occurred since the preparation of the budget. In this instance, PECO is claiming that it has the ability to perfectly forecast plant addition amounts and timing. To claim such perfect forecasting abilities without providing the detailed data calls into question the reasonableness of the Company's claims. The burden of proof is on the Company, not the OCA, to justify its claims. The Commission must hold the Company accountable for proving its claims. The Company admits that the basis of its forecast through June 2022 was data prepared in June 2019 and updated in June 2020. To be able to project 2 to 3 years in the future without any changes is an extraordinary feat and without the supporting information requested, it cannot be given much credence.

Q. WHY DO YOU BELIEVE THAT THE COMPANY'S PLANT IN SERVICE CLAIM IS OVERSTATED?

A. The Company's plant in service claim is overstated primarily because of two reasons. First, the Company uses data that reflect more robust economic activity than currently exists. In fact, the Company admits that the FPFTY budget is based on the Company's Long Range Plan which was developed in June 2019[7] (although the Company states the Company then further updated the budget in July 2020). I will discuss this further later in this testimony. The use of the 2019 data means that the growth pattern before the COVID-19 pandemic is being used to determine the corresponding plant in service projections. Customer usage and customer growth have changed since the onset of the pandemic. (OCA witness Scott J. Rubin further discusses the impact of the pandemic on individuals and small businesses.) Second, the Company has made no attempt to recognize the decline in economic activity in its

[7] Witness Stefani Rebuttal Testimony at page 2, lines 18 to 20.

projections. While Mr. Bradley argues that there will be no continual delay or "catch up" beyond the middle of 2021, and no impact to the FPFTY capital program, he totally ignores the fact that approximately 13.0 percent of the Company's capital expenditures is related to capacity expansion and new connections.[8] Therefore, the projected plant in service balances for the FPFTY reflect the plant needed to serve customer demand that is based on a more robust economy. Less economic activity will mean less plant investment will be needed. PECO has chosen to ignore this reality which has led to the overstatement of its plant additions.

Q. DID PECO PROVIDE ANY DATA TO SHOW THAT IT IS INCURRING CAPITAL EXPENDITURES AT THE LEVEL PROJECTED?

A. No. The Company only asserts that the COVID-19 pandemic will not have an impact on the FPFTY.[9]

Q. ARE YOU AWARE OF ANY UTILITIES THAT HAVE RECOGNIZED THE IMPACT OF THE COVID-19 PANDEMIC ON ITS PLANT IN SERVICE?

A. Yes. In UGI – Gas Division's most recent rate case in Docket No. R-2019-3015162, the company recognized that the pandemic impacted its capital expenditures and revised its plant projections downward to reflect a more realistic forecast.[10] Here, PECO has done no such thing.

Q. PLEASE SUMMARIZE MR. STEFANI'S RESPONSE TO YOUR ADJUSTMENT TO PLANT IN SERVICE.

[8] PECO Statement 1-R at 4.
[9] PECO Statement 1-R at 4.
[10] Docket No. R-2019-3015162, UGI Gas Utilities, Inc. – Gas Division, Statement No. 2-R, Rebuttal Testimony of Stephen F. Anzaldo, page 6, line 24 to 35.

A. In my direct testimony, as part of my adjustment to plant in service, I explained that the budget data, on which the FTY and FPFTY were derived, were not reasonable.[11] I described the process as an abbreviated approach which was independent of the normal budgeting process.

In his rebuttal testimony, Mr. Stefani disagrees with my explanation and argues that PECO's budgeting process is described in detail in his direct testimony.[12] He indicates that PECO adhered to its usual and ongoing budgeting process to develop the capital and operating budgets for the FTY and FPFTY.[13] Specifically, he states that the FPFTY budget is based on the Company's Long-Range Plan which was developed in June 2019 and was approved by PECO's senior management in January 2020.[14] He also stated that the budget was then updated in July 2020 with the most recent information available to accommodate PECO's use of a fiscal year, rather than calendar year budget.[15] He indicated that the budget was updated with the latest information with respect to customer load, capital expenses, operations and maintenance expenses, depreciation and amortization expense, and interest and tax expense, and the budget update was finalized in August 2020.[16]

Q. WAS THE FOREGOING EXPLANATION INCLUDED IN MR. STEFANI'S DIRECT TESTIMONY?

A. No. Despite Mr. Stefani's assertion that PECO's budgeting process is described in detail in his direct testimony, none of the foregoing explanation was included in his direct testimony. In fact, the explanation in his Rebuttal Testimony supports my claim

[11]OCA Statement 1 at 7-13.
[12] PECO Statement 2-R at 2-3.
[13] *Id*.
[14] *Id*.
[15] *Id*.
[16] *Id*.

that the projected data supporting the FPFTY was not the approved budget, but instead adjusted budgeted data.

Q. HOW DID YOU CONCLUDE THAT THE BUDGETING DATA WAS THE PRODUCT OF AN ABBREVIATED APPROACH?

A. I reached my conclusion based on the Company's response to OCA-II-2, where the Company stated:

> The base data for the FPFTY and FTY that was used to develop PECO's capital and operating budgets for the twelve months ending June 30, 2022 and 2021 respectively were prepared in July 2020 and finalized in August 2020.[17]

This description is completely different from the budgeting process discussed in Mr. Stefani's direct testimony (Page 11, lines 3 to 22).[18] There he states the budgeting process begins in June of each year, and that it is sometime after September before the two-year budget is developed.[19]

Q. DID YOU MAKE AN ADDITIONAL EFFORT TO UNDERSTAND THE DERIVATION OF THE FPFTY BUDGET?

A. Yes. In OCA-XV-12, the following questions were asked:

Questions:

a. If work begins on the two-year detailed budget after the LRP process concludes in September, when is the two-year detailed budget completed?

b. Is it true that, based on the foregoing, the budget on which the FPFTY is based is not the corporate budget that was formerly adopted by management for the 12-month period ended June 30, 2022? If no, please explain and provide documentation showing that the data in the FPFTY corresponds to the approved budget data for the 12-month period ending June 30, 2022.

Responses:

[17] OCA Statement 1, App. B at 1.
[18] PECO Statement 2 at 11.
[19] *Id*.

a. The two-year detailed, calendar-year budget is completed in January.

b. No. The budget on which the FPFTY is based was approved by PECO's senior management in January 2020. The FPFTY budget was then prepared in July 2020 and finalized in August 2020 for alignment with the fiscal year ending June 30, 2022.

As can be seen, the Company's reference to multiple FPFTY budgets creates confusion as to what the amounts in the cost of service represents.

Q. WHY IS IT IMPORTANT TO KNOW WHETHER THE BUDGET DEVELOPED THROUGH THE FORMAL BUDGET PROCESS IS BEING USED FOR RATEMAKING?

A. A budget is like a "roadmap" that governs the Company's expenditures for each financial year. Performance is measured against the budget, and it is the plan by which management lives. Consequently, it is the financial data that is a proxy for the actual "per books" data. Now that the Commission uses a fully projected future test year, the cost of service should be based on the same budget that has undergone a rigorous review because that is the plan on which management decisions will be based. Any other budget that has been modified, adjusted, or "realigned" for the purpose of the rate case does not carry the same integrity and credibility as the formal budget approved by management because it is not used to guide decisions and measure performance. Therefore, I recommend that the Commission pay keen attention to the underlying data that is used to support the cost of service.

Q. DO YOU STILL BELIEVE THE BUDGETED DATA PRESENTED BY THE COMPANY IS NOT REASONABLE?

A. Yes. One of the reasons I have reached the conclusion that the budgeted data was not reasonable is the inconsistencies in data presentation and the explanations. Even Mr. Stefani's Rebuttal Testimony on the budgeted data provides a new explanation of the budgeted data that differs from his direct testimony and the response to OCA-II-2. In addition to the inconsistencies, there is a lack of detail supporting the Company's plant in service claim. Mr. Stefani's explanation in his rebuttal testimony raises new questions that cannot be addressed at this late juncture. For instance, he states that the budget was updated in July 2020 with more recent data and he indicated that the budget was updated with the latest information with respect to customer load, capital expenses, operations and maintenance expenses, etc., and the budget update was finalized in August 2020.[20] If this information were provided in his direct testimony, there would have been adequate time to fully review the underlying data. Therefore, based on the unknown information, I recommend that the Commission reject the Company's FPFTY plant in service claim.

Q. WHY IS IT REASONABLE TO USE THE FTY PLANT IN SERVICE WHEN YOU HAVE DETERMINED THE FPFTY PLANT IN SERVICE IS NOT REASONABLE?

A. It is reasonable to allow for some growth in plant in service because it is not probable that plant in service will remain at the HTY level. It is also generally the case that the further out forecasts are made, the less accurate they are. Therefore, I have used the FTY as a reasonable proxy for the forecasted plant in service for the FPFTY.

Repairs Deduction

Q. WITH RESPECT TO YOUR ADJUSTMENT TO PLANT IN SERVICE, MR. TRZASKA STATES THAT YOU FAILED TO PROPOSE AN ADJUSTMENT TO THE REPAIRS DEDUCTION THAT WOULD BE ASSOCIATED WITH THE DISALLOWANCE OF INCREMENTAL FPFTY PLANT ADDITIONS. PLEASE RESPOND.

[20] PECO Statement 2-R at 2-3.

A. As explained in my direct testimony, my adjustment to plant in service reduced the plant in service balance to reflect the FTY level of plant. As part of that adjustment, I should have recalculated income taxes too by using the repairs deduction that corresponds to the FTY in the calculation of income taxes instead of leaving the effect of the FPFTY repairs deduction in the income tax expense. I did not. It was an oversight on my part.

Based on Mr. Trzaska's rebuttal testimony, I have corrected the income tax calculation to reflect the FTY repairs deduction. I have also reflected the FTY accelerated state and federal tax depreciation in my corrected income tax calculation. This recalculation is presented on Surrebuttal Schedule LKM-31.

Pension Asset

Q. PLEASE RESPOND TO MR. TRZASKA'S DISAGREEMENT WITH YOUR ADJUSTMENT TO REMOVE THE PENSION ASSET FROM RATE BASE.

A. In my direct testimony, I explained why it is appropriate to remove the Pension Asset from rate base.[21] In short, I explained that, under past Commission rulings, only capital investments are allowed to earn a return. I also explained that inclusion of the pension asset would overstate rate base.

Mr. Trzaska disagrees with my adjustment and cites several reasons why he believes my adjustment is inappropriate.[22] I will address each of those reasons below. One area where Mr. Trzaska and I agree, conceptually, is that the basis for pension expense for ratemaking purposes has been the contribution to the pension plan rather than the method used for financial reporting purposes pursuant to the Financial

[21] OCA Statement 1 at 15-19
[22] PECO Statement 3-R at 16-18.

Accounting Standards Board (FASB) Accounting Standards Codification 715-30 (ASC 715).[23]

Q. MR. TRZASKA CITES THE STIPULATION, IN DUQUESNE LIGHT COMPANY'S RATE CASE SETTLEMENTS, WHERE IT IS STATED THAT THE PENSION ASSET MAY BE INCLUDED IN RATE BASE AS SUPPORT FOR PECO'S PROPOSAL.[24] IS THAT A VALID RATIONALE?

A. No. A settlement is a product of negotiation and generally does not establish precedents. Therefore, the settlements reached in those dockets are inconsequential. Each case must be decided based upon the facts and circumstances as they apply to the company under review. The record in those cases is not part of this case, so the costs cannot be included in rate base on that basis, regardless of statements made by the OCA in each of those cases. The OCA's statements were based on the facts in the case.

Q. MR. TRZASKA STATES THAT YOU HAVE SAID THAT PECO IS ALREADY RECOVERING ALL OF THE CASH CONTRIBUTIONS TO ITS PENSION FUND THROUGH BASE RATES.[25] IS THAT TRUE?

A. No. Nowhere in my testimony do I state, "PECO is already recovering **all** of the cash contributions to its pension fund through base rates."[26]

Q. PLEASE IDENTIFY THE ACCOUNT IN WHICH THE PENSION ASSET IS RECORDED AND PROVIDE THE FEDERAL ENERGY REGULATORY COMMISSION (FERC) ACCOUNT INSTRUCTION FOR THAT ACCOUNT.

[23] PECO Statement 3-R at 10.
[24] PECO Statement 3-R at 12-16.
[25] PECO Statement 3-R at 15.
[26] PECO Statement 3-R at 15.

A. The Pension Asset is recorded in FERC Account 186 - Miscellaneous deferred debits. The account instructions read as follows:

> A. This account shall include all debits not elsewhere provided for, such as miscellaneous work in progress, construction certificate application fees paid prior to final disposition of the application as provided for in gas plant instruction 15A, and unusual or extraordinary expenses not included in other accounts which are in process of amortization, and items the final disposition of which is uncertain.
>
> B. The records supporting the entries to this account shall be so kept that the utility can furnish full information as to each deferred debit included herein.

Q. IS FERC ACCOUNT 186 A CAPITAL INVESTMENT ACCOUNT?

A. No, it is not a capital investment account. In fact, as a deferred debit it is treated as a current asset.[27]

Q. DOES THE COMMISSION INCLUDE CURRENT ASSETS IN RATE BASE?

A. Generally, no. The exception to the rule would be working capital accounts such as Materials and Supplies. FERC Account 186 - Miscellaneous deferred debits is not a working capital account.

Q. MR. TRZASKA STATES "ALTHOUGH THE NON-EXPENSE PORTION OF TOTAL PENSION COSTS IS CAPITALIZED PER BOOKS, THE COMPANY WILL NEVER BE COMPENSATED FOR THAT ACTUAL INVESTMENT OF SHAREHOLDER DOLLARS UNLESS THE PENSION ASSET IS INCLUDED IN RATE BASE".[28] IS THAT CORRECT?

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[27] Current assets represent all the assets of a company that are expected to be conveniently sold, consumed, used, or exhausted through standard business operations within one year. Current assets appear on a company's balance sheet, one of the required financial statements that must be completed each year.--https://www.investopedia.com/terms/c/currentassets.asp

[28] PECO Statement 3-R at 16.

A. No, the statement is not correct. The pension asset is not a capital investment account. It represents the difference between the financial basis of reporting and the cash contribution, as I have indicated in my direct testimony. The actual investment in rate base is the amount recognized for financial reporting, and that is the amount that is recorded in the plant balances included in rate base.

On Attachment OCA-II-22(a), the Company shows that the contribution amount exceeds the financial report amount in virtually every year. Since the Company has agreed that the contribution amount is the amount included in rates, it can be argued that the Company has collected more than the financial reporting amount.

Q. IS THE PENSION ASSET DEPRECIATED OR AMORTIZED AS PART OF THE COST OF PLANT IN SERVICE?

A. No. Since the pension asset is not a capital investment account, it does not get depreciated or amortized. In the response to OCA-II-26, the Company stated:

> The pension asset on PECO's balance sheet represents cumulative cash contributions made by PECO in excess of PECO's cumulative pension cost and does not get amortized to expense. The change in the pension asset represents annual contributions paid by PECO to the pension trust and annual pension cost accounted for in accordance with ASC 715.[29]

Based on the Company's own words, the Pension Asset account is not a capital investment account. The account only keeps track of the difference in the pension plan contributions and the pension costs reported for financial purposes.

Q. MR. TRZASKA STATES THAT "PENSION COSTS ARE AN EMPLOYEE COST – JUST LIKE EMPLOYEE SALARIES AND WAGES. A PORTION

[29] OCA Statement 1, App. B at 11.

OF EMPLOYEE SALARIES AND WAGES ARE CAPITALIZED (USING THE APPLICABLE CAPITALIZATION RATE) AND INCLUDED IN THE ORIGINAL COST OF UTILITY PLANT IN SERVICE ON WHICH THE COMPANY EARNS A RETURN. IF THE ERRONEOUS PRINCIPLE ESPOUSED BY MR. MORGAN WERE APPLIED UNIFORMLY, THEN THE PORTION OF SALARIES AND WAGES NOT CHARGED TO EXPENSE WOULD ALSO HAVE TO BE EXCLUDED FROM RATE BASE ON THE MISGUIDED ASSUMPTION THAT INCLUDING CAPITALIZED WAGES AND SALARIES IN RATE BASE WOULD ALLOW A UTILITY TO EARN A RETURN ON 'EXPENSES.'"[30] PLEASE RESPOND.

A. Mr. Trzaska is mischaracterizing the nature of my adjustment. I have not stated that pension costs should not be included in rate base. In fact, in OCA-II-28 and OCA-II-30, I had the Company confirm that there was a portion of pension costs that was capitalized. The cost that is inappropriate for inclusion in rate base is the pension asset which is not a capital investment amount. There is no portion of other employee benefits or salaries and wages that is similar to the pension asset. Therefore, Mr. Trzaska is misrepresenting my adjustment.

Q. MR. TRZASKA STATES "RATE BASE IS NOT OVERSTATED. BECAUSE PECO DOES NOT RECOVER A RETURN OF THE ASSET ABSENT AMORTIZATION, THE COMPANY ONLY RECOVERS A RETURN ON THE ACTUAL UNAMORTIZED BALANCE…"[31] PLEASE COMMENT.

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[30] PECO Statement 3-R at 16.
[31] PECO Statement 3-R at 17.

A. Mr. Trzaska is wrong. The inclusion of the pension asset in rate base would result in an overstatement of rate base because the inclusion is inappropriate. Inclusion in rate base would lead to a higher return than necessary and an over-recovery of the return.

Payroll Expense

Q. PLEASE RESPOND TO MR. STEFANI'S DISAGREEMENT WITH YOUR ADJUSTMENT TO PAYROLL EXPENSE.

A. In my direct testimony, I explained that I reduced the FPFTY number of employees because the Company has not adequately supported the increase in the number of positions for the FPFTY.[32] I also removed the Company's request to recover a one-time ratification bonus paid to union employees.[33]

In his rebuttal testimony, Mr. Stefani disagrees with my adjustment.[34] To support the costs claimed by the Company, he provided a list of positions that are to be filled.[35] He also stated that as of December 31, 2020, "the Company's employee count was 612 (inclusive of FTEs and allocated employees)", and that "[t]he Company had anticipated achieving a total headcount of 635 employees by December 2020, as stated in the Company's response to Interrogatory IE-RE-8."[36] He states that the Company was unable to meet its goal because of the impact of COVID-19.[37]

Mr. Stefani's comparison of the actual December 31st employee count of 612 to the projected forecasted headcount of 635 employees is misleading. The actual December 31st number of employees that Mr. Stefani uses includes allocated employees and he has compared that number to the projected December 31st number of employees which excludes allocated employees. As a result, the gap between the

[32] OCA Statement 1 at 23-24.
[33] OCA Statement 1 at 24-25.
[34] PECO Statement 2-R at 11.
[35] *Id.*
[36] *Id.*
[37] *Id.* at 11-12.

actual and the projected number of employees appears to be smaller, as if the Company were closer to meeting its hiring goal. Therefore, the Commission should disregard this comparison.

It is worth noting that, as the Company admits here, the COVID-19 pandemic clearly has an impact on the Company's operations, but for capital expenditures, the Company would prefer to ignore the impact of the COVID-19 pandemic.

It is also important to note that in the Company's rebuttal, it does not dispute my claim that in the response to OCA-IX-10 and OCA-IX-11 it did not provide any support for new positions to be filled during the FTY and the FPFTY. As I explained in my direct testimony, the Company claimed 37 additional employees would be hired during the FTY and FPFTY[38], but when asked to provide supporting documentation to substantiate the projected increase in employees, it provided information for employees hired during the HTY.[39] Even when asked to provide the job descriptions for the additional FPFTY employees, the Company provided job descriptions for HTY employees. In fact, in OCA-IX-11, I specifically requested the management approval documentation. The Company responded stating:

> Management approval for positions is documented electronically. The standard approval process requires the hiring manager, hiring manager's reporting manager and HR Recruitment sign-off prior to posting.

When I have asked a similar request of other companies in other proceedings, I was provided with printouts to support their claim. Hence, it was apparent to me that the Company does not have the detailed information to substantiate its claim. This is another example of a pattern of the Company being unable to support its claim which

[38] Company Exhibit MJT-1, Schedule D-6, Page 65.
[39] Company Response to OCA-IX-10; see also OCA Statement 1, App. B at 20.

led me to conclude that the FPFTY projections are not reasonable. Therefore, I urge the Commission to reject the Company's salaries and wages claim.

Q. PLEASE RESPOND TO MR. TRZASKA'S REBUTTAL TESTIMONY ADDRESSING YOUR ADJUSTMENT TO REMOVE THE ONE-TIME PAYMENT FOR RATIFICATION OF THE UNION CONTRACT.

A. In my direct testimony, I explained that the one-time bonus should be removed because it is a prior period cost, and recovery would constitute retroactive ratemaking and violate normal ratemaking principles.[40] There were no future obligations, services or tasks that were expected from the employees. Employees were free to voluntarily leave the company or retire. Any employee who left after the payment of the one-time bonus was not required to repay the $1,000.

Mr. Trzaska argues that the "Company has consistently paid a ratification bonus to union employees each time it negotiates new union contracts and there is no reason to believe that PECO will depart from that practice in the FTY and FPFTY."[41] He claims that it has been a Commission practice to spread such expenses over the average length of the Company's collective bargaining agreements.[42]

Mr. Trzaska's recommendation should be rejected because it is not consistent with Commission practice, as it constitutes retroactive ratemaking. The ratification payment was a past expense payment for past action of employees. The Company does not dispute this fact. In OCA-II-42, the Company stated "[t]here were no specific future tasks, service or obligations that were expected from those who received the one-time payment." The future collection of a prior period cost is the definition of retroactive ratemaking. Mr. Trzaska's argument that there is no reason to

[40] OCA Statement 1 at 24-25.
[41] PECO Statement 3-R at 21.
[42] *Id.*

expect PECO to depart from making future ratification bonuses should also be rejected because the amounts are not known or certain at this time.

OPEB Expense

Q. MR. STEFANI DISAGREES WITH YOUR ADJUSTMENT TO OPEB EXPENSE. PLEASE RESPOND TO HIS REBUTTAL TESTIMONY ON OPEB EXPENSE.

A. In my direct testimony, I recommended an adjustment to the Company's proposed OPEB expense to reflect the Company's most-recent three-year average expense because I could not locate the source of the Company's claim from the document to which I was referred. Mr. Stefani has now provided a different document (PECO Exhibit RJS-4-R CONFIDENTIAL) that provides the OPEB costs. Based on the data presented in that document, I have recalculated my adjustment to OPEB expense based upon the 3-year average (2020 to 2022) of OPEB costs. This adjustment is presented on Surrebuttal Schedule LKM-13.

Cost to Achieve

Q. PLEASE RESPOND TO MR. STEFANI'S REBUTTAL TO YOUR ADJUSTMENT TO REMOVE THE COST TO ACHIEVE.

A. In my direct testimony, I recommended an adjustment to remove PECO's claim for a 3-year recovery of the costs to achieve merger savings.[43] I recommended that these costs should not be included in rates because the Commission did not authorize deferral of these costs for future recovery. As a result, they are not eligible for recovery. Instead, they are prior period costs and inclusion in rates would be retroactive ratemaking.

[43] OCA Statement 1 at 33-36.

According to Mr. Stefani, my position is fundamentally unfair.[44] He argues that the merger-related costs will produce significant merger-related savings long after the occurrence of the Exelon/Pepco merger, and that the merger-related savings flow to customers by reducing the costs.[45] However, Mr. Stefani fails to recognize that, until rates from this proceeding go into effect, all of the savings related to the merger have been held by the Company. The rates were not reduced to reflect the savings. As a result, the savings were held by the Company and not passed on to customers through lower rates. So, essentially, the costs to achieve were offset by the savings. Given that customers' rates were not reduced to reflect the savings, it would be improper to retroactively pass the cost to achieve to customers. Therefore, the Commission should reject the Company's claim for the cost to achieve.

EBSC Charges

Q. PLEASE RESPOND TO MR. STEFANI'S DISAGREEMENT WITH YOUR ADJUSTMENT TO EBSC CHARGES.

A. In my direct testimony, I recommended an adjustment to EBSC charges because I disagree with the use of inflation escalations as the basis of the increase in costs.[46] The Company claims that its annual budgeting and planning process is designed "to integrate and align PECO's operational, regulatory, and financial plans."[47] However, inflation adjustments are typically blanket adjustments or increases which do not directly relate to actual costs expected to be incurred by the Company in the period in which rates are to be set.

[44] PECO Statement 2-R at 14.
[45] *Id.*
[46] OCA Statement 1 at 36-37.
[47] PECO Statement 2 at 10.

According to Mr. Stefani, the FPFTY expenses are appropriate because Counsel has advised him that the Commission has repeatedly accepted the use of inflation factors as a reasonable method to derive the pro forma levels of operating expense items that were not otherwise separately adjusted.[48]

The charges from EBSC (as shown on Surrebuttal Schedule LKM-20) are composed of a variety of corporate support services. The costs relate to services such as Communication, Executives, Utilities, Finance, Government Affairs, Human Resource, Legal Governance, Security, Supply, etc. Each of these functional areas are managed by Exelon employees and are subject to similar guidelines for budget preparation as PECO. Therefore, it is possible for proper budget projections to have been made instead of applying an inflation escalation to these non-homogeneous categories. Inflation escalation should not be used just because one can show that they have been accepted by the Commission in the past. In fact, the use of inflation escalation for the EBSC costs is another indication that the Company has chosen to use an abbreviated budget approach. In an instance where it is possible to obtain proper budget forecast, the Company has chosen to shortcut the process and use inflation escalation. This shortcut approach does not produce more accurate projections.

In Docket No. R-2019-3008208, the Commission stated that Wellsboro Electric Company did not demonstrate that making a blanket inflation adjustment directly relates to the actual costs expected to be incurred in each expense account in the FPFTY.[49] Similarly, I believe that PECO has not met its burden in demonstrating that its proposed blanket inflation escalation to a diverse group of expenses would

[48] PECO Statement 2-R at 17.
[49] Docket No. R-2019-3008208, Order and Opinion at 40.

meet the "known and measurable" standard for increasing each expense claim in the FPFTY.

Therefore, the Commission should reject the Company's projections for EBSC costs because the resulting amounts do not meet the known and certain standard in this instance. Properly budgeted data would have been based on integrating and aligning PECO's operational, regulatory, and financial plans, and would have been more accurate.

Employee Activity Expenses

Q. PLEASE RESPOND TO MR. STEFANI'S DISAGREEMENT WITH YOUR ADJUSTMENT TO EMPLOYEE ACTIVITY EXPENSES.

A. In my direct testimony, I adjusted the employee activity expense to reflect the HTY level of expense because of the uncertainty of the COVID-19 pandemic.[50]

Mr. Stefani disagrees with my adjustment.[51] To support the Company's claim, he argues that Pennsylvania's ratemaking has employed projections of future operating conditions for nearly 45 years, and that the Commonwealth's response to the emergency, including stay-at-home orders in effect during the second quarter of 2020, are unlikely to recur in 2021 and 2022.[52] However, he fails to acknowledge that a significant portion of employee activity costs are related to gatherings of employees. Despite the relaxing of stay-at-home requirements, large gatherings of people are still being curtailed. The indications from public health officials, even in January 2021, was that the pandemic and associated health precautions will be with us for an extended period of time. Moreover, given that these expenses are largely

[50] OCA Statement 1 at 40.
[51] PECO Statement 2-R at 22.
[52] *Id.*

discretionary, it is not likely to return to pre-pandemic levels in the near future. Therefore, the Commission should deny the Company's claim.

Employee Travel Expenses

Q. DO YOU AGREE WITH MR. STEFANI'S REBUTTAL TESTIMONY REGARDING EMPLOYEE TRAVEL?

A. No. Employee Travel Expense has been impacted in a manner similar to Employee Activity Expense.

Mr. Stefani argues that the availability of a COVID-19 vaccine and other measures will mitigate the impact of COVID-19 but makes no specific claim as to how those things will impact corporate travel, meals and entertainment.[53] As it stands, it is nearly impossible to forecast such costs. During the pandemic, organizations have adjusted to virtual meetings, remote working and reduced public gatherings. It is safe to say that for the near future, employee travel activity will be reduced. Therefore, the Commission should reject Mr. Stefani's position.

Injuries and Damages Expense

Q. WHAT IS YOUR RESPONSE TO MR. STEFANI'S REBUTTAL TESTIMONY RELATING TO YOUR INJURIES AND DAMAGES EXPENSE ADJUSTMENT?

A. In my direct testimony, I explained that the FPFTY budget amount for Injuries and Damages is significantly higher than previous years, and that the nature of Injuries and Damages is that no single year is representative of the normal level of expense since the expense fluctuates from year to year.[54] Therefore, I proposed to normalize the Injuries and Damages expenses over a period of 3 years to avoid an over-recovery of costs.

[53] PECO Statement 2-R at 23.
[54] OCA Statement 1 at pages 30.

Mr. Stefani's rebuttal testimony makes claims about my testimony, on Injuries and Damages expense, that I did not make. He stated that I indicated that the Company has not adequately explained the budgeted increase in injuries and damages expense for the FPFTY.[55] I did not make such a statement in my testimony.

I continue to believe my adjustment to Injuries and Damages is appropriate. The Company has not provided any evidence to show that its claim for the FPFTY injuries and damages approximates a normalized level. Therefore, the Commission should reject the Company's claim.

Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

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[55] PECO Statement 2-R at 24.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	**Docket No. R-2020-3018929**
v.	)	
	)	
PECO Energy Company - Gas Division	)	

SCHEDULES ACCOMPANYING THE
SURREBUTTAL TESTIMONY

OF

LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

February 9, 2021

PECO Energy Company - Gas Division

Summary of Operating Income
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Company Amounts at Present Rates	OCA Adjustments	Amounts After OCA Adjustments	Pro Forma Change in Revenues	Amounts After Change in Revenues
	Operating Revenues					
1	Base Customer Charges	$ 361,576	$ -	$ 361,576	$ -	$ 361,576
2	Supply Cost Revenue	226,900	-	226,900	-	226,900
3	Other Operating Revenue	1,538	-	1,538	-	1,538
4	Revenue Increase	-	-	-	(11,475)	(11,475)
5	Total Operating Revenues	$ 590,014	$ -	$ 590,014	$ (11,475)	$ 578,539
6						
7	Operating Revenue Deductions					
8	O&M Expenses	$ 370,135	$ (9,322)	$ 360,813	(40)	360,773
9	Depreciation & Amortization	86,146	(7,827)	78,319	-	78,319
10	Amortization of Regulatory Expense	2,812	-	2,812	-	2,812
11	Taxes Other Than Income Taxes	7,545	(299)	7,246	(35)	7,211
12	Total Operating Revenue Deductions	466,638	(17,448)	449,190	(75)	449,115
13						
14	Operating Income Before Income Taxes	123,376	17,448	140,824	(11,400)	129,424
15						
16	Income Taxes @ Effective Tax Rates	(18,019)	14,844	(3,175)	(3,294)	(6,468)
17	Income Taxes @ Statutory Tax Rates	-	-	-	-	-
18						
19	Net Operating Income	$ 141,395	$ 2,604	$ 143,999	$ (8,106)	$ 135,893
20						
21	Rate Base	$ 2,463,555		$ 2,157,035		$ 2,157,035
22						
23	Return On Rate Base	5.74%		6.68%		6.30%

PECO Energy Company - Gas Division

Summary of Revenue Increase at OCA Rate of Return
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description			Amount	Source
1	Adjusted Rate Base		$	2,157,035	Schedule LKM-2, Page 2
2	Required Rate of Return			6.300%	Per OCA Witness O'Donnell
3					
4	Net Operating Income Required		$	135,893	
5	Net Operating Income at Present Rates			143,999	Schedule LKM-1, Page 1
6					
7	Income Deficiency/(Surplus)		$	(8,106)	
8	Revenue Multiplier			1.415588	
9					
10	Required Change in Company Revenue		$	(11,475)	
11					
12	Proposed Revenue Change		$	(11,475)	
13	Less: Uncollectibles	0.3472%		(40)	
14	Revenues After Uncollectibles			(11,435)	
15	Less: PUC Assessments	0.3080%		(35)	
16					
17	Income Before State Taxes		$	(11,400)	
18	State Income Tax Effect Tax Rate	9.9900%			
19	Less: State Income Tax			(1,139)	
20					
21	Income Before Federal Taxes		$	(10,261)	
22	Federal Income Tax	21.0000%		(2,155)	
23					
24	Net Income Surplus/(Deficiency)		$	(8,106)	

PECO Energy Company - Gas Division

Summary of Rate Base
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount per Company Filing	OCA Rate Base Adjustments	Amount After OCA Adjustments
1	Utility Plant	$ 3,537,669	$ (305,555)	$ 3,232,114
2	Accumulated Depreciation	(892,383)	41,453	(850,930)
3	Common Plant	136,770	(8,323)	128,447
4	Net Plant in Service	$ 2,782,056	$ (272,424)	$ 2,509,632
5				
6	Working Capital	$ 3,437	$ (491)	$ 2,946
7	Pension Asset/(Liabilities)	35,059	(35,059)	-
8	Accumulated Deferred Income Taxes	(247,620)	3,570	(244,050)
9	Customer Deposits	(13,400)	(0)	(13,400)
10	Customer Advances for Construction	(1,255)	(0)	(1,255)
11	Materials & Supplies	444	-	444
12	ADIT - Reg Liability	(126,322)	(2,115)	(128,437)
13	Gas Storage	31,156	-	31,156
14				
15	Total Rate Base	$ 2,463,555	$ (306,520)	$ 2,157,035

PECO Energy Company - Gas Division

Summary of Rate Base Adjustments
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Source		Amount
1	Rate Base per Company Filing	Schedule LKM-2, Page 1	$	2,463,555
2				
3	OCA Adjustments:			
4				
5	Adjustment to Plant in Service	Schedule LKM- 4		(270,970)
6	Remove Pension Asset from Rate Base	Schedule LKM- 5	$	(35,059)
7	Cash Working Capital	Schedule LKM- 6		(491)
8	Average Gas Inventory Balance	Schedule LKM- 7		-
9	Average Customer Deposits	Schedule LKM- 8		(0)
10	Average Materials & Supplies	Schedule LKM- 9		-
11	Average Customer Advances	Schedule LKM- 10		(0)
12	Total Ratemaking Adjustments		$	(306,520)
13				
14	Adjusted Rate Base per OCA		$	2,157,035

PECO Energy Company - Gas Division

Summary of Adjustments to Income Before Income Taxes
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.		Amount	Source
1	Operating Income per Company	$ 141,395	Schedule LKM-
2			
3	OCA Adjustments:		
4	Annualize FPFTY Payroll	$ 2,447	Schedule LKM- 11
5	Revise Benefits Expense	315	Schedule LKM- 12
6	Annualize Postretirement Benefits Expense	486	Schedule LKM- 13
7	Annualize Pension Expense	-	Schedule LKM- 14
8	Remove Advance Recovery of MGP Remediation	287	Schedule LKM- 15
9	Normalize Injuries and Damages Expense	464	Schedule LKM- 16
10	Normalize Rate Case Expenses	208	Schedule LKM- 17
11	Normalize Regulatory Initiative Costs	40	Schedule LKM- 18
12	Remove Recovery of Cost to Achieve	370	Schedule LKM- 19
13	Normalize EBSC Charges	997	Schedule LKM- 20
14	Adjustment to Normalize R&D Expense	138	Schedule LKM- 21
15	Reflect Annual Regulatory Commission Expense	462	Schedule LKM- 22
16	Normalize Contracting Expenses	367	Schedule LKM- 23
17	Annualize Employee Activity Expenses	71	Schedule LKM- 24
18	Annualize Travel Meals & Entertainment Expense	178	Schedule LKM- 25
19	Remove Increase in Energy Efficiency Costs	2,492	Schedule LKM- 26
20	Annualize Depreciation Expense	7,827	Schedule LKM- 27
21	Remove Inflation Escalation From Property Taxes	112	Schedule LKM- 28
22	Remove Inflation Escalation From Payroll Taxes	187	Schedule LKM- 29
23	Interest Synchronization	-	Schedule LKM- 30
24			
25	Total OCA Adjustments	17,448	
26			
27	Total OCA Adjustments	$ 158,843	

PECO Energy Company - Gas Division

Summary of Adjustments to Income Before Income Taxes
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.		Operating Revenues	O&M Expenses	Depreciation & Amortization	Regulatory Expense Amortization	Taxes Other Than Income	Operating Income Before Income Taxes
1	Amount per Company	$ 590,014	$ 370,135	$ 86,146	$ 2,812	$ 7,545	$ 123,376
2							
3	OCA Adjustments:						
4	Annualize FPFTY Payroll	$ -	$ (2,447)	$ -	$ -	$ -	$ 2,447
5	Revise Benefits Expense	-	(315)	-	-	-	315
6	Annualize Postretirement Benefits Expense	-	(486)	-	-	-	486
7	Annualize Pension Expense	-	-	-	-	-	-
8	Remove Advance Recovery of MGP Remediation	-	(287)	-	-	-	287
9	Normalize Injuries and Damages Expense	-	(464)	-	-	-	464
10	Normalize Rate Case Expenses	-	(208)	-	-	-	208
11	Normalize Regulatory Initiative Costs	-	(40)	-	-	-	40
12	Remove Recovery of Cost to Achieve	-	(370)	-	-	-	370
13	Normalize EBSC Charges	-	(997)	-	-	-	997
14	Adjustment to Normalize R&D Expense	-	(138)	-	-	-	138
15	Reflect Annual Regulatory Commission Expense	-	(462)	-	-	-	462
16	Normalize Contracting Expenses	-	(367)	-	-	-	367
17	Annualize Employee Activity Expenses	-	(71)	-	-	-	71
18	Annualize Travel Meals & Entertainment Expense	-	(178)	-	-	-	178
19	Remove Increase in Energy Efficiency Costs	-	(2,492)	-	-	-	2,492
20	Annualize Depreciation Expense	-	-	(7,827)	-	-	7,827
21	Remove Inflation Escalation From Property Taxes	-	-	-	-	(112)	112
22	Remove Inflation Escalation From Payroll Taxes	-	-	-	-	(187)	187
23	Interest Synchronization	-	-	-	-	-	-
24							
25	Total OCA Adjustments	$ -	$ (9,322)	$ (7,827)	$ -	$ (299)	$ 17,448
26							
27	Total Adjusted Income Before Income Taxes	$ 590,014	$ 360,813	$ 78,319	$ 2,812	$ 7,246	$ 140,824

PECO Energy Company - Gas Division

Adjustment to Plant in Service
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description		FPFTY Amount	FTY Amount	Adjustment
	Intangible Plant				
1	G302 - Franchises & Consents		$ 50	$ 50	$ -
2	G303 - Intangible Property		18,179	18,487	307
3		Subtotal	18,229	18,537	307
4	**Manufactured Gas Production Plant**				
5	G305 - Structures and Improvements		1,206	1,215	10
6	G311 - Liquefied Petroleum Gas Equip.		14,334	14,334	-
7		Subtotal	15,539	15,549	10
8	**Other Storage Plant**				
9	G360 - Land and Land Rights		16	16	-
10	G361 - Structures & Improvements		14,919	14,883	(36)
11	G362 - Gas Holders		7,084	7,084	-
12	G363 - Gas Storage Equipment		50,409	44,519	(5,890)
13		Subtotal	72,428	66,502	(5,926)
14	**Distribution Plant**				
15	G374 - Land and Land Rights		3,637	3,716	79
16	G375 - Structures and Improvements		15,745	15,006	(739)
17	G376 - Gas Mains		1,771,990	1,614,315	(157,675)
18	G378 - Measure & Regulate Sta Equip		24,652	22,324	(2,328)
19	G379 - City Gate Station		77,160	67,136	(10,024)
20	G380 - Services		1,111,048	1,008,483	(102,565)
21	G381 - Meters		164,090	158,421	(5,668)
22	G382 - Meter Installations		221,083	204,996	(16,087)
23	G387 - Other Equipment		2,118	2,118	-
24	G388 - ARO Costs Distribution Plt		1,454	1,456	2
25		Subtotal	3,392,977	3,097,970	(295,007)
26	**General Plant**				
27	G390 - Structures & Improvements		10,387	9,321	(1,065)
28	G391 - Office Furniture & Equipment		6,858	5,097	(1,761)
29	G394 - Tools, Shop & Garage Equip		16,155	14,156	(1,999)
30	G397 - Communication Equipment		4,872	4,740	(133)
31	G398 - Miscellaneous Equipment		107	119	12
32	G399.1 - ARO Costs General Plt		116	123	7
33		Subtotal	38,495	33,556	(4,939)
34					
35	**Total**		$ 3,537,669	$ 3,232,114	$ (305,555)

PECO Energy Company - Gas Division

Adjustment to Accumulated Depreciation
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	FPFTY Amount	FTY Amount	Adjustment
	Intangible Plant			
1	G302 - Franchises & Consents	$ -	$ -	$ -
2	G303 - Intangible Property	16,737	15,334	(1,403)
3	Subtotal	16,737	15,334	(1,403)
4	**Manufactured Gas Production Plant**			
5	G305 - Structures and Improvements	798	786	(12)
6	G311 - Liquefied Petroleum Gas Equip.	12,423	12,329	(94)
7	Subtotal	13,221	13,115	(106)
8	**Other Storage Plant**			
9	G360 - Land and Land Rights	-	-	-
10	G361 - Structures & Improvements	7,292	6,957	(336)
11	G362 - Gas Holders	6,900	6,881	(18)
12	G363 - Gas Storage Equipment	17,080	17,117	37
13	Subtotal	31,273	30,955	(317)
14	**Distribution Plant**			
15	G374 - Land and Land Rights	(158)	(79)	79
16	G375 - Structures and Improvements	6,022	5,715	(307)
17	G376 - Gas Mains	365,491	348,477	(17,014)
18	G378 - Measure & Regulate Sta Equip	8,285	7,964	(321)
19	G379 - City Gate Station	24,867	23,497	(1,370)
20	G380 - Services	262,159	251,526	(10,632)
21	G381 - Meters	71,646	66,641	(5,005)
22	G382 - Meter Installations	75,793	72,340	(3,453)
23	G387 - Other Equipment	1,428	1,295	(133)
24	G388 - ARO Costs Distribution Plt	555	478	(77)
25	Subtotal	816,087	777,853	(38,234)
26	**General Plant**			
27	G390 - Structures & Improvements	3,347	3,134	(213)
28	G391 - Office Furniture & Equipment	2,781	2,247	(534)
29	G394 - Tools, Shop & Garage Equip	5,373	4,877	(497)
30	G395 - Laboratory Equipment	-	-	-
31	G397 - Communication Equipment	4,583	4,428	(155)
32	G398 - Miscellaneous Equipment	29	33	4
33	G399.1 - ARO Costs General Plt	18	21	(1,394)
34	Subtotal			
35	**Total**	$ 893,447	$ 851,997	$ (41,453)

PECO Energy Company - Gas Division

Adjustment to Common Plant
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	FPFTY Total	FTY Total	Adjustment
1	**Common Plant in Service:**			
2	Land	$ 7,057	$ 6,920	$ (137)
3	Organization	677	677	-
4	Software	365,156	338,268	(26,888)
5	General Plant	734,696	671,511	(63,185)
6	Other	-	-	-
7				
8	Subtotal	$ 1,107,586	$ 1,017,376	$ (90,210)
9				
10	**Common Plant Accumulated Depreciation:**			
11	Land	$ -	$ -	$ -
12	Organization	-	-	-
13	Software	280,592	251,288	(29,304)
14	General Plant	233,117	208,349	(24,767)
15	Other	-	-	-
16	Subtotal	$ 513,709	$ 459,637	$ (54,072)
17				
18	Net Common Plant	$ 593,877	$ 557,739	$ (36,138)
19				
20	Allocation Factor	23.030%	23.030%	23.030%
21				
22	Common Plant in Service to Utility	$ 255,077	$ 234,302	$ (20,775)
23	Common Plant Accumulated Depreciation to Utility	118,307	105,854	(12,453)
24	Net Common Plant to Utility	$ 136,770	$ 128,447	$ (8,323)

PECO Energy Company - Gas Division

Adjustment to ADIT
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Utility Amount	Percent to Distribution	Distribution Amount
	HTY			
1	ADIT - CIAC	$ (10,667)	100.00%	$ (10,667)
2	ADIT - Common Plant	6,582	100.00%	6,582
3	ADIT - Gas Distribution	242,089	100.00%	242,089
4	Sub-Total	238,004		238,004
5	**FTY**			
6	DIT - CIAC	(1,771)	100.00%	(1,771)
7	DIT - Common Plant	-	100.00%	-
8	DIT - Gas Distribution	7,816	100.00%	7,816
9	Sub-Total	6,046		6,046
10	FTY ADIT	244,050		244,050
11	**FPFTY**			
12	DIT - CIAC	(1,994)	100.00%	(1,994)
13	DIT - Common Plant	-	100.00%	-
14	DIT - Gas Distribution	5,564	100.00%	5,564
15	Sub-Total	3,570		3,570
16				
17	Total	$ 247,620		$ 247,620
18				
19	FPFTY to FTY Adjustment			

PECO Energy Company - Gas Division

Adjustment to Regulatory Liability ADIT
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Utility Amount	Percent to Distribution	Distribution Amount
	HTY			
1	ADIT - Distribution	$ 136,680	100.00%	$ 136,680
2	ADIT - CIAC	(3,547)	100.00%	(3,547)
3	Subtotal HTY	133,133		133,133
4	**FTY**			
5	DIT - Distribution	(5,780)	100.00%	(5,780)
6	DIT - CIAC	1,085	100.00%	1,085
7	Subtotal FTY	(4,695)		(4,695)
8				128,438
9	**FPFTY**			
10	DIT - Distribution	(3,100)	100.00%	(3,100)
11	DIT - CIAC	985	100.00%	985
12	Subtotal FPFTY	(2,115)		(2,115)
13				
14	**Total**	$ 126,322		$ 126,322
15				
16	FPFTY to FTY Adjustment			$2,115

PECO Energy Company - Gas Division

Adjustment to Remove Pension Asset from Rate Base
For the Rate Year Ending September 30, 2021
($ in Thousands)

Line No.	Description	Amount
1	Gas Distribution Pension Asset	$ 35,059
2		
3	Adjustment to Rate Base	$ (35,059)

[1/] Exhibit MJT-1, Schedule C-5, Page 32.

PECO Energy Company - Gas Division

Adjustment to Cash Working Capital
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	FPFTY Expenses	OCA Adjustments	FPFTY Expenses After OCA Adjustments	(Lead)/Lag Days	Dollar-Days	
1	**Working Capital Requirement**						
3	Revenue Lag Days				43.17		
4							
5	Expense Lag						
6	Payroll (Dist Only)	$ 42,209	$ (2,447)	$ 39,762	13.67	$ 543,551	
7	Pension Expense	2,513	-	2,513	14.00	35,182	
8	Commodity Purchased - Gas	226,710	-	226,710	36.51	8,277,182	
9	Payment to Suppliers	63,454	-	63,454	56.21	3,566,749	
10	Other Expenses	96,118	(6,876)	89,242	37.54	3,350,138	
11	Total O&M and POR Payments	431,004	(9,322)	421,681		15,772,803	
12							
13	O&M Expense / POR Payment Lag Days				37.40		
14							
15	Net (Lead)/Lag Days				5.77		
17	Days in Current Year				365		
18							
19	Operating Expenses Per Day			1,155.29			
20							
21	Working Capital for O&M Expense			6,660.75			7.352941
22							
23	Average Prepayments			2,091			
24	Accrued Taxes			189			
25	Interest Payments			(5,995)			
26							
27	Total Working Capital Requirement Per OCA			2,946			
	Total Working Capital Requirement Per PECO			3,437			
	Adjustment			$ (491)			
28							
29	Pro Forma O&M Expense	370,135.00					
30	Uncollectible Expense	2,585.42					
31	Pro Forma Cash O&M Expense	367,549.58					

PECO Energy Company - Gas Division

Calculation of Prepaid Expenses
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	AGA Membership Dues	EAP Membership Dues	NGA Membership Dues	PUC Assessment Gas	Maintenance	IT License & Maintenance	Prepaid Rent	VEBA Adjust	Facilities Contracts	IT License & Maintenance	Fleet Activities	IT License & Maintenance	Customer Experience	Postage
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	September	$ 98	$ -	$ -	$ 1,301	$ 15	$ 500	$ 86	$ -	$ 23	$ 488	$ 237	$ 836	$ 100	$ 719
2	October	98	(20)	(9)	1,156	15	437	70	-	(4)	792	298	594	56	537
3	November	33	10	5	1,012	15	364	90	-	(31)	680	323	759	46	659
4	December	1	(1)	-	867	15	297	74	135	-	339	337	516	17	595
5	January	371	114	-	723	15	201	58	135	175	441	339	586	258	743
6	February	337	104	-	578	15	134	77	135	159	397	339	382	226	588
7	March	303	93	41	434	10	67	54	120	143	376	359	185	218	698
8	April	270	83	37	289	10	22	38	120	127	444	364	645	209	618
9	May	236	73	32	144	10	729	57	120	111	355	354	467	168	808
10	June	202	62	28	0	10	662	41	1,174	95	306	356	620	148	720
11	July	168	52	23	930	10	595	25	1,174	79	265	360	772	174	886
12	August	135	41	18	764	10	527	12	1,174	64	172	302	597	130	628
13	September	101	31	14	1,517	10	460	31	2,152	48	96	328	432	88	813
14															
15	Total SUM L1 to L13	$ 2,353	$ 642	$ 189	$ 9,715	$ 160	$ 4,995	$ 713	$ 6,439	$ 989	$ 5,151	$ 4,296	$ 7,391	$ 1,838	$ 9,012
16															
17	Distribution Percentage	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	23.03%	23.03%	23.03%	23.03%	24.84%	24.84%	24.84%
18															
19	Distribution Amount L15 * L17	$ 2,353	$ 642	$ 189	$ 9,715	$ 160	$ 4,995	$ 713	$ 1,483	$ 228	$ 1,186	$ 989	$ 1,836	$ 456	$ 2,238
20															
21	Number of Months	13	13	13	13	13	13	13	13	13	13	13	13	13	13
22															
23	Monthly Average L19 / L21	$ 181	$ 49	$ 15	$ 747	$ 12	$ 384	$ 55	$ 114	$ 18	$ 91	$ 76	$ 141	$ 35	$ 172
24															
25														Total Prepayment per OCA	$2,091

Source:
Exhibit MJT-1, Schedule C-5, Page 32.

PECO Energy Company - Gas Division

Adjustment to Average Gas Inventory Balance
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	13-Month Average Gas Stored Underground per OCA	$ 31,156 [1/]
2		
3	13-Month Average Gas Stored Underground per PECO	31,156 [2/]
4		
5	Adjustment to Rate Base	$ -
6		

Notes:
1/ Schedule LKM 7, Page 2.
2/

PECO Energy Company - Gas Division

Calculation of 13-Month Average Gas Inventory Balances
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount [1/]
1	September, 2019	$ 40,231
2	October	44,365
3	November	43,166
4	December	36,910
5	January, 2020	29,780
6	February	23,132
7	March	20,887
8	April	20,142
9	May	23,136
10	June	26,087
11	July	29,262
12	August	32,372
13	September	35,558
14		
15	13-Month Average Gas Stored Underground	$ 31,156

Notes:
1/ Response to IE-RB-7-D(a)

PECO Energy Company - Gas Division

Adjustment to 13-Month Average Customer Deposits
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount	
1	13-Month Average Customer Deposits per OCA	$ 13,401	1/
2			
3	13-Month Average Customer Deposits per PECO	13,401	2/
4			
5	Adjustment to Rate Base	$ (0)	

Notes:
1/ Schedule LKM 8, Page 2.

PECO Energy Company - Gas Division

Calculation of 13-Month Average Customer Deposits Balances
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description		Amount [1/]
1	September, 2019	$	12,994
2	October		13,033
3	November		13,029
4	December		13,058
5	January, 2020		14,034
6	February		14,014
7	March		14,066
8	April		13,916
9	May		13,711
10	June		13,488
11	July		13,226
12	August		12,971
13	September		12,667
14			
15	13-Month Average Customer Deposits	$	13,401

Notes:
1/ Attachment I&E-RB-3-D.

PECO Energy Company - Gas Division

Adjustment to 13-Month Average Materials & Supplies
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount	
1	13-Month Average Materials & Supplies per OCA	$ 444	1/
2			
3	13-Month Average Materials & Supplies per PECO	444	2/
4			
5	Adjustment to Materials & Supplies to Reflect Updated 13-Month Average	$ -	

Notes:
1/ Schedule LKM 9, Page 2.

PECO Energy Company - Gas Division

Calculation of 13-Month Average Materials & Supplies Balances
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Materials& Supplies 1/	Undistributed Stores Expense	Total
1	September, 2019	$ 602	$ -	$ 602
2	October	595	(670)	(75)
3	November	590	(664)	(74)
4	December	592	-	592
5	January, 2020	443	107	550
6	February	434	151	585
7	March	453	-	453
8	April	461	(6)	455
9	May	434	(32)	402
10	June	436	(242)	194
11	July	464	(209)	255
12	August	450	(486)	(36)
13	September	398	(478)	(80)
14				
15	13-Month Average Materials & Supplies	$ 489	$ (195)	$ 294

Notes:

1/ Attachment I&E-RB-6-D.

PECO Energy Company - Gas Division

Adjustment to 13-Month Average Customer Advances
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount	
1	13-Month Average Customer Advances per OCA	$ 1,255	1/
2			
3	13-Month Average Customer Advances per PECO	1,255	2/
4			
5	Adjustment to Rate Base	$ (0)	

Notes:
1/ Schedule LKM 10, Page 2.
2/ Exhibit MJT-1, Schedule C-9, Page 36.

PECO Energy Company - Gas Division

Calculation of 13-Month Average Customer Advances
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount [1/]
1	September, 2019	$ 1,429
2	October	1,901
3	November	1,879
4	December	1,082
5	January, 2020	1,319
6	February	1,355
7	March	1,198
8	April	1,228
9	May	1,032
10	June	1,004
11	July	983
12	August	1,000
13	September	899
14		
15	13-Month Average Customer Advances	$ 1,255

Notes:
1/ Attachment I&E-RB-53-D.

PECO Energy Company - Gas Division

Adjustment to Annualize FPFTY Payroll
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Union		Non-Union		Total	
1	Total Payroll					$ 283,336	1/
2	O&M Ratio					61.7%	2/
3							
4	O&M Payroll					$ 174,818	
5	Gas Allocator					20.22%	1/
6							
7	Base Labor					$ 35,348	
8	Overtime Labor					5,548	6/
9							
10	FPFTY Annualized Salaries and Wages Before Adjustment					$ 40,896	
11	FPFTY Average Number of Employees					638	3/
12							
13	Average Salary & Wages per Employee					$ 64	
14	Number of Employees at September 2020					604	4/
15							
16	FPFTY Annualized Salaries & Wages based on Actual Number of Customers	$ 20,144		$ 18,512		$ 38,656	
17	Number of Months TY	6	5/	8	5/		
18	Rate for Increase TY	2.50%	5/	2.50%	5/		
19	Total Wage Increase TY	$ 252		$ 309		560	
20	Other Payroll Premium					546	6/
21	Total Payroll per OCA					$ 39,762	
22	Total Payroll per Company					42,209	3/
23							
24	Adjustment to O&M Expenses					$ (2,447)	

Notes
[1] Attachment OCA-IX-2(a).
[2] Public Attachment IE-8-D(a).
[3] Exhibit MJT-1, Schedule D-6, Page 65.
[4] Response to OCA-II-47(a).
[5] Exhibit MJT-1, Schedule D-6, Page 64.
[6] Attachment OCA-IX-1(a).

PECO Energy Company - Gas Division

Adjustment to Revise Benefits Expense for Change in Number of Employees
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Total Benefits Costs [1]	Benefits Capitalized [1]	Benefits Expense	Benefits Expense per Employee	Benefits Expense Using HTY Employees
1	Medical	$ 6,100	$ 2,158	$ 3,942	$ 6.18	$ 3,732
2	Dental	366	120	246	0.39	233
3	Other Benefit Plan	109	(32)	141	0.22	133
4	401K Plan	2,210	960	1,250	1.96	1,183
5	ESPP	205	131	74	0.12	70
6	Disability Plan	133	26	107	0.17	101
7	Excess Benefits Saving Plan	12	5	7	0.01	7
8	Workers Comp	239	101	138	0.22	131
9	Pension	-	-	-	-	-
10	OPEB	-	-	-	-	
11						
12	Subtotal	$ 9,374	$ 3,469	$ 5,905		$ 5,590
13						
14	Unadjusted Benefits Expense				5,905	
15	Company's Adjustment to Include Additional Employee				11 [2]	
16	Total Benefits Expense per Company					5,916
17						
18	Adjustment to Benefits Expense					$ (315)
19						

Notes:
[1] Attachment IE-RE-9-D(a)
[2] Exhibit MJT-1, Schedule D-8, Page 69.

Please note that Schedule LKM-13 contains

Confidential Information and has been redacted

from the Public Version.

PECO Energy Company - Gas Division

Adjustment to Annualize Pension Expense
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount	
1	FPFTY Expense Portion of Pension Contribution	$ 2,525	[1/]
2	FPFTY Expense Portion of ASC 715 Pension Costs	563	[1/]
3			
4	Adjustment to Pension Expense	$ 1,962	
5	Company's Adjustment to Pension Expense	1,962	[2/]
6			
7	Adjustment to O&M Expenses	$ -	

Notes:
[1/] Attachment OCA-XIII-16(a)
[2/] Exhibit MJT-1, Schedule D-9, Page 70.

PECO Energy Company - Gas Division

Adjustment to Remove Advance Recovery of MGP Remediation
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	Regulatory Asset for Unrecovered MGP Remediation Liability	$ 7,237 [1/]
2	Normalization Period	14
3		
4	Annual Recovery of MGP Liability	$ 517
5	Annual Recovery of Claimed by PECO	804
6		
7	Adjustment to O&M Expenses	$ (287)

Notes:
[1/] Exhibit MJT-1, Schedule D-13, Page 74.

PECO Energy Company - Gas Division

Adjustment to Normalize Injuries and Damages Expense
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description		Amount [1/]
1			
2	2018 Injuries and Damages Expense	$	301
3	2019 Injuries and Damages Expense		(9)
4	2020 Injuries and Damages Expense		231
5			
6	3-Year Average Injuries and Damages Expense	$	174
7	FPFTY Injuries and Damages Expense		638
8			
9	Adjustment to Injuries and Damages	$	(464)

Notes:
[1/] Company's Response to I&E-RE-7.

PECO Energy Company - Gas Division

Adjustment to Normalize Rate Case Expenses
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
	Total Rate Case Expense	$ 1,559
1	Normalization Period	5
2		
3	Annual Normalization Amount	$ 312
4	Amount per Company	520
5		
6	Adjustment to O&M Expenses	$ (208)

Notes:

PECO Energy Company - Gas Division

Adjustment to Normalize Regulatory Initiative Costs
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount	
1	Gas Unbundling of GPC/MFC Expense Portion	$ 21	[1/]
2	Gas Neighborhood Pilot Program Expense	-	
3			
4	Authorized Deferred Costs	$ 21	
5	Normalization Period	3	[2/]
6			
7	Normalization of Deferred Costs	$ 7	
8	Annual Cost Recovery Sought by PECO	47	[1/]
9			
10	Adjustment to O&M Expenses	$ (40)	

Notes:
[1/] Company's Response to OCA-II-54.
[2/] Exhibit MJT-1, Schedule D-14, Page 75.

PECO Energy Company - Gas Division

Adjustment to Remove Recovery of Cost to Achieve
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	Cost to Achieve Cost Recovery Included in O&M Expenses	$ 370 [1/]
2		
3	Adjustment to O&M Expenses	$ (370)

Notes:
[1/] Exhibit MJT-1, Schedule D-15, Page 76.

PECO Energy Company - Gas Division

Adjustment to Normalize EBSC Charges
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	7/1/2019 - 6/30/2020 Amount [1/]	7/1/2018 - 6/30/2019 Amount [2/]	7/1/2017 - 6/30/2018 Amount [2/]	Average
1	Communication	$ 329	$ 303	$ 386	$ 339
2	Executives	1,074	1,897	1,238	1,403
3	Exelon Utilities	989	1,516	1,069	1,191
4	Finance	2,239	2,643	2,343	2,408
5	Government Affairs	56	138	160	118
6	Human Resource	978	1,036	905	973
7	Legal Governance	1,025	970	1,019	1,005
8	Security	1,080	1,038	1,007	1,042
9	Supply	199	195	181	192
10	Other EBSC Services	127	52	-	60
11					
12	Total	$ 8,096	$ 9,788	$ 8,308	8,731
13	FPFTY Amount per Company				9,728
14					
15	Adjustment to O&M Expenses				$ (997)

Notes:
[1/] Attachment III-A-22(a)
[2/] Attachment IE-RE-11-D(a), Page 2.

PECO Energy Company - Gas Division

Adjustment to Normalize R&D Expense
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount [1]
1	7/1/2017 - 6/30/2018 Expense Amount	$ 59
2	7/1/2018 - 6/30/2019 Expense Amount	113
3	7/1/2019 - 6/30/2020 Expense Amount	253
4		
5	Average Annual R&D Expense	142
6	FPFTY R&D Expense	280 [2]
7		
8	Adjustment to O&M Expenses	(138)

Notes:
[1] Company's Response to I&E -17-D.
[2] Company's Response to OCA-V-22.

PECO Energy Company - Gas Division

Adjustment to Reflect Annual Regulatory Commission Expense
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	HTY Regulatory Commission Expense	$ 1,735 [1/]
2	FPFTY Regulatory Commission Expense Claimed by Company	2,197 [2/]
3		
4	Adjustment to O&M Expenses	$ (462)

Notes:
[1/] Exhibit MJT-1, Schedule D-9, Page 70.
[2/] Company's Response to OCA-II-27.

PECO Energy Company - Gas Division

Adjustment to Normalize Contracting Expenses
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	7/1/2019 - 6/30/2020 Amount [1/]	7/1/2018 - 6/30/2019 Amount [1/]	7/1/2017 - 6/30/2018 Amount [1/]	Average
1	Contracting Professional	$ 715	$ 784	$ 534	$ 678
2					
3	Contracting Services	548	552	781	627
4					
5	Total	$ 1,263	$ 1,336	$ 1,315	1,305
6					
7	FPFTY Amount per Company				1,672 [2/]
8					
9	Adjustment to O&M Expenses				$ (367)

Notes:
[1/] Attachment OCA-V-18(a)
[2/] Attachment III-A-28(a)

PECO Energy Company - Gas Division

Adjustment to Annualize Employee Activity Expenses
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	HTY Amount [1]	FPFTY Amount [2]	Adjustment
1	Employee Recognition Awards	$ 7	$ 36	$ (29)
2				
3	Employee Service Awards	12	21	(9)
4				
5	Employee Picnic, Celebration, Other Employee Compact Expenses	48	81	(33)
6				
7	Employee Network Groups	1	1	-
8				
9	Adjustment to O&M Expenses			$ (71)

Notes:
[1] Attachment IE-RE-26-D(a).

PECO Energy Company - Gas Division

Adjustment to Annualize Travel Meals & Entertainment Expense
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount [1/]
1	HTY Travel Meals & Entertainment Expense	$ 165
2	FPFTY Travel Meals & Entertainment Expense	343
3		
4	Adjustment to O&M Expenses	$ (178)

Notes:
[1/] Attachment OCA-XIII-23(a).

PECO Energy Company - Gas Division

Adjustment to Remove Increase in Energy Efficiency Costs
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	Remove Ennergy Efficiency Costs	$ 2,492 [1/]
2		
3	Adjustment to O&M Expenses	$ (2,492)

Notes:
[1/] Exhibit MJT-1, Schedule D-11, Page 72.

PECO Energy Company - Gas Division

Adjustment to Depreciation Expense
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	FTY Depreciation Expense	$ 78,320 [1/]
2	FPFTY Depreciation Expense	86,146 [2/]
3		
4	Adjustment to O&M Expenses	$ (7,827)

Notes:
[1/] Exhibit MJT-2, Schedule D-1, Page 40.
[2/] Exhibit MJT-1, Schedule D-1, Page 40.

PECO Energy Company - Gas Division

Adjustment to Remove Inflation Escalation From Property Taxes
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	FTY Property Taxes	$ 3,594 [1/]
2	Inflation factor	102.500% [2/]
3		
4	Property Taxes before Inflation	$ 3,506
5	FPFTY Property Taxes	3,618 [1/]
6		
7	Adjustment to Taxes Other Than Income	$ (112)

Notes:
[1/] Attachment IE-RE-19-D(a)
[2/] Response to IE-RE-50-D(a).

PECO Energy Company - Gas Division

Adjustment to Annualize Payroll Taxes
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	FPFTY Payroll Adjustment	$ (2,447) [1/]
2	Payroll Tax Rate	7.650%
3		
4	Adjustment to Taxes Other Than Income	$ (187)

Notes:
[1/] Schedule LKM-11.

PECO Energy Company - Gas Division

Interest Synchronization Adjustment
For the Fully Projected Future Test Year Ending June 30, 2022

Line No.	Description	Amount	
1	Company Rate Base	$ 2,157,035	[1]
2	Weighted Cost of Debt	1.920%	
3			
4	Adjusted Interest Deduction	$ 41,415	
5	Interest Deduction Per Company	44,098	[2]
6			
7	Adjustment to Synchronize Interest Expense	$ (2,683)	
8	Effective State Income Tax Rate	9.99%	
9			
10	Adjustment to State Income Taxes	$ 268	
11			
12	Federal Income Tax Base	$ (2,415)	
13	Federal Income Tax Rate	21.00%	
14			
15	Adjustment to Federal Income Taxes	$ 507	

Notes:
[1] Schedule LKM-2, Page 1.
[2] Exhibit MJT-1,Schedule D-18, Page 91.

PECO Energy Company - Gas Division

Calculation of Income Taxes
For the Fully Projected Future Test Year Ending June 30, 2022
($ in Thousands)

Line No.	Description	Present Rates [1]	OCA Adjustments	After OCA Adjustments	Rate Increase	Proposed Rates
1	Revenue	$ 590,014	$ -	$ 590,014	$ (11,475)	$578,539
2	Operating Expenses	466,638	(17,448)	449,190	(75)	449,115
3	OIBIT	$ 123,376	$ 17,448	$ 140,824	$ (11,400)	$129,424
4						
5	Synchronized Interest Expense	44,098	(2,683)	41,415	-	41,415
6	Base Taxable Income	$ 79,278	$ 20,131	$ 99,409	$ (11,400)	$ 88,009
7						
8	State Accelerated Tax Depreciation	$ 60,609	$ (2,534)	$ 58,075	$ -	$ 58,075
9	Pro Forma Book Depreciation	86,146	(7,827)	78,319	-	78,319
10	State Tax Depreciation (Over) Under Book	$ 25,537	$ (5,293)	$ 20,244	$ -	$ 20,244
11	Regulatory Asset Programs M-1, Pension & Post-Retirement	(3,054)	-	(3,054)	-	(3,054)
12	Other Property Basis Adjustments (CIAC/ICM)	(12,276)	-	(12,276)	-	(12,276)
13	Removal Costs/Software	(9,120)	-	(9,120)	-	(9,120)
14	AFUDC Equity	(5,482)	-	(5,482)	-	(5,482)
15	Permanent Adjustments	775	-	775	-	775
16	Repair Deduction	(132,540)	32,693	(99,847)	-	(99,847)
17						
18	State Taxable Income	$ (56,881)	$ 47,531	$ (9,350)	$ (11,400)	$ (20,750)
19						
20	State Income Tax Rate	9.99%	9.99%	9.99%	9.99%	9.99%
21	State Income Tax Benefit / (Expense) before NOL	$ 5,682	$ (4,748)	$ 934	$ 1,139	$ 2,073
22	Net Operating Loss Utilization %	100.00%	100.00%	100.00%		
23	Net Operating Loss Utilization	(5,682)	4,748	(934)		
24	State Income Tax Benefit / (Expense)	$ -	$ -	$ -	$ 1,139	$ 2,073
25						
26	Federal Accelerated Tax Depreciation	$ 48,481	$ -	$ 48,481	$ -	$ 48,481
27	Pro Forma Book Depreciation	86,146	(7,827)	78,319	-	78,319
28	Federal Tax Deducts (Over) Under Book	$ 37,665	$ (7,827)	$ 29,838	$ -	$ 29,838
29	Regulatory Asset Programs M-1, Pension & Post-Retirement	(3,054)	-	(3,054)	-	(3,054)
30	Other Property Basis Adjustments (CIAC/ICM)	(12,276)	-	(12,276)	-	(12,276)
31	Removal Costs/Software	(9,120)	-	(9,120)	-	(9,120)
32	AFUDC Equity	(5,482)	-	(5,482)	-	(5,482)
33	Permanent Adjustments	775	-	775	-	775
34	Repair Deduction	(132,540)	32,693	(99,847)	-	(99,847)
35	Federal NOL	-	-	-	-	-
36	Federal Taxable Income	$ (44,754)	$ 44,997	$ 244	$ (10,261)	$ (9,083)
37						
38	Federal Income Tax Rate %	21.00%	21.00%	21.00%	21.00%	21.00%
39	FIT Benefit / (Expense) before Deferred and Adjustments	$ 9,398	$ (9,449)	$ (51)	$ 2,155	$ 1,908
40	Total Tax Benefit / (Expense) before Deferred Income Tax	$ 9,398	$ (9,449)	$ (51)	$ 3,294	$ 3,980
41						
42	**DEFERRED INCOME TAXES**					
43	Deferred Taxes on Timing Differences- Federal	$ 1,904	$ (647)	$ 1,257	$ -	$ 1,453
44	Deferred Taxes on Timing Differences- State	(1,531)	-	(1,531)	-	(1,531)
45	Deferred Taxes on State NOL	5,682	(4,748)	934	-	-
46	Excess Deferred Amortization	3,455	-	3,455	-	3,455
47	Federal Income Tax on Flow Through Adjustments	(953)	-	(953)	-	(953)
48						
49	Deferred Income Taxes Benefit / (Expense)	$ 8,557	$ (5,395)	$ 3,162	$ -	$ 2,424
50						
51	Net Income Tax Benefit / (Expense)	$ 17,955	$ (14,844)	$ 3,111	$ 3,294	$ 6,404
52						
53	**Other Income Tax Adjustments**					
54	Amortization of Investment Tax Credit	$ 64	$ -	$ 64	$ -	$ 64
55						
56	Combined Income Tax Benefit / (Expense)	$ 18,019	$ (14,844)	$ 3,175	$ 3,294	$ 6,468
57						
58	Federal Income Tax Benefit / (Expense)	$ 13,868	$ (10,096)	$ 3,772	$ 2,155	$ 5,927
59	State Income Tax Benefit / (Expense)	4,151	(4,748)	(597)	1,139	541
60	Total Income Tax Benefit / (Expense)	$ 18,019	$ (14,844)	$ 3,175	$ 3,294	$ 6,468

Notes
[1] Exhibit MJT-2, Schedule D-18, Page 91.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018929
	:	
PECO Energy Company – Gas Division	:	

VERIFICATION

I, Lafayette K. Morgan, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 2-SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: February 9, 2021
*303586

Signature: Lafayette Morgan Jr.
Lafayette K. Morgan

Consultant Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-3575

OCA Statement No. 3-SR

R-2020-3018929
2/17/21 JK

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**DOCKET NO. R-2020-3018929**
	:	
PECO ENERGY COMPANY – GAS DIVISION	:	

SURREBUTTAL TESTIMONY OF

KEVIN W. O'DONNELL, CFA

ON BEHALF OF

OFFICE OF CONSUMER ADVOCATE

February 9, 2021

Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Kevin W. O'Donnell. I am President of Nova Energy Consultants, Inc ("Nova"). My business address is 1350 SE Maynard Rd., Suite 101, Cary, North Carolina 27511.

Q. ON WHOSE BEHALF ARE YOU PRESENTING SURREBUTTAL TESTIMONY IN THIS PROCEEDING?

A. I am presenting this surrebuttal testimony on behalf of the Pennsylvania Office of Consumer Advocate ("OCA"). The OCA represents consumers before the Pennsylvania Public Utility Commission ("the Commission").

Q. MR. O'DONNELL, DID YOU SUBMIT WRITTEN DIRECT TESTIMONY AND REBUTTAL TESTIMONY ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE IN THIS CASE?

A. Yes. I presented direct and rebuttal testimonies as part of the OCA's alternative recommendation in the event the Commission does not adopt the OCA's primary position of no rate increase as outlined by OCA Witness Scott Rubin for PECO Energy – Gas Division ("PECO Gas" or "the Company").

Q. HAVE YOU REVISED YOUR RECOMMENDED OVERALL COST OF CAPITAL RECOMMENDATION?

A. No. My overall cost of capital recommendation as included within **Exhibit KWO-1** to my direct testimony has not changed. I have included this recommendation again in **Table 1S** below:

Table 1S: OCA Overall Recommended Rate of Return[1]

Component	Capital Structure Ratio (%)	Cost Rate (%)	Wgtd. Cost Rate (%)
Debt	50.00%	3.84%	1.92%
Common Equity	50.00%	8.75%	4.38%
Total Capitalization	**100.00%**		**6.30%**

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY IN THIS PROCEEDING?

A. To respond to the rebuttal testimonies of PECO Gas Witnesses Paul R. Moul, Ronald A. Bradley and Robert J. Stefani on various cost of capital issues.

Q. DO YOU AGREE WITH MR. MOUL'S CONTINUED RECOMMENDATION TO ALLOW PECO GAS A RETURN ON EQUITY OF 10.95%?

A. No, I do not. In his direct testimony, as well as his rebuttal testimony, Mr. Moul has recommended a 10.95% ROE.[2] In my direct testimony, I identified flaws and improper adjustments used by Mr. Moul that skew his recommendation upwards to arrive at an overstated cost of equity claim. Additionally, within my rebuttal testimony, I explained why I&E Witness Christopher Keller's 10.24% ROE recommendation is also excessive and will, if accepted by the Commission, be the highest ROE granted to a natural gas utility in the past year.

[1] Witness O'Donnell's Direct Testimony: **Exhibit KWO-1**.
[2] Witness Moul's Rebuttal Testimony, page 12: lines 7 – 8.

In his rebuttal testimony, Mr. Moul has now recalculated his entire cost of capital analysis to include an additional six months of actual data, including information that was available prior to the Company's September 30, 2020 base rate case filing. Mr. Moul opined that the recalculations included within his rebuttal testimony support the Company's 10.95% ROE claim. However, even if there was time, and if it was procedurally appropriate, I do not need to recalculate my cost of capital analyses to know that the Company's cost of capital request, inclusive of a 10.95% ROE, is still overstated. Adoption of Mr. Moul's recommendation, or even I&E's direct case position, would allow PECO Gas to over-earn in a marketplace that is reflective of much lower capital costs.

Q. PLEASE LIST MR. MOUL'S REBUTTAL TESTIMONY POSITIONS THAT YOU WILL RESPOND TO.

A. In this surrebuttal testimony, I will respond to the following points:

- Mr. Moul's position that a 10.95% ROE is appropriate for PECO Gas, inclusive of an upward adjustment of 25-basis points to recognize his perceived effectiveness of the Company's management;[3]
- Mr. Moul's opposition to my recommended capital structure;[4]
- Mr. Moul's update to the Company's cost of debt;[5]
- Mr. Moul's position that investment risk for PECO Gas is heightened in the current COVID-19 environment;[6]

[3] Witness Moul's Rebuttal Testimony, page 45: lines 17 – 20.
[4] Witness Moul's Rebuttal Testimony, page 4: lines 11 – 12.
[5] Witness Moul's Rebuttal Testimony, page 9: line 20.
[6] Witness Moul's Rebuttal Testimony, page 10: lines 12 – 16.

- Mr. Moul's proposal that the Commission's Quarterly Earnings Report Return on Equity ("ROE") measure for Distribution System Improvement Charge ("DSIC") purposes should serve as a floor in this proceeding;[7]
- Mr. Moul's criticism and misunderstanding of the proxy group as utilized within my direct testimony;[8]
- Mr. Moul's inclusion of "updated" data and recalculated cost of capital results within his rebuttal testimony;[9]
- Mr. Moul's criticism of my discounted cash flow ("DCF") model analysis;[10] and
- Mr. Moul's comments regarding my capital asset pricing model ("CAPM") analysis.[11]

[7] Witness Moul's Rebuttal Testimony: page 13: lines 16 – 22 and page 14: lines 1 – 6.
[8] Witness Moul's Rebuttal Testimony, page 18: lines 2 – 18.
[9] Witness Moul's Rebuttal Testimony, page 10: line 7.
[10] Witness Moul's Rebuttal Testimony, page 24: line 15.
[11] Witness Moul's Rebuttal Testimony, page 35: line 16.

II. MR. MOUL'S 25-BASIS POINT UPWARD ADJUSTMENT FOR HIS PERCEPTION OF THE COMPANY'S EXEMPLARY MANAGEMENT PERFORMANCE

Q. DO YOU AGREE WITH MR. MOUL'S 25-BASIS POINT ADJUSTMENT FOR EXEMPLARY MANAGEMENT PERFORMANCE?

A. No, I do not. As noted within my direct testimony, Mr. Moul's direct indicated that this 25-basis point upward adjustment to reward the Company for perceived exemplary performance of management was based upon his "…*analysis of the Company and its superior performance…."*[12] However, nowhere within his direct testimony, nor his response to data request **OCA-IV-19**, has Mr. Moul presented any detail as to what "analysis" he performed that would exemplify why a 25-basis point upward adjustment was appropriate in this case.

All of the criticisms included in the above paragraph were noted within my direct testimony. However, in Mr. Moul's rebuttal testimony, all he offered in response to these criticisms was that my "…*specific criticisms of PECO's performance are incorrect, as Mr. Bradley explains in PECO Statement No. 1-R*."[13] I maintain my belief that in order to award PECO Gas a management performance bonus, the Company must supply the Commission with evidence. Mr. Moul has not provided any such evidence substantiating the exemplary management performance claim made by PECO Gas in this proceeding.

Q. HOW DID THE COMPANY QUANTIFY ITS REQUEST?

[12] Witness Moul Direct Testimony, page 2: lines 7 – 10. (underlined emphasis added)
[13] Witness Moul Rebuttal Testimony, page 43: lines 11 – 13.

A. In rebuttal, Mr. Bradley stated that PECO should be allowed "*an ROE near the upper end of the range recommended*" by Mr. Moul.[14] According to **OCA-IV-19**, Mr. Moul's "range" is comprised of the results of all of his models. However, Mr. Moul's reply to **OCA-IV-9** contained the circular explanation: "*Mr. Moul's recommended 10.95% (i.e., 10.70% + 0.25%) rate of return on common equity provides recognition for the Company's management effectiveness that includes this 0.25% increment*."

Q. DO YOU AGREE THAT THE COMPANY SHOULD RECEIVE A ROE INCREASE FOR PERCEIVED EXEMPLARY PERFORMANCE OF ITS MANAGEMENT?

A. No. PECO Gas has an obligation to provide service that is safe, adequate, reasonable, and efficient. A 25-basis point increment applied to what would constitute a proper, market-based cost of equity would impose significant additional cost on ratepayers. The same is true of Mr. Bradley's position that the "high end" of a range should be considered. PECO Gas has not demonstrated that its performance so far exceeds the Company's obligation to provide safe, adequate, reasonable, and efficient service to justify the additional cost to ratepayers.

The Company made its rate filing during the midst of a global pandemic and still felt that it was appropriate to request a 25-basis point upward adjustment to reward shareholders for the Company's performance spanning many years prior to the current rate case. The Company's request is at odds with the hardships currently faced by PECO Gas'

[14] Witness Bradley Rebuttal Testimony (Public Version), page 18: lines 5 – 6.

customers, many of whom have been unemployed or underemployed and are continuing to struggle to pay for PECO Gas' service at current rates.

Q. WHY DO YOU BELIEVE THAT PECO GAS HAS NOT DEMONSTRATED THAT PERFORMANCE OF ITS MANAGEMENT HAS BEEN EXEMPLARY?

A. As explained within my direct testimony, my contention with the Company's request for any level of ROE addition due to their perceived exemplary performance of management is centered around three points.

First, the Company has an obligation under state law to provide service to the public which is reasonable, safe, and adequate. PECO Gas' customers should not be charged extra for the Company being able to meet its service obligations under state law or regulations. Based upon the Commission-approved "Penrose Lane Settlement" between PECO and I&E, the Company is also obligated to take specific steps and make certain investments to improve gas safety and reliability. I disagreed with Mr. Bradley's position in his direct testimony that PECO's activities to implement gas safety improvements required by the Commission-approved settlement of a gas explosion investigation should be treated as "exemplary management performance."

Second, within the direct testimony of OCA Witness Roger Colton, Mr. Colton analyzed the Company's performance in certain areas related to customer service and found the Company's performance has not been superior. Mr. Colton examined the Company's performance based on Commission data and metrics.

Third, I disagreed with Mr. Moul's position – as stated in **OCA-IV-19** – that because *"PECO's customer service has been recognized by J.D. Power"*, the Company should be allowed 25-basis points in additional equity return. As stated in my direct testimony, if the J.D. Power rankings are to be given any consideration at all, they do not show that PECO's performance is so exemplary as to rank at the top of its comparable company segment.

Q. HOW HAS MR. MOUL SUPPORTED THE COMPANY'S CLAIM OF EXEMPLARY MANAGEMENT PERFORMANCE IN REBUTTAL?

A. Mr. Moul has simply said "*Mr. O'Donnell's specific criticisms of PECO's performance are incorrect, as Mr. Bradley explains in PECO Statement No. 1-R*."[15] As such, Mr. Moul offered no evidence or support against the related criticisms from my direct testimony.

Q. DOES MR. BRADLEY'S REBUTTAL JUSTIFY AN INCREASE IN BASE RATES FOR MANAGEMENT PERFORMANCE?

A. No, it does not. Mr. Bradley pointed to the Company's progress in replacing mains, bare steel services, and reduction in leaks.[16] As I noted in my direct testimony, PECO *should* be operating and investing to provide reasonable, adequate, and safe service as required by state law and regulation. Mr. Bradley does not acknowledge the full context. PECO operates under a Long-Term Infrastructure Improvement Plan ("LTIIP"). The Commission approved PECO's Second Modified LTIIP plan to accelerate bare steel service replacements in June 2017 as "*reasonable, cost-effective and designed to*

[15] Witness Moul Rebuttal Testimony, page 43: lines 11 – 13.
[16] Witness Bradley Rebuttal Testimony (Public version), page 17, lines 7 – 13.

maintain efficient, safe, adequate, reliable and reasonable service."[17] In the first four years of PECO's LTIIP, the Company had not met its annual goal, hence the need to accelerate bare steel service replacement goals through 2022.[18]

PECO's operation under a Commission-approved LTIIP allows PECO to recover certain infrastructure improvement costs between base rate cases through a DSIC. As I noted in my direct, the market has already factored in PECO's activities and investments in gas safety and infrastructure replacement. The Company and its shareholders benefit from operation under a Commission-approved LTIIP and implementation of a DSIC. I disagree that PECO customers should pay up to 25-basis points more in equity return for PECO to provide safe, reliable, and adequate service, all of which are expected in the normal course of business for any gas distribution utility.

Q. PLEASE COMMENT ON MR. BRADLEY'S REBUTTAL REGARDING THE PENROSE LANE SETTLEMENT.

A. In rebuttal, Mr. Bradley asked the Commission to recognize PECO's efforts to improve its gas mapping program as exemplary, claiming that such efforts were under development before the Penrose Lane Settlement.[19] I disagree. As I stated in my direct testimony, PECO Gas has an obligation to make specific gas safety improvements pursuant to a 2016 Commission-approved settlement of an investigation of a 2014 gas explosion – the Penrose Lane Settlement. PECO paid a civil penalty of $900,000. PECO began implementation of its gas mapping program in 2018 and is not expected to

[17] Petition of PECO Energy Company for Approval of its Second Modified Gas Long-Term Infrastructure Improvement Plan, Docket No. P-2013-2347340, Opinion and Order, pages 1, 13.
[18] PECO Gas Second Modified LTIIP Order, page 11.
[19] Witness Bradley Rebuttal Testimony (Public version), page 17, lines 16 – 21.

complete it until 2037. I disagree with Mr. Bradley's rebuttal position that PECO's claimed readiness to negotiate that settlement should qualify as proof of exemplary management performance.

Q. DO PECO'S ACTIVITIES TO HELP CONSUMERS DURING THE COVID-19 PANDEMIC SUPPORT AN AWARD OF 25-BASIS POINTS FOR MANAGEMENT PERFORMANCE?

A. No. I disagree with Mr. Bradley's rebuttal position that the Company activities described by PECO Witness Colarelli are examples of exemplary management performance. The Commission has ordered and encouraged utilities to take measures to help keep consumers connected during these extraordinary times. As addressed by OCA Witness Colton's surrebuttal testimony, the PECO initiatives described by Ms. Colarelli should be modified and improved upon, to better help consumers.

Q. SHOULD THE COMMISSION AWARD PECO 25-BASIS POINTS FOR MANAGEMENT PERFORMANCE BASED UPON J.D. POWER'S SCORES?

A. No. Mr. Bradley's rebuttal testimony has one sentence on this topic, "*As with Mr. Colton, Mr. O'Donnell focuses on J.D. Power scores without appropriately noting the significant improvement that PECO has achieved*."[20] First, I disagree that the J.D. Power scores are a meaningful gauge of management performance to support a 25-basis point increase in the allowed equity return in this proceeding. As addressed by OCA Witness Colton and within my own direct testimony, there are many reasons why the Commission should find

[20] Witness Bradley's Rebuttal Testimony, page 17: lines 4 – 5.

that PECO's management performance does not rise to the level of exemplary or superior. Second, Mr. Bradley's rebuttal testimony's reference to PECO's "significant improvement" does not acknowledge that PECO's 2020 score placed PECO 7th out of 12 companies in the J.D. Power East Large Segment. Viewed in context, the limited J.D. Power results cited by Mr. Bradley simply do not support charging PECO consumers higher rates based upon management performance. Being in the middle of the pack is hardly worthy of any claim of superior management performance.

III. <u>MR. MOUL'S DISCUSSION OF THE COMPANY'S CAPITAL STRUCTURE</u>

Q. HOW DO YOU RESPOND TO MR. MOUL'S CLAIM THAT YOUR CAPITAL STRUCTURE RECOMMENDATION IS CONTRARY TO COMMISSION PRECEDENT?

A. As justification for the Company's proposed common equity ratio of 53.38%, Mr. Moul referenced the Commission's establishment of the cost of capital for an electric utility in 2018 with a 54.02% common equity capital structure as the most relevant benchmark for this case.[21] I disagree with Mr. Moul on this point.

In contrast, I believe that the Commission should evaluate whether PECO Gas' projected end of the FPFTY capital structure is reasonable and fair to determine an appropriate cost of capital in this proceeding that does not overburden ratepayers. As I explained in my direct testimony, equity is more costly as the dollars collected in rates are subject to taxes. The information contained in **Table 7** to my direct testimony are comparative benchmarks that investors consider when making investment decisions. As such, the equity ratios included within **Table 7** to my direct testimony are more closely aligned with market expectations in this case as opposed to citing Commission precedent in a previous electric rate case decision. Even in light of the related Commission precedent in a previous electric utility case, I believe that the 53.38% equity capital structure requested by PECO Gas in this case is too heavily weighted towards equity, is not representative of equity ratios found in comparable companies, and is simply too expensive for consumers.

[21] Witness Moul's Rebuttal Testimony, page 6: lines 6 – 10.

Q. ON WHAT FACTS DID YOU BASE YOUR CAPITAL STRUCTURE RECOMMENDATION?

A. As shown in **Table 7** to my direct testimony, I based my capital structure recommendation of 50.00% equity / 50.00% debt upon figures such as the average common equity ratio granted by state regulators across the country for the Natural Gas Industry during 2019 (*i.e.*, 51.75%), the average common equity ratio granted by state regulators across the country for the Natural Gas Industry over the previous 15-year period (*i.e.*, 49.91%), the average common equity ratio in 2019 of each of the comparable proxy group companies included within my cost of capital analyses (*i.e.*, 50.70%), and the 2019 common equity ratio for PECO Gas' parent company Exelon (*i.e.*, 50.40%). I did not place more reliance on one specific measure than another when developing my 50% equity capital structure recommendation.

IV. <u>MR. MOUL'S REVISION TO THE COMPANY'S COST OF DEBT</u>

Q. DID PECO GAS UPDATE ITS COST OF DEBT AS PART OF ITS REBUTTAL TESTIMONY?

A. Yes. In his direct testimony, Mr. Moul recommended a cost of long-term debt of 3.97%.[22] In data request **OCA-XII-2**, I asked Mr. Moul to update the information upon which he based his cost of debt calculations.

The Company's updated debt cost information provided in response to **OCA-XII-2**, showed reduced cost rates for the March 2021, September 2021, and March 2022 anticipated "First and Refunding Mortgage Bonds" debt issuances. In my direct testimony, and as shown in **Exhibit KWO-8,** I adjusted the Company's estimated long-term debt cost rate as of June 30, 2022 downward to 3.84%, based upon the Company's reduced interest rate projections.

In rebuttal, PECO witness Moul revised his summary cost of capital schedule for June 30, 2022 to reflect a long-term debt cost rate of 3.84%, reduced from the original 3.97%.[23] Specifically, Mr. Moul updated the estimated March 2021 debt interest rate of 3.46% to 2.90%, the September 2021 debt rate from 3.46% to 2.90%, and the March 2022 debt rate of 3.51% to 2.90%.[24]

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[22] Witness Moul's Direct Testimony: PECO Exhibit PRM-1, Schedule 6: page 3.

[23] Witness Moul's Rebuttal Testimony, page 10, lines 2 - 3 identified his revised cost of debt value as "3.80%." However, as shown in, (1) Witness Moul's Rebuttal Testimony: PECO Exhibit PRM-1 (Updated), Schedule 1: page 1 and (2) PECO Exh. MJT-1 Revised, Sch. B-7, p. 13, Update 1-19-2021, these exhibits reflect "3.84%" as the Long-Term Cost of Debt.

[24] Compare, PECO Exhibit PRM-1, page 13, Schedule 6 [3 of 4] and PECO Exhibit PRM-1 (Updated), page 13, Sch. 6 [3 of 4], the "Effective Cost Rate" column for the last three First Mortgage Bonds issues.

Additionally, note that PECO Witness Trzaska stated in rebuttal that as result of Mr. Moul's updated long term debt cost rate of 3.84%, "*the Company's revenue requirement is reduced by $1.5 million*."[25]

Q. DO YOU ACCEPT THE COMPANY'S REDUCED EMBEDDED COST OF DEBT?

A. Yes, I accept the 3.84% cost of debt. I employed 3.84% as the long-term cost of debt in my direct testimony so my original overall cost of debt recommendation is unchanged.

Q. SHOULD THE COMPANY'S REDUCED END OF FPFTY COST OF DEBT IMPACT THE COST OF EQUITY THE COMMISSION ALLOWS IN THIS CASE?

A. Yes. As recognized by Mr. Moul in his rebuttal, the cost of debt has fallen tremendously. Investors looking for an alternative over the relatively small interest now being paid on fixed income securities (bonds) are buying equities (stocks), thereby driving the stock market to all-time highs of-late. When such a situation occurs, investors are paying higher and higher prices for a given level of income and expected growth. Simple math then implies investors are expecting lower costs of equity. To capture this lower expected cost of equity, the authorized ROE should also be set lower.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THE INCREASE IN PRICE OF A STOCK WILL RESULT IN A LOWER ROE?

[25] Witness Trzaska's Rebuttal Testimony, page 5: lines 5 – 6.

A. Yes. In **Table 2S** below, I have provided an example scenario of such a stock increase. In the first column, which I have labeled as "Jan. 1, 2021", the price of ABC stock is $25 per share, the dividend is $1.00 per share, and the growth rate is 5.0%. In this example, $1 divided by $25 represents a 4.0% dividend yield which, when combined with the 5.0% growth rate, produces a ROE of 9.0%. The second column, which I have labeled "Feb. 9, 2021" is identical to the first column with the exception that the price of ABC stock has risen to $30 per share. In this example, the $1.00 dividend is divided by the $30 share price for a 3.3% dividend yield which, when paired with the 5.0% growth rate, results in an 8.3% ROE.

Table 2S: Price Increase to Lower ROE

	Date	
	Jan. 1, 2021	Feb. 9, 2021
Dividend	$ 1.00	$ 1.00
Price	$ 25.00	$ 30.00
Div Yld (Rx)	4.0%	3.3%
Growth	5.0%	5.0%
ROE (Rx)	**9.0%**	**8.3%**

The above example shows that, when the stock price increases from $25 to $30 and nothing else changes, the ROE will fall from 9.0% to 8.3%. With interest rates at historic lows, equity investors are bidding up stock prices for entities such as utilities that have a strong dividend payment history. In the example above, a 3.3% to 4.0% dividend yield is a better current income yield than investors can receive in the bond market where interest rates are so low. This lower required return, which is the move from 9.0% to 8.3% in the above example where investors bid up the stock price from $25 to $30, is simply a matter of investors being willing to pay more for a given equity with the same underlying financial position.

Q. HAS PECO GAS RESPONDED TO ANY OF YOUR OTHER CRITICISMS IN RELATION TO THE COMPANY'S COST OF DEBT?

A. Yes. As noted within my direct testimony, PECO's outstanding debt includes Trust IV securities with an interest rate of 7.38%, an interest rate which is incredibly high in today's market. In response to **OCA-VIII-12**, PECO indicated that early redemption of these securities would be cost prohibitive. I did not make any adjustment to the Company's cost of debt in relation to these Trust IV securities. But I did note that the complicated structure of the Trust IV securities is an example of less than efficient management by the Company, contrary to the Company's claim of exemplary performance.

In rebuttal, PECO Witness Stefani provided a calculation of the expected cash outlay that would be required to redeem the Trust IV securities in PECO Exhibit RJS-5-R.[26] Based upon this information, I agree that the cost of redemption of these Trust IV securities would outweigh the benefit. However, my original concern – that the structure of the Trust IV securities arrangement inherently made redemption costly – still supports my position that this original debt financing does not reflect efficient management.

[26] Witness Stefani's Rebuttal Testimony, page 29: lines 12 – 17.

V. MR. MOUL'S STANCE ON PECO GAS' INVESTMENT RISK

Q. PLEASE EXPLAIN WHY YOU BELIEVE MR. MOUL'S RECOMMENDATION TO ALLOW PECO GAS A 10.95% ROE IS EXCESSIVE AND UNWARRANTED.

A. PECO Energy – Gas Division's last rate case was under R-2010-2161592. In the Company's 2010 rate case, a ROE of 11.75% was requested. That rate case was ultimately settled and approved by the Commission on December 16, 2010.[27] PECO Energy – Electric Division's most recent rate case was under Docket No. R-2018-3000164. That 2018 rate filing by the Company's electric utility affiliate was made on March 29, 2018, included a 10.95% ROE request and was partially settled and approved by the Commission on December 20, 2018.[28] However, subsequent to both December 16, 2010 and December 20, 2018, financial markets across the country have undergone tremendous change.

Q. HOW HAVE THE FINANCIAL MARKETS CHANGED SINCE THE COMPANY'S MOST RECENT RATE CASES?

A. As referenced extensively in both my direct and rebuttal testimonies, subsequent to the Company's last Natural Gas case in 2010 and its last Electric case in 2018, interest rates have fallen significantly since these rate cases and the DJUA has increased notably as well. Such a strong downward movement in interest rates indicates lower costs to enter

[27] S&P Global Rate Case History (Past Rate Cases); Years: All; Service Type: All; Company List: PECO Energy Co.; States: Pennsylvania; Date Accessed: October 19, 2020. The Settlement resolved all issues, but one issue regarding cost allocation, which is not materially relevant for the purposes of this testimony.
[28] *Id.*

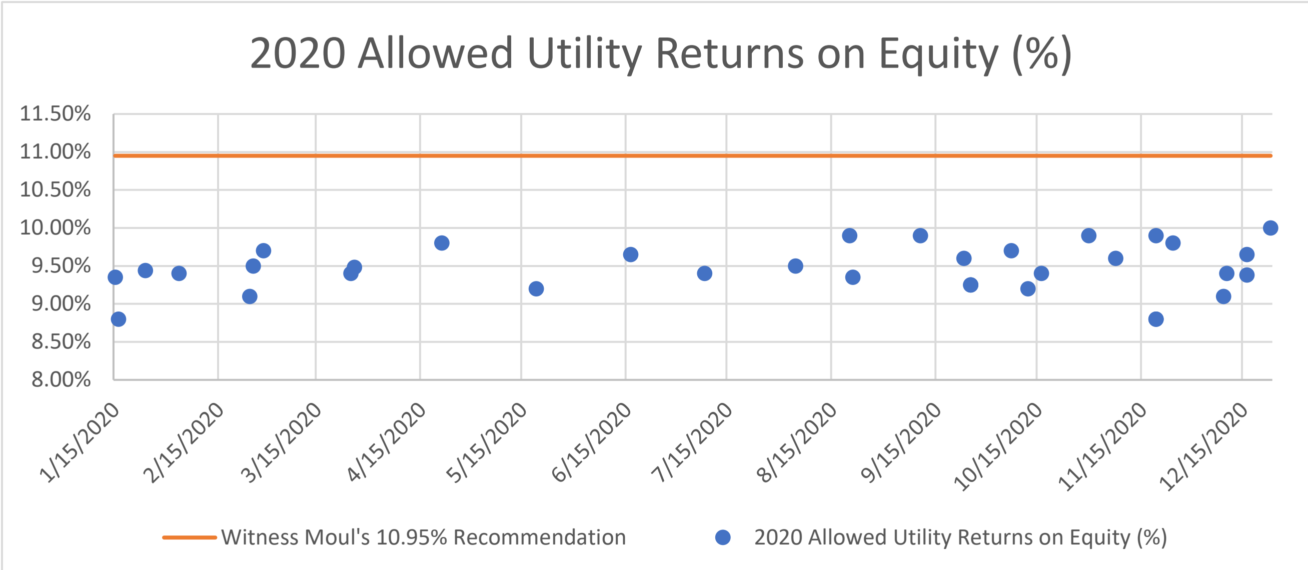
the debt market and such a strong upward movement in the utility equity market is indicative of investors accepting a lower cost of capital on their investments.

Q. HOW DOES MR. MOUL'S RECOMMENDED ROE OF 10.95% COMPARE TO THE NATIONAL AVERAGE ROE GRANTED BY STATE REGULATORS ACROSS THE COUNTRY DURING 2020?

A. As of the end of 2020, the overall allowed ROE for natural gas utilities was 9.46%, which was down from the 9.71% allowed by state regulators for natural gas utilities in 2019.[29] Mr. Moul's recommended ROE of 10.95% is well above the 9.46% average across the United States in 2020. Additionally, of the 34 completed natural gas cases reported during 2020 that comprised the 9.46% average for the year, there were no rate cases with an allowed return higher than 10.00%[30], which is in contrast to Mr. Moul's recommended ROE in this case of 10.95%. See **Chart 1S** below for reference:

[29] S&P Global Market Intelligence Rate Case Statistics; Frequency: Annually; Date Range: 01/01/2019 – 12/31/2020; Service Type: Natural Gas; Chart Items: Return on Equity (%); Date Accessed: January 28, 2021.
[30] S&P Global Market Intelligence Rate Case Statistics; Company List: All; Date Range: 01/01/2020 – 12/31/2020; Service Type: Natural Gas; Chart Items: Return on Equity (%); Date Accessed: January 28, 2021.

Chart 1S: 2020 US Allowed Utility Returns on Equity (%)[31]



Q. DOES MARKET VOLATILITY SUGGEST THAT THE APPROPRIATE COST OF EQUITY FOR PECO GAS HAS RISEN?

A. No. Within his rebuttal testimony, Mr. Moul claims that because the Volatility Index ("VIX") averaged 32.21 during 2020 in comparison to 16.33 in 2019, this constituted reasoning for why he believed that PECO Gas' cost of equity had risen.[32] I disagree. As I have noted previously, the DJUA has largely rebounded from its low in March 2020 brought on by the COVID-19 pandemic. Additionally, interest rates have remained at low levels for a sustained period of time. Simply pointing to a higher VIX as justification for a higher cost of equity for PECO Gas is erroneous and misleading.

Mr. Moul's recommended 10.95% ROE was overstated when the Company filed its base rate case on September 30, 2020. Economic and financial changes in the intervening months do not show that a 10.95% return on equity is necessary to account

[31] *Id.*
[32] Witness Moul's Rebuttal Testimony, page 15: lines 21 – 23.

for Mr. Moul's perceived change in risk. Mr. Moul's recommendation would allow PECO Gas to over-earn, at the expense of captive consumers in Pennsylvania, in a marketplace that is reflective of much lower capital costs.

Q. SHOULD THE COMMISSION BE GUIDED BY 2008 AND 2009 CONSIDERATIONS AS CONTENDED BY MR. MOUL?

A. No. Within his rebuttal, Mr. Moul suggested that the Commission:

> *…be guided in deciding the return on equity in this case by looking back to the last time when the VIX was showing high risk. That time would be for the year 2008 and 2009 during the Financial Crisis. The average VIX for 2008 and 2009 was 34.04 and 32.83, respectively. During that time, natural gas distribution utilities nationally were on average granted returns on equity of 10.39% in 2008 rate cases and 10.22% in 2009 rate case cases decided during a period of similar market turmoil.*[33]

First, I disagree with Mr. Moul's implication and do not believe in any such correlation. In my over three decades of experience in this industry, I have never seen any research that implies VIX drives market returns more so than interest rates or even basic risk/return variables. Simply put, Mr. Moul's statement as noted above is a far stretch for an unjustifiably high ROE.

Secondly, as shown below within **Table 3S**, the average granted returns on equity were in excess of 10% from 2005 – 2010, regardless of what the VIX value was during those years:

[33] Witness Moul's Rebuttal Testimony, page 15: line 23, and page 16: lines 1 – 6.

Table 3S: VIX Volatility Index in Relation to Annual Average Allowed Nat Gas ROE's

Year	Average Annual Allowed Natural Gas ROE[34]	Average Annual VIX Volatility Index[35]
2005	10.41%	12.81
2006	10.40%	12.81
2007	10.22%	17.54
2008	10.39%	32.69
2009	10.22%	31.48
2010	10.15%	22.55

Contrary to Mr. Moul's suggestion, the Commission should not use past average annual VIX values from 2008 and 2009 as a guide to set PECO Gas' ROE in this proceeding. If the Commission follows Mr. Moul's logic regarding the VIX and the allowed ROE, it must then turn a blind eye to interest rate levels and all of the other variables that impact the risk and return of PECO Gas in this case. In addition, if one were to follow the logic being suggested by Mr. Moul in this instance, it would necessitate that companies should receive significantly lower allowed ROEs in years when the VIX is lower, such as 2005, 2006, and 2007 as shown in the table above.

Additionally, as shown in **Table 3S**, the allowed ROE's for natural gas utilities steadily declined from 2005 – 2010, with the 2010 average ROE for natural gas utilities being 10.15%. As shown within **Chart 4** to my direct testimony, this trend continued from 2010 – 2019, with the 2019 average ROE for natural gas utilities being 9.71%. This trend then continued into 2020 as well, with the 2020 average ROE for natural gas utilities being 9.46%.[36]

[34] S&P Global Market Intelligence Rate Case Statistics; Date Range: 15 Years; Service Type: Natural Gas; Chart Items: Return on Equity (%); Date Accessed: January 20, 2021.
[35] CBOE VIX Index Historical Data, http://www.cboe.com/products/vix-index-volatility/vix-options-and-futures/vix-index/vix-historical-data, Date Accessed: January 20, 2021.
[36] S&P Global Market Intelligence Rate Case Statistics; Frequency: Annually; Date Range: 01/01/2020 – 12/31/2020; Service Type: Natural Gas; Chart Items: Return on Equity (%); Date Accessed: January 28, 2021.

Q. WHAT OTHER CONCERNS DO YOU HAVE ABOUT PECO GAS' REQUEST IN THIS CASE?

A. The Commission should also consider the economic impact of the pandemic on Pennsylvania households and businesses as noted by OCA Witness Rubin in his direct and surrebuttal testimony. These facts as reported by Mr. Rubin are stark. Citizens of Pennsylvania are suffering. Placing any rate increase on citizens at this time will serve to only compound the economic suffering now being endured by consumers.

Q. MR. O'DONNELL, WHAT IS A "REGULATORY PREMIUM"[37] AS NOTED BY MR. MOUL IN HIS TESTIMONY?

A. A regulatory premium is defined as the difference between an allowed return on equity ("ROE") and interest rates. An example would be the difference between an allowed ROE of 8.75% and the prevailing interest rate of a 30-year US Treasury bond of 1.50%. In this example, the regulatory premium would be 7.25% (*i.e.*, 8.75% less 1.50%).

Q. DO YOU AGREE WITH MR. MOUL'S CLAIM THAT ALTHOUGH REGULATED ROE'S HAVE TRENDED DOWNWARD, REGULATORY PREMIUMS HAVE INCREASED?

A. Yes. However, Mr. Moul fails to provide the necessary context to support his argument. While I agree the regulatory premiums have risen, I do not believe the increase in the regulatory premium has offset the lower cost of capital for regulated utilities.

[37] Witness Moul's Rebuttal Testimony, page 16: line 12.

Utility regulators across the country tend to move more slowly in regard to changes in allowed ROEs. As such, it is not surprising that allowed ROEs have not fallen at the same pace as interest rates. The net result of the slow fall of allowed ROEs, as compared to the more rapid change in the decreasing interest rates over time, has led to an increase in the "regulatory premium" as noted by Mr. Moul. The situation as indicated by Mr. Moul is simply a function of regulators being concerned with making changes to allowed ROEs at a pace similar to that of the abrupt changes seen within interest rates. Such an observation is inherent in regulation. It does not, however, negate the fact that the cost of capital in today's market is lower than it was at the time of the Company's and its electric affiliate's previous rate filings, as evidenced by the decrease in interest rates and the bounce back / increase in the utility equities market. One simply cannot deny the strong increase in the stock market and the environment of lower interest rates has resulted in a lower cost of capital environment for utilities.

VI. MR. MOUL'S PROPOSED ADOPTION OF AN ROE FLOOR

Q. WHAT IS THE DISTRIBUTION SYSTEM IMPROVEMENT CHARGE?

A. The DSIC allows PECO to employ a surcharge on ratepayers to recover certain eligible investments in gas distribution system replacements between base rate cases. As such, the DSIC amounts to an automatic rate recovery mechanism for PECO that, in turn, lowers its risk.

Consumers are protected by a 5% cap on the amount of eligible investment in plant which PECO may recover through the DSIC surcharge. If the Commission established an allowed ROE for the utility in a base rate case within two years prior, that ROE is used as an earnings cap for DSIC purposes. Otherwise, the Commission's Quarterly Earnings Report identifies a ROE which is used as the upper limit on the return that the utility may earn on the plant investments recovered through its DSIC.

Q. DO YOU AGREE WITH MR. MOUL'S POSITION THAT THE COMMISSION'S ROE FOR DSIC PURPOSES SHOULD SERVE AS THE FLOOR FOR THE COMMISSION'S ROE DETERMINATION IN THIS BASE RATE CASE?

A. No, I do not. The "10.15% ROE for DSIC purposes" cited by Mr. Moul serves a specific purpose for operation of the DSIC surcharge.[38] Mr. Moul's inference that all DSIC-eligible plant investment incurred between base rate cases is recovered, including a ROE at the level reported in the Commission's Quarterly Earnings Report, is incorrect.

First, PECO may only recover through the PECO DSIC a surcharge of up to 5% of PECO's investment in DSIC-eligible plant investment. When PECO's DSIC

[38] Witness Moul's Rebuttal Testimony: page 13: lines 16 – 22 and page 14: lines 1 – 6.

investment is in excess of 5%, the amount of plant in excess of 5% is not recoverable through the DSIC surcharge.[39] PECO's investment in DSIC-eligible plant in excess of the 5% cap is recognized for rate-setting in the Company's next base rate case, just like other PECO additions to rate base which are not DSIC-eligible.

Second, Pennsylvania law and regulations allow PECO to implement a DSIC surcharge to further public policy which favors investment in main replacements, subject to consumer protections. The Commission's Quarterly Earnings Report identifies a ROE that serves as a guard against over-earnings. If PECO's calculated achieved return on its DSIC investment exceeds the benchmark ROE, then PECO cannot collect the DSIC surcharge for the next quarter.

I recommend that the Commission reject Mr. Moul's proposed floor. An ROE that is calculated in some way by Commission staff, for use in a single quarter test of whether PECO is over-earning through its DSIC surcharge, is not suited to identification of the cost of common equity which PECO should be allowed the opportunity to earn as of the end of the FPFTY.

[39] PECO's December 2020 Quarterly DSIC Report calculated a DSIC rate of over 18%, based on net recoverable DSIC cost and projected annualized revenues. The DSIC tariffed surcharge at 5% did not change. PECO Energy Company Quarterly Distribution System Improvement Charge Gas Operations, Docket No. M-2018-3000671, Letter dated Dec. 11, 2020.

VII. MR. MOUL'S DISCUSSION OF THE PROXY GROUP UTILIZED IN MY DIRECT TESTIMONY

Q. DOES YOUR SEPARATE ANALYSIS OF A COST OF EQUITY FOR PECO GAS' PARENT EXELON PROVIDE USEFUL INFORMATION?

A. Yes. As referenced in my direct testimony, due to the outcomes of the Hope/Bluefield cases, commissions across the country use proxy groups to set the return on equity in regulated rate cases. As such, I conducted a cost of equity analysis based upon a comparable company proxy group comprised of natural gas utilities, but I also conducted a separate analysis of Exelon.

Mr. Moul claimed that I did not provide any valid reason to examine Exelon separately in this case.[40] I disagree. The data produced by the analysis performed specifically on Exelon provides a direct link between Exelon and PECO Gas. Indeed, one cannot buy stock in PECO Gas directly but must, instead, purchase stock in Exelon. Hence, it is critical in the analysis of PECO Gas that one also examine the financial details of Exelon, its parent holding company, given the direct link between the two. Credit rating agencies have recognized this undeniable bond between a parent holding company and its utility subsidiary and closely tie the corresponding credit ratings of the two entities. Hence, it is naïve to think the equity cost of capital for Exelon is not determinative as to the equity cost of capital for PECO Gas.

To avoid the problem of circularity, I have also included the ten gas utilities in my comparable proxy company group that I examined. In doing so, I have provided the Commission with a well-rounded examination of several different proxy companies for

[40] Witness Moul's Rebuttal Testimony, page 18: lines 9 – 10.

PECO Gas. Such a holistic analysis is far better than picking and choosing companies that may or may not provide information as to the proper cost of capital for a utility.

Q. DO YOU HAVE ANY OTHER COMMENTS ON MR. MOUL'S CRITICISM OF YOUR PROXY GROUP?

A. Yes. Within my direct testimony, I explained that I opted to use the full group of ten gas utilities compiled and followed by *Value Line* due to the fact that the number of available gas utilities followed by financial agencies has been dwindling in recent years.[41] In contrast, Mr. Moul argued within his direct testimony that UGI Corporation should be removed from the *Value Line* industry grouping because its operations are more diversified outside of the gas distribution business in contrast to the other companies in the group.[42] I pointed out within my direct that Chesapeake Utilities also operates a diverse set of businesses and that as such, I did not find it appropriate to include one diverse company while simultaneously excluding another.[43]

As part of the proxy group screening process now explained within his rebuttal, Mr. Moul provided various financial metrics for each of the companies within his proxy group. These metrics included: (1) the percentage of regulated utility revenues out of total revenues, (2) the percentage of regulated utility income out of total income, and (3) the percentage of regulatory utility assets out of total assets.[44] The percentages included in this portion of Mr. Moul's rebuttal testimony were taken from his response to interrogatory

[41] Witness O'Donnell's Direct Testimony: page 31: lines 4 – 14.
[42] Witness Moul's Direct Testimony, page 6: lines 1 – 6.
[43] Witness O'Donnell's Direct Testimony, page 33: lines 7 – 16.
[44] Witness Moul's Rebuttal Testimony, page 19: lines 8 – 14.

I&E-RR-5-D. Based on my inspection of Mr. Moul's response to this I&E interrogatory, I identified flaws with the data used by Mr. Moul in taking this approach.

First, the data used to compile the values in Mr. Moul's response to interrogatory I&E-RR-5-D is outdated as the data was sourced from the 2018 10-K's of these various natural gas companies. There are also issues with the data selected by Mr. Moul from these 10-K's. As one example, the value shown by Mr. Moul in his response to interrogatory I&E-RR-5-D for the Regulated Revenues and Total Revenues of New Jersey Resources Corp. are $25,299 and $46,286 (values presented in thousands), respectively. However, an inspection of New Jersey Resources Corp.'s 2019 10-K shows that the values of $25,299[45] and $46,286[46] are actually the interest expense values for the Company during 2018, rather than the revenue values. The actual regulated utility operating revenues and total operating revenues for New Jersey Resources Corp. for 2018 are $731,865[47] and $2,915,109[48], and the 2019 regulated utility operating revenues and total operating revenues for New Jersey Resources Corp. are actually $710,793[49] and $2,592,045[50], respectively.

Q. WHAT DO THESE ISSUES WITH MR. MOUL'S PROXY GROUP PROCESS MEAN WITHIN THE CONTEXT OF THIS RATE CASE?

A. In an industry where there are a higher number of such comparable companies, I have historically taken a deeper look into which companies I believe are more appropriate than others to be included within my proxy group. However, the number of companies within

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[45] New Jersey Resources Corp. 2019 10-K: page 125.
[46] *Id.*
[47] New Jersey Resources Corp. 2019 10-K: page 70.
[48] *Id.*
[49] New Jersey Resources Corp. 2019 10-K: page 70.
[50] *Id.*

the natural gas industry is dwindling due to a variety of factors that I explained within my direct. As such, given that none of the ten companies within the Natural Gas industry grouping provided by *Value Line* were undergoing any sort of bankruptcy, legal issues, restructuring, or merger activities at the time when my direct testimony was filed, I utilized the full ten companies provided by *Value Line* as opposed to examining metrics of whose importance is inherently subjective to the analyst performing the cost of capital analysis. Mr. Moul, however, chose to use various financial metrics as a basis for developing his proxy group, the underlying data of which included numerous issues.

I ultimately believe that a large part of what this proxy group process provides, especially in an industry where the number of comparable companies is already so small, is simply a look into how an analyst attempts to shape their comparable company proxy group to fit the ROE narrative for their respective client. Put simply, by including such voluminous discussion of the composition of one's proxy group, Mr. Moul is distracting from the key point in this case that his 10.95% ROE recommendation is grossly in excess of any such benchmark or comparable measure and is inflated by his choices of certain forecasted data and his various unwarranted upward adjustments.

VIII. MR. MOUL'S INCLUSION OF RECALCULATED COST OF CAPITAL RESULTS WITHIN HIS REBUTTAL TESTIMONY

Q. DOES MR. MOUL'S REVISED COST OF EQUITY ANALYSIS JUSTIFY THE COMPANY'S 10.95% ROE REQUEST?

A. No. Within his rebuttal testimony, Mr. Moul recalculated the entirety of his cost of equity models, in part because the market data included in his direct testimony filed on September 30, 2020 was based upon data through June 30, 2020.[51]

The impact of Mr. Moul's recalculations included within his rebuttal testimony is that his DCF and CAPM results increased by 72- and 34-basis points, respectively, as shown in **PECO Exhibit PRM-1 (Updated), Schedule 1, page 2** within his rebuttal.[52] Just as the calculations included in his direct testimony did not justify the Company's 10.95% ROE request, neither do these updated calculations in his rebuttal testimony. As set forth in my direct testimony, Mr. Moul's DCF and CAPM cost of capital analyses are flawed and include improper adjustments. Using the same cost of capital analyses and adjustments with more current data does not improve the reliability of his results.

Q. DO YOU BELIEVE THAT THE COMPANY'S REQUIRED ROE IS NOW HIGHER THAN IT WAS PRIOR TO THE COVID-19 PANDEMIC?

A. No, I do not. As stated previously within this testimony, the DJUA has largely rebounded from its low in March 2020 brought on by the COVID-19 pandemic, and interest rates have remained depressed as well. In light of these simple facts, PECO Gas' cost of equity

[51] Witness Moul's Direct Testimony, PECO Exhibit PRM-1, Schedule 1: page 2.
[52] Witness Moul's Rebuttal Testimony, PECO Exhibit PRM-1 (Updated), Schedule 1: page 2.

capital is not higher now than it was when its most recent previous rate case concluded, or since the beginning of the COVID-19 pandemic.

Q. DO YOU AGREE WITH THE OVERALL APPROPRIATENESS OF MR. MOUL'S INCLUSION OF UPDATED DATA WITHIN HIS REBUTTAL TESTIMONY?

A. No. Mr. Moul's direct testimony was filed on September 30, 2020 and only included information through June 2020. In his rebuttal testimony, Mr. Moul noted the following:

> *I have prepared an update of the data I used to measure the cost of equity. With these later data, I have moved beyond the initial data that I employed in my direct testimony. There, the market data ended in June 2020 and I focused on three-month averages for reasons explained in PECO Energy Statement No. 5. In the update, I moved forward the date to December 2020, and also reverted to my usual six-month averages in light of market conditions and the COVID-19 pandemic.*[53]

Of the additional data reviewed and included by Mr. Moul, only the October, November, and December data was unavailable when the Company filed Mr. Moul's direct testimony.

Q. PLEASE COMMENT ON MR. MOUL'S DIVIDEND YIELD UPDATE.

A. Mr. Moul stated in his direct that it is his "long-standing" practice to use a six-month of data in his DCF and Risk Premium models.[54] However, in this proceeding, Mr. Moul used a 3-month average period "*using data that follows from the beginning of the economic recession*."[55]

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[53] Witness Moul's Rebuttal Testimony, page 10: lines 7 – 12.
[54] Witness Moul's Direct Testimony, page 3: lines 10 – 19.
[55] *Id.*

In effect, by departing from his "*long-standing*" practice of using the six-month data for the dividend yield portion of the DCF, and instead using the three-month data from the period of April 2020 through June 2020, Mr. Moul increased his unadjusted dividend yield used in his direct testimony's DCF analysis from 3.06% (six-months) to 3.16% (three-months), as shown in **PECO Exhibit PRM-1, Schedule 7, page 1**. This change from Mr. Moul's long-standing practice of using the six-month data to using the three-month data in his direct testimony increased Mr. Moul's DCF results in his direct testimony by 10-basis points. Mr. Moul then adjusted this three-month average dividend yield of 3.16% upward by 12-basis points to 3.28%.[56] However, as I noted in my direct testimony, other than simply providing the names of three different dividend yield adjustment methods and then averaging those three such adjustments to arrive at his 12-basis point adjustment, Mr. Moul did not provide any explanation as to what this 12-basis point dividend yield adjustment constituted or why it was appropriate in the first place.[57]

However now within his rebuttal testimony, Mr. Moul has "reverted" to using the six-month data for the dividend yield portion of the DCF and claimed the change was "*in light of market conditions and the COVID-19 pandemic.*" Based upon inspection of the more recent data for Mr. Moul's proxy group companies and Mr. Moul's dividend yield calculations within his rebuttal, there is now no difference between Mr. Moul's unadjusted three-month average and six-month average dividend yields. Mr. Moul used the three-month average dividend yield in his direct testimony when that dividend yield resulted in a higher ROE recommendation at that time, but now that the three- and six-month dividend yields are the same value, Mr. Moul has reverted to his "long-standing" approach of using

[56] Witness Moul's Direct Testimony, page 25, lines 15-20.
[57] Witness O'Donnell's Direct Testimony, page 98: lines 1 – 17.

the six-month average. The Commission needs an unbiased view of the marketplace and Mr. Moul does not provide such a view when his methods are repeatedly changing back and forth.

Q. WAS MR. MOUL'S DIVIDEND YIELD AVERAGE CHANGE BETWEEN HIS DIRECT AND REBUTTAL NECESSARY TO PRESENT THE COMMISSION WITH A DIVIDEND YIELD MEASURE THAT CAPTURES 2020 ECONOMIC DEVELOPMENTS, INCLUDING THE PANDEMIC?

A. No. PECO Gas made the decision to file their base rate case during the midst of a global pandemic. Mr. Moul's rebuttal incorporated an additional six months of data from July 2020 – December 2020 that was not included in his direct testimony, despite the fact that half of this additional data was readily available at the time of the Company's rate filing on September 30, 2020. This data may be new to the Company's case as of Mr. Moul's rebuttal testimony, but my direct testimony already captured and incorporated financial and market data available as of December 2020.

Q. PLEASE COMMENT ON THE OTHER PARTS OF MR. MOUL'S DCF ANALYSES IN HIS REBUTTAL TESTIMONY.

A. Mr. Moul's updated dividend yield includes adjustments which are still not explained and not necessary. Mr. Moul did not change his DCF growth rate in rebuttal from 7.50%.[58] However, Mr. Moul recalculated his leverage adjustment in rebuttal, an increase from 1.96% to 2.17%.[59] As I explained in my direct testimony, Mr. Moul's adjustment to the

[58] Witness Moul's Rebuttal Testimony, page 11: lines 4 – 5 and page 21: line 17.
[59] Witness Moul's Rebuttal Testimony, page 11: line 4.

dividend yield and addition of a "leverage adjustment" to the DCF each contribute to a cost of equity estimate which is unsound and overstated. Mr. Moul's chosen growth rate is also overstated based in large part by his narrow reliance on forecasted earnings per share growth rates. The Commission has also not been persuaded in recent years to adopt Mr. Moul's leverage adjustment.

Mr. Moul infers that a Commission allowance of his leverage adjustment and his recommendation for basis points to award the Company for management performance would constitute a reasonable outcome,[60] however neither should not be adopted. Mr. Moul has not shown that PECO is subject to the particular financial risk which requires a leverage adjustment of the type described by Mr. Moul in the current economic climate. Further, the Company has not provided support for an allowance of 25-basis points in equity return for exemplary management performance.

[60] Witness Moul's Rebuttal Testimony, page 29, lines 13 – 22, page 30, line 1 – 6.

IX. <u>MR. MOUL'S CRITICISM OF MY DCF CALCULATION INPUTS AND ASSOCIATED RESULTS</u>

Q. IS MR. MOUL'S CRITICISM OF YOUR DCF GROWTH RATES VALID?

A. No. In my direct testimony and associated exhibits, I included EPS, DPS, and BPS growth rates from historical and forecasted perspectives, as well as plowback (*i.e.*, percent retained to common equity) growth rates. Mr. Moul responded to my use of these metrics in his rebuttal testimony by stating:

> *Mr. O'Donnell presents DPS (dividends per share) and BPS (book value per share) growth rates in addition to EPS (earnings per share) growth. Mr. O'Donnell is incorrect to believe that DPS and BPS have any role in the DCF Model.*[61]

Mr. Moul also faults my use of plowback (*i.e.*, percent retained to common equity) growth rates.[62] I disagree with the arguments presented by Mr. Moul and note that there are various academic articles and journals that specifically call into question the accuracy of earnings predictions and forecasts. For example, as noted within my direct testimony, in November 2003, Louis K. C. Chan, Jason Karceski and Josef Lakonishok published an article entitled "*Analysts' Conflict of Interest and Biases in Earnings Forecasts*" in the *Journal of Finance*. The conclusion of the paper stated:

> *. . . it is commonly suggested that one group of informed participants, security analysts, may have some ability to predict growth. The dispersion in analysts' forecasts indicates their willingness to distinguish boldly between high- and low-growth prospects. IBES long-term growth estimates are associated with realized growth in the immediate short-term future. Over long horizons, however, there is <u>little forecastability in earnings, and analysts' estimates tend to be overly optimistic</u>.*[63]

[61] Witness Moul's Rebuttal Testimony, page 25: lines 5 – 7.
[62] Witness Moul's Rebuttal Testimony, page 26: lines 8 – 22, and page 27: lines 1 – 10.
[63] K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance* (2003), page 683. (underline emphasis added)

I recognize that, as referenced by Mr. Moul, there are other academic articles and journals that support the opposite viewpoint. However, given the fact that this remains a debated topic, I have historically included EPS, DPS, BPS (from both an historical and forecasted perspective), and plowback growth rates within my DCF analysis. By relying entirely on EPS growth rates, and specifically only relying on those provided from a forecasted perspective as Mr. Moul has done in his analysis, he has not considered all of the available data and has taken an unnecessarily narrow viewpoint. Please note that within my DCF analysis, I have also clearly evaluated certain forecasted EPS growth rates. However I believe that relying entirely upon forecasted EPS growth rates produces unrealistically high returns on equity numbers that cannot be sustained indefinitely.

Q. DO YOU AGREE WITH MR. MOUL'S DISCUSSION REGARDING HIS SOLE USE OF FORECASTED GROWTH RATES FOR APPLICATION WITHIN THE DCF?

A. No, I do not. Historical growth rates, in conjunction with my use of forecasted growth rates, helped me arrive at my ultimate recommendation of a 4.25% to 6.25% growth rate range for application within my DCF model.[64] Mr. Moul criticized my use of historical growth rates by stating the following within his rebuttal:

> *…forecast earnings growth is the only valid measure of growth for DCF purposes*.[65]

As I stated in direct testimony, investors examine a wide variety of growth rate metrics to inform their investment decisions. One of my main purposes when presenting testimony

[64] Witness O'Donnell's Direct Testimony, page 73: lines 8 – 12.
[65] Witness Moul's Direct Testimony, page 28: lines: 2 – 3.

to a Commission is to provide an analysis that is as complete and as thoroughly researched as possible. Presenting such a thorough analysis includes the presentation of EPS, DPS, and BPS growth rates from a historical and forecasted perspective as well as the presentation of other growth rates, such as plowback. The data included within an analyst's testimony should speak for itself without the analyst feeling the need to make various modifications or adjustments to the data that would ordinarily constitute the final results.

Additionally, there is an inconsistency in Mr. Moul's testimonies in this case. On one hand, Mr. Moul expresses concern that PECO Gas' risk is higher than other comparable companies. On the other hand, Mr. Moul relies solely upon forecasted growth rates for application within the DCF. These forecasted growth rates represent estimates being made by analysts during a period when the COVID-19 pandemic has led to greater uncertainty in relation to the accuracy of such forecasted growth rates. The historical growth rate data is readily available, but Mr. Moul has ignored such data.

Q. MR. MOUL CLAIMED THAT YOU DID NOT REFUTE HIS PROPOSED 196-BASIS POINT LEVERAGE ADJUSTMENT AND THAT THE ADJUSTMENT SHOULD BE ACCEPTED. IS THIS CORRECT?

A. No, this is not correct. In his rebuttal testimony, Mr. Moul included the following:

> *I&E witness Keller and OCA witness O'Donnell have not refuted the accuracy of the Company's leverage adjustments to the DCF and beta component of the Capital Asset Pricing Model ("CAPM"). Without such opposition, these should be accepted.*[66]

[66] Witness Moul's Rebuttal Testimony, page 3: lines 16 – 20.

In including the above statement within his rebuttal testimony, Mr. Moul has not acknowledged the section of my direct testimony which stated the following:

> ***Q. DO YOU AGREE WITH MR. MOUL'S USAGE OF THE 196-BASIS POINT LEVERAGE ADJUSTMENT.***
>
> *A. No. This adjustment stems from Mr. Moul's apparent belief that investors are unaware of debt on the Company's books and, therefore, they must be compensated for the additional risk.*[67]

Within pages 101 – 103 following the above Q&A from my direct testimony, I outlined in detail why I do not agree conceptually with the principles behind Mr. Moul's leverage adjustment and why I believe that this leverage adjustment is simply an attempt to justify an unreasonable return on equity for the Company.

Additionally, the selection above from Mr. Moul's rebuttal says that "*The I&E and OCA witnesses have <u>not refuted the accuracy</u> of the Company's leverage adjustments…*"[68] However, within Mr. Moul's direct testimony, he goes as far to admit that he knows "…*<u>of no means to mathematically solve for the 1.96% leverage adjustment</u> by expressing it in the terms of any particular relationship of market price to book value. <u>The 1.96% adjustment is merely a convenient way to compare</u> the 12.74% return computed directly with the Modigliani & Miller formulas to the 10.78% return generated by the DCF model…based on a market value capital structure*."[69] Based on the previously referenced sections from Mr. Moul's direct testimony, he has, himself, refuted the accuracy of his own adjustment.

The inclusion of such a leverage adjustment by Mr. Moul stems from his belief that investors, when purchasing an equity, are unaware that the market price of a security

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[67] Witness O'Donnell's Direct Testimony, page 101: lines 11 – 15.
[68] Witness Moul's Rebuttal Testimony, page 3: lines 16 – 20. (underline emphasis added)
[69] Witness Moul's Direct Testimony, page 36: lines 13 – 19. (underline emphasis added)

is different than the book value of the underlying security. Such a belief is simply irrational. Mr. Moul's market-to-book leverage adjustment (which has been increased from 1.96% in Mr. Moul's direct testimony to 2.17% in his rebuttal testimony[70] without merit) is, again, another attempt to justify a higher allowed ROE than what is currently being found in the marketplace.

Q. MR. MOUL LATER CLAIMED WITHIN HIS REBUTTAL TESTIMONY THAT YOU DID REFUTE HIS PROPOSED LEVERAGE ADJUSTMENT. IS THIS CORRECT?

A. Yes. Mr. Moul later contradicted himself within his rebuttal and stated that I actually did disagree with his leverage adjustment,[71] despite the fact that he stated the opposite previously.[72] As referenced in the Q&A above, I stated within my direct testimony the reasoning for why I do not agree in principle with Mr. Moul's leverage adjustment. However, I again call attention to Mr. Moul's response to two separate data requests in which Mr. Moul noted that he had proposed a leverage adjustment within his DCF model in over thirty different rate cases on behalf of a Pennsylvania public utility in the past ten years,[73] and that Mr. Moul was not aware of any such cases within the past ten years in which the Commission approved one of these leverage adjustments. Mr. Moul has not provided sound reasoning as to why the Commission should adopt this leverage adjustment in determining an appropriate cost of equity for PECO Gas and the Company's ratepayers in this proceeding.

[70] Witness Moul's Rebuttal Testimony, page 11: line 4.
[71] Witness Moul's Rebuttal Testimony, page 31: lines 6 – 14.
[72] Witness Moul's Rebuttal Testimony, page 3: lines 16 – 20.
[73] Witness Moul's response to Question No. **OCA-IV-5**.

X. MR. MOUL'S CRITICISM OF MY CAPM CALCULATION INPUTS AND ASSOCIATED RESULTS

Q. MR. MOUL CRITICIZED YOUR CAPM MODEL FOR NOT INCLUDING FORWARD-LOOKING DATA SPECIFIC TO THE RISK-FREE RATE OF RETURN. DO YOU HAVE A RESPONSE TO THIS CLAIM?

A. Yes. Within his rebuttal testimony, Mr. Moul makes the assertion that:

> *Mr. O'Donnell's CAPM approach suffers from the infirmity of not positioning the risk-free rate of return in a forward-looking manner – rather he used historical results obtained from the past year*.[74]

Within my direct testimony and related exhibits, I noted that I developed my CAPM results of 5.50% – 7.75%[75] based partially upon my use of the maximum, average, and minimum values of the 30-year U.S. Treasury Bond Yields from December 11, 2019 to December 11, 2020 to approximate the risk-free rate. The average value for this period was 1.59%,[76] and the value as of December 11, 2020 was 1.63%.[77] In reference to the risk-free rate that I utilized within my CAPM, Mr. Moul criticized my use of such data for my risk-free rate and opined that if had I used expectational data to develop my risk-free rate for use within the CAPM, my results would have been markedly different.

Given that the risk-free rate used by Mr. Moul in his direct testimony was 1.75%[78], there is not a drastic difference in the risk-free rates used in my CAPM analysis in comparison to what was used by Mr. Moul in his direct. Note that within his rebuttal

[74] Witness Moul's Rebuttal Testimony, page 36: lines 5 – 7.
[75] Witness O'Donnell's Direct Testimony, page 87: line 9.
[76] Witness O'Donnell's Direct Testimony, page 86: line 14.
[77] Witness O'Donnell's Direct Testimony, page 86: line 12.
[78] Witness Moul's Direct Testimony, PECO Exhibit PRM-1, Schedule 13: Page 2.

testimony however, Mr. Moul raised his risk-free rate from 1.75% to 2.00%[79], for which he does not provide an explanation.

Not only does Mr. Moul provide no discussion as to the appropriateness of the increase in his risk-free rate, but most in the industry do not anticipate interest rates to significantly rise any time in the near future. For instance, an article recently published by *Barron's* entitled "*Fed Signals Near-Zero Rates Through 2023 Even if Recovery Quickens*" stated that in accordance with recently approved strategy by the Federal Reserve, "*…officials predicted interest rates would remain unchanged through at least 2023, as most investors and Wall Street strategists had expected*."[80] As outlined within this article, interest rates are not expected to return to the 2.00% level now asserted by Mr. Moul within the "updated" cost of capital analysis within his rebuttal testimony at any point in the near term or even the next several years.

Additionally, in a different natural gas utility base rate case in January 2019, Mr. Moul claimed that the forecasted risk-free rate for use within the CAPM was appropriate to be set at 3.75%.[81] For context, at the start of 2019, the 30-year US Treasury Bond yield was 2.97%, decreased to 2.39% as of the end of 2019 (*i.e.*, prior to the impacts of the COVID-19 pandemic), and then decreased to 1.79% as of January 27, 2021.[82] Mr. Moul's own previous forecasts and overreliance upon positioning the "*risk-free rate of return in a forward-looking manner,"* have simply missed the mark badly even prior to the impacts of the COVID-19 pandemic.

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[79] Witness Moul's Direct Testimony, PECO Exhibit PRM-1, Schedule 13: Page 2.

[80] https://www.barrons.com/articles/fed-signals-near-zero-rates-through-2023-even-if-recovery-quickens-51600281377?mod=article_inline

[81] Pa. P.U.C. v. UGI Utilities – Gas Div., Docket No. R-2018-3006814, Company Rate Filing, Book IV, UGI Gas St. 5, Paul R. Moul Direct Testimony, page 46.

[82] https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield.

Q. MR. MOUL CRITICIZED YOUR USE OF THE GEOMETRIC MEAN IN EVALUATING HISTORICAL RETURNS DATA. HAVE YOU ONLY RELIED UPON THE GEOMETRIC MEAN IN ANALYZING SUCH RETURNS?

A. No. Mr. Moul included the following passage within his rebuttal testimony:

> *Mr. O'Donnell has incorrectly used the geometric mean in his historic analysis of the total market returns.*[83]

In the selection above from Mr. Moul's rebuttal testimony, he referenced page 83 of my direct testimony. However, within the **Table 10** included on page 83 of my direct testimony, I very clearly included both the geometric and arithmetic mean returns as provided by the Ibbotson SBBI Annual Yearbook for the purpose of the comparison of these returns to the forecasted market return and resulting risk premium used by Mr. Moul. Nowhere within my direct testimony did I say that I singularly relied upon the geometric mean instead of the arithmetic mean, nor that I afforded the arithmetic mean no weight in my analysis.

I presented both the geometric average return and the arithmetic average return within my direct testimony in order to provide the Commission as much information as possible. Mr. Moul's comments on my reliance upon the geometric mean versus the arithmetic mean is simply a failed attempt to mislead the Commission by misrepresenting my testimony.

Mr. Moul also claimed in his rebuttal testimony that within **Table 10** to my direct testimony, I had "*erroneously reported the Long-Term Govt. Bond return as 8.7%, when the correct return is 6.0%*."[84] In response I refer him to Exhibit 2.14 "Summary Statistics

[83] Witness Moul's Rebuttal Testimony, page 36: lines 15 – 16.
[84] Witness Moul's Rebuttal Testimony, footnote 7.

of Annual Returns (%) 1972 – 2019" of the Stocks, Bonds, Bills, and Inflation ("SBBI") 2020 Summary Edition[85], which clearly shows an Arithmetic Average Return of 8.7% for "Long-term Gov't Bonds." It is unclear why Mr. Moul made the above statement without checking with the source as cited in my direct testimony. Had Mr. Moul done so, he would have clearly seen that my inclusion of 8.7% was accurate.

In this instance, I believe that Mr. Moul confused the annual return period examined within my direct testimony and as cited in the 2020 Summary Edition of the SBBI. The 6.0% long-term return is for the time period dating back to 1926, which was the original starting period for SBBI, but this is not the time period which I cited in my direct testimony from the 2020 Summary Edition of the SBII.

Q. MR. MOUL CRITICIZED YOUR USE OF CERTAIN FORECASTED MARKET RETURNS.[86] WHAT DO THESE MARKET RETURN PROJECTIONS SHOW AND WHY DO YOU FEEL THEY ARE MORE APPROPRIATE THAN THE FORECASTED MARKET RETURNS USED BY MR. MOUL?

A. On Pages 83 – 85 of my direct testimony in this case, I presented various forecasted market returns from a multitude of sources that ultimately led to my projected equity risk premium of 4.25% - 6.25%[87], which when taken in conjunction with my 30-year risk free rate range of 0.99% to 2.39% provide my forecasted overall market return range. As shown within my direct testimony, each of the forecasted market returns from the sources that I referenced are all significantly lower forecasted market returns than that which Mr.

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[85] https://www.cfainstitute.org/-/media/documents/book/rf-publication/2020/rf-sbbi-summary-edition.ashx
[86] Witness Moul's Rebuttal Testimony, page 38: lines 7 – 13.
[87] Witness O'Donnell's Direct Testimony, **Exhibit KWO-7**.

Moul contended of 15.74%, 6.07%, and 9.04% in his direct testimony[88] and 9.79%, 11.21%, and 9.04% in his rebuttal testimony.[89]

In response to these forecasted market return expectations that indicate that future return expectations for U.S. equities will be lower than what they have been historically, Mr. Moul claims that the sources I provided on Pages 83 – 85 of my direct testimony were "*non-standard sources*."[90] My sources are certainly not "non-standard sources" as contended by Mr. Moul. *Vanguard* is the second largest mutual fund industry in the country and *Schwab* is the third largest. In this section of my testimony, I also cited *Morningstar*, which Mr. Moul, himself, cited in his direct testimony.[91] Mr. Moul may not like the forecasts provided the financial institutions I cited (inclusive of *Vanguard*, *Schwab*, and *Morningstar*) as such forecasts would indicate lower market return forecasts than those claimed by Mr. Moul, but the sources are all highly regarded mainstream financial service providers and are in no way "non-standard".

Q. HOW DO MR. MOUL'S SOURCES TO DEVELOP HIS MARKET RETURN FORECASTS COMPARE TO THOSE WHICH YOU USED?

A. In reference to the sources used by Mr. Moul for the forecasted market premiums within his CAPM analysis, note that in my direct testimony I criticized Mr. Moul's use of a "Median Appreciation Potential" as part of his Forecasted "Value Line Return", which was one of the two data points he used to develop his Forecasted Market Return.[92] This

[88] Witness Moul's Direct Testimony, PECO Exhibit PRM-1, Schedule 13: Page 2.
[89] Witness Moul's Rebuttal Testimony, PECO Exhibit PRM-1 (Updated), Schedule 13: Page 2.
[90] Witness Moul's Rebuttal Testimony, page 38: line 11.
[91] Witness Moul's Direct Testimony, page 31: line 17.
[92] Witness O'Donnell's Direct Testimony, page 110: lines 14 – 21 and page 111: lines 1 – 17.

Median Appreciation Potential value approximates the overall market's 18-month appreciation price potential. However, this price appreciation potential varies widely, especially when an anomalous event such as the COVID-19 pandemic occurs. For example, in my direct testimony, I referenced the fact that the Median Appreciation Potential provided by *Value Line* on June 26, 2020 was 13.34% (as used by Mr. Moul in his direct), but that the Median Appreciation Potential was just 7% "26 weeks" prior to June 26, 2020, was 72% during the "Market Low" period on March 23, 2020, and was 6% during the "Market High" period on February 19, 2020.[93]

As yet another example of the wild variability of this metric used by Mr. Moul, the Median Appreciation Potential as of December 25, 2020 as applied by Mr. Moul in his rebuttal testimony was just 7.79%.[94] The sharp decrease in this metric from June 26, 2020 to December 25, 2020 resulted in a 5.95% decrease in the Forecasted "Value Line Return" (*i.e.,* 15.74%[95] to 9.79%[96]), which was used as one of the data points employed by Mr. Moul to develop the Forecasted Market Return within his CAPM analysis.

One would ordinarily conclude that such a large decrease within one of the two data points used to develop a Forecasted Market Return would have led to the overall Forecasted Market Return used in a CAPM analysis to decrease considerably. However, Mr. Moul's overall Forecasted Market Return only decreased 0.41% (*i.e.,* 10.91%[97] to 10.50%[98]).

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[93] Witness O'Donnell's Direct Testimony: page 109: lines 22 – 24, page 110: lines 19 – 21, and page 111: lines 1 – 3.
[94] Witness Moul's Rebuttal Testimony: PECO Exhibit PRM-1 (Updated), Schedule 13: Page 2.
[95] Witness Moul's Direct Testimony: PECO Exhibit PRM-1, Schedule 13: Page 2.
[96] Witness Moul's Rebuttal Testimony: PECO Exhibit PRM-1 (Updated), Schedule 13: Page 2.
[97] Witness Moul's Direct Testimony: PECO Exhibit PRM-1, Schedule 13: Page 2.
[98] Witness Moul's Rebuttal Testimony: PECO Exhibit PRM-1 (Updated), Schedule 13: Page 2.

Q. IF ONE OF THE TWO DATA POINTS USED BY MR. MOUL TO DETERMINE HIS FORECASTED MARKET RETURN DECREASED SO DRASTICALLY, WHY DID HIS OVERALL FORECASTED MARKET RETURN NOT DECREASE AT A SIMILAR RATE?

A. As explained within my direct testimony, Mr. Moul used two data points to develop his Forecasted Market Return, (1) a Forecasted "Value Line Return" and (2) a Forecasted "DCF Result for the S&P 500 Composite." He then took the average of these two values to determine his overall Forecasted Market Return for use in his analyses.

Mr. Moul was able to guard against the large decrease within his Forecasted "Value Line Return" data point by changing each of the inputs that he used to develop his second Forecasted Market Return data point (*i.e.*, Forecasted "DCF Result for the S&P 500 Composite"). Through the increase of each of the inputs employed to compute this second data point that was then used to develop his overall Forecasted Market Return, Mr. Moul increased his Forecasted "DCF Result for the S&P 500 Composite" by 5.14% (*i.e.*, 6.07%[99] to 11.21%[100]). See **Table 4S** below for a presentation of these values:

Table 4S: Witness Moul's Forecasted Market Returns Direct Testimony vs. Rebuttal

Testimony	Mr. Moul's Direct[101]	Mr. Moul's Rebuttal[102]	Change (Rx)	Percent Change (Rx)
Forecasted "Value Line Return"	15.74%	9.79%	(5.95%)	(38%)
Forecasted "DCF Result for the S&P 500 Composite"	6.07%	11.21%	5.14%	85%
Average Overall "Forecasted Market Return"	10.91%	10.50%	(0.41%)	(4%)

[99] Witness Moul's Direct Testimony: PECO Exhibit PRM-1, Schedule 13: Page 2.
[100] Witness Moul's Rebuttal Testimony: PECO Exhibit PRM-1 (Updated), Schedule 13: Page 2.
[101] Witness Moul's Direct Testimony: PECO Exhibit PRM-1, Schedule 13: Page 2.
[102] Witness Moul's Rebuttal Testimony: PECO Exhibit PRM-1 (Updated), Schedule 13: Page 2.

As shown above, simply with the addition of an extra 6 months of data, Mr. Moul's two overall Forecasted Market Return data points had a percent change fluctuation of (38%) and 85%, respectively. Such wide fluctuations in the data inputs shows a critical flaw with Mr. Moul's use of such data in his CAPM as an analyst should never use such short-term highly variable data when determining components in any cost of capital analysis.

Q. DO YOU HAVE ANY OTHER COMMENTS ON THE MARKET RETURN FORECASTS USED BY MR. MOUL?

A. Yes. As noted within my direct testimony, I included reference to Exelon's (*i.e.*, PECO Gas' parent company) own pension plan estimates. In response to data request **OCA-IV-20**, Exelon noted that they have assumed a 7% expected return on pension assets, which is clearly far below Mr. Moul's overall Forecasted Market Return.[103]

Mr. Moul himself provided the data request response to **OCA-IV-20** and opted not to address this criticism of his growth rates within his rebuttal testimony. Ultimately, Mr. Moul's chosen overall Forecasted Market Return is simply illogical and directly conflicts with his employer's own pension forecast, upon which the pension revenue requirement in this case is calculated.

For the reasons outlined above, the Forecasted Market Return and related Forecasted Market Premium used by Mr. Moul should be given no weight in this proceeding. The proper Forecasted Market Premium for application within the CAPM more closely approximates 4.25% – 6.25% as I have explained in my direct testimony.

[103] Witness Moul's response to Question No. **OCA-IV-20**.

Q. IN HIS REBUTTAL TESTIMONY, MR. MOUL STATED THAT THE ADJUSTMENTS HE MADE TO HIS CAPM MODEL WERE APPROPRIATE. DO YOU HAVE A RESPONSE TO THIS SPECIFIC CLAIM?

A. Yes. I still oppose Mr. Moul's leverage and size adjustments used within his CAPM analysis. As I noted above in response to Mr. Moul's similar claim for his leverage adjustment within his DCF, the adjustments Mr. Moul employed in his CAPM only serve as a measure to artificially inflate his ROE recommendation.

I explained in detail within my direct testimony my reasoning for my disagreement with Mr. Moul's unleveraging and releveraging of the Betas used in the CAPM and Mr. Moul's CAPM 102-basis point firm size adjustment. In regard to Mr. Moul's adjustment of the Betas, *Value Line* already performs an adjustment upon the historical unadjusted Betas to ensure that the Betas presented through their service are forward looking and prospective. Mr. Moul provided no basis as to why his unleveraging and releveraging of the *Value Line* Betas used within his CAPM is warranted, nor why it was appropriate to increase the Beta used within his CAPM from 1.05 in his direct to 1.10[104] in his rebuttal. Additionally, in regard to the 102-basis point CAPM size adjustment, such an adjustment is simply unwarranted to use for a utility the size of PECO Gas.

Furthermore, I want to again call attention to Mr. Moul's response to two separate data requests wherein Mr. Moul noted that he had proposed a firm size adjustment within his CAPM models in over thirty different rate cases on behalf of a Pennsylvania public utility in the past ten years,[105] and that Mr. Moul was not aware of any case within the

[104] Witness Moul's Rebuttal Testimony: PECO Exhibit PRM-1.
[105] Witness Moul's response to Question No. **OCA-IV-5**.

past ten years in which the Commission had approved his proposed firm size adjustment to a CAPM analysis.[106]

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

[106] Witness Moul's response to Question No. **OCA-IV-6**.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018929
	:	
PECO Energy Company – Gas Division	:	

VERIFICATION

I, Kevin W. O'Donnell, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 3-SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: February 9, 2021
*303587

Signature: Kevin W. O'Donnell
Kevin W. O'Donnell

Consultant Address: Nova Energy Consultants, Inc.
1350 SE Maynard Road
Suite 101
Cary, NC 27511

OCA Statement No. 4-SR

R-2020-3018929
2/17/21 JK

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
	)	
v.	)	Docket No. R-2020-3018929
	)	
	)	
PECO ENERGY COMPANY – GAS DIVISION	)	
	)	

SURREBUTTAL TESTIMONY
OF
GLENN A. WATKINS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

FEBRUARY 9, 2021

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 6377 Mattawan Trail, Mechanicsville, Virginia 23116.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS CASE?

A. Yes. I pre-filed direct testimony in this proceeding on December 22, 2020, which was designated as OCA Statement No. 4, as well as rebuttal testimony on January 19, 2021, which was designated as OCA Statement No. 4R.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of this testimony is to respond to the rebuttal testimonies of PECO witnesses Jiang Ding and Joseph Bisti, Philadelphia Area Industrial Energy Users Group ("PAIEUG") witness Billie Laconte, and OSBA witness Robert Knecht on issues concerning class cost of service and revenue allocations.

Q. ON PAGE 7 OF HER REBUTTAL TESTIMONY, MS. DING STATES THAT YOU HAVE OVEREMPHASIZED THE SIZE OF PIPE IN DETERMINING THE COST OF MAINS INSTALLATIONS. PLEASE RESPOND TO THIS ASSERTION.

A. Ms. Ding takes my testimony in this regard out of context. My testimony is clear and simple in that as the capacity of a given pipe increases, the cost of installing that pipe increases at a lesser rate. One must use an apples-to-apples comparison on a project-by-project basis. However, Ms. Ding obfuscates the issue by claiming that different projects may require different installation costs. Of course, different projects are confronted with different requirements. However, my testimony relates to apples-to-apples comparison; i.e., projects with similar "environmental obstructions" or "concerns that need to be addressed during the construction of the pipeline."

Q. ON PAGE 7 OF HER REBUTTAL TESTIMONY, MS. DING CLAIMS THAT YOU HAVE A FLAWED ASSUMPTION CONCERNING YOUR OBSERVATIONS THAT THERE IS NOT A NON-LINEAR RELATIONSHIP BETWEEN INCREASED PIPE CAPACITY AND COSTS. PLEASE RESPOND TO MS. DING'S CLAIM.

A. First, Ms. Ding states that my "assumption" is not necessarily true. In her support for an exception to my observations in this regard, Ms. Ding states that there is a point at which increasing demand necessitates material changes to the main such as a materials change from plastic to steel. Certainly, there are exceptions to every specific construction project, but most importantly and as provided in my response to PECO Data Request OCA-V-1, I showed how the cost of materials increases at a much slower rate than the capacity provided by larger diameter pipe. In this regard, I would agree that there are exceptions from time to time in that a company may install steel pipe instead of plastic pipe (which tends to cost more per foot) while there are many other exceptions as well. Furthermore, as also noted in my response to PECO Data Request OCA-V-1, the data specific to PECO was requested in this case but was not provided, yet Ms. Ding's rebuttal testimony is limited to exceptions to the facts I set forth in my testimony by stating it is "not necessarily true."

Q. PLEASE RESPOND TO MS. DING'S AND MS. LACONTE'S ASSERTIONS THAT THE PEAK & AVERAGE ("P&A") IS FLAWED BECAUSE THERE IS A DOUBLE-COUNT WITHIN AVERAGE ANNUAL USAGE.

A. Ms. Ding's assertion is found on page 8 of her rebuttal testimony while Ms. Laconte's assertion is discussed on page 6 of her rebuttal testimony. These statements of Ms. Ding and Ms. Laconte are nothing but red herrings and are misleading. While there is no doubt that average day demand is less than peak demand by mathematical definition, there is no double count in that these are distinctly different concepts. With respect to average day demand, this is the exact same percentage across classes as annual throughput, which is known as energy in the electric industry. As such, average day demand, annual throughput, and energy measure the utilization of resources over time. Peak demand measures the highest level of demand placed on the system and is conceptually the amount of load on a system at a single point in time. The concepts are totally different in that average demand measures utilization, while peak demand measures peak load. As a matter of physics, these concepts are totally different. As an analogy, consider a motor vehicle's average miles per gallon compared to its fuel burned during peak load. Over the course of a year, a vehicle will burn a certain amount of fuel over the course of thousands of miles and hours of use. This will equate to average miles per gallon. However, when that vehicle is towing a large trailer or has a heavy load, its fuel burned at that point in time is much greater than the average fuel consumption over the course of an entire year. The concepts are entirely different. One being energy usage and the other being peak load.

Q. ON PAGE 8 OF HER REBUTTAL TESTIMONY, MS. DING PURPORTEDLY PROVIDES SHORT QUOTES FROM THE AGA <u>GAS RATES FUNDAMENTALS</u>. THE FIRST QUOTE SHE CITES IS FROM PAGE 145 OF THIS BOOK AND STATES "[C]OST CAUSATION IS NOT THE RATIONALE." PLEASE RESPOND TO MS. DING'S STATEMENT IN THIS REGARD.

A. Attached as my Schedule GAW-1SR, is Chapter 7 – Cost Allocation Studies from the most recent (Fourth Edition) of the AGA book that Ms. Ding refers. Ms. Ding's quote relates to a method that was used for a short time by FERC known as the "United Method" in which 75% of all fixed costs are assigned to the commodity classification. This in no way is how the P&A method is utilized in that only mains-related costs are assigned on peak and average demands while other fixed costs such as production plant, storage plant, general plant, meters, service lines, etc. are allocated based on other criteria; e.g., peak demand, number of customers, or salaries and wages.

Q. IN THE SAME PARAGRAPH ON PAGE 8 OF HER REBUTTAL TESTIMONY, MS. DING STATES "THOSE COST ALLOCATION APPROACHES, LIKE THE P&A METHOD PROPOSED BY MR. WATKINS, REFLECT A DESIRE TO PRODUCE A CERTAIN OUTCOME THAT IS NOT DRIVEN BY COST CAUSATION." PLEASE RESPOND TO MS. DING'S STATEMENT.

A. First, while cost allocation experts may disagree on the concepts of how costs should be allocated across classes, I take great offense at her accusation that my difference of opinion is somehow results oriented. Indeed, one could make the same claim of Ms. Ding's study. However, it is my assumption that Ms. Ding's approach is based on her philosophical opinion which differs from other fellow experts.

Q. MR. WATKINS, MS. DING CLEARLY IS OF THE OPINION THAT THE P&A METHOD YOU RECOMMEND IS NOT REASONABLE AND ASSERTS THAT IT IS NOT IN ACCORDANCE WITH ACCEPTED INDUSTRY PRACTICES. HAS THE P&A METHOD AS YOU UTILIZED IN THIS CASE BEEN ACCEPTED AS A REASONABLE APPROACH IN OTHER CASES AND BEFORE OTHER COMMISSIONS?

A. Yes. The P&A approach is the only approved methodology used to allocate natural gas mains in the State of Washington. The P&A method has been deemed the most fair and reasonable approach in a recent Washington Gas Light case before the Virginia State Corporation Commission, the Kentucky Public Utility Commission has acknowledged that the P&A method is reasonable, the Maryland Public Service Commission has accepted the P&A method in natural gas cases, and perhaps most importantly, the Pennsylvania Public Utility Commission utilized the P&A method exactly as I have done in this case for decades.[1]

Q. MR. WATKINS, HAS THIS COMMISSION RELIED UPON ANOTHER SOURCE AS BEING AUTHORITATIVE FOR COST ALLOCATION STUDIES?

A. Yes. This Commission has referred to the NARUC Cost Allocation Manual as being the authoritative source for class cost allocations.[2]

[1] See for example, National Fuel Gas Distribution Corporation, Docket No. R-00942991, Final Order, 83 Pa. PUC at 359.

[2] See for example, PPL Electric Utilities Corporation, Docket No. R-2012-2290597, Final Order, page 113 and PPL Electric Utilities Corporation, Docket No. R-2010-2161694, Final Order, page 36.

Q. HAS NARUC PUBLISHED A NATURAL GAS COST ALLOCATION MANUAL?

A. Yes. Although the most recent AGA Gas Rate Fundamentals book was published in 1987, the most recent Natural Gas Distribution Rate Design Manual (which includes cost allocations) was published in June 1989.

Q. DOES THE NARUC NATURAL GAS MANUAL MENTION THE AVERAGE & EXCESS ("A&E") METHOD AS AN APPROVED METHODOLOGY TO ALLOCATE DISTRIBUTION MAINS?

A. No. The NARUC Gas Distribution Rate Design Manual lists three methods commonly used to allocate natural gas distribution mains. These methods include: the Coincident Demand (Peak Responsibility) method; Non-Coincident Demand method; and, Average & Peak Demand method. In this regard, NARUC's reference to "Average & Peak" is the same as Peak & Average. Attached to my testimony as Schedule GAW-2SR is the section of this Manual concerning cost allocations wherein this discussion can be found on pages 26 and 27.

Q. ON PAGE 9 OF HER REBUTTAL TESTIMONY, MS. DING ALSO ATTEMPTS TO REFER TO THE AGA GAS RATES FUNDAMENTALS BOOK WHEREIN SHE CLAIMS THE BOOK STATES "WHETHER AN INTERRUPTIBLE CUSTOMER SHOULD RECEIVE LESS THAN ITS PROPORTIONAL SHARE OF CAPACITY COSTS OR EVEN NO CAPACITY COSTS DEPENDS ON THE PHILOSOPHY OF THE COST ANALYST." PLEASE RESPOND TO MS. DING'S ASSERTION IN THIS REGARD.

A. As shown in my Schedule GAW-1SR, Ms. Ding's quote relates to the discussion of the Non-Coincident Demand method and not the Average & Excess or P&A methods. In this regard, and as it relates to the assignment of cost responsibility to interruptible customers, I recognized the inferior quality of service provided to interruptible customers by not assigning full cost responsibility to these customers. At the same time, I have assigned some mains cost responsibility to the interruptible classes by only assigning a portion of the cost responsibility to the interruptible classes.[3]

Q. ON PAGE 12 OF HER REBUTTAL TESTIMONY, MS. DING DISAGREES WITH YOUR RECOMMENDATION TO ASSIGN STORAGE PLANT BASED ON HER OWN "STORAGE" ALLOCATOR BY CLAIMING THAT "STORAGE PLANT IS USED TO MEET DESIGN DAY PEAK AND SHORT-TERM NEEDS FOR FIRM SALES CUSTOMERS; I.E., NOT FOR INTERRUPTIBLE CUSTOMERS UNDER RATE CLASSES SUCH AS TS-1." PLEASE RESPOND TO MS. DING'S THEORY IN THIS REGARD.

A. First, it is well known that one of the primary purposes of storage plant is to purchase gas during lower cost periods in the Summer, store that gas, and then make that cheaper gas available to sales customers throughout the more expensive heating season. A secondary and smaller purpose of storage is to assist with balancing for transportation customers. In these regards, I have utilized Ms. Ding's own storage allocator which she used only to assign gas storage inventory costs, but not the investment in storage plant. The following table provides a comparison of the design day demand Ms. Ding used to allocate storage plant to her own storage allocator that I utilized:

Class	Ding's Allocator Used For Storage Plant (Design Day)	Watkins' Allocator Used For Storage Plant (Ding's Storage Allocator)
Resid.	64.98%	66.86%
GC	34.71%	30.92%
Large	0.17%	0.02%
MVF	0.14%	0.01%
MVI	0.00%	0.00%
Interrupt.	0.00%	0.00%
Temp. Control	0.00%	0.00%
Firm Transport.	0.00%	0.97%
Interrupt. Transport.	0.00%	1.23%
TOTAL	100.00%	100.00%

[3] As discussed in my direct testimony, my recommended P&A allocation method assigns no "peak" portion to interruptible customers but only the "average" portion. Therefore, because my P&A method is weighted 50% on peak demand and 50% on average demand, the interruptible classes were only assigned their proportionate share of the 50% average demand and 0% associated with the peak demand component.

Q. MR. WATKINS, THE ABOVE TABLE INDICATES THAT YOU HAVE ALLOCATED MORE STORAGE PLANT COSTS TO THE RESIDENTIAL CLASS THAN DOES MS. DING. WAS THIS A RESULT OF YOUR SO-CALLED "DESIRE TO PRODUCE A CERTAIN OUTCOME THAT IS NOT DRIVEN BY COST CAUSATION?"

A. No. It is my opinion that my allocation approach based on Ms. Ding's own storage allocator reflects a better assignment of this cost responsibility. In summary, while Ms. Ding developed a storage allocator that reasonably recognizes the cost associated with storage plant, she elected to assign storage plant investment costs based on design day and not on her own storage allocator. As reflected in Ms. Ding's own calculated storage allocator, transportation customers benefit to a small degree from storage for their balancing needs.

Q. PLEASE RESPOND TO MS. DING'S DISCUSSION CONCERNING FORFEITED DISCOUNTS IN HER REBUTTAL TESTIMONY.

A. On pages 12 through 15, Ms. Ding discusses my treatment of forfeited discounts wherein I observed that Ms. Ding has not reflected the additional forfeited discounts that will be generated as a result of the Company's overall revenue increase. In this regard, and as discussed in my direct testimony, Ms. Ding's own cost of service study indicates that under the Company's application, PECO will realize an additional $88,491 in forfeited discount (late payment fee) revenues.[4] This is undisputed by Ms. Ding and furthermore, Ms. Ding does not refute the fact that she did not reflect this in her study. Rather, she spends almost two pages discussing a revenue conversion factor. My analysis is clearly correct in that determining the operating income impact of such an increase one must recognize the income taxes and other revenue-related costs associated with this revenue increase by applying a revenue conversion factor, plain and simple.

[4] Per Ms. Ding's Exhibit JD-1, page 2, line 63.

Q. ON PAGES 1 AND 2 OF HER REBUTTAL TESTIMONY, MS. LACONTE CLAIMS THAT YOUR P&A METHOD TO ALLOCATE DISTRIBUTION MAINS IS "NOT BASED ON ACCEPTED CLASS COST-OF-SERVICE STUDY (CCOSS) METHODOLOGIES AND PRODUCE INAPPROPRIATE RATES." HAVE YOU ALREADY RESPONDED TO THIS ALLEGATION?

A. Yes. As noted earlier, the P&A method is specifically specified in the most recent NARUC Gas Distribution Rate Design Manual. Furthermore, the P&A method is widely used in the industry and has been specifically approved by several commissions, including the Pennsylvania Public Utility Commission.

Q. PLEASE RESPOND TO MS. LACONTE'S CLAIM THAT AVERAGE DEMAND HAS NO PLACE IN THE COST ALLOCATION OF DISTRIBUTION MAINS BECAUSE IT "CONTRADICTS THE REALITY THAT THE UTILITY MUST PROVIDE THE INFRASTRUCTURE TO DELIVER GAS WHEN IT IS NEEDED THE MOST, DURING THE DESIGN DAY."

A. I have set forth the reasons why the recognition of average day demands, in conjunction with peak day demands is relevant and appropriate in my direct testimony as well as provided this Commission's own opinion in this regard in prior cases.[5]

Q. ON PAGE 4 OF HIS REBUTTAL TESTIMONY, MR. KNECHT OBSERVES THAT MS. LACONTE'S PREFERRED CUSTOMER/DEMAND METHOD, THE AVERAGE & EXCESS METHOD, AND P&A METHOD, PRODUCE HUGE DIFFERENCES IN ALLOCATED COSTS. DO YOU AGREE WITH THIS STATEMENT?

A. I do. This is specifically why cost of service studies should only be used as a guide in evaluating class revenue responsibility. The reality is the vast majority of any public utility's embedded distribution costs are incurred in a joint manner that are used to serve

[5] See Pa. PUC v. Philadelphia Gas Works, Docket No. R-00061931, Order, at page 80 wherein the Commission stated:

> "Reviewing the record, we find that the allocation of distribution Mains investment costs should be done using both annual and peak demands."

all customers. There are no engineering or mathematical approaches that can truly assign such cost responsibility across classes and perhaps most important is the fact that because joint costs are shared by all customer classes, all customers are better off than if they had to provide such services themselves on a stand-alone basis.

Q. MR. KNECHT THEN OPINES THAT NONE OF THE ABOVE-REFERENCED METHODS HAVE A CREDIBLE THEORETICAL BASIS FOR ALLOCATING NETWORK COSTS. DO YOU AGREE WITH MR. KNECHT'S OPINION IN THIS REGARD?

A. Only in part. As noted above, the true theoretical basis for assigning cost responsibility would either be through marginal cost analyses or through stand-alone cost analyses. Neither of these approaches are used at all (at least for traditional rates) in the regulated natural gas industry.[6]

Q. ON PAGE 12 OF HIS REBUTTAL TESTIMONY, MR. KNECHT HAS CONCERNS REGARDING YOUR RECOMMENDING LARGE RATE INCREASES FOR TRANSPORTATION SERVICE (RATES TS-F AND TS-I) BECAUSE YOU DO NOT ADJUST FOR THE FACT THAT SOME TS-F AND TS-I CUSTOMERS ARE ON NEGOTIATED RATES. PLEASE RESPOND TO THIS CONCERN OF MR. KNECHT.

A. I note that Mr. Knecht takes conflicting positions on issues related to the assignment of cost and revenue responsibility across customer classes. With regard to low-income programs, Mr. Knecht has argued on many occasions that these costs should be borne only by residential customers because low-income programs are not available to commercial or industrial customers and that residential customers are the only class that may benefit from such programs. However, in this instance, Mr. Knecht claims that it is unfair to assign cost and revenue responsibility to those classes that can only enjoy discounted rates; i.e., large commercial and industrial customer classes.

[6] It is acknowledged that stand-alone costs are quite often used in evaluating the reasonableness of negotiated discounted rates.

Q. ON PAGES 3 AND 4 OF HIS REBUTTAL TESTIMONY, MR. BISTI INDICATES THAT MR. KNECHT STATED THAT THE COMPANY SHOULD HAVE COMPLETELY ELIMINATED THE REMAINING DIFFERENCE BETWEEN THE CLASS RATES OF RETURN BETWEEN RATE GC AND L AND THE SYSTEM RATE OF RETURN IN THIS CASE. IS THIS STATEMENT IN ACCORDANCE WITH MR. KNECHT'S RECOMMENDATION?

A. No. As shown in Table IEc-5 on page 39 of Mr. Knecht's direct testimony, he recommends no change in revenue responsibility associated with Rate GC and Rate L.

Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

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GAS RATE FUNDAMENTALS

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Chapter 7
Cost Allocation Studies

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A determination of the cost of serving each customer class is a major factor in a gas company's rates. Such a "cost-of-service study" assigns or apportions to each of the utility's homogeneous classes or jurisdictions all of the company's expenses and investments dedicated to serving the utility's customers. These cost-allocations are used to determine the revenue requirements of a specific jurisdiction and the revenue requirements of specific customers or rate classes. Such cost studies require data inputs from all facets of the utility's operations, including accounting records, engineering analyses, financial forecasts, load research, and customer billing and usage records.

Cost allocation studies are not formula-oriented. They require an in-depth analysis and understanding of the utility as well as judgmental decisions by the cost allocator. Properly conducted, the cost study supports a utility's recommendations for a rate design, which will reflect cost incurrence and the company's philosophy for apportioning costs.

Cost-of-service studies can be of two types: embedded and marginal. The former can be further subdivided into historical and projected (forecasted). Marginal cost studies can be split into short-run and long-run. The historical cost-of-service study is widely used by utilities and regulatory authorities. Nevertheless, the other approaches can also be helpful in the design of rates because each method provides information about the past, present, or future costs of serving a utility's customers.

EMBEDDED COST-OF-SERVICE STUDIES

Two general criteria underlie utility rates: rates should not be "unduly discriminatory" and the investments of the utility must be "used and useful." These two requirements trigger the need for cost-of-service studies. The "not unduly discriminatory" criterion means that all customers served on the utility's rate schedules must be treated on a consistent and fair basis. The criterion "used and useful" applies to the determination of the utility's rate base. The investment made by the utility to provide service to the customer must actually be used and must be in the customer's best interest.

Regulators will review the utility's rates to determine if the rate schedules conform to these two general criteria. To conform, a utility's total cost of service must be apportioned such that each group of customers pays for the costs it causes the utility to incur. The cost-of-service study is the vehicle for making this assessment explicit.

If each dollar of expense and investment could be specifically assigned to a single customer group, there would be no need for the *allocation* process of a cost-of-service study. Most utility investments, however, serve many different groups of customers. Thus, it is virtually impossible for a utility to attribute specific cost responsibility for these "common costs."

The fully allocated cost-of-service study breaks down the total cost to serve into four cost *functions*: production, storage, transmission, and distribution. This facilitates the allocation of the costs to classes of service by the application of allocation factors. This functional disaggregation also provides a framework for recovering these costs through proper rate design.

The customers of a utility are grouped into homogeneous classes according to various characteristics. These include the amount of service the customers use, the pressure at which they receive service, the conditions under which customers take service, and their load characteristics by end use. Customer class definitions vary from utility to utility but generally include: residential with heating, residential without heating, small general service – firm, medium general service – firm, large general service – firm, medium general service – interruptible, large general service – interruptible, public authority, lighting, resale, and transportation.

Utilities are required to maintain their accounting records in accordance with a uniform system of accounts prescribed by a state regulatory commission. These closely follow the accounts prescribed by the FERC. Table 7–1, for example, provides a list of the FERC gas plant accounts. Such accounting records are a basic source of data for conducting a cost-allocation study. Table 7–1 shows the accounts just for the company's investment in utility plant. Other sections of the system of accounts would cover, for example, operation and maintenance expenses. Unfortunately, such plant and expense items in the uniform system of accounts cannot be allocated directly to the various customer

TABLE 7-1
Gas Plant Accounts

301	Organization	329	Other structures
302	Franchises and consents	330	Producing gas wells–Well construction
303	Miscellaneous intangible plant	331	Producing gas wells–Well equipment
304	Land and land rights	332	Field lines
305	Structures and improvements	333	Field compressor station equipment
306	Boiler plant equipment	334	Field measuring and regulating station equipment
307	Other power equipment	335	Drilling and cleaning equipment
308	Coke ovens	336	Purification equipment
309	Producer gas equipment	337	Other equipment
310	Water gas generating equipment	338	Unsuccessful explorations and development costs
311	Liquefied petroleum gas equipment	340	Land and land rights
312	Oil gas generating equipment	341	Structures and improvements
313	Generating equipment–other processes	342	Extraction and refining equipment
314	Coal, coke and ash handling equipment	343	Pipelines
315	Catalytic cracking equipment	344	Extracted products storage equipment
316	Other reforming equipment	345	Compressor equipment
317	Purification equipment	346	Gas measuring and regulating equipment
318	Residual refining equipment	347	Other equipment
319	Gas mixing equipment	350.1	Land
320	Other equipment	350.2	Rights-of-way
325.1	Producing lands	351	Structures and improvements
325.2	Producing leaseholds	352	Wells
325.3	Gas rights	352.1	Storage leaseholds and rights
325.4	Rights-of-way	352.2	Reservoirs
325.5	Other land and land rights	352.3	Nonrecoverable natural gas
326	Gas well structures	353	Lines
327	Field compressor station structures	354	Compressor station equipment
328	Field measuring and regulating station structures	355	Measuring and regulating equipment

(Continued)

TABLE 7-1 (Continued)

356	Purification equipment	355	Measuring and regulating equipment
357	Other equipment	376	Mains
360	Land and land rights	377	Compressor station equipment
361	Structures and improvements	378	Measuring and regulating station equipment–General
362	Gas holders	379	Measuring and regulating station equipment–City gate check stations
363	Purification equipment	380	Services
363.1	Liquification equipment	381	Meters
363.2	Vaporizing equipment	382	Meter installations
363.3	Compressor equipment	383	House regulators
363.4	Measuring and regulating equipment	384	House regulator installations
363.5	Other equipment	385	Industrial measuring and regulating station equipment
364.1	Land and land rights	386	Other property on customer's premises
364.2	Structures and improvements	387	Other equipment
364.3	LNG processing terminal equipment	387	Other equipment
364.4	LNG transportation equipment	389	Land and land rights
364.5	Measuring and regulating equipment	390	Structures and improvements
364.6	Compressor station equipment	391	Office furniture and equipment
364.7	Communication equipment	392	Transportation equipment
364.8	Other equipment	393	Stores equipment
365.1	Land and land rights	394	Tools, shop and garage equipment
365.2	Rights-of-way	395	Laboratory equipment
366	Structures and improvements	396	Power operated equipment
367	Mains	397	Communication equipment
368	Compressor station equipment	398	Miscellaneous equipment
369	Measuring and regulating station equipment	399	Other tangible property
370	Communication equipment		
371	Other equipment		
374	Land and land rights		

Source: Code of Federal Regulations, Title 18, Conservation of Power and Water Resources, Part 201, pp. 210–211.

groups. The cost analyst must separate out the components of such costs for which each customer class should be held responsible.

Because the utility's investment in property and the company's associated expenses are shared by resale and retail customers who are regulated by different authorities, costs must be allocated to each jurisdiction. To accomplish this, the cost expert must analyze, for example, property used exclusively to service a specific customer class. The remaining property and expenses reflect *common* or shared use. For these items, a cost *allocation* to determine the appropriate portions of investment and expenses used by each class must be made (see Table 7-2).

Assigning plant costs (i.e., investments) and related operation, maintenance, depreciation, and tax expenses to the basic functions of production, storage, transmission, and distribution is called *functional assignment*. A further breakdown of these costs into sub-functions helps to identify costs that are linked to specific classes or customers and those costs that are common to two or more classes.

Some plant items can be designated as specific and are readily assignable to a customer within a class of service. Some cost items may require a special analysis for proper assignment. The remaining costs, which represent the bulk of the utility's investment in production, storage, transmission, and distribution facilities, must be allocated to classes of service by the application of allocation factors. Breaking costs down into sub-functions permits the most equitable allocation of costs by using the appropriate allocation factors.

Cost-of-service studies employ a three-step approach: functionalization, classification, and allocation. In the first step, the *functionalization* procedure begins with the FERC plant accounts. All plant facilities are assigned to cost-of-service functions. Then, the investment associated with each facility is assigned. After the cost analyst assigns plant costs functionally, a related expense can often follow the same functionalization.

TABLE 7-2
Assignment and Allocation of Costs

Investment and Costs	Specific to One Customer Class	Assigned Directly to Class
	Common to Several Classes	Allocated to Classes or Among Classes

From this analysis, ratios based on the proportion of gas plant assigned to each cost-of-service function can be developed. These plant ratios can be used for the functionalization of most of the other cost items. Other relationships, such as labor ratios, must be developed. These can be used to assign labor related costs, such as payroll taxes. Similarly, the pattern of use of utility vehicles might be studied to assign transportation costs. Such ratios are then used to assign costs to each function. This process requires the cooperation of company rate, engineering, and accounting experts to match the plant investment and associated operating expenses to the proper cost function.

In the second step of the cost-of-service study, *classification*, each functional cost is further divided by cost causation. There are four principal categories, each related to a measurable cost-defining characteristic of providing gas services: demand, commodity, customer, and revenue. The term demand (or capacity) refers to that aspect of utility service that must be available upon the customer's demand. *Demand-related costs* are related to the peak usage of utility service by the company's customers. Thus, fixed costs are usually assigned to the demand classification, except at the distribution level, where facilities are designed with the number and size of loads in mind. Gas plant ownership costs are fixed cost and demand related – they do not vary (in the short term) with the number of customers or the amount of gas that customers use. These are the costs necessary to maintain the facilities at a level sufficient to satisfy the greatest demand that all the customers could place upon the system. They can be apportioned on the basis of the relative demands placed on the system by the various customer classes. Production, storage, transmission, and distribution functions all have demand components.

The term "commodity" is usually expressed in quantitative terms (i.e., Mcf or therms). *Commodity-related costs,* such as the commodity component of the cost of gas, are variable; they reflect the number of units consumed or supplied during a period of time (e.g., a month or year).

The closer a plant item (e.g., a meter and service line) is located to a customer, the more that particular item is related to the specific requirements of that customer. Thus, the customer component of distribution costs reflects the theoretical distribution system that would be needed to serve customers at nominal or minimal load conditions. Customers, of course, are grouped into cost classes for cost allocation studies. These groupings may differ from the grouping of customers under existing rate schedules. For example, an industrial rate may be broadly applicable to a wide range of customer uses or there may be end-use rates that are applicable to specific uses within a given class. A customer's service requirements must be identified with regard to size, load factor, and predominant use. *Customer-related costs,* then, are primarily distribution and customer accounting costs. They are allocated directly to the customers of a particular class of service. Metering costs are an example of customer-related costs.

Revenue-related costs, such as gross-receipt taxes, vary with the amount of sales revenue. These costs can be apportioned according to the percentage of the total revenue received from each class of customer.

To recapitulate, the separation of the functionalized costs (step one) into four cost-causation components – demand, commodity, customer, and revenue – is called classification (step two). These cost components can then be allocated to classes by using allocation factors (step three). For example, investment and related expenses for the demand-related costs are allocated by use of a factor derived from the magnitude of the class loads imposed at each functional level of the gas utility system. By identifying the points of attachment of all loads, allocation factors can be developed for each functional level. Because customers may be served at various pressure levels, some customers may not share the cost responsibility for all facilities. Thus, to determine the relative contribution of each class to the total cost responsibility for a particular function, the class loads are developed at each functional level. This provides a suitable basis for determining cost allocation factors.

Commodity costs are allocated to customer classes based on annual or seasonal consumption. Similarly, customer costs are allocated based on the number of customers or a weighted number of customers. Revenue-related costs are allocated based on the revenues received from each class of service. The relationship between functions and cost-causation components is shown in Table 7–3.

Cost items are assigned directly to one or more cost-of-service functions. However, there are a number of cost items that are not readily functionalized. The analyst must consider the following costs in more detail:

- Costs that cannot be assigned completely to one function
- Functionalized costs that cannot be classified directly to demand, energy, customer, or revenue components
- Functionalized and classified costs that cannot be assigned directly or readily to specific classes of service
- Costs that cannot be separated by jurisdiction.

These considerations require judgmental decisions that must be made in the course of a cost-allocation study. A logical decision can usually be made after a thorough study of the company's records and

TABLE 7-3
Functions and Cost Causation Components

Function	Cost-Causation Component
Production, Storage and Gas Supply	Demand-related
Costs:	
Transmission	Commodity-related Demand-related
Distribution	Customer-related
Other Customer	Customer-related
Revenue	Revenue-related

the way the utility's system is operated. In this process, advice may be sought from the analyst's associates, management, and the accounting staff. A company may keep records in which accounts are broken down into more detail by the use of sub-accounts. These can be helpful in a cost allocation study. In summary, cost allocation should pass the test of common sense.

THE COST-OF-SERVICE STUDY PROCESS

A cost-allocation study itemizes and summarizes a utility's "fully distributed" historical costs. A detailed study of the type described below typically is required to support a utility's rate filing before a regulatory commission.

In the cost study, the fixed capital elements of cost (e.g., return, depreciation, and taxes) mirror the allocation of plant costs. Annual operating and maintenance expenses follow the allocation of the basic cost-causing element. For example, the allocation of distribution mains *expenses* would parallel the allocation of the plant *investment* in distribution mains.

Cost data must be selected for a certain time period (e.g., twelve months ended last June or the past year ending in December) called a *test year.* These basic cost data may be adjusted to reflect normal operating conditions (e.g., the test year selected may have had an unusually cold winter, which would be reflected in higher than normal sales of gas for space heating). Adjustments in basic data may also be necessary to reflect changes in revenues, wages, fuel costs, or other cost items.

ALLOCATION OF PLANT COSTS AND RELATED EXPENSES

If the cost allocation study is for a rate filing, the test period is usually determined by regulation. It could be the calendar year, some other specified fiscal year, or the latest 12-month period for which data are available.

If the cost study is for management or some other "in-house" use, the test period should coincide with the calendar year. Such studies are easier to conduct than "odd-year" studies, for three reasons. First, most utilities do not keep 12-months ended statistics. Second, construction work in progress is analyzed and usually "closed-out" only at the end of the year. Third, income taxes are normally estimated each month but not finalized until year end.

Sometimes a study will be required to estimate costs for a *future* test year. In this case, the time period will usually be defined as the first year when the proposed rates would be in effect. Projected studies may also be required to analyze short- and long-run incremental costs.

Jurisdictional cost separations may pose difficulties for the analyst. The sum of the jurisdictional allocations may not equal the whole (i.e., utility's total costs). For example, a utility may serve two jurisdictions, each having different accounting systems. One state may require the utility's gas plant to be stated at year-end original cost while another state may use the average of the beginning and year end original costs. Thus, the allocated plant investment will not add up to the company's total plant-in-service. Two separate cost allocation studies, one for each jurisdiction, may be necessary. In addition, various jurisdictions may prefer different allocation factors for the separation of costs.

ADJUSTMENTS TO BASIC DATA

Capital costs and expenses should be reviewed to see if any adjustments to booked costs should be made. Adjustments should be made if cost allocations are based on a period other than that in which the costs were actually incurred. For example, changes in labor and material costs and insurance or tax costs that would more nearly reflect the utility's conditions during the period the rates would be in effect should be recognized in the study. Adjustments should also be made when the utility's operating conditions differ from normal. Allocations are usually made on the basis of load conditions for a given time, usually a year. The effect of changes in the business cycle on loads of the various classes should be considered. Some industrial loads may be quite responsive to changes in the economy, while residential loads may be relatively stable. Therefore, normalization of loads may be desirable in developing allocation factors.

SELECTING CLASSES OF SERVICE

The dimensions of a cost study are set by the classes of customers or rates included in it. Conversely, the type of study affects the definition of classes. Several broad categories of classes may be studied. In a FERC jurisdictional separation, there are customer groups and rates that must be analyzed. Similarly, in a retail service cost study, the profitability for each rate within one or more of the individual retail classes of service may be examined.

In a cost-allocation study, the utility's total cost of service is the "whole" that must be allocated to groups of customers. These groups are given class status because of their service characteristics, which include size of the loads, diversity of the loads, the predominant uses, and possibly jurisdiction of user. The volume of consumption of a customer at either end of a class, of course, will be different from the customer having average use. Such variation is especially true with regard to plant requirements, load factor, and peaking needs. A class subsumes this diversity among individual customers within the class.

Conducting a cost study by individual rate schedule at the distribution level should be undertaken after completing a class cost-allocation study. Each class is then considered the "whole" that must be allocated to the rate schedules within that class. If a rate of return is needed for each rate schedule, the class cost allocation study should be performed first.

Customers of comparable size and service characteristics should be grouped together in a class. A class, however, could be composed of customers taking service on more than one rate schedule. Certain classes, such as the residential class, could be expanded to include space heating and water heating customers as separate subclasses. Generally, the number of classes studied should be minimized. This makes the results more predictable and acceptable, because a class may be dominated by one or two prevalent rate schedules. Separating cost data into smaller and smaller pieces may make the results less reliable.

SEGREGATING DIRECTLY ASSIGNABLE COSTS

An analysis of accounts may indicate specific costs that should be assigned directly to a particular class of service. These costs might include, for example, a lateral gas main built specifically to serve one of a group of industrial customers. Both the plant investment and associated expenses of this lateral should be assigned directly to the industrial class.

REARRANGING COSTS INTO FUNCTIONAL GROUPS

Although the system of accounts generally follows functional groups, a cost allocation study will require rearranging many costs into functional groups that are more descriptive of their origin. Such groups combine costs incurred for a similar purpose. A relatively small number of groups – 20 to 30 – is often adequate (see Table 7–4). Thus, each functional group can be treated as a unit in the assignment to the cost components.

ALLOCATION FACTORS

With all of the costs assigned to the major cost components, the next step is to determine suitable allocation factors. These are used to apportion the major cost components to classes of service. For gas utility operations, the three basic allocators are capacity, commodity, and customer, as explained earlier in this chapter. The allocation of the commodity and customer components poses no real problem because the quantities are the sum of the class totals. Capacity cost allocations, however, are more difficult because of the difference in demands of the various groups and their relation to the system demand and capacity. Nevertheless, three capacity cost allocation methods have received considerable attention: coincident demand, noncoincident demand, and average and excess demand, as described below.

Coincident Demand (CP)

The CP method, also called peak responsibility, allocates capacity-related costs based on the demands of the various classes of service at the time of the system peak. The rationale for the CP method is that the utility's costs associated with its maximum load should be divided among the customers causing that peak. The magnitude of those customers' demands at other times of the day, month or year or the length of those demands is not a consideration. Under this method, the "allocator" for capacity costs is the ratio of the demand of the various classes of service at the time of the system peak to the total demand at that time. An example is shown in Table 7–5.

Thus, the residential and industrial classes would each bear 40 percent of the capacity costs, commercial customers would bear 20 percent, and the interruptible class would not be allocated any of the capacity costs. The CP method has the following characteristics:

TABLE 7–4
Cost of Service Study
Functional Service Levels

Item	Demand	Classification with Allocation Methods: Commodity	Customer	Specific	Revenue
Production & Gas Supply					
1. Gas Supply	CP	Mcf or Therms			
2. Storage	CP	Seasonal Mcf or Th			
3. Liquefied Nat Gas	CP	Seasonal Mcf or Th			
4. Propane	CP	Seasonal Mcf or Th			
Transmission					
5. Compressor Stations	CP	Mcf or Th		Spec Assign	
6. Mains	CP	Mcf or Th		Spec Assign	
7. Regulatory Stations	CP	Mcf or Th	Spec Assign		
Distribution					
8. Compressor Stations	NCP				
9. Mains	NCP		No. of Cust.	Spec Assign	
10. M&R Stations	NCP		No. of Cust.	Spec Assign	
11. Services	NCP		No. of Cust.		
12. Meter & Install			Wgt. Cust		
13. House Reg & Install			Wgt. Cust		
14. Imd M&R Stations				Spec Assign	
15. Cust. Install				Spec Assign	
Other					
16. Customer Accts			Wgt. Cust		
17. Sales Expense			Wgt. Cust		
Revenue					
18. Revenue from Sales					Revenue
19. Revenue Taxes					Revenue

TABLE 7–5
Cost Allocation by Coincident Demand

Class of Service	Demand at Time of System Peak (Mcf/Day)	Ratio to System Peak
Residential	4,000	0.40
Commercial	2,000	0.20
Industrial	4,000	0.40
Interruptible	–	0.00
Total (System Peak)	10,000	1.00

- It may produce radically different results if the time of the system peak shifts.
- It requires a determination of class demands at the time of the system or sub-system peaks.
- It may require a load study.
- It allocates no capacity costs to off-peak or curtailed customers, as illustrated by the interruptible class in Table 7–5. The CP allocation may be appropriate if off-peak operations result from control by the customer or the utility, as in the case of interruptible service, or if off-peak use stems from natural characteristics as, for example, air conditioning.

Noncoincident Demand (NCP)

This method, also called class demand, is based on the maximum demands of the individual classes of service regardless of when those demands occur. Under the NCP method, the effects of diversity are apportioned in equal proportions to each class. Thus, the allocator for capacity costs is the ratio of each of the class maximum demands to the sum of all the class maximum demands irrespective of time of occurrence. An illustration is shown in Table 7–6.

Each class pays part of the total capacity costs. Under the NCP method, this includes the interruptible class, which bore no capacity costs under the peak responsibility method. The NCP method has the following characteristics:

- It assumes that the cost of joint facilities to serve the various classes should be allocated in proportion to the facilities necessary to serve each class as though it were served alone.
- It is not affected by shifts in the time of maximum class demands.

- It allocates costs to all groups of customers whether or not they create any demand at the time of the system peak. For this reason, the NCP method is inappropriate for incremental cost studies.
- It leads some analysts to contend that interruptible customers are charged for "too much" capacity because the capacity used by them is that "released" by others. Whether an interruptible customer should receive less than its proportional share of capacity costs or even no capacity costs depends on the *philosophy* of the cost analyst.

Average and Excess Demand Method (A&E)

Under the A&E method, also called "used and unused capacity," capacity costs are allocated by a two-part formula.[1] It recognizes both the average use of capacity and responsibility for the capacity required to meet the maximum system load. Used capacity costs are calculated by multiplying total capacity costs by the system load factor. These costs are allocated to the various classes in proportion to their respective use (Mcf sold). System load factor is the ratio, expressed as a percent, of used capacity (Mcf sold) to total capacity. The remainder of the capacity costs represent the costs associated with the unused portion of capacity (i.e., that portion above *average* requirements). These costs

TABLE 7-6
Cost Allocation by Non-Coincident Demand

Class of Service	Maximum Class Demand (Mcf/Day)	Ratio to Sum of Class Demands
Residential	4,500	0.375
Commercial	2,700	0.225
Industrial	4,000	0.333
Interruptible	800	0.067
Total (Non-Coincident)	12,000	1.000

[1] "Used capacity" is the minimum capacity needed to deliver the total gas used. Hence, it is numerically equal to the average deliveries. "Unused capacity" is the difference between average (used) capacity and peak capacity. Used, unused, or peak capacity may be expressed in terms of hours, days, year, or any other period. Peak capacity is usually expressed in terms of the peak hour or day.

are allocated to the various classes in the ratio that the individual group demands, in *excess* of used demands, bear to the summation of such excess demands. A simplified example is shown in Table 7–7.

Use of the A & E method has the following effects:

- Shifts in the time of the system peak do not greatly affect the cost allocations.
- The allocation of unused capacity is similar to the non coincident demand method except that it is applied only to the excess of class demands above the average.
- The load factor of the various classes is recognized.

Two additional cost-allocation approaches deserve discussion: the Seaboard and United methods. While generally referred to as allocation methods, they are really cost classification methods. These two approaches have been used in FERC proceedings involving pipeline cost allocation studies. Recent FERC decisions, however, have moved towards a modified fixed-variable approach, which will be discussed later. Some analysts argue that such cost allocation methods are actually pricing mechanisms.

The Seaboard method assigns 50 percent of the fixed (demand) costs to the commodity classification and the other 50 percent to the demand classification. These costs are allocated to the various classes by the appropriate demand and commodity-allocation factors. The Seaboard method shifts capacity-related costs from classes with lower load factors (e.g., seasonal heating requirements) to classes with a more uniform or stable year-round (i.e., higher) load factor.

The United method (sometimes called the "Modified Seaboard" method) assigns 75 percent of the fixed costs to the commodity classification and the rest to the demand classification. Again, capacity-related costs are shifted from low to high load factor customers. Cost causation is not the rationale.

In recent FERC proceedings, the modified fixed-variable approach has been used. This allocation method permits all fixed costs to be classified in the demand component, except for return on equity and associated taxes. These are placed in the commodity component. Then the demand costs are allocated 50 percent on the basis of historical Average Peak Day and 50 percent on the customer's Annual Volume.

ALLOCATION OF SPECIAL COSTS

Taxes

Taxes are levied by federal, state, and local authorities. Taxes can be classified on the basis of assessment (i.e., income, revenue, property,

TABLE 7-7
Cost Allocation by Average and Excess Demand

Class of Service	Annual Use (Mcf)	System Peak (Mcf/Day)	Class Max Demand (Mcf/Day)
	(1)	(2)	(3)
Residential	365,000	N/A	3,000
Commercial	182,500	N/A	1,250
Industrial	146,000	N/A	1,100
Interruptible	219,000	N/A	3,000
Total	912,500	4,167	8,350

Class of Service	Class Max Demand (Mcf/Day)	Average Demand (Mcf/Day)	Process Demand Alloc. Basis (Mcf/Day)
	(4)	(5)	(6)
Residential	3,000	1,000	2,000
Commercial	1,250	500	750
Industrial	1,100	400	700
Interruptible	3,000	600	2,400
Total	8,350	2,500	5,850

Class of Service	Average Demand (Mcf/Day)	Excess Demand (Mcf/Day)	A & E Demand (Mcf/Day)
	(7)	(8)	(9)
Residential	1,000	570	1,570
Commercial	500	214	714
Industrial	400	199	599
Interruptible	600	684	1,284
Total	2,500	1,667	4,167

Column

1: Total annual consumption by class. This is equivalent to the commodity allocation factor.
2: Actual (estimated) peak day(s) demands of the system. The individual class values are not shown because they are not used in the calculation.
3: The sum of the individual class maximum demands (class NCP). Each class maximum demand may occur at a different time.
4: The sum of the individual class maximum demands (class NCP). Each class maximum demand may occur at a different time.
5: Calculated by dividing each element in Column 1 by 365 days.
6: Column 4 less Column 5.
7: Calculated by dividing each element in Column 1 by 365 days.
8: Calculated by multiplying the ratio of each to the total in Column 6 times the system excess demand. The system excess demand is defined as the system peak less the total system average demand. For example:

System excess demand would be

4,167 less 2,500=1,667

Residential class excess demand would be

$$\frac{2,000}{5,850} \times 1,667 = 570$$

9: Sum of Column 7 and Column 8.

and payroll). For the gas utility industry, income taxes, both federal and state, are by far the most significant.

Income taxes are levied on the basis of the utility's taxable net income and are allocated to the several classes of service on the same basis. There is a difference, however, in quantifying income (before income taxes) as used for regulatory purposes and measuring taxable income for IRS purposes. The difference stems mainly from the treatment of accelerated depreciation and interest expenses. Other items also affect this difference. The cost-of-service study should separately identify, functionalize, classify, and allocate these items to the classes of service. In this way, the study can employ the *statutory* income tax rates.

Determining the amount of taxes to deduct from income is complicated by tax laws, which permit increased deductions for depreciation in the calculation of a utility's current liability for income taxes. These laws, passed to encourage the expansion of industry and the early retirement of obsolete equipment, permit the use of several formulae in computing depreciation. This can lower the amount of taxes payable. While not changing the company's total tax liability over time, these optional payment methods encourage expansion or improvement by giving the company tax reductions in the early years.

Regulatory commissions have interpreted the intent of these liberalized depreciation laws in different ways. Some commissions allow *normalized* taxes (i.e., the amount that would be payable without the benefit of the deferment provisions) as income deductions. Others allow only the taxes actually paid. Normalization gives the utility the benefits of the tax deferment in accordance with the intent of Congress. The second method takes this benefit away from the utility and *flows through* the benefit to the ratepayers (unless offset by provisions in the allowable rate of return). In preparing a cost-of-service study, the local regulatory requirement must be ascertained.

Taxes other than income, revenue, property, and payroll usually represent a small part of the utility's total tax expense. These can be allocated on a number of different bases (e.g., gross revenue, operating expenses, number of customers, and investment). The choice of a particular basis for allocating these taxes will be of minor consequence in determining the cost of serving the several classes of customers.

Administrative and General Expenses

These include the salaries, expenses, and services incurred in the administration and direction of the business. The size and complexity of the utility enterprise affects the amount of administrative and general costs. The functionalization, classification, and allocation of these costs may involve detailed studies. Many methods or bases are used to distribute these costs (e.g., the total number of customers served, the total payroll exclusive of the administrative and general payroll, and the sum of all other costs). Another method would be to functionalize, classify, and allocate these costs in proportion to the sum of all other costs, exclusive of gas purchased and fuel used in production.

Depreciation

The allocation of depreciation expenses to the various classes should reflect the method used by the utility to determine the total amount of annual depreciation (e.g., specific depreciation rates for primary plant accounts, functional groups, or total depreciable property). Other methods include judgment or a percentage of revenue or plant.

The allocation of depreciation expenses can follow the allocation of plant to the various classes of service if determined on the basis of specific depreciation rates. If depreciation is computed by use of composite depreciation rates for functional groups, a lower degree of accuracy results. However, this method facilitates the treatment of depreciation expenses.

Working Capital

Working capital "is made up of that amount of funds required above the investment and fixed assets and intangibles necessary for the economical and satisfactory conduct of the enterprise. In substance, it is an allowance for the sum that a company needs to supply from its own funds for the purpose of enabling it to meet its current obligations as they arise and to operate economically and efficiently."[2]

The components of working capital (e.g., cash requirements or materials and supplies) included in rate base vary among regulatory jurisdictions. Cash working capital equivalent to a given number of days of operating expenses, excluding depreciation or taxes, is generally allowed. The period may vary from 30 to 60 days, with the most common being 45 days.

Other methods for determining cash working capital are also used. One approach for *allocating* this item is on the basis of operation and maintenance expenses. A modification of this would be to allocate on

[2] Vermont Public Service Commission, 83 PUR NS 415.

the basis of the operation and maintenance expenses, excluding purchased gas and fuel for production. In addition to such formula approaches, other methods, such as a lead-lag study or a balance sheet study, may be used to determine the cash working capital amount.

Materials and supplies include fuel for gas production and stores items for maintaining and operating the system. The amount of fuel on hand takes into consideration peak shaving requirements and the need to provide uninterrupted service to customers during interruptions of normal supply. Materials and supplies can be allocated to the three major cost components (capacity, commodity, and customer) with factors determined from a detailed analysis. Alternatively, each item in the material and supplies group can be allocated separately depending on its probable use or function.

REVENUE REQUIREMENTS AND UNIT COSTS

The final step in a cost-of-service study is determining revenue requirements and the unit cost to serve each customer. Calculating the revenue requirement is a mathematical procedure. The utility's overall rate base is multiplied by the requested rate-of-return on rate base to yield net income. This is adjusted for income taxes and added to the utility's other operating expenses to produce the total required revenues. Sometimes the required revenues must be adjusted for revenue-related taxes and reduced by miscellaneous revenues received by the utility. Subtracting current revenues from these calculated required revenues determines the dollar amount of the rate increase. The cost allocation study is often the sole determinant of the requested rate increase because the study develops the jurisdictional separation of the utility's revenues, expenses, and rate base.

A cost allocation study can impart useful cost information to the rate designer in the form of unit costs. These can be calculated from the functional class revenue requirements. For example, if the revenue requirement for the purchased gas commodity function is $4 million and the utility sold 1 million Mcf to its customers, the unit cost for this function would be $4.00 per Mcf. These unit cost calculations are extremely helpful in developing a cost-based customer charge. The unit cost section of any cost allocation study serves as the bridge from cost allocation to rate design. An example of a fully developed revenue requirement and unit cost calculation is presented in Appendix A.

GAS DISTRIBUTION RATE DESIGN MANUAL

Prepared by the
NARUC Staff Subcommittee on Gas

June 1989

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B. Historic or Embedded Cost of Service

Historic or embedded cost of service studies attempt to apportion total costs to the various customer classes in a manner consistent with the incurrence of those costs. This apportionment must be based on the fashion in which the utility's system, facilities and personnel operate to provide the service. Basic load and operating data are needed, in addition to the costs, to conduct a cost allocation study.

Embedded cost of service studies are generally conducted in the following steps: (1) functionalization of costs as either production, storage, transmission or distribution; (2) classification of costs into three basic categories -- customer, energy or commodity, and demand or capacity costs; and (3) the allocation of these costs to customer classes or to types of load. All items that can be directly attributed to a particular service (such as revenues from a specific service or the cost of a high pressure main constructed for a particular customer or group of customers) should be segregated and directly assigned to the appropriate customers. There is no scientifically correct method of making necessary allocations. A certain amount of judgment must be used in any cost of service study. Consequently, cost allocation studies should only be utilized as a general guide or as a starting point for rate design.

1. Functionalization of Costs

Functionalization is the arrangement of costs according to major functions, such as production, storage, transmission or distribution. This functional categorization of costs helps to facilitate a determination as to which customer groups are jointly responsible for such costs. Some costs, such as those associated with the general or common plant and administrative and general expenses, generally are not directly assigned to the established functional groups. These costs did not appear to have any direct relationship to the service characteristics employed for purposes of functionalization.

The primary operating functions to which costs can be broadly categorized are described as follows:

Production costs are the costs relating to producing, purchasing or manufacturing gas. Included are purchases of pipeline or producer gas and all costs associated with producing owned or peaking gas; i.e. the gas itself, feedstocks, capital costs, operations and maintenance expense.

Storage costs are the costs associated with storing gas normally during off-peak for use in times of cold weather. Also included are related operation and maintenance expenses.

Transmission costs are the costs incurred in transporting gas from interstate pipelines to the distribution system. Included are the capital costs of transmission mains, as well as city gas metering station costs and related operation and maintenance.

Distribution system costs are those costs incurred to deliver the gas to the customers. Included are capital and operating costs for distribution mains, compressors, customer services, meters, and regulators.

Other costs include those costs that do not fit the above functions, such as the cost associated with common plant and working capital, general and administrative costs, customer accounting, and advertising costs.

The functionalization of costs is generally the easiest step in a cost of service study, since utility investment and expense records are maintained in accordance with prescribed uniform accounting systems. These systems, such as the Uniform System of Accounts, classify costs according to primary operating functions. Thus, the functionalization of costs is already done for the cost of service analyst.

2. Classification of Costs

The functionalization of costs is of limited use in the allocation of costs. Therefore, it is necessary to further classify costs into customer, energy or commodity, and demand or capacity costs.

a. Customer Costs

Customer costs are those operating capital costs found to vary directly with the number of customers served rather than with the amount of utility service supplied. They include the expenses of metering, reading, billing, collecting, and accounting, as well as those costs associated with the capital investment in metering equipment and in customers' service connections.

A portion of the costs associated with the distribution system may be included as customer costs. However, the inclusion of such costs can be controversial. One argument for inclusion of distribution related items in the customer cost classification is the "zero or minimum size main theory." This theory assumes that there is a zero or minimum size main necessary to connect the customer to the system and thus affords the customer an opportunity to take service if he so desires.

Under the minimum size main theory, all distribution mains are priced out at the historic unit cost of the smallest main installed in the system, and assigned as customer costs. The remaining book cost of distribution mains is assigned to demand. The zero-inch main method would allocate the cost of a theoretical main of zero-inch diameter to the customer function, and allocate the remaining costs associated with mains to demand. A calculation of a minimum size main is shown in the illustrative cost allocation study. The contra argument to the inclusion of certain distribution costs as customer costs is that mains and services are installed to serve demands of the consumers and should be allocated to that function. Under this basic system theory, only those facilities, such as meters, regulators and service taps, are considered to be customer related, as they vary directly with the number of customers on the system.

Another controversial item is the inclusion of sales promotion expenses in the customer cost component. Analysts vary in their opinions as to the extent of the inclusion. Some would include all, some none, and some a portion of sales promotion expense in the customer category. With emphasis placed on conservation, many regulatory bodies have prohibited this type of activity, and in those cases, if cost were incurred, it should be deleted from the study based upon its being a "below the line" or a stockholder expense.

b. Energy or Commodity Costs

Energy or commodity costs are those which vary with the quantity of gas produced or purchased. They are largely made up of the commodity portion of purchased gas cost and the cost of feedstock, catalyst, fuel, and other variable expenses used in the production of gas from a manufactured or synthetic gas (SNG) plant. Energy or commodity costs increase or decrease as more or less gas is consumed.

c. Demand or Capacity Costs

Demand or capacity costs vary with the quantity or size of plant and equipment. They are related to maximum system requirements which the system is designed to serve during short intervals and do not directly vary with the number of customers or their annual usage. Included in these costs are: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of distribution plant not allocated to customer costs, such as the costs associated with distribution mains in excess of the minimum size.

3. Allocation of Costs to Customer Classes

After the assignment of costs to the customer, energy, and demand categories, each category must be allocated to the various service classifications or to their subdivisions.

a. Customer Costs

Customer costs may be distributed in proportion to the number of customers in a class, or a more detailed study may be made whereby certain components of the customer costs may be distributed on a per-customer basis, directly assigned or distributed on a weighted per-customer basis. The latter method permits recognition of known or ascertainable customer cost differences such as the frequency of meter readings, complexity in obtaining readings or integrating meter reading charts, and the individiual attention which may be given to large customers, such as separate meter reading schedules.

As discussed earlier, while there may be differences on whether certain items of plant should be assigned to customer costs, there are clearly certain expenses which are independent of whether a customer consumes gas or not. Since these costs will not be recouped if little or no gas is consumed, they are generally included in a minimum bill or customer service charge. One of the useful by-products of a detailed cost of service study is that the customer costs are broken out by service classification or class of customer. When these costs are divided by the number of customers within a particular subdivision, the analyst is provided with an indication of what the minimum or customer service charge should be.

b. Energy or Commodity Costs

Energy or commodity costs may be distributed to customer groups on the basis of the quantity of gas consumed during some historical or projected test period, with or without allowance for losses incurred in transporting the gas from the production plant or city gate station to the customer. If the historical test period were abnormally cold or warm, the sales and related cost should be normalized before allocation. The analyst in reviewing the operation of the system could find that certain classes of customers might appropriately be allocated a greater or lesser than average level of lost and unaccounted for gas. This determination will be affected by such factors as the degree of utilization of distribution facilities, quality of metering equipment and the timing of meter readings relative to purchases.

c. Demand or Capacity Costs

Demand or capacity costs are allocated to customer classes based upon an analysis of system load conditions and on how each customer class affects such costs. These are largely joint or common costs, and their allocation generates the largest controversy surrounding a cost of service study. This subject has been studied and argued for years without resolution, and often represents the largest item which can dramatically alter the result of a study.

d. Other Costs

Other costs, such as those associated with common plant, working capital and administrative and general expenses, cannot be readily categorized as either customer, energy or demand. Thus, they are not normally allocated on the basis of a single classification. These other costs are generally allocated on a composite basis of certain other cost categories. For example: common plant may be allocated on the composite allocation of all production, transmission, storage and distribution plant; and administrative and general expenses may be allocated in accordance with the composite allocation of all other operating and maintenance expense, excluding the cost of gas.

4. Methods of Allocation of Demand or Capacity Costs

a. Theory

There is a wide variety of alternative formulas for allocating and determining demand costs, each of which has received support from some rate experts. No method is universally accepted, although some definitely have more merit than others. The electric industry has produced more alternatives than the gas industry. For instance, in an early 1950 case before the Illinois Commerce Commission, an executive of Commonwealth Edison Company noted the existence of 29 different formulas for the apportionment of demand costs. The application of these formulas produced drastically different cost assignments to the several service classifications. As a result, the Illinois Commission refused to direct that the utility present such evidence. The NARUC published in 1955, through its Engineering Committee, a detailed discussion of 16 such methods.

The multiplicity of available methods (which in fact reflects the insoluble nature of the problem) has led many recognized experts to express grave doubts about the efficacy of cost of service analyses.

The most commonly used demand allocations for natural gas distribution utilities are the coincident demand method, the non-coincident demand method, the average and peak method, or some modification or combination of the three.

b. Coincident Demand Method

In the coincident demand (peak responsibility) method, allocation is based on the demands of the various classes of customers at the time of system peak. This method favors high load factor customers who take gas at a steady rate all year long by assigning the greater percentage of demand costs to lower load factor heating customers whose consumption is greatest at the time of the system peak. Generally, interruptible customers would receive no allocation of demand costs under this formula since they should be off the system during the peak period. The demand component of the cost of gas is generally allocated on a coincident demand method.

c. Noncoincident Demand Method

This method would result in all classes of customers being allocated a portion of system cost based upon their actual peak, regardless of the time of its occurrence. This method assigns cost to customer classes such as interruptibles, and thereby reduces the costs allocated to the heating customer under the peak demand method. The demand related portion of distribution mains and transmission mains are commonly allocated on a noncoincident demand method.

d. Average and Peak Demand Method

This method reflects a compromise between the coincident and noncoincident demand methods. Total demand costs are multiplied by the system's load factor to arrive at the capacity costs attributed to average use and are apportioned to the various customer classes on an annual volumetric basis. The remaining costs are considered to have been incurred to meet the individual peak demands of the various classes of service and are allocated on the basis of the coincident peak of each class. This method allocates cost to all classes of customers and tempers the apportionment of costs between the high and low load factor customers.

5. Use of Load Studies For Allocation of Demand Costs

a. Concepts

As previously mentioned, load data are necessary for a cost of service study. These data are the basis for any demand allocation and, if inaccurate, can give misleading results regardless of the case taken with the remainder of the analysis. The load characteristics of each utility's system and each customer class on a system are unique and must be separately surveyed in each case. The purpose of the survey is to determine for relatively homogenous customer groups such information as load pattern, amount and time of occurrence of maximum load, load factor, and diversity or coincidence factor.

Arriving at load patterns is not an easy task. Most of the necessary information is not readily available from the normal record keeping of a utility. To secure the information requires a systematic activity known as load research. It embraces a whole gamut of engineering, statistical, and mathematical methods and procedures, ranging from the simple application of judgments to available data to refined mathematical probes into the significance of sampling techniques. The gas industry generally has not devoted the same resources to this area in the past as the electric industry on the whole has, so in most cases more reliance will have to be placed on use of existing records than would be preferred. However, since system peaks in the gas industry are highly weather sensitive, a fairly reliable correlation between temperature versus gas consumption can be developed from utility records. By applying a least square fit to "average degree day" and "use per day" data for each customer group, one can calculate with reasonable accuracy the demands to be placed on the system. A relatively unsophisticated estimate of system peaks is included in the illustrative cost of service study.

More attention is now being devoted to this important phase of input data needed for not only studies of this sort, but in understanding customer load profiles in general. The following briefly summarizes the steps which can be taken to develop load curves.

b. Determination of Load Curves By Billing Records

Load curves can be determined for some classes from the billing records of customers who are equipped with standard recording instruments. This is feasible for classes in which all, or nearly all, the customers are so equipped. Normally, this is the case for interruptible and large industrial customers, a tiny fraction of all customers served by a utility.

c. Determination of Load Curves By Load Surveys

The load curves for residential and small commercial and industrial classes must be developed from data for sample groups of these classes, obtained from field surveys, and expanded to include the entire energy use of these classes. The particular procedure adopted will be dictated largely by the economic considerations of conducting such tests and by the availability of manpower and test-metering equipment. However, test groups of sample customers must be carefully selected in accordance with sound statistical principles. The sample customers should be chosen at random so as to properly reflect the specific energy use characteristics of all substantially homogenous customer groups within a service classification.

There may be difficulty in getting customers to accept test meters, since their premises must be available for meter printout sheet or tape replacement where necessary so that the test data will be continuous for the period involved. This complicates the selection procedure.

The selection process must result in a valid statistical sample. Ultimately, there must be selected a representative cross-section of customers willing to cooperate in the test-metering program, sufficiently large in number to be statistically significant. About three times the number of customers for which tests are needed must be initially selected. Factors such as examination of the types of customers produced by the random selection to assure that they are representative; field inspection of premises to determine type of premises; connected load and number of people who live or work on the premises; and unwillingness or inability of a customer to cooperate, all must eventually be tested. A considerable expenditure of time and manpower is needed to complete the process.

C. <u>Illustrative Embedded Cost of Service Study</u>

A cost of service study is a series of choices regarding potentially controversial methods of identifying and allocating costs incurred by a utility. This illustrative study represents one possible means of computing class cost of service. There are many other equally correct methods. For illustrative purposes, the following example demonstrates how the factors discussed above are utilized in a fully allocated cost of service study.

The first step in preparation of the study is a separation of all plant and expense items incurred during the test period into the <u>functional</u> categories of production, storage, transmission, distribution and general. This functionalization is shown throughout the study on Schedules 3, 4 and 5, according to Monopolytown's accounting system. Where possible, functional costs are directly assigned to the classes of service based upon details from the utility's books or by special analysis or studies. This is illustrated in Schedule No. 2 where Rate Revenues are directly assigned to the classes which produce them.

The costs not directly assignable were allocated among the customer classifications according to factors developed from the basic statistical data. The derivation of the allocation factors is illustrated on Schedules 10 and 11. The following is an explanation of the major allocation factors used in this study.

The Peak Day Demand (Allocation Factor 100) is the computed quantity of gas which would be supplied on a day when the mean temperature of the utility's service territory is 5 degrees Fahrenheit (the coldest day in 20 years for this particular system), which equates to a 60 degree-day deficiency. Schedule No. 12 provides the details of the peak day calculations. There are two predominant Commodity allocation factors which consist of normalized and curtailed gas sales during the test period. Factor No. 110 is comprised of sales without transportation volumes. Factor No. 120 is the total throughput quantity which includes gas sales and transportation. The primary Customer allocation factor, No. 160, consists of the number of bills rendered during the test period.

Once the allocation factors are prepared, they should be applied to the functionalized costs in relation to how those costs are incurred by the utility. Expenses and plant are classified or considered to be fixed, variable, customer, or revenue related. Classification is an integral part of the allocation process and once costs are classified, the appropriate allocation factors are applied to these costs as shown in the last column in each of Schedules 2 through 9. Fixed costs are normally allocated on the basis of demand, while variable costs are allocated on the basis of commodity sales. Costs incurred as a result of a customers' connection to the utility system are allocated on the basis of a customer factor, and costs related to revenues are allocated on the basis of a revenue factor. Costs which cannot be related to one of the four basic classifications are allocated on the basis of a composite factor, reflecting two or more elements of the expense or plant accounts. This is illustrated on Schedule No. 4 where account 374 (land and land rights) is allocated on the basis of allocation Factor No. 13, which reflects a composite of the allocation of all other distribution plant.

As a more detailed explanation of the allocation process, consider the allocation of utility plant which is shown on Schedule No. 4. Production plant, which includes a propane-air facility, was designed and constructed by the utility to meet peak load requirements. Consequently, production plant has been allocated on the basis of peak day demand (Allocation Factor No. 100).

The distribution plant investment in mains may be classified as both demand and customer related. The customer component was determine as the amount of investment that would be required it all mains were comprised of a theoretical minimum size. Monopolytown's smallest mains (1.5 inch diameter) were installed at an average unit cost of $0.61 per foot. The customer component of mains is computed by multiplying the total length of mains (6,385,860 feet) by the unit cost of the smallest mains. The resulting amount ($3,988,733) represents approximately 20 percent of the total investment in mains. The remaining 80 percent is considered to be demand related. Therefore, the investment and expenses associated with mains are allocated on the basis of composite allocation Factor No. 150. Factor No. 150 is a weighted average of allocation Factor No. 160 (20 percent weight) and Factor No. 100 (80 percent weight).

Plant facilities such as gas services and meters are allocated to the rate schedules by using allocation factors designed to reflect the various cost differentials among classes. To accomplish this weighted computation for gas services, the typical current cost to construct gas services for each customer class is determined. The class gas service costs are then divided by the typical residential gas service cost. The resulting ratio is a weighting factor which is then multiplied by the number of customers in each class. The product of this calculation then becomes the basis of the gas service Allocation Factor No. 200. The meter allocation factor is determined in a similar manner and the weighting factors utilizied for both meters and gas services are the following:

WEIGHTING FACTORS

Class	Services	Meters
Residential	1	1
*Commercial	5	5
*Industrial	50	40
Interruptible	50	40
Transportation	50	40

* The Commercial and Industrial classes are combined in the study under "GENERAL SERVICE"

Once the allocation of plant is accomplished, depreciation and working capital are the next steps which ultimately lead to the determination of rate base. The allocation of depreciation is illustrated on Schedule No. 5 and the allocation of working capital is demonstrated on Schedule No. 6. The allocation of rate base is illustrated on Schedule No. 7, where figures from previous schedules are assembled to determine customer class rate base for ratemaking purposes.

The allocation of operating expenses is illustrated in Schedule No. 3. Expenses which are demand related, such as pipeline demand charges and gas production expenses, are allocated on the basis of peak day demand, Allocation Factor No. 100. Expenses which are commodity related, such as commodity gas purchases, are allocated on the basis of sales excluding transmission, Allocation Factor No. 110. Customer oriented expenses, such as customer accounting, meter reading and advertising expenses are allocated on the basis of the number of customers on the system or the number of meters, Allocation Factor No. 160 or 180.

Many expenses, such as supervision and engineering, administration and general costs, taxes, and depreciation, are allocated on the same basis as the related plant investment. These are composite allocation factors developed as a line item summary of various elements in the cost of service study as it progresses. For example, Allocation Factor No. 13 is the respective customer class percentage of total distribution plant costs. Therefore, the allocation of any costs which are allocated on the basis of Factor No. 13 would have to proceed after total distribution plant by class is computed on Schedule No. 4. The composite allocation factors are illustrated on Schedule No. 11, with the appropriate reference to their development in the cost of service study.

Following the allocation of all plant and expenses, a summary is developed in Schedule No. 1. The relevent totals from each schedule previously explained are brought forward to Schedule No. 1 as a summary of the cost of service study and to examine the rate of return generated by the entire system as well as each class of service.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018929
	:	
PECO Energy Company – Gas Division	:	

VERIFICATION

I, Glenn A. Watkins, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 4-SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: February 9, 2021 Signature: ______________________
*303589 Glenn A. Watkins

Consultant Address: Technical Associates, Inc.
6377 Mattawan Trail
P.O. Box 1690
Mechanicsville, VA 23116

OCA Statement No. 5SR

R-2020-3018929
2/17/21 JK

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2020-3018929
PECO Energy Company –Gas Division	:	

Surrebuttal Testimony of
Roger D. Colton

On Behalf of:
Office of Consumer Advocate
Statement No. 5SR

February 9, 2021

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Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, MA.

Q. ARE YOU THE SAME ROGER COLTON WHO PREVIOUSLY PREPARED DIRECT AND REBUTTAL TESTIMONY FOR THE OFFICE OF CONSUMER ADVOCATE IN THIS PROCEEDING?

A. Yes.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY.

A. The purpose of my Surrebuttal Testimony is to respond to the following Rebuttal Testimony of the following parties:

- PECO Gas (Ronald Bradley [PECO Gas St. 1-R]; Joseph Bisti [PECO Gas St. 7-R]; Richard Schlesinger [PECO Gas St. 8-R]; and Kelly Colarelli [PECO Gas St. 10-R]);
- OSBA (Robert Knecht [OSBA St. 1-R]); and
- PAIEUG (Billie LaConte [PAIEUG St. 1-R]).

Part 1. Response to PECO Gas Rebuttal Witnesses.

A. Response to PECO Gas Witness Ronald Bradley.

Q. PLEASE EXPLAIN THE RECOMMENDATION IN MR. BRADLEY'S REBUTTAL TESTIMONY THAT YOU ADDRESS?

A. In his Rebuttal Testimony, PECO Gas witness Ronald Bradley asserts that the utility has demonstrated "exemplary management" because it has improved its customer satisfaction since 2014 / 2016. (PECO Gas St. 1-R, at 16). He asserts that "there was a significant improvement from 2014 (82%) to 2016 (88%). . .PECO achieved similar results on J.D. Power scores of no lower than 89% from 2015 through 2019, with a significant improvement from 2014 (84%) to 2015 (89%)." (PECO Gas St. 1-R, at 16). In response to Mr. O'Donnell, Mr. Bradley again asserts "the significant improvement that PECO has achieved." (Id., at 17). What Mr. Bradley cannot overcome, and does not address, is that, whether or not PECO has "improved" its performance in the past seven years (i.e., since 2014), its performance remains in the middle of the pack when compared to other Pennsylvania gas distribution utilities.

As I note in my Direct Testimony, the PUC has prescribed certain data to be used specifically for the purpose of the Commission's assessment of utility performance regarding customer service. Using six of those metrics specifically reported for the purpose of reviewing utility management performance, I found that "while, in many ways, PECO does not perform worse than other Pennsylvania utilities in the realm of customer service, PECO certainly does not perform substantially better than Pennsylvania utilities. Indeed, in many ways the performance of PECO on customer service related factor[s] is toward the bottom level of performance in Pennsylvania." (OCA St. 5, at 100). Using those metrics, I found that "PECO cannot lay claim to superior or exemplary management when it relates to customer service." (Id., at 101).

Notwithstanding Mr. Bradley's assertions, whatever the "improvement" in the PECO Gas customer service performance, he has not demonstrated that PECO Gas has "improved" from ordinary to exemplary. At best, even if I acknowledge the "improvements" that Mr. Bradley asserts, any "improvement" that PECO Gas has achieved has resulted in management performance that is, at best, "not. . .substantially better than Pennsylvania utilities. Indeed, in many ways, the performance of PECO on customer service related factors is toward the bottom level of performance in Pennsylvania." (OCA St. 5, at 100). Mr. Bradley's testimony does not establish to the contrary.

Q. IS THERE ANY FINAL ISSUE IN MR. BRADLEY'S REBUTTAL TESTIMONY THAT YOU WISH TO ADDRESS?

A. Yes. Mr. Bradley attributes a proposed $47,624,803 reduction in claimed plant additions to me in his Rebuttal Testimony. (PECO Gas St. 1-R, at 18). My Direct Testimony did not address plant additions, or any other aspect of the PECO Gas rate base. Accordingly, I do not address that issue here. Instead, presumably the appropriate I&E witness, Ethan Cline, who presented that Direct Testimony, will respond to Mr. Bradley's Rebuttal Testimony. My failure to respond to Mr. Bradley's testimony on this issue is nothing other than an acknowledgement that the issue was not one that was presented in my Direct Testimony in the first instance.

B. Response to PECO Gas Witness Rebuttal Witness Bisti.

Q. PLEASE IDENTIFY THE ISSUE FROM YOUR DIRECT TESTIMONY THAT PECO GAS WITNESS BISTI ADDRESSES IN HIS REBUTTAL.

A. In his Rebuttal Testimony, PECO Gas witness Joseph Bisti responds to my Direct Testimony regarding the proposed change to the PECO Gas residential customer charge.

(PECO Gas St. 7-R, at 10). Mr. Bisti's Rebuttal Testimony does not address the data and analysis I present in my Direct Testimony.

First, Mr. Bisti asserts, without any supporting facts or analysis, that low-income customers are more likely to be "high-usage" and thus "more likely to experience high monthly bills." (PECO Gas St. 7-R, at 10). He states that the Company's proposed increase to the customer charge will "provide a relative benefit to high-usage, low-income customers. . ." (PECO Gas St. 7-R, at 10). Mr. Bisti offers no facts, however, to support his claim that low-income customers are high-usage. His Rebuttal Testimony does not attempt to counter the extensive analysis presented in my Direct Testimony that low-income customers in the PECO Gas service territory disproportionately, and on average, tend to be low use customers. Thus, while I agree with Mr. Bisti that "any division of cost between fixed and volumetric components in a customer class will have relative winners and losers," (PECO Gas St. 7-R, at 10), the evidence in this case is that low-income customers will, disproportionately and on average, be amongst the losers from the PECO Gas proposal to increase its residential customer charge.

Mr. Bisti's dismissal of my discussion of LIHEAP in my Direct Testimony indicates that he is not recognizing the impact of the PECO Gas proposal on those customers who can least afford to pay the increase in the PECO Gas unavoidable fixed customer charge. While Mr. Bisti is correct when he asserts that "PECO is not involved in the establishment of LIHEAP funding levels," (PECO Gas St. 7-R, at 10), that observation does not detract from the fact that the proposed increase in the unavoidable fixed charge proposed by PECO Gas will have the same impact on PECO Gas low-income customers as reducing LIHEAP benefits to $0. The low-income customers of PECO Gas receive federal assistance to help pay their PECO Gas bills. The PECO Gas proposal to increase its fixed monthly customer charge, standing alone, effectively reduces the benefits of LIHEAP assistance to nothing. (See OCA St. 5, at 31). For every dollar in assistance that LIHEAP delivers to PECO Gas low-income customers, PECO Gas is effectively proposing to remove a dollar through its proposed increase to the fixed monthly residential customer charge.

Finally, Mr. Bisti references PECO Gas witness Colarelli's discussion of the Company's pending proposal to transition its Customer Assistance Program (CAP) to a percentage of income program. (PECO Gas St. 7-R, at 10). I address that discussion in my response to witness Colarelli below.

C. Response to PECO Gas Rebuttal Witness Richard Schlesinger.

Q. PLEASE EXPLAIN THE ISSUE THAT PECO WITNESS SCHLESINGER ADDRESSES.

A. PECO witness Richard Schlesinger seeks to justify the PECO Gas proposal to impose a fee of $460 for investigating fraud and theft (proposed Rule 17.7), replacing the current theft/fraud reconnection fee of $370. (PECO Gas St. 8-R, at 1-4). As Mr. Schlesinger correctly notes, the objections I raised in my Direct Testimony in opposition to the proposed Rule 17.7 would apply with equal force to the existing Rule 17.6. I agree with his observation in that regard. The fact that Rule 17.6 has been previously included in the

PECO Gas tariff, however, is not sufficient, unto itself, to establish its reasonableness. When challenged, PECO Gas needs to establish the reasonableness of charges imposed on customers, even if included in existing tariff provisions. Consider, for example, that the Suspension Order in this proceeding specifically identifies that "4.That this investigation shall include consideration of the lawfulness, justness, and reasonableness of the Respondent's *existing* rates, rules, and regulations" as well as the proposed changes." (emphasis added).

Q. DOES MR. SCHLESINGER ESTABLISH THE REASONABLENESS OF PROPOSED RULE 17.7, OR THE EXISTING RULE 17.6, IN HIS REBUTTAL TESTIMONY?

A. No. First, the level of the fee has not been adequately established by Mr. Schlesinger. Consider, for example, that Mr. Schlesinger states that "the theft and/or fraud fee would *only be applied* in cases of confirmed active theft (i.e., where there is a loss of gas revenue due to tampering with the service.)." (PECO Gas St. 8-R, at 2 – 3) (emphasis added). "Active gas theft," as Mr. Schlesinger states, involves very specific tampering with a meter. (Id., at 3, note 1). The dollar value of the fee, however, is based on "the average cost that PECO incurs to investigate and remediate theft *or fraud*." (Id., at 2) (emphasis added). "Fraud," however, is an action that is very distinct from "theft" due to meter tampering under PUC regulations. (Compare PUC regulations 56.32(a)(vi) to Section 56.32(a)(vii); see also, 56.35(b)(1); compare 56.98(a)(2) to 56.98(a)(3); compare 56.321(6) to 56.321(7)). As I note in my Direct Testimony, an allegation of "fraud," for example, must involve PECO Gas making a determination of whether the person so accused has, in fact, committed "fraud" or has merely made a "mistake." Instances "where there is a loss of gas revenue due to tampering with the service" would not involve that same degree of investigation. By his own testimony, in other words, when Mr. Schlesinger asserts that the cost is based on the cost of investigating fraud, Mr. Schlesinger also acknowledges that the proposed fee is excessive when only applied to "active gas theft" as he asserts. By PECO Gas' own testimony, the charge does not apply to fraud, but only to "active gas theft." Accordingly, the costs of investigating "fraud," which would involve greater effort and thus greater costs, should not be used to support a fee applied to the investigation of such "active gas theft."

Second, by his own rebuttal testimony, Mr. Schlesinger establishes that the existing Rule 17.6 (and proposed rule 17.7) is excessively broad. Mr. Schlesinger asserts that "The theft and/or fraud fee would only be applied in cases of confirmed active theft (i.e., where there is a loss of gas revenue due to tampering with the service)." (PECO Gas St. 8-R, at 2-3). Despite his claim that the fee is applied only to "confirmed active theft," the existing Rule 17.6 (and proposed Rule 17.7) seeks to apply the fee to "applicants" for service. The term "applicant," of course, is a term that is defined by Commission regulation. According to PUC rules, an applicant is "A natural person at least 18 years of age *not currently receiving service* who applies for residential service provided by a public utility. . ." (Section 56.2) (emphasis added). Mr. Schlesinger does not explain how a person "not currently receiving service" can be engaged in "confirmed active theft."

Third, Mr. Schlesinger further effectively acknowledges that the proposed Rule 17.7 (and existing Rule 17.6) is excessively broad. The proposed (and existing) Tariff language on its face applies to ***both*** "fraud" ***and*** "theft." According to Mr. Schlesinger's Rebuttal Testimony, however, "[a]lthough not detailed in its tariff, PECO has established procedures in place to investigate theft and/or fraud and apply fees as appropriate. The theft and/or fraud fee would only be applied in cases of confirmed active theft (i.e., where there is a loss of gas revenue due to tampering with the service)." (PECO Gas St. 8-R, at 2-3). Witness Schlesinger acknowledges, in other words, that: (1) even PECO Gas narrows its application of the tariff language; (2) that such narrowing is voluntary on its part, accomplished through "procedures in place,"; and (3) that PECO Gas' narrowing of the applicability of the proposed rule is "not detailed in its tariff" (and, accordingly, has never been presented to and approved by the Commission). Should the Commission approve the proposed tariff language, there is nothing to prevent PECO from deciding to adopt "procedures in place" to apply that tariff language in a different (and broader) fashion.

Finally, Mr. Schlesinger claims to address the excessive amount of the proposed $460 fee included in Rule 17.7 (and the excessive amount of the existing $370 fee included in Rule 17.6) by making a *de minimis* revenue adjustment of $10,000 to the "budgeted theft fee revenue" to address the administrative and overhead costs already included in rates. (PECO Gas St. 8-R, at 3). There is, however, no effort on the part of Mr. Schlesinger to tie his claimed adjustment to the actual overhead and administrative costs included in the proposed $460 (and existing $370) fee. (See, Company response to CAUSE-PA-II-3(a)).

D. Response to PECO Gas Rebuttal Witness Kelly Colarelli.

Q. PLEASE IDENTIFY THE ISSUE WHICH PECO WITNESS COLARELLI ADDRESSES IN REBUTTAL?

A. The Rebuttal Testimony of PECO Gas witness Kelly Colarelli addresses issues involving my recommended COVID-19 relief program, low-income issues, and the allocation of universal service costs. I will respond to each of these in turn.

Q. PLEASE RESPOND TO THE REBUTTAL TESTIMONY OF KELLY COLARELLI REGARDING COVID-19 EMERGENCY RELIEF.

A. PECO witness Colarelli responded to my recommended COVID-19 emergency relief program by asserting that it is not "necessary or appropriate." (PECO Gas St. 10-R, at 5). She does not explain why my recommended COVID-19 relief is not "appropriate." In contrast, I provide detailed information about the impact of COVID-19 on low-wage customers. The financial crisis impacts that I identify not only have occurred to date, as I explain, but can be expected to continue for the foreseeable future. As I document in my Direct Testimony, many of the jobs that have been lost due to COVID-19 will be permanently lost. In addition, households –particularly low-wage households—have been forced to exhaust their savings and to increasingly rely on credit in order to pay day-to-day expenses. Going forward, the economic crisis for these customers will potentially be even greater than the economic crisis has been to date.

Witness Colarelli asserts that PECO is providing a sufficient response because "any residential customer that identifies a financial difficulty is provided with information about PECO's universal service programs." (PECO Gas St. 10-R, at 5). Providing information about PECO's universal service programs, however, does not address the needs of PECO's customers. As my Direct Testimony documents, and witness Colarelli does not dispute, the economic crisis created by COVID-19 extends to low-wage customers, not merely low-income customers. The households facing an economic emergency not only may have, but are likely to have incomes that exceed those incomes which would qualify them for the PECO Gas universal service programs. The need for emergency assistance extends beyond households with income up to 150% of Poverty Level. While my recommended emergency relief program addresses that need, neither PECO's existing, nor PECO's proposed, COVID-19 responses do so.

Witness Colarelli further asserts that PECO is providing a sufficient response because it has proposed "a $50 bill credit (*for CAP customers*)." (PECO Gas St. 10-R, at 5). (emphasis added). Limiting emergency assistance to additional financial benefits for CAP participants is an insufficient response to the COVID-19 pandemic. As I document in my Direct Testimony, PECO Gas enrolls only a fraction of its estimated low-income population into its CAP. Witness Colarelli acknowledges that the Company's CAP population is only 25.8% of its estimated low-income population. (PECO Gas St. 10-R, at 6). The PECO Gas proposal, in other words, excludes not only 100% of its customers who exceed the CAP income-eligibility, but also excludes more than 3-of-4 (74.2%) of its income-eligible population.

Finally, witness Colarelli asserts that PECO's proposal to establish "a payment agreement with a term of *__up to__* 24 months" is a sufficient COVID-19 response. (PECO Gas St. 10-R, at 5). That recommendation is insufficient for the following reasons. First, the PECO proposal allows the utility to establish a payment agreement of less than 24-months. The 24-month figure, according to witness Colarelli's own testimony, is merely a maximum; an arrangement of 12-months or 18-months (or some other term of less than 24-months), in other words, is in compliance with the PECO Gas proposal to offer payment arrangements of "up to" 24-months. In contrast, my recommended emergency relief provides for a payment arrangement in compliance with PUC regulations or 24-months *__whichever is longer__*. Second, the PECO Gas proposal is not even in compliance with the PUC's existing regulations. Section 1405(b) of Pennsylvania's statutes, for example, provides that utilities shall offer payment arrangements of not to exceed "Three years for customers with a gross monthly household income level exceeding 150% and not more than 250% of the Federal poverty level." The existing statute, in other words, provides a longer period for payment arrangements than allowed by the PECO Gas COVID-19 emergency relief proposal.

In sum, the proposed PECO Gas COVID-19 emergency relief program reviewed by witness Colarelli is an insufficient response to the economic crisis facing PECO Gas customers attributable to COVID-19. Witness Colarelli's review of that existing (and proposed) response does not sufficiently respond to the COVID-19 economic crisis that I documented in my Direct Testimony. My proposed emergency response should be adopted.[1]

Q. PLEASE RESPOND TO THE REBUTTAL TESTIMONY OF KELLY COLARELLI REGARDING LOW-INCOME ISSUES.

A. PECO Gas witness Colarelli asserts that the "general low-income customer participation concerns" raised in my Direct Testimony "are misplaced." (PECO Gas St. 10-R, at 6). Witness Colarelli notes that PECO Gas enrolls 25.8% of its estimated low-income population in its CAP. (PECO Gas St. 10-R, at 6). Even if accurate, the significance of this is that PECO Gas *fails* to enroll 74.2% of its income-eligible population (nearly 3-out-of-4 of every low-income customer) in its CAP. For this three-fourths of the PECO Gas low-income population that is not enrolled in CAP, PECO Gas proposes not only to increase rates, but proposes to impose a disproportionate increase in the unavoidable, fixed monthly customer charge.

In addition, Ms. Colarelli responds to my Direct Testimony by asserting that PECO has proposed modifying its current CAP to become a percentage of income program. Witness Colarelli states that "PECO expects the PIPP to improve bill affordability for all CAP income groups as compared to its current FCO." (PECO Gas St. 10-R, at 8). While I do not disagree with this statement, the statement does not address the issue presented in my Direct Testimony. What witness Colarelli fails to acknowledge is that my Direct Testimony was not in furtherance of proposed changes to the PECO Gas universal

[1] As stated in response to discovery from PECO Gas to OCA, there is a mistake in Schedule RDC-1 of my Direct Testimony. In Part 2(a)(i) of Schedule RDC-1, there should be a period (.) after the word "restrictions." The words "adopted pursuant to paragraph 1" should be deleted.

service programs. Rather, my Direct Testimony established, and PECO witness Colarelli did not seek to rebut, that PECO's proposed customer charge disproportionately adversely affects low-income customers. As I stated in my Direct Testimony:

> [T]he PECO Gas proposal to increase its customer charge will harm low-income customers in each of the following ways (with each bullet below incorporating every other bullet):
>
> - It will increase both the breadth and depth of arrears, each of which imposes additional utility costs on low-income households along with the social consequences appurtenant thereto.
>
> - It will increase the incidence of service disconnections for nonpayment, along with the increased utility costs on low-income households in addition to the social consequences appurtenant thereto.
>
> - It will increase the incidence of the threat of service disconnections for nonpayment, along with the increased utility costs and social consequences appurtenant thereto.
>
> - It will decrease the ability of low-income customers to maintain deferred payment arrangements through which they can retire past-due balances outside of the participation in CAP.
>
> - It will increase Home Energy Insecurity, along with the resulting utility costs on low-income households, in addition to the social consequences appurtenant thereto.

(OCA St. 5, at 33, internal notes omitted).

Q. PLEASE RESPOND TO THE REBUTTAL TESTIMONY OF KELLY COLARELLI REGARDING THE ALLOCATION OF UNIVERSAL SERVICE COSTS.

A. The Rebuttal Testimony of PECO witness Colarelli does not directly address my Direct Testimony regarding the allocation of universal service costs over all customer classes. Instead, she states that "The Company does not support a change in universal service cost allocation *as part of this proceeding*. . ." (PECO Gas St. 10-R, at 12) (emphasis added). She states that PECO "intends to address the allocation of universal service costs in its *next electric base rate proceeding*." (Id., emphasis added). Colarelli makes this recommendation because, she asserts, "PECO's gas-only CAP population is an exceedingly small part of its total CAP population." (Id.)

Ms. Colarelli's proposal to delay any decision on the inter-class allocation of PECO Gas universal service costs to PECO's next electric rate case should not be accepted for the following reasons.

First, Ms. Colarelli's proposal is in conflict with the Commission's explicit directive in the Revised CAP Policy Statement. In its 2019 Final Policy Statement and Order in the PUC's generic investigation into energy affordability in Pennsylvania (Docket M-2019-3012599),[2] the Commission explicitly directed "That the. . . natural gas distribution companies listed in Ordering Paragraph No. 5 be prepared to address recovery of customer assistance program costs (and other universal service costs) *in their next individual rate case proceedings*, recognizing that non-residential classes need not be routinely considered exempt from universal service obligations." (Final Order, at 110) (emphasis added). PECO Energy was one of the "natural gas distribution companies

[2] http://www.puc.pa.gov/about_puc/consolidated_case_view.aspx?Docket=M-2019-3012599 (November 5, 2019) (last accessed May 16, 2020) (hereafter "Final Order").

listed in Ordering Paragraph No. 5." It is not at all clear that proposing to postpone a decision on the allocation of universal service costs to a future electric base rate proceeding is "addressing" the "recovery of customer assistance program costs (and other universal service costs)." Given the complete record provided by the testimonies of OCA, CAUSE-PA, OSBA and PAIEUG in this proceeding, it would be more reasonable for the Commission to make its decision on the record developed in this rate proceeding in accord with its directive in its Final Order on the Revised CAP Policy Statement.

Second, when Ms. Colarelli proposes to "address the allocation of universal service costs in its ***next*** electric base rate proceeding" (emphasis added), there is no time-frame established for presenting this issue to the Commission for decision relative to PECO. PECO does not necessarily file annual electric base rate proceedings. And, there is no currently pending electric base rate case proceeding. What Ms. Colarelli is proposing, in other words, is an indefinite postponement of the presentation of the issue of PECO universal service cost allocation to the Commission. Given the need for the change in the inter-class allocation of universal service costs, to indefinitely postpone a decision is not reasonable.

Third, even if PECO were to file an *electric* base rate case in the near-term, I have been informed by counsel that decisions regarding electric rates could not be automatically be applied to the allocation of natural gas costs. What Ms. Colarelli's proposal does, in other words, is not only to postpone the presentation of the universal service cost allocation question to the next PECO electric base rate proceeding, but also to delay the presentation of the universal service cost allocation *for gas customers* to the next natural gas base rate proceeding subsequent to that electric base rate proceeding. Again, given the need for the change in the inter-class allocation of universal service costs, to indefinitely postpone a decision for PECO Gas customers is not reasonable.

Fourth, even if PECO's universal service costs were allocated amongst all customer classes in PECO's next electric base rate proceeding, I have been informed by counsel that that decision could not *a priori* be applied retroactively to PECO's natural gas rates.

Finally, Ms. Colarelli's reasoning should be rejected because it proves too much. Given the disparate size between PECO Gas operations and PECO Electric operations, accepting Ms. Colarelli's rationale with respect to universal service costs would further justify postponing any decision that would affect both electric and natural gas customers to PECO Electric base rate proceedings. Establishing the precedent that any decision affecting both gas and electric operations would be postponed to an electric base rate proceeding would be an inappropriate and unreasonable way to approach natural gas ratemaking for PECO Gas.

Part 2. Response to OSBA Witness Robert Knecht.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR SURREBUTTAL TESTIMONY.

A. In this section of my testimony, I respond to the Rebuttal Testimony of OSBA witness Robert Knecht. Mr. Knecht opposes my recommendation that universal service costs be spread over all customer classes.

Q. PLEASE RESPOND TO MR. KNECHT'S DISCUSSION OF THE PENNSYLVANIA COMMISSION'S RECENT REVISED POLICY STATEMENT REGARDING THE ALLOCATION OF UNIVERSAL SERVICE COSTS AMONGST CUSTOMER CLASSES.

A. Mr. Knecht's primary argument in opposition to spreading universal costs over all customer classes is that he disagrees with the Pennsylvania PUC's recent decision regarding cost allocation. Mr. Knecht erroneously asserts that the Commission's "primary rationale for considering a change to the policy appears to be that the low-income assistance programs have become unaffordable to those residential customers who are ineligible or who otherwise do not participate in the programs." (Knecht Rebuttal, at 22).

Mr. Knecht mis-represents the Commission's decision. Rather than the limited decision that Mr. Knecht portrays, the Commission identified specific factors that it said should be taken into consideration in any review of the allocation of universal service costs. While my Direct Testimony assessed each of those factors one-by-one (OCA St. 5, at 58 – 71), Mr. Knecht has failed to consider any of them.

In its September 2019 Final Order quoted above, the Pennsylvania PUC identified several factors that "contribute to households struggling to afford utility service" and indicated that such factors "are not just residential class problems." Amongst those factors which the PUC identified were "poverty, poor housing stock, and other factors." In my Direct Testimony, I considered the various aspects of Poverty and how each of those aspects are not caused by the residential class. (OCA St. 5, at 58 – 71). My discussion of the Commission-identified factors (i.e., poverty, poor housing, "other factors"), which included the wage levels throughout the Company's service territory, demonstrates that the residential class is not the "cause" of the need for CAP.

I conclude that the observation in my Direct Testimony remains accurate, that "the Pennsylvania PUC was correct when it observed in September 2019 that Poverty is a broad-based social problem not associated with any particular customer class, including specifically not being associated with the residential class exclusively. I find that a substantial number of wage-earning customers participate in PECO's universal service programs. I find further that one reason that these customers income qualify for PECO's universal service programs is because a substantial number of people throughout the PECO service territory are working at Poverty wages." (OCA St. 5, at 71).

Q. WHAT IS YOUR NEXT RESPONSE TO MR. KNECHT'S REBUTTAL TESTIMONY?

A. OSBA witness Knecht presents an extensive discussion of his perspective on whether the cost of providing universal service programs should be included in utility rates at all. (OSBA St. 1-R, at 23 – 24). He creates a distinction, for example, between "two general philosophies" of providing universal service: (1) the "tax" model; or (2) the "insurance" model. He then discusses his opinion about the relative advantages and disadvantages of using one of those "general philosophies" or the other. (Id., at 23).

Mr. Knecht's Rebuttal Testimony approaches the issue of universal service as though it is newly being determined whether such programs are appropriate or not. (OSBA St. 1-R, at 23 – 24). As the PUC noted in is September 2019 Final CAP Policy Statement order, however, that is simply not the case. The Commission has stated that:

> Universal service and energy conservation" is a collective term for the "policies, protections and services that help low-income customers to maintain service" as mandated by statute. The four universal service programs are: (1) CAPs, which may provide discounted pricing, arrearage forgiveness, and/or other benefits for enrolled low-income residential customers; (2) Low-Income Usage Reduction Programs (LIURP), which provide weatherization and usage reduction services to help customers reduce their energy utility bills; (3) Customer Assistance and Referral Evaluation Services (CARES), which provide information and referral services for low-income, special needs customers; and (4) Hardship Fund programs, which provide grants to help customers address utility debt, restore service, or stop a service termination. EDCs and NGDCs are required to offer these universal service programs in each distribution territory and to submit updated USECPs every three years for Commission approval.

(PUC Final CAP Policy Statement Order, at 3, internal notes omitted). The Commission continued:

> We note there is no statutory or appellate prohibition that limits the recovery of CAP costs, whether specifically calculated or as part of total universal service costs, to funding from the residential class. Universal service funding from non-residential classes, while not mandatory, is permissible:
>
> > Thus, under *Lloyd*, there is no statutory requirement that the funding for special programs come only from those who benefit from the programs. However, the lack of such a requirement does not mean that funding for special programs must come from those who do not benefit.
>
> *MEIUG v. Pa. PUC*, 960 A.2d 189, 202 (2008), citing *Lloyd v. Pa. PUC*, 904 A.2d 1010 (Pa. Cmwlth. 2006).
>
> Consistent with the comments of the Low Income Advocates and OCA, the Commission concludes that the General Assembly clearly identified the public purpose of these programs in the Competition Acts by requiring that their costs be nonbypassable when a customer switches energy providers.

(Id., at 98 – 99, internal notes omitted). Mr. Knecht's critiques based on his opinions as to the nature of, or the legitimacy of the existence of, utility-funded universal service programs should be rejected.

Q. PLEASE RESPOND TO MR. KNECHT'S DISCUSSION OF THE MEANING OF THE REQUIREMENT THAT UNIVERSAL SERVICE COSTS BE "NONBYPASSABLE."

A. Mr. Knecht argues that PECO's current recovery of universal service costs is "already non-bypassable, because universal service costs are recovered in base distribution rates and the USFC, both of which apply equally to sales and shopping customers." (OSBA St. 1-R, at 25). He argues that "the bypass issue is unrelated to interclass allocation or public benefits." (Id.)

The electric restructuring act (66 Pa.C.S. §2804(9)) and the corresponding section of the natural gas restructuring act (66 Pa.C.S. §2203(8)) present mirror images of universal service cost recovery requirements. Both statutes provide that universal service program costs are to be recovered through an "appropriate nonbypassable competitively neutral" charge in the distribution company's rates. The common understanding of the bypass problem is that some customers will either leave the distribution system entirely (and leave their share of system costs behind) or that those customers will negotiate a discount off their distribution charges by raising the threat that they will leave the system entirely.

In arguing that the "nonbypassable" language does not contemplate that costs be allocated to non-residential classes, Mr. Knecht fails to consider that universal service costs have been found to be public goods. As I demonstrated in detail in my Direct Testimony (OCA St. 5, at 84 – 89), "public goods are those products and services that are valuable to society but which are undersupplied when society relies on private markets to provide them." (OCA St. 5, at 84). The public good model has cost allocation implications not recognized by Mr. Knecht. As I noted in my Direct Testimony, the National Regulatory Research Institute (NRRI) has found that the public good model is based upon the premise that the costs of achieving the public good –universal service in the current instance—"are ultimately born *by the general body of ratepayers*. . ." (OCA St. 5, at 85) (emphasis added).

This issue previously has been presented to, and resolved by, the Commission. In the PUC's Revised CAP Policy Statement, the PUC noted that stakeholders such as OSBA, Penn State University, and the industrial stakeholders, have previously argued against the conclusion that universal service was a public good, while OCA argued that universal service was a public good. After reviewing those arguments, the PUC concluded that "Clearly, there is a persuasive argument to be made that home heating and energy assistance for low-income households serves a public good whose responsibility is not merely other residential ratepayers." (Final Order, at 96 – 97). Moreover, even more directly, the PUC held that "Consistent with the comments of the Low Income Advocates and OCA, *the Commission concludes- that the General Assembly clearly identified the public purpose of these programs* in the Competition Acts by requiring that their costs be 'nonbypassable' when a customer switches energy providers." (Id., at 98 – 99) (internal notes omitted) (emphasis added).

Q. PLEASE RESPOND TO MR. KNECHT'S DISCUSSION OF "COMPETITIVE NEUTRALITY."

A. Mr. Knecht argues that the allocation of universal service costs among all customer classes, as I recommend, is not "competitively neutral" since, under his calculations, small businesses would pay a higher cost per MCF than would large businesses. (OSBA St. 1-R, at 28). He does not, however, establish that the cost-per-MCF is an appropriate measure of competitive neutrality. In fact, contrary to Mr. Knecht's rebuttal testimony, "competitive neutrality" references neither the cost per MCF nor comparisons between customer classes. The phrase requires that customers who access competitive gas supplies are treated no differently than customers who do not.

Moreover, Mr. Knecht then confuses the requirement that universal service cost responsibility be "nonbypassable" with the requirement that it be "competitively neutral." Contrary to what Mr. Knecht asserts, whether customers can or "cannot avoid the universal service charge by switching from utility gas supply to competitive natural gas supply" is not a question of competitive neutrality. It is rather a question of whether such costs can be bypassed.

Mr. Knecht's discussion of competitive neutrality is in error, and provides no basis for disapproving the allocation of universal service costs amongst all customer classes as I recommend.

Q. PLEASE RESPOND TO MR. KNECHT'S PROPOSED COST ALLOCATION METHODOLOGY.

A. Mr. Knecht attempts to piggyback his overall cost of service methodology into the discussion of the allocation of universal service costs. Mr. Knecht does not dispute this. He states: 'Specifically, I *started with my estimate* of the cost-based increase needed to *move rates into line with allocated cost from my GCOSS*, and I adjusted those values for the cost changes show in [the Table] above. . .As shown, the OCA cost allocation change would have only a small impact on *my revenue allocation proposal*." (OSBA St. 1-R, at 29) (emphasis added). Given that OCA witness Watkins has explained why several aspects of Mr. Knecht's overall cost-of-service methodology are inappropriate with which to begin, Mr. Knecht's conclusions flowing from the use of that methodology are equally flawed. The Commission should not use a flawed methodology as a basis to upon which to make universal service cost allocation decisions.

Part 3. Response to PAIEUG Witness Billie LaConte

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR SURREBUTTAL TESTIMONY.

A. In this section of my Surrebuttal Testimony, I respond to the Rebuttal Testimony of Billie LaConte regarding the allocation of universal service costs amongst all customer classes. PAIEUG witness LaConte opposes the recommendation I advance in my Direct Testimony that universal service costs be allocated amongst all customer classes.

Q. PLEASE RESPOND TO THE FIRST ARGUMENT PRESENTED BY MS. LACONTE IN OPPOSITION TO ALLOCATING UNIVERSAL SERVICE COSTS AMONGST ALL CUSTOMER CLASSES.

A. PAIEUG witness LaConte argues that "PECO's other customer classes do not receive the benefits of USFC, and, therefore, should not subsidize the residential rate class's (sic) USFC." (PAIEUG St. 1-R, at 10).

Ms. LaConte does not attempt to rebut the extensive set of direct financial benefits that all customer classes, including large industrial customers, receive from universal service programs such as those provided by PECO Gas. As I document in my Direct Testimony, universal service programs have been found, by extensive research both by industrial stakeholders and by academic researchers examining the impacts of such programs on commercial and industrial customers, that it is an error to assert, as Ms. LaConte does, that non-residential customer classes do not benefit from universal service programs.

Contrary to the assertion set forth in Ms. LaConte's testimony, the positive impact to business arising from addressing financial stressors of low wage workers has been extensively studied. That research, summarized in my Direct Testimony, reports among other things that business benefits from programs such as the PECO Gas universal service program because:

- Such programs "contribute to the overall competitiveness of the Pennsylvania economy." (OCA St. 5, at 71-72, internal citations omitted). In contrast, the failure to have such programs, in a wide variety of ways, would "impede the competitiveness of the state's business and industry." (OCA St. 5, at 73, internal citations omitted). I cited research finding that, overall, the financial stressors which PECO Gas helps to alleviate through its universal service programs "produce slower rates of growth." (OCA St. 5, at 82, internal citations omitted).

- Such programs "help to control the need to provide local government services, the cost of which is largely borne by non-residential taxpayers. There is a direct connection between unaffordable home energy bills and the costs of providing public health services. There is a documented connection between unaffordable home energy bills and public safety costs." (OCA St. 5, at 74, internal citations omitted).

- The failure to provide such programs "generates poor health among workers, making them less reliable still and raising the cost of employing them." (OCA St. 5, at 71, internal citation omitted). Indeed, the failure of PECO to provide such programs "can affect employee productivity," thus increasing "the estimated costs to businesses when financially stressed employees are left to struggle on their own." (OCA St. 5, at 76, internal citations omitted).

- The PECO Gas universal service program generates "increases in employee productivity" because "[p]overty produces ill-prepared workers whose lives are easily disrupted by small catastrophes." (OCA St. 5, at 71).

I cited research documenting that "financial stress adversely affects employers both through absenteeism and presenteeism." (OCA St. 5, at 77, internal citations omitted). Absenteeism is when employees miss work. Presenteeism is when an employee is at work, but less productive due to outside distractions. As I cited in my Direct Testimony, "presenteeism and absenteeism costs are 15-20% of total compensation paid to all employees in the businesses studied." (OCA St. 5, at 78, internal citations omitted). Employers report that their workers "lose nearly one month of productive work time (23-31 days per year) over financial concerns." (OCA St. 5, at 79, internal citations omitted).

Moreover, my Direct Testimony documented that industry and academic research has found that "financial stress was. . .hurting the health of millions of American workers." (OCA St. 5, at 75, internal citations omitted). Indeed, as my Direct Testimony documented "an increase in health care costs is one of the most cited costs imposed on employers due to financial stress." (OCA St. 5, at 76, internal citations omitted). Employers reported that workers "reporting high stress were $413 more costly per year on average than workers who were not at risk from stress." (OCA St. 5, at 76-77, internal citations omitted).

In short, Ms. LaConte would allow non-residential customers to pocket all of these financial benefits generated by the PECO Gas universal service programs while bearing none of the responsibility for paying the costs of generating those benefits. That argument should be rejected.

Q. DOES PAIEUG WITNESS LACONTE SUBSEQUENTLY REARTICULATE THIS SAME ARGUMENT IN A DIFFERENT FORM?

A. Yes. Ms. LaConte asserts, while providing no factual basis, that "imposing higher costs on non-residential customers would only make the business environment less sustainable and could further threaten recovery efforts essential to restoring pre-pandemic employment levels, wages and personal incomes." (PAIEUG St. 1-R, at 12). She asserts that "some transportation customers" (such as hospitals) would be unfairly burdened by paying their share of universal service costs "especially since they do not benefit from the [Universal Service Fund Charges]." (PAIEUG St. 1-R, at 12 – 13). The argument that bearing their share of universal service costs "makes the business environment less sustainable" is contrary to all of the ways in which industrial and academic researchers have found to the contrary. Ms. LaConte's argument that transportation customers, including hospitals, "do not benefit" from the universal service programs is simply a restatement of her argument that "PECO's other customer classes do not receive the benefits of USFC. . ." (PAIEUG St. 1-R, at 12).

In fact, Ms. LaConte's choice to use hospitals as an illustration of a type of customer who would be harmed by paying their share of PECO Gas' universal service costs is particularly misplaced. Hospitals have a disproportionate share of low wage workers who would be harmed by the lack of PECO Gas universal service programs. Moreover, hospitals have a disproportionately high share of total costs that are employee-related, the very costs that would be reduced by addressing the financial stress of its low-wage workers. Moreover, as discussed in my Direct Testimony, the provision of universal service programs helps ***improve*** the health outcomes of customers served through such programs. To the extent that hospitals may struggle with capacity shortages attributable to COVID-19, offering universal service programs to financially-stressed employees (just as offering other employee-based wellness programs) would benefit hospitals, not burden them, by helping to address the health problems contributing to their capacity issues.

Q. DO YOU HAVE ANY FINAL RESPONSE TO MS. LACONTE'S REBUTTAL TESTIMONY THAT ALLOCATING UNIVERSAL SERVICE COSTS TO ALL CUSTOMER CLASSES WOULD HARM BUSINESSES?

A. Yes. As I note above, Ms. LaConte asserts that allocating universal service costs to all customer classes would "only make the business environment less sustainable and could further threaten recovery efforts essential to restoring pre-pandemic employment levels, wages and personal incomes." (PAIEUG St. 1-R, at 12). Despite making that assertion, Ms. LaConte offers no evidence that this assertion is, in fact, accurate.

In fact, the Commission has been presented with this identical argument before, and has rejected it. In its 2019 Final Policy Statement and Order in the PUC's generic investigation into energy affordability in Pennsylvania (Docket M-2019-3012599),[3] the PUC noted:

> OSBA and the Industrial Customers have argued that recovering costs of universal service programs from industrial and commercial customers may negatively impact businesses in the Commonwealth. However, we have not seen evidence that the economic climate in Philadelphia has been negatively

[3] http://www.puc.pa.gov/about_puc/consolidated_case_view.aspx?Docket=M-2019-3012599 (November 5, 2019) (last accessed May 16, 2020).

> impacted as a result of universal service costs charged by PGW. Further, as noted by multiple parties in the *Review* proceeding, many states recover the cost of utility low-income programs from all ratepayer classes, including New York, New Jersey, Ohio, Illinois, Maine, and New Hampshire. We are not aware that this practice has negatively impacted the business climate of any these states.

(Final Order, at 98, internal citation omitted). Data on economic activity supports this PUC decision. The Table below shows the difference between the 2019 Quarter 4 and the 2020 Quarter 3 Gross Domestic Product by state for nine states (using the same states I identified in my Direct Testimony). (OCA St. 5, at 88). In this Table, only Pennsylvania allocates universal service costs exclusively to the residential class. As can be seen in this Table, whatever drives economic performance in a state, it is not the allocation of utility universal service costs amongst customer classes.

Difference Between 2019 Q4 and 2020 Q3 Gross Domestic Product (GDP) By State[4]	
Nevada	-4.3%
Pennsylvania	-4.2%
Maine	-4.2%
New Jersey	-3.9%
Ohio	-3.5%
New Hampshire	-3.4%
Illinois	-3.0%
Maryland	-2.6%
Colorado	-2.0%

[4] Ettinger and Hennsley (January 13, 2021). COVID-19 Economic Crisis by State, Table A3, available at https://public.tableau.com/views/GreatRecessionandCOVIDRecessionGDPChange/Dashboard1?:language=en&:display_count=y&:origin=viz_share_link&:showVizHome=no (last accessed January 26, 2021).

Work from the Brookings Institute reinforces the conclusions from the above data. If Ms. LaConte were correct that the allocation of universal service costs to all customer classes is the factor that makes the difference in the economic recovery after COVID-19, we would be able to see that difference between Pennsylvania and Ohio, Pennsylvania's next-door-neighbor. Ohio allocates its universal service costs amongst all customer classes, while Pennsylvania does not. The Brookings Institute has compared the impact of the COVID-19 recession on key economic indicators in 53 very large metropolitan areas (with population over 1 million).[5] The data for Ohio and Pennsylvania are set forth below. Brookings color-coded the "performance" of each metropolitan area. Red-shaded cells show weaker performance, while green-shaded cells show stronger performance. Grey-shading is in the middle.

Impact of the COVID-19 recession on key economic indicators
(green = stronger, red=weaker, grey=middle)

Metro area	Jobs	Unemployment Rate	Job Postings	Small Biz Hours	Small Biz Open
Cincinnati	-5.0%	-1.5%	+10.3%	-28.7%	-20.1%
Cleveland-Elyria	-8.2%	+2.5%	+0.9%	-24.3%	-23.5%
Columbus	-6.9%	+1.5%	+11.2%	-18.3%	-21.6%
Philadelphia-Camden-Wilmington	-7.3%	+3.3%	+24.0%	-38.9%	-32.5%
Pittsburgh	-7.5%	+1.8%	+32.0%	-38.4%	-30.3%

As can be seen, Ms. LaConte's assertions are not borne out by the data. As can be seen from the above data, regarding jobs, unemployment rate, small business hours, and small business openings, the allocation of utility universal service costs is not the factor that drives economic metrics in a state or metropolitan area. The PUC's previous rejection of

[5]Ala Berube (July 2020). The Metro Recovery Index; Tracking Metropolitan Economics through the COVID-19 Crisis, available at https://www.brookings.edu/interactives/metro-recovery-index/ (last accessed January 26, 2021).

the argument that allocating universal service costs over all customer classes will harm Pennsylvania's business environment is supported by the data.

Q. DO YOU HAVE A RESPONSE TO MS. LACONTE'S ARGUMENT THAT "LOW-INCOME ISSUES ARE BEST ADDRESSED BY THE LEGISLATURE"?

A. Yes. Ms. LaConte argues in her rebuttal testimony that since reallocating universal service costs to all customer classes "cannot meaningfully address the needs of low-income customers," she recommends that "low-income issues are best addressed by the state legislature." (PAIEUG St. 1-R, at 12). The Commission has previously considered this argument and has explicitly rejected it. (Final Order, supra, at 98 – 99).

Q. PLEASE RESPOND TO MS. LACONTE'S PROPOSAL TO ALLOCATE UNIVERSAL SERVICE COSTS ON A PER CUSTOMER BASIS.

A. PAIEUG witness LaConte recommends that universal service costs be allocated over customer classes on a per-customer basis. (PAIEUG St. 1-R, at 13). Ms. LaConte offers no justification for charging large industrial customers no more than $10.85 a year, or less than $1 (one dollar) per month, other than her proposal would "not place an undue hardship on other customers." (PAIEUG St. 1-R, at 13).

Ms. LaConte makes no effort to rebut the observation in my Direct Testimony that universal service costs "should be based on the percentage of revenue provided by each customer class at base rates" because, in part, "This approach reflects the fact that these universal service costs are being treated as a distribution-related expense. In addition, many of the benefits and savings of the programs are captured in the distribution component of the base rates." (OCA St. 5, at 90).

Moreover, Ms. LaConte's proposal treats universal service costs as though they are a static figure once established in a rate case. She fails to recognize that universal service cost recovery for PECO Gas is reconcilable. (See, PECO Ex. JAB-2, at 40 of 83). While Ms. LaConte estimates universal service costs to be $5.9 million (PAIEUG St. 1-R, at 13), PECO's estimated universal service costs (including CAP credits) are simply estimates. (PECO St. 3, at 7). While, as I note in my Direct Testimony, my recommended cost allocation methodology has the advantage of being "administratively easy to apply," (OCA St. 5, at 90), Ms. LaConte's proposal would involve extraordinary complexity. Reconciliation could involve changes in her recommended per customer charge of fractions of a cent on a monthly basis. (see, OCA-III-19). Ms. LaConte does not explain how such a monthly charge could be imposed which would provide PECO Gas full cost recovery.

Finally, Ms. LaConte's proposal treats the number of customers as though it is a static figure from month-to-month (or year-to-year). PECO Gas data demonstrates that this figure would not be constant. (OCA-III-16, OCA-III-6(c)). The process of adjusting PECO universal service cost recovery based on changes in the number of customers would add yet another layer of complexity to Ms. LaConte's recommendation that she neither acknowledged nor considered. In contrast, the cost allocation recommended in my Direct Testimony would not generate such complexity.

In short, apart from its lack of a conceptual foundation, Ms. LaConte proposes to allocate universal service costs on a per-customer basis, even though neither the costs nor the number of customers is a known figure. Her recommendation should not be approved.

Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018929
	:	
PECO Energy Company – Gas Division	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 5-SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: February 9, 2021
*303588

Signature: ____________________
Roger D. Colton

Consultant Address: Fisher, Sheehan, & Colton
34 Warwick Road
Belmont, MA 02478

OCA Statement 6-SR

R-2020-3018929
2/17/21 JK

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-2020-3018929
PECO ENERGY COMPANY – GAS DIVISION	:	

SURREBUTTAL TESTIMONY
OF
GEOFFREY C. CRANDALL

ON BEHALF OF
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

FEBRUARY 9, 2021

I. QUALIFICATIONS

Q. What is your name and business address?

A. My name is Geoffrey C. Crandall. My business address is MSB Energy Associates, Inc., 6907 University Avenue #162, Middleton, Wisconsin 53562.

Q. On whose behalf are you testifying today?

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

Q. Are you the same Geoffrey Crandall that provided Direct Testimony in this Docket?

A. Yes.

II. SURREBUTTAL TESTIMONY

Q. What is the purpose of your Surrebuttal Testimony?

A. The primary purpose is to respond to the Rebuttal Testimony of PECO Witness Doreen Masalta, PECO Statement No. 9-R. I address:

A. The TRC for PECO's proposed portfolio. I specifically disagree with Ms. Masalta's conclusion that the Revised Analysis of PECO's proposed EE&C portfolio has a TRC of 1.02 (PECO Statement 9-R, page 3, line 18) and I provide an updated analysis.

B. The use of seasonal avoided cost to evaluate space heating measures. I disagree that there is insufficient load shape data to consider a seasonal approach to evaluating space heating efficiency measures. (PECO Statement 9-R, page 3, lines 11-15)

C. The proposed EE&C budget overall. I disagree with the PECO proposal to more than double its EE&C budget, and recommend that there be no increase in PECO's EE&C budget. (PECO Statement 9-R, page 4, lines 14-22)

D. The amount of administrative cost. I disagree with Ms. Masalta that my proposed budget for administrative cost is unreasonable. (PECO Statement 9-R, page7, lines 9-20)

A. TRC Correction and Comparison

Q. Did PECO revise the cost effectiveness analysis of its proposed EE&C portfolio since its original filing?

A. Yes. PECO actually revised its cost effectiveness analysis twice during the course of this proceeding. PECO based its Direct Testimony on an analysis based on data it provided in a spreadsheet in response to OCA VII-26 in early December. On December 18, PECO provided a revised spreadsheet and data, which I incorporated into my Direct Testimony. On January 15, PECO provided the second revised spreadsheet and data, which was the basis of PECO's Revised Analysis presented in its Rebuttal Testimony. In this Surrebuttal Testimony, I have updated my analysis to reflect the second revised spreadsheet and data.

Q. Witness Masalta listed the changes made in PECO's Revised Analysis, many of them acknowledging corrections you identified in your Direct Testimony. Please comment on each of PECO's corrections.

A. With one exception, I'm generally in agreement with the changes PECO made in its Revised Analysis.

PECO's Revised Analysis reduced the gas savings attributable to each smart thermostat from 62 MCF/yr to 4.76 MCF/yr. I used 4.96 MCF/yr in my analysis presented in my Direct Testimony (OCA Statement No. 6). I accept PECO's revised savings per smart thermostat and used it in my updated analysis.

PECO's Revised Analysis used gas avoided costs that were updated from PECO's original filing. PECO provided the updated avoided costs in an updated response to OCA VII-26 on December 18. I was able to use the revised gas avoided costs in my analysis presented in my Direct Testimony and continue to use them in my updated analysis.

PECO's Revised Analysis added electric avoided costs. My updated analysis uses PECO's electric avoided costs.

PECO's Revised Analysis added electricity savings to the analysis of smart thermostats and residential and commercial furnaces. My updated analysis uses PECO's electricity savings, but corrects the incremental cost of residential furnaces in PECO's Revised Analysis, as discussed further below.

PECO's Revised Analysis added commercial gas EE&C programs. These were included in PECO's updated response to OCA VII-26 on December 18. I included them in my analysis presented in my Direct Testimony and continue to use them in my updated analysis.

Q. What is the error you corrected in PECO's Revised Analysis?

A. For its Residential furnace programs, PECO included the electricity savings associated with a high efficiency gas furnace using a fan with an electronically commutated motor ("ECM"). However, PECO used the incremental measure cost of a high efficiency gas furnace without an ECM fan, thus understating the incremental cost of its measure by $98 per installation. While that doesn't sound like much, it is enough to cause PECO's entire proposed portfolio to fall below 1.0 in the TRC test.

Q. Please explain.

A. The spreadsheet underlying PECO's Revised Analysis (Second Revised Confidential Attachment OCA-VII-26(a).xlsx) indicates that the data source for the pertinent measure characteristics was the Mid-Atlantic Technical Resource Manual ("TRM"). The Mid-Atlantic TRM states that for an efficient condensing gas furnace replacing an 80% efficient furnace (the condition PECO modeled), the efficient furnace saves no electric energy and does not reduce summer peak[1]. In addition, the incremental cost for the 95% and 97% efficient residential gas furnaces are $537 and $659 in the TRM, the same as PECO used. (See Schedule GCC-SR-1)

The TRM goes on to say that if the efficient furnace has an electronically commutated motor (ECM) fan that there will be electricity savings that should be claimed as characterized in the "Central Furnace Efficient Fan Motor" section of the TRM. The Company included those electricity savings in its Revised Analysis.

The Central Furnace Efficient Fan Motor section indicates, however, that the incremental cost of an ECM motor at time of sale (not retrofit) is $98[2]. The Company failed to include those increased costs in its Revised Analysis. Thus, the Company inappropriately

[1] Mid-Atlantic Technical Reference Manual Version 9, October 2019, pages 131-133 of 601.
[2] Ibid, page 75 of 601.

included the electricity cost savings from an efficient furnace with an ECM, but did not include the incremental costs associated with that product.

The corrected incremental cost in Schedule GCC-SR-1 includes the furnace and ECM fan incremental costs. To recap, for the residential efficient furnaces without the ECM fan, the TRM shows no electrical savings. The electrical savings PECO included must come from the inclusion of the ECM fan motor, but PECO failed to add the cost of the ECM motor to the incremental cost of the measure it was evaluating from an energy standpoint.

Q. How significant is the inclusion of electricity savings on the measure and program TRCs?

A. It is very significant. There are only four measures in PECO's portfolio to which PECO ascribed electricity savings. These measures are the residential high efficiency furnace, the residential higher efficiency furnace, the smart thermostat, and the commercial high efficiency furnace measure. Under PECO's calculations, the measure level TRCs went from not being cost effective without including electricity to being cost effective for the residential and commercial high efficiency furnaces and nearly cost effective for the higher efficiency residential furnace. Only the smart thermostat remained clearly not cost effective. (See Schedule GCC-SR-2).

At the program level in 2021, using PECO's calculations the residential programs (excluding low income) went from a TRC of 1.02 to 1.31 as a result of adding electricity savings to the TRC calculation. The TRC went from 1.01 to 1.77 for the commercial sector and was unchanged for the low-income programs. The overall portfolio TRC rose from 0.80 without electricity savings to 1.02 with electricity savings, using PECO's calculations. (See Schedule GCC-SR-2).

Once PECO corrected the error in smart thermostat savings in its initial filing, its proposed portfolio would not be cost effective if not for the inclusion of the electricity savings.

Q. What is the impact of the erroneous incremental cost for residential high efficiency furnaces on the program and portfolio TRCs?

A. It has no effect on the low income and commercial sector programs. However, it results in a significant reduction in the TRC for residential programs, from 1.31 down to 1.18 which brings PECO's entire proposed portfolio down from 1.02 to 0.95. It is no longer cost effective when correcting for the incremental ECM cost error in PECO's calculations. (See Schedule GCC-SR-2).

PECO modeled its low-income programs as not saving electricity, thus the error in the ECM incremental cost did not affect the low-income programs. PECO correctly modeled its commercial high efficiency furnaces to include both savings and incremental costs of an ECM fan, consistent with the TRM.[3] In other words, the error in the residential ECM incremental cost was not repeated in the commercial furnace program, and did not affect the commercial programs.

Q. Did you analyze the effect of including electricity savings on the cost effectiveness of OCA's recommended portfolio as summarized in Table 7 of OCA Statement No. 6, page 29?

A. Yes. I updated the analyses contained in Schedules GCC-6, GCC-7 and GCC-8 in my Direct Testimony to account for PECO's Revised Analysis (including electricity savings, using PECO's revised smart thermostat gas savings, but correcting for the residential furnace incremental cost error). As was the case in my analysis without electricity savings summarized in Schedule GCC-6 in my Direct Testimony, my proposal resulted in better benefit cost ratios than PECO's, even though overall savings were less. The comparison of PECO's and my proposals are summarized in Schedule GCC-SR-3. This corresponds to Schedule GCC-6 (without electricity savings and with my smart thermostat gas savings correction rather than PECO's current corrected value).

[3] Ibid, pages 447-450 of 601.

Q. How do the portfolio TRCs for the PECO proposal and your proposal change over time?

A. The benefit cost ratios improve slightly from year to year. The following table compares the TRC values of PECO's proposed portfolio and budget and my proposed portfolio and budget for each year of the 2021-2024 time period.[4] Both use all of the corrections and enhancements that PECO made in its Revised analysis and the correction I made for the residential furnace ECM fan incremental costs.

Comparison of Portfolio TRCs for PECO and OCA EE&C Plan Proposals		
Year	PECO Proposal	OCA Proposal
2021	0.95	1.35
2022	0.97	1.39
2023	1.01	1.42
2024	1.04	1.47

Schedule GCC-SR-4 is a three-page summary providing more detail of PECO's proposed energy efficiency portfolio each year 2021-2024. Schedule GCC-SR-4 uses PECO's Revised Analysis information, with the exception that it includes the ECM fan incremental cost correction.

[4] See Statement 6, page 30, Table 7 for a detailed comparison between PECO's proposed budget and my proposed budget.

Schedule GCC-SR-5 is a three-page summary providing more detail of my proposed energy efficiency portfolio each year 2021-2024. Schedule GCC-SR-5 uses my proposed budget, which reflects no increase to current spending levels, and PECO's Revised Analysis information, with the exception that it includes the ECM fan incremental cost correction, information to determine the energy and economic impacts.

B. Seasonal Avoided Cost Analysis

Q. Referring to PECO Statement No. 6, page 3, lines 11-15, Witness Masalta stated that she agrees with you that using the annual levelized cost of gas could understate the actual avoided costs for space and water heating measures. She then stated that accurate gas load shape data is not readily available to change the models to a seasonal approach, and then effectively that it wasn't important because the portfolio was cost effective without it. Do you agree ?

A. No. PECO should analyze the impact of higher heating season avoided gas costs on the cost effectiveness of measures showing seasonal usage differences, especially space heating measures.

First, the portfolio is no longer cost effective when correcting PECO's Revised Analysis for the incremental cost of ECM on residential furnaces. Without the inclusion of electricity savings, PECO's portfolio was not cost effective, so it is a misnomer to suggest that the portfolio remains cost effective with the other changes she described.

Even if it had been cost effective and continued to be, failure to include the appropriate avoided costs for some of the measures means that those measures may be under-utilized in the portfolios.

Second, sufficiently accurate load shape data is available to estimate most of the impact of higher seasonal gas prices have on the gas avoided cost and the heating season sensitive loads. PECO provided monthly gas avoided costs. It is not necessary to have more detail than the monthly space heating load data, which should be derivable from billing cycles and heating degree days per billing cycle. In addition, the season gas price differential is greatest during the winter strip pricing period, which is also the months of the greatest space heating load. Although an accurate load shape would ideally include data for the spring, fall and summer months, most of the space heating load, and thus most of the impact on cost-benefit analyses of space heating measures, comes from the winter months. PECO does not need a perfect load shape to capture most of the effect of seasonally differentiated gas costs and gas usage. Until PECO collects the accurate gas load shape data it claims not to have, and until it develops a seasonal or monthly benefit cost model, it should estimate the effect of seasonally differentiated gas prices. PECO has access to more data regarding costs and space heating loads in its service territory than I have, and PECO should be able to improve on my estimate of the impact of using space heating season rather than annualized gas avoided costs in its benefit cost model. That additional insight would greatly help shape the energy efficiency programs and improve the cost effectiveness of the overall EE&C Portfolio.

<u>C. EE&C Annual Budget</u>

Q. Do you have a concern regarding the magnitude and therefore the appropriateness of PECO's proposed budget?

A. Yes. Citizens and businesses in Pennsylvania and throughout the United States are coping with difficult economic conditions. As explained by OCA Witness Scott Rubin (OCA Statement 1, Page 11, lines 2-5), in 2018 Pennsylvania had a work force of approximately 6,576,000 people. Mr. Rubin further testified that since the pandemic started in Mid-March 2020, almost half of Pennsylvania's workforce has filed an unemployment claim (OCA Statement 1-SR, page 2, lines 14-28).   These are trying economic times given the worldwide pandemic and the unemployment levels. They result in ratepayers facing food insecurity, eviction or foreclosure threats, which are principal targets of Covid relief proposals. In addition to jobs lost, household income is also stressed by reduced work hours and increased medical and health insurance costs. Each of these factors reduce discretionary household income. In this time of economic and public health crisis, unnecessarily increasing costs to ratepayers, further reducing discretionary income, is inappropriate. PECO's proposal to double its approved budgets, which would quadruple its actual expenditures on EE&C programs in recent years, is not appropriate during these economic hard times.

Q. Does PECO have experience and the capability to design and implement energy efficiency programs for its residential and commercial customers?

A. Yes. PECO has offered its residential and commercial customers energy efficiency programs and services for approximately a decade, if not longer. They have operational experience with energy efficiency measures, programs and portfolios. In conjunction with the settlement agreement authorized by the Pennsylvania Public Utility Commission in R-2010-2161592, PECO was authorized to fund energy efficiency programs for residential and (a small amount) for Commercial customers in the total amount of $2,030,500 per year.[5] As noted in my Direct Testimony, from 2017 through 2019, PECO spent an average of approximately $1.1 million per year on its residential portfolio which represents 55% of the $2,008,000 PECO was authorized to collect each year for these programs. Unfortunately PECO's actual experience and track record for this program calls into question PECO's need for the proposed amount of funding. The Company's proposed funding is approximately four times greater per year than PECO was able to demonstrate it needed to operate their energy efficiency programs and make energy efficiencies available to their residential and commercial customers for over the past decade.

While I believe that energy efficiency programs have the potential to enhance Pennsylvania's housing infrastructure and serve as a hedge against gas cost increases, the current economic hardships encountered by residential, low income and commercial customers would be exacerbated by a gas rate increase at this time. The Commission and PECO will need to balance consideration of a gas rate increase against the residential,

[5] $2,008,000 was allocated to the residential programs and $22,500 was allocated to the commercial programs.

commercial and low-income customer’s ability to pay their monthly utility bill and not incur arrearages and further increase the stress and hardship that could be imposed upon those customers. Therefore, it would not be unreasonable for the Commission to authorize PECO’s continuation of the existing annual funding of $2,030,500 for residential and commercial energy efficiency programs. I would also note that my proposed budget and EE&C portfolio maintains PECO’s existing budget, demonstrates a higher benefit-cost ratio than PECO’s proposal, and would include adoption of the Company’s proposed low-income program, the latter of which is particularly important considering that low-income customers need assistance and support to help them understand how they can reduce energy use, energy waste and reduce dollars needed to heat their homes, hot water, etc.

D. Administrative Cost Component

Q. Did Witness Masalta disagree with your budget belt tightening suggestions to reduce non-incentive costs in the portfolio budget?

A. Yes. She indicated on Pages 7 and 8 of her Rebuttal testimony tha**t** the Commission found that Phase IV EE&C plans must limit non-incentives spending to less than 50% of the total plan cost.

Q. Do you have examples of non-incentives and incentives costs?

A. Incentive costs refer to rebates and financial incentive costs that are provided to customers who purchase and install high efficiency furnaces, water heaters and other energy efficiency measures. Non-incentive costs include administrative, marketing, tracking and program management software, legal costs, consultants, program development, modification costs, etc.

Q. Do you have further discussion and concerns regarding the administrative cost component of the budget?

A. Yes. The primary difference between PECO's administrative budget and mine is the CSP administrative budget as it applies to the residential (excluding low income) programs.

In reviewing PECO's low-income budget related information, PECO proposes a CSP administrative budget for low-income programs which ends up being 13% of the low-income direct install budget. I don't disagree and also used 13% in my proposed low-income program budget. (See Schedule GCC-SR-6, my response to PECO-OCA-III-10)

However, for non-low-income residential programs, PECO proposed a CSP administrative budget which ends up being 23% of the incentives budget. I propose a CSP administrative budget for non-low-income residential programs to be similar to PECO's low-income administrative budget costs. PECO is proposing a CSP administrative budget for the non-low-income programs nearly double (as a percentage of the incentives budget) that for the low-income CSP administrative budget.

Q. Why is there such a difference between CSP administrative costs for low income (13%) and non-low-income CPS delivery costs (23%)?

A. PECO has not specifically addressed the reason for the 77% higher value for the non-low income CSP administrative budget other than to indicate that E&C Plans must limit non-incentive spending to under 50%. (PECO Statement 9-R, page 7, lines 9-20)

Q. Is your concern over the level of administrative cost for non-low-income customers a fatal flaw in the proposed energy efficiency portfolio?

A. I do not think so. PECO is proposing an CSP administrative cost level that turns out to be 23% while my cost component for this same item is 12%. See my attached schedule GCC-SR-6. If PECO modified this item, or had a suitable and reasonable justification this discrepancy should be a relatively minor problem to resolve.

I would also note that as a percentage of the overall budget for residential and low-income programs, mine and PECO's proposal are not substantially different. PECO's administrative costs are approximately 27% of their overall residential and low-income program budget, whereas my proposed administrative costs amount to 21% of my overall residential and low-income program budget. See Sch. GCC-SR-6 at 2 and 3.

Q. Does that complete your Surrebuttal Testimony?

A. Yes.

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Measure	Demand Savings kW	Energy Savings kWh	Gas Savings MCF	Incremental Measure Cost	
				As PECO Modeled	As Corrected
Residential Furnace >95% AFUE	0.03675	358.25	11.31	537	635
Residential Furnace >97% AFUE	0.03675	358.25	12.82	659	757
Residential Smart Thermostat	0	80.03	4.76	154	154
Commercial Furnace < 225kBtu/hr >90% AFUE	0.19	733	11.47	429	429

Measures	TRC without Electric Savings	TRC with Electric Savings	
		With PECO Incremental Cost	Corrected Incremental Cost
Residential Furnace >95% AFUE	0.67	1.11	0.94
Residential Furnace >97% AFUE	0.62	0.98	0.85
Residential Smart Thermostat	0.66	0.81	0.81
Commercial Furnace < 225kBtu/hr >90% AFUE	0.85	2.59	2.59
Programs - 2021			
Residential Sector Programs	1.02	1.31	1.18
Low Income Sector Programs	0.21	0.21	0.21
Commercial Sector Programs	1.01	1.77	1.77
Total Portfolio - 2021	**0.80**	**1.02**	**0.95**

COMPARISON OF PECO AND OCA ENERGY EFFICIENCY PORTFOLIOS 2021						
	PECO Proposed with Incremental Cost Correction			OCA Proposed with Incremental Cost Correction		
	Participants	MCF Savings	MWh Savings	Participants	MCF Savings	MWh Savings
ENERGY STAR® Furnace (>= 95% AFUE)	5,025	56,838	1,800	1,727	19,531	619
ENERGY STAR®+ Furnace (>= 97% AFUE)	500	6,410	179	150	1,923	54
ENERGY STAR® Boiler (>= 90% AFUE)	500	2,919	0	0	0	0
Storage Water Heater (0.67 EF)	250	282	0	0	0	0
Smart Thermostat	6,650	31,628	532	1,000	4,756	80
Low Flow Faucet Aerator	7,250	2,088	0	7,250	2,088	0
Low Flow Shower Head	7,200	8,617	0	7,200	8,617	0
Residential Program Total	**27,375**	**108,782**	**2,511**	**17,327**	**36,914**	**753**
Low-income Home Audit	289	3,529	0	289	3,529	0
Low Income Total	**289**	**3,529**	**0**	**289**	**3,529**	**0**
ENERGY STAR® Furnace <225 kBtu/hr (>= 90% AFUE)	40	459	29	40	459	29
ENERGY STAR® Boiler <300kBTU/hr (>= 90% AFUE)	35	732	0	35	732	0
Commercial Program Total	**75**	**1,191**	**29**	**75**	**1,191**	**29**
Portfolio Total	**27,739**	**113,501**	**2,540**	**17,691**	**41,634**	**782**

COMPARISON OF PECO AND OCA ENERGY EFFICIENCY PORTFOLIO BENEFIT COST RATIOS 2021								
	PECO Proposed w Incremental Cost Correction				OCA Proposed with Incremental Cost Correction			
	Residential	Low Income	Commercial	**Portfolio**	Residential	Low Income	Commercial	**Portfolio**
Present Value TRC Benefits	$6,552,000	$211,000	$70,000	**$6,832,000**	$3,554,000	$211,000	$70,000	**$3,835,000**
Present Value Costs	$5,553,000	$1,000,000	$39,000	**$6,676,000**	$1,589,000	$1,000,000	$34,000	**$2,838,000**
Net Present Value TRC Benefits	$999,000	-$789,000	$30	**-$385,000**	$1,965,000	-789,000	$36,000	**$997,000**
Total Resource Cost Test Benefit-Cost Ratio	1.18	0.21	1.77	**0.95**	2.24	0.21	2.07	**1.35**
Utility Cost Test Benefit-Cost Ratio	1.05	0.11	1.41	**0.70**	1.26	0.11	1.77	**0.56**

PECO Proposal

Program Year 2021

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	5,025	56,838	$1,507,500
ENERGY STAR Furnace (>=97% AFUE)	500	6,410	$250,000
ENERGY STAR Boiler (>=90 AFUE)	500	2,919	$150,000
Storage Hot Water Heater (0.67 EF)	250	282	$25,000
Smart Thermostat	6,650	31,628	$332,500
Low Flow Faucet Aerator (<=1.5 GPM)	7,250	2,088	$29,000
Low Flow Showerhead (<=2.0 GPM)	7,200	8,617	$36,000
Residential Program Total	**27,375**	**108,782**	**$2,330,000**
Low Income Home Audit	289	3,529	$883,866
Low Income Program Total	**289**	**3,529**	**$883,866**
ENERGY STAR Furnace <225 kBTU/h (>=90% AFU	40	459	$12,000
ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE	35	732	$10,500
Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**27,739**	**113,501**	**$3,236,366**

Program Year 2022

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	5,025	56,838	$1,507,500
ENERGY STAR Furnace (>=97% AFUE)	500	6,410	$250,000
ENERGY STAR Boiler (>=90 AFUE)	500	2,919	$150,000
Storage Hot Water Heater (0.67 EF)	250	282	$25,000
Smart Thermostat	6,650	31,628	$332,500
Low Flow Faucet Aerator (<=1.5 GPM)	7,250	2,088	$29,000
Low Flow Showerhead (<=2.0 GPM)	7,200	8,617	$36,000
Residential Program Total	**27,375**	**108,782**	**$2,330,000**
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Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**27,739**	**113,501**	**$3,236,366**

Program Year 2023

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	5,025	56,838	$1,507,500
ENERGY STAR Furnace (>=97% AFUE)	500	6,410	$250,000
ENERGY STAR Boiler (>=90 AFUE)	500	2,919	$150,000
Storage Hot Water Heater (0.67 EF)	250	282	$25,000
Smart Thermostat	6,650	31,628	$332,500
Low Flow Faucet Aerator (<=1.5 GPM)	7,250	2,088	$29,000
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ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE	35	732	$10,500
Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**27,739**	**113,501**	**$3,236,366**

Program Year 2024

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	5,025	56,838	$1,507,500
ENERGY STAR Furnace (>=97% AFUE)	500	6,410	$250,000
ENERGY STAR Boiler (>=90 AFUE)	500	2,919	$150,000
Storage Hot Water Heater (0.67 EF)	250	282	$25,000
Smart Thermostat	6,650	31,628	$332,500
Low Flow Faucet Aerator (<=1.5 GPM)	7,250	2,088	$29,000
Low Flow Showerhead (<=2.0 GPM)	7,200	8,617	$36,000
Residential Program Total	**27,375**	**108,782**	**$2,330,000**
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ENERGY STAR Furnace <225 kBTU/h (>=90% AFU	40	459	$12,000
ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE	35	732	$10,500
Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**27,739**	**113,501**	**$3,236,366**

PECO Proposal

Program Year 2021				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	27,375	108,782	$2,875,000	$2,330,000	$0	$545,000	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$28,125	$22,500	$0	$5,625	$0
Admin and Education	N/A	N/A	$500,000	$0	$0	$0	$500,000
Emerging Technologies Pilots	N/A	N/A	$125,000	$0	$0	$0	$125,000
Portfolio Total	**27,739**	**113,501**	**$4,528,125**	**$2,352,500**	**$883,866**	**$666,759**	**$625,000**

Program Year 2022				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	27,375	108,782	$2,875,000	$2,330,000	$0	$545,000	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$28,125	$22,500	$0	$5,625	$0
Admin and Education	N/A	N/A	$500,000	$0	$0	$0	$500,000
Emerging Technologies Pilots	N/A	N/A	$125,000	$0	$0	$0	$125,000
Portfolio Total	**27,739**	**113,501**	**$4,528,125**	**$2,352,500**	**$883,866**	**$666,759**	**$625,000**

Program Year 2023				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	27,375	108,782	$2,875,000	$2,330,000	$0	$545,000	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$28,125	$22,500	$0	$5,625	$0
Admin and Education	N/A	N/A	$500,000	$0	$0	$0	$500,000
Emerging Technologies Pilots	N/A	N/A	$125,000	$0	$0	$0	$125,000
Portfolio Total	**27,739**	**113,501**	**$4,528,125**	**$2,352,500**	**$883,866**	**$666,759**	**$625,000**

Program Year 2024				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	27,375	108,782	$2,875,000	$2,330,000	$0	$545,000	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$28,125	$22,500	$0	$5,625	$0
Admin and Education	N/A	N/A	$500,000	$0	$0	$0	$500,000
Emerging Technologies Pilots	N/A	N/A	$125,000	$0	$0	$0	$125,000
Portfolio Total	**27,739**	**113,501**	**$4,528,125**	**$2,352,500**	**$883,866**	**$666,759**	**$625,000**

PECO Proposal

Program Year 2021

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$6,552	$5,553	$999	1.18	1.05
Low Income	$211	$1,000	-$789	0.21	0.11
Commercial	$70	$39	$30	1.77	1.41
Portfolio Total	**$6,832**	**$7,217**	**-$385**	**0.95**	**0.70**

Program Year 2022

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$6,741	$5,553	$1,188	1.21	1.08
Low Income	$217	$1,000	-$783	0.22	0.11
Commercial	$72	$39	$32	1.83	1.46
Portfolio Total	**$7,029**	**$7,217**	**-$188**	**0.97**	**0.72**

Program Year 2023

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$6,963	$5,553	$1,410	1.25	1.13
Low Income	$223	$1,000	-$777	0.22	0.12
Commercial	$74	$39	$35	1.89	1.51
Portfolio Total	**$7,260**	**$7,217**	**$43**	**1.01**	**0.75**

Program Year 2024

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$7,201	$5,553	$1,648	1.30	1.18
Low Income	$230	$1,000	-$770	0.23	0.12
Commercial	$77	$39	$37	1.95	1.57
Portfolio Total	**$7,508**	**$7,217**	**$291**	**1.04**	**0.78**

OCA Proposal

Program Year 2021

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	1,727	19,531	$518,000
ENERGY STAR Furnace (>=97% AFUE)	150	1,923	$75,000
ENERGY STAR Boiler (>=90 AFUE)	0	0	$0
Storage Hot Water Heater (0.67 EF)	0	0	$0
Smart Thermostat	1,000	4,756	$50,000
Low Flow Faucet Aerator (<=1.5 GPM)	7,250	2,088	$29,000
Low Flow Showerhead (<=2.0 GPM)	7,200	8,617	$36,000
Residential Program Total	**17,327**	**36,914**	**$708,000**
Low Income Home Audit	289	3,529	$883,866
Low Income Program Total	**289**	**3,529**	**$883,866**
ENERGY STAR Furnace <225 kBTU/h (>=90% AFU	40	459	$12,000
ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE)	35	732	$10,500
Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**17,691**	**41,634**	**$1,614,366**

Program Year 2022

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
ENERGY STAR Furnace (>=95% AFUE)	1,727	19,531	$518,000
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Program Year 2024

Measure	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted Measure Incentives / Direct Install Cost
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Residential Program Total	**17,327**	**36,914**	**$708,000**
Low Income Home Audit	289	3,529	$883,866
Low Income Program Total	**289**	**3,529**	**$883,866**
ENERGY STAR Furnace <225 kBTU/h (>=90% AFU	40	459	$12,000
ENERGY STAR Boiler <300 kBTU/h (>=90% AFUE)	35	732	$10,500
Commercial Program Total	**75**	**1,191**	**$22,500**
Portfolio Total	**17,691**	**41,634**	**$1,614,366**

OCA Proposal

Program Year 2021				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	17,327	36,914	$792,960	$708,000	$0	$84,960	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$22,500	$22,500	$0	$0	$0
Admin and Education	N/A	N/A	$215,040	$0	$0	$0	$215,040
Emerging Technologies Pilots	N/A	N/A	$0	$0	$0	$0	$0
Portfolio Total	**17,691**	**41,634**	**$2,030,500**	**$730,500**	**$883,866**	**$201,094**	**$215,040**

Program Year 2022				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	17,327	36,914	$792,960	$708,000	$0	$84,960	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$22,500	$22,500	$0	$0	$0
Admin and Education	N/A	N/A	$215,040	$0	$0	$0	$215,040
Emerging Technologies Pilots	N/A	N/A	$0	$0	$0	$0	$0
Portfolio Total	**17,691**	**41,634**	**$2,030,500**	**$730,500**	**$883,866**	**$201,094**	**$215,040**

Program Year 2023				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	17,327	36,914	$792,960	$708,000	$0	$84,960	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$22,500	$22,500	$0	$0	$0
Admin and Education	N/A	N/A	$215,040	$0	$0	$0	$215,040
Emerging Technologies Pilots	N/A	N/A	$0	$0	$0	$0	$0
Portfolio Total	**17,691**	**41,634**	**$2,030,500**	**$730,500**	**$883,866**	**$201,094**	**$215,040**

Program Year 2024				Breakdown of Program Costs			
Program	Forecasted Participation	Forecasted Gross MCF Savings	Forecasted TOTAL Program Costs	Incentives	Direct Install Measure Costs	CSP Administration	PECO Administration
Residential	17,327	36,914	$792,960	$708,000	$0	$84,960	$0
Low Income	289	3,529	$1,000,000	$0	$883,866	$116,134	$0
Commercial	75	1,191	$22,500	$22,500	$0	$0	$0
Admin and Education	N/A	N/A	$215,040	$0	$0	$0	$215,040
Emerging Technologies Pilots	N/A	N/A	$0	$0	$0	$0	$0
Portfolio Total	**17,691**	**41,634**	**$2,030,500**	**$730,500**	**$883,866**	**$201,094**	**$215,040**

OCA Proposal

Program Year 2021

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$3,554	$1,589	$1,965	2.24	1.26
Low Income	$211	$1,000	-$789	0.21	0.11
Commercial	$70	$34	$36	2.07	1.77
Portfolio Total	**$3,835**	**$2,838**	**$997**	**1.35**	**0.56**

Program Year 2022

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$3,644	$1,589	$2,055	2.29	1.30
Low Income	$217	$1,000	-$783	0.22	0.11
Commercial	$72	$34	$38	2.13	1.82
Portfolio Total	**$3,933**	**$2,838**	**$1,095**	**1.39**	**0.58**

Program Year 2023

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$3,746	$1,589	$2,157	2.36	1.36
Low Income	$223	$1,000	-$777	0.22	0.12
Commercial	$74	$34	$40	2.20	1.89
Portfolio Total	**$4,043**	**$2,838**	**$1,205**	**1.42**	**0.61**

Program Year 2024

Program	Present Value TRC Benefits ($000)	Present Value TRC Costs ($000)	Net Present Value TRC Benefits ($000)	Total Resource Cost Test	Utility Cost Test
Residential	$3,854	$1,589	$2,265	2.43	1.42
Low Income	$230	$1,000	-$770	0.23	0.12
Commercial	$77	$34	$43	2.28	1.97
Portfolio Total	**$4,160**	**$2,838**	**$1,323**	**1.47**	**0.63**

PECO ENERGY COMPANY
Docket No. R-2020-3018929
Interrogatories of PECO Energy Company to
The Office of Consumer Advocate
Set III

PECO-OCA-III-10. Refer to OCA Statement No. 6, page 35, lines 3-5, please set forth the factual basis for the statement that "a 15% overhead to cover administrative, education and CSP costs is not unreasonable."

Response:

The passage referenced in OCA Statement No. 6 does not reflect the administrative costs actually included in the benefit cost analysis of the budget Mr. Crandall proposed for OCA. To put it into context, most of Mr. Crandall's adjustment to the CSP and utility administrative budget is a reflection of the smaller scale residential sector portfolio that Mr. Crandall proposed, $2.008 million instead of $4.5 million proposed by PECO. Following is a comparison of PECO's CSP and administrative budget to Mr. Crandall's, expressed as a percentage productive direct cost (direct installation for low income and incentives for the rest of the residential portfolio).

For the low income program, PECO is proposing a CSP administrative budget that turns out to be 13% of the direct install budget for PECO. It is also 13% for Mr. Crandall's proposal.

For the non-low-income residential programs, PECO is proposing a CSP administrative budget that turns out to be 23% of the incentives budget. Mr. Crandall proposes 12%, roughly the same as PECO proposed for the low income CSP administrative costs. It should be noted that PECO's proposed CSP administrative budget for its residential portfolio (excluding low income) is a dollar amount PECO derived in a hidden section of its spreadsheet for a portfolio different from that PECO is proposing. PECO's hidden calculation is based on a portfolio with larger incentives ($2.725 million rather than PECO's proposed amount of $2.333 million and on programs that are not in the PECO EE&CP (e.g., tankless water heater and residential marketplace programs). The portfolio in the hidden calculation also did not include the Smart Thermostat, Low Flow Aerators and Low Flow Showerheads programs which are included in PECO's proposed portfolio.

For the utility administrative costs, PECO proposed a budget that turned out to be 13% of the money budgeted for incentives, direct installations and CSP administrative costs. Mr. Crandall's utility administrative cost budget is 12% of his incentives, direct install (for low income) and CSP administrative costs.

Please refer to Attachment PECO-OCA-III-10.

ATTACHMENT PECO-OCA-III-10

COMPARISON OF ADMINISTRATIVE COSTS IN PECO AND OCA PROPOSED BUDGETS			
		PECO	OCA
1	Low Income Program Direct Install (productive)	$ 883,866	$ 883,866
2	Low Income CSP Administration	$ 116 134*	$ 116 134
3	CSP Admin % of Direct install (2/1)	13%	13%
4	Total Low Income Program Budget (1+2)	$ 1,000,000	$ 1,000,000
5	Residential Program (excl. Low Income) Incentives (productive)	$ 233,0000	$ 708,000
6	Residential (excl. Low Income) CSP Administration	$ 545,000	$ 84,960
7	CSP Admin % of Incentives (6/5)	23%	12%
8	Total Residential Program Budget (excl. Low Income) (5+6)	$ 2,875,000	$ 792,960
9	Utility Res/LI program costs (productive and CSP admin) (4+8)	$ 3,875,000	$ 1,792,960
10	Utility Administrative costs	$ 500,000	$ 215,040
11	Utility Admin % of Res/LI program costs (10/9)	13%	12%
12	Total Res/LI Portfolio Budget (Incl. productive and admin) (9+10)***	$ 4,375,000**	$ 2,008,000
13	Total CSP and Utility Admin Costs (2+6+10)	$ 1,161,134	$ 416,134
14	CSP and Util Admin costs as % of Res/LI Portfolio Budget	27%	21%

* In developing its proposed administrative budget of $1,045,000, PECO excluded the low income CSP administrative costs and left them embedded in the $1,000,000 low income budget.

ATTACHMENT PECO-OCA-III-10

The $1,045,000 administrative budget is the sum of the residential CSP administrative budget (row 6) and the utility administrative budget (row 10).

** PECO's budget in row 12 does not include $125,000 for its proposed emerging technologies pilots. Including the budget for the pilots would increase the total budget associated with the residential sector to $4.5 million, the budget PECO presented in its application, and reduce the administrative cost percentage to 26%.

*** PECO's application did not include any specific budgets for the continuation of a very small commercial sector program. However, PECO included a budget of $22,500 for commercial sector incentives and $5,625 for commercial sector CSP administration in its Confidential Attachment OCA-VII-26(a) Revised-Final. Incorporating those amounts still results in CSP/Util Admin cost of 27% for PECO and 21% for OCA (row 14).

Witness: Geoffrey C. Crandall
Dated: 01/08/2021

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2020-3018929
	:	
PECO Energy Company – Gas Division	:	

<u>VERIFICATION</u>

I, Geoffrey C. Crandall, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 6-SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: February 9, 2021
*303590

Signature: Geoffrey C Crandall
Geoffrey C. Crandall

Consultant Address: MSB Energy Associates, Inc.
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Middleton, WI 53562