STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

**In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of an Increase in Electric and Gas
Rates and for Changes in the Tariffs for
Electric and Gas Service, B.P.U.N.J.
No. 16 Electric and B.P.U.N.J. No. 16
Gas, and for Changes in Depreciation Rates,
Pursuant to N.J.S.A. 48:2-18,
N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and
for Other Appropriate Relief**

BPU Docket Nos. _______________

DIRECT TESTIMONY
OF
SCOTT JENNINGS

VICE PRESIDENT – UTILITY FINANCE

January 12, 2018
P-2

TABLE OF CONTENTS

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DIRECT TESTIMONY
OF
SCOTT JENNINGS

VICE PRESIDENT – UTILITY FINANCE

I. <u>INTRODUCTION</u>

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

A. My name is Scott Jennings, and I am Vice President – Utility Finance of Public Service Electric and Gas Company ("PSE&G," "Public Service," the "Company," or "Petitioner"). My credentials are set forth in the attached Schedule SSJ-1.

Q. Please describe your responsibilities as Vice President – Utility Finance PSE&G.

A. I have been employed for 19 years in a number of financial positions with Public Service Enterprise Group ("Enterprise"). Since October 2015, I have been Vice President – Utility Finance, PSE&G. In this capacity, I am responsible for PSE&G's business planning process, financial reporting and forecasting, and rates teams.

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

A. I am the Company's witness supporting overall financial policy and the revenue requirements that form the basis of the rates proposed in this proceeding. My testimony sets forth the reasons for this filing and the significant steps the Company has taken both to mitigate the effects of the filing and to provide safe and reliable service to its customers at the lowest reasonable rates. My testimony will discuss PSE&G's capital investments;

PSE&G's cost containment efforts, results and comparisons; the rate of return being sought, including the appropriate capitalization structure to achieve targeted credit ratings; treatment of recently enacted Federal tax reform and certain other tax matters; treatment of incentive compensation; a new proposed Green Enabling Mechanism; and other items. My testimony will conclude with a description of the test year employed and a description of the schedules that I am providing to support the revenue requirement sought in this filing.

Q. Do you sponsor any schedules as part of your direct testimony?

A. Yes. I sponsor the following schedules that were prepared or compiled under my direction and supervision:

- Schedule SSJ-1: Credentials
- Schedule SSJ-2: Determination of Revenue Requirements
- Schedule SSJ-3: Rate Base
- Schedule SSJ-4: Weighted Average Cost of Capital
- Schedule SSJ-5: Long Term Debt
- Schedule SSJ-6: Revenue Factor
- Schedules SSJ-7 through 15: Support for components of rate base
- Schedule SSJ-16: Income Statement
- Schedules SSJ-17 through 25: Support for components of the income statement
- Schedule SSJ-26: Pro-forma Distribution Operating Income
- Schedules SSJ-27 through 47: Support for pro-forma adjustments to test year operating income

II. THE FILING

Q. Why is PSE&G making this base rate filing at this time?

A. This filing is being made to obtain approval to increase PSE&G's annual revenue requirement as discussed later in my testimony. Also, this filing is being made, in part, to comply with the New Jersey Board of Public Utilities ("BPU" or "the Board") order approving our Energy Strong Program. By order dated May 21, 2014 in BPU Docket Nos. E013020155 and G013020156 ("Energy Strong Order"), the BPU approved a Stipulation authorizing PSE&G to undertake its Energy Strong Program to bolster its electric and gas infrastructure, making it less susceptible to damage from future major storm events. The Energy Strong Order as supplemented by the Board Order of November 21, 2017, requires the Company to make a base rate case filing by no later than February 1, 2018.

Q. What is the rate increase being sought?

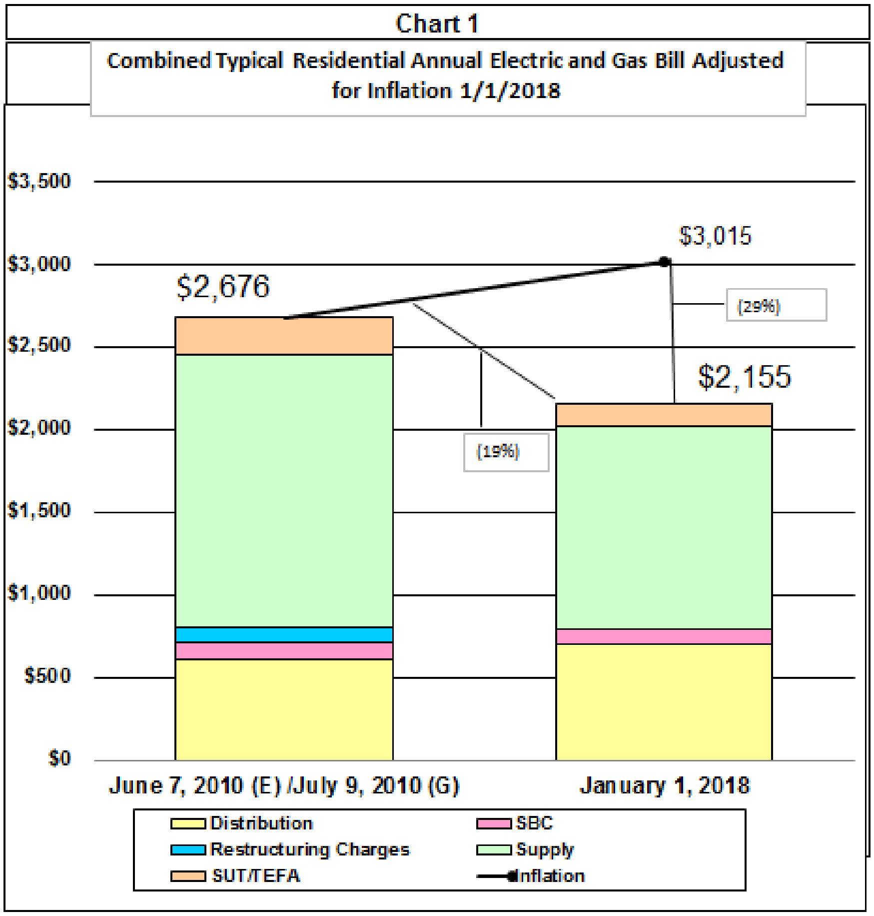
A. PSE&G is seeking to increase its base delivery rates by a total annual average of approximately 1.4% relative to overall revenues over the next five years. This amount is net of certain tax benefits that we propose to flow through to customers as discussed later in my testimony. The rate change effective October 1, 2018, is approximately $95 million, or approximately 1.2% relative to overall revenues, comprised of an increase of $27 million, or 0.5%, for electric distribution and $68 million, or 3.0%, for gas distribution. In subsequent years (after the cessation of a one-time credit for excess income taxes collected between January 1, 2018 and the time of new rates described in more detail below), we propose to increase the amount of tax credits flowed back to customers, resulting in rate decreases over the subsequent three years, which will offset other proposed increases such as those resulting from our pending GSMP II capital investment program. The annual impacts are illustrated below in Chart 9 of my testimony.

Q. What are the key drivers behind the average 1.4% increase?

A. The increase is primarily due to capital investments that we have made but have not received recovery of and a proposed change in depreciation rates to reflect a proposed change in the recovery methodology for future costs of removal of equipment. This is largely offset by a reduction in tax rates due to the recently enacted Federal tax reform legislation and the flow back of certain tax benefits mentioned previously and discussed further below.

Q. Can you provide context for this increase?

Yes. Relative to this proposed moderate revenue increase, it is important to note that since our last base rate case in 2010, our overall bills for a typical residential electric and gas customer have declined by approximately 19% on an absolute basis and approximately 29% on an inflation adjusted basis. The declines are primarily due to lower supply costs and continuous cost control efforts, all while making substantial capital investments needed to modernize our electric and gas distribution systems.



Further, as illustrated in the charts below, our annual bill for a typical residential electric customer is 7% lower than it was in 2010 on an absolute basis, and, adjusted for inflation, is down approximately 17%. At the same time, our annual bill for a typical residential gas customer is 32% lower than it was in 2010 on an absolute basis, and, adjusted for inflation, is down approximately 40%. In addition to the above decrease in gas costs, PSE&G also provided bill credits totaling $593 to its residential customers.

Chart 2

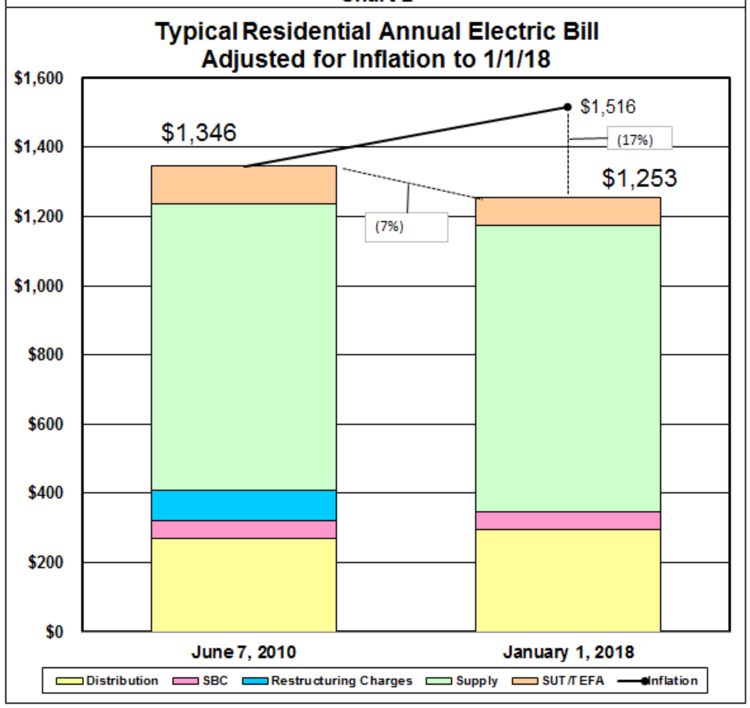
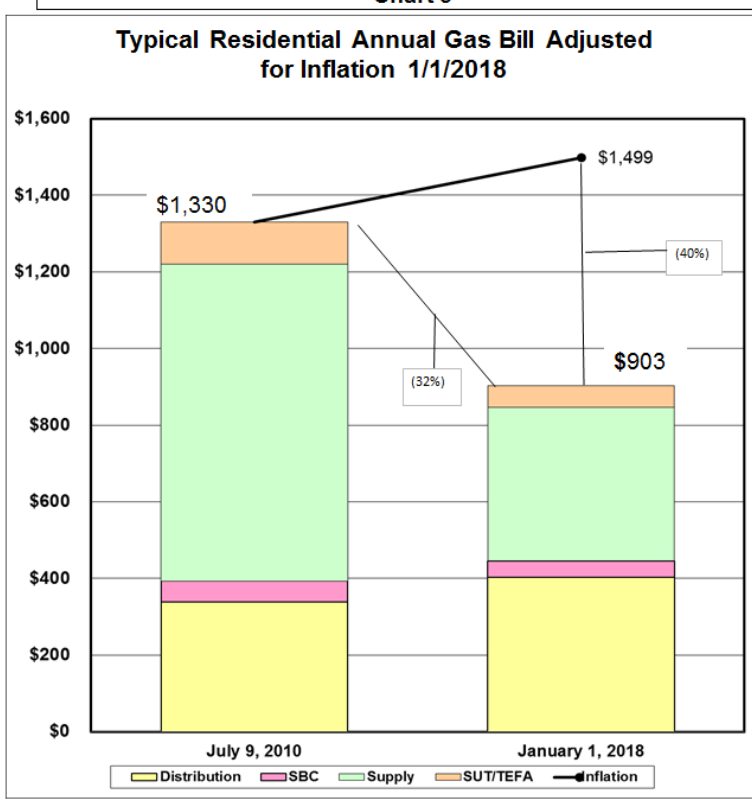


Chart 3



The primary driver of the proposed rate increase is PSE&G's significant capital investments since the Company's most recent electric and gas base rate case that were made largely to upgrade, modernize, and harden our distribution facilities. While we have successfully reduced total Operation and Maintenance ("O&M") costs to less than the level reflected in our last base rate case approximately eight years ago, we have made a significant amount of capital investments in our electric and gas distribution systems and incurred material storm costs that were deferred, but have not been recovered. This rate case provides us with the opportunity to recover those just and reasonable costs and earn a fair return on the capital invested in the distribution system.

The proposed revenue requirement is based on an overall rate of return of 7.40%, a capital structure consisting of a common equity component of 54%, and a 10.3% return on common equity. As discussed below and in the testimony of Company witness Ann Bulkley, these return levels are consistent with market conditions and the Company's operational performance, combined with a capital structure that supports our investment grade credit rating.

Q. Are there other elements of the filing?

A. Yes. Other elements of the filing include recovery of our operating costs; our proposal to flow back tax benefits to customers; updating our depreciation rates; updating the Company's pension accounting practices to adopt new accounting requirements and incorporate market conditions; and bringing our rate design into line with State policies, the results of our cost of service study, and industry peers.

For example, in order to better align State, customer, environmental and Company interests, we are proposing to establish a Green Enabling Mechanism ("GEM"). The GEM is a revenue decoupling mechanism that will align Company interests with customer, environmental, and State objectives and support investments in energy efficiency ("EE"), renewables, or other green initiatives on behalf of our customers. With approval of the GEM, PSE&G expects to continue, and significantly expand, its energy efficiency offerings for the benefit of our customers.

Q. Has PSE&G taken steps to minimize the rate change requested?

A. Yes. I will describe later in my testimony some of the successful cost containment efforts we have made to enable the Company to reduce our total O&M expense since our last test year in 2009. We take very seriously our responsibility to customers to manage our costs prudently and be good stewards of the electric and gas distribution systems and the customer funds needed to operate and maintain them effectively. As illustrated later in my testimony, had we not successfully contained our costs, the Company's revenue requirement could have been between approximately $300 million higher (using the Consumer Price Index ("CPI") since our last test year in 2009) and approximately $700 million higher (using absolute rates or average cost escalation rates of NJ electric and gas utilities). It is important to note, however, that while maintaining a much lower cost structure, we have preserved operational performance – safety, reliability, and customer satisfaction – which is, generally, top quartile in the industry, as noted in the testimony of Michael Adams of Concentric and in the testimony of PSE&G witness Jorge Cardenas. In short, I will demonstrate that PSE&G has provided excellent service at reasonable rates as further evidenced through the SAIDI per

Distribution O&M/MWh (Chart 3) and leak response rate per Distribution O&M/dekatherm (Chart 4) as presented in the Direct Testimony of Mr. Cardenas.

Q. Briefly describe the elements of the rate increases being requested.

A. The rate increases being requested are based upon a July 1, 2017 through June 30, 2018 test year, with capital expenditure adjustments through December 31, 2018 and changes in certain expenses through September 30, 2019, rate bases of $5.6 billion and $4.0 billion for electric distribution and gas distribution, respectively, pro-forma operating income of $334.7 million and $167.5 million for electric and gas, respectively, and a required rate of return of 7.40%.

III. FACTORS DRIVING THE NEED FOR RATE RELIEF

Q. You mentioned that PSE&G took steps that enabled the Company to reduce the size of this rate filing. Why is the Company seeking the requested rate increase?

A. As noted earlier, it has been approximately eight years since our last base rate case filing, so we have successfully operated for an extended period of time without having to seek a base rate increase. But after eight years, despite the Company's execution of a very successful strategy of cost mitigation and expense control, there are a number of significant factors that have driven our financial results well below our authorized rate of return and which represent the primary drivers of the rate increase sought in this filing. These factors include:

- Unrecovered Capital Investments
- Depreciation

- Flat Sales Growth
- Storm Cost Recovery; and
- Recovery of the gas excess cost of removal refund.

A. Unrecovered Capital Investments

Q. Please explain how unrecovered capital costs impact this filing.

A. While PSE&G has previously incorporated into its base rates substantial investment made under the Energy Strong Program and the Gas System Modernization Program ("GSMP") since the conclusion of our last base rate case in 2010, the Company has invested a substantial amount of capital to maintain, upgrade and harden our system that has not been reflected in rates. This unrecovered amount of capital investment above depreciation expense reduces the Company's rate of return. Excluding investments to serve new business, as the Company invests above its depreciation expense its rate base grows without any corresponding revenue increase, reducing its rate of return. It is for this reason that the Company sought interim rate recovery to proceed with the significant necessary investments that were approved by the Board in the Energy Strong and GSMP orders, and this factor is an important consideration underlying the Board's recently-approved regulation supporting infrastructure investment through accelerated cost recovery.[1] While the Company's rate adjustments for its Energy Strong and GSMP investments have been approved by the Board, the interim rates only recover a portion of the investment in those programs. In addition,

[1] Docket No. AX1750469, In the Matter of the Proposed Rule Making for Infrastructure Investment Programs: N.J.A.C. 14:3-2A.1, et seq. (approved by the Board at its December 19, 2017 agenda meeting).

aside from the Energy Strong Program and GSMP, the Company has invested capital in excess of its depreciation expense and therefore needs to recover those capital investments. A primary driver of our requested increase is directly related to obtaining a return of and on these unrecovered capital investments.

Q. Please describe the unrecovered capital costs that PSE&G seeks to recover through this filing.

A. The Company's unrecovered capital costs include costs associated with capital projects PSE&G agreed to undertake in the settlements of the Energy Strong and GSMP cases; capital invested to serve new business; and base capital investments made by PSE&G outside the scope of the Energy Strong and GSMP programs.

a. **Energy Strong –** The Company was authorized in the Energy Strong Order to invest up to $1 billion ($600 million for electric and $400 million for gas) to be recovered through a special rate adjustment mechanism, designated the Energy Strong Adjustment Mechanism ("ESAM"). The Energy Strong Order also authorized recovery of up to $220 million of incremental costs for specified Energy Strong projects, to the extent incurred, in the Company's "next base rate case." The Company is effectively and reasonably managing the Energy Strong Program as supported by the testimony of Mr. Cardenas. PSE&G's proposed revenue requirement includes all investment associated with the Energy Strong Program through December 31, 2018. Likewise, all revenues associated with the ESAM rate adjustments are included in Operating Revenues, reducing our revenue request in this proceeding. Further, as described in more detail below, a *pro forma* adjustment is being proposed to annualize the ESAM rate adjustments during the test year to ensure the Company does not double count the revenues associated with the ESAM and the base rate change as a result of this proceeding. The Company is seeking to recover all Energy Strong investment, net of recoveries through the ESAM and the *pro forma* adjustment as described in more detail below, as part of this rate case pursuant to the Energy Strong Order.

b. **GSMP –** The Company was authorized in the GSMP Order to invest up to $905 million to:

i. Replace utilization pressure cast iron main ("UPCI");
ii. Replace unprotected steel main and services;
iii. Uprate the UPCI system to higher pressure;
iv. Install excess flow valves;
v. Abandon district regulators;
vi. Replace high pressure cast iron mains ("HPCI"); and
vii. Recover the incremental cost of relocating inside meter sets outside.

Of the $905 million approved for GSMP, up to $650 million, referred to as "Program investment", could be recovered through a special rate adjustment mechanism, the Alternative Rate Mechanism ("ARM"). The Program investment to be recovered through the ARM excluded any costs associated with replacing HPCI and relocating inside meter sets outside.

In addition to the $650 million in Program investment, the Company was required to invest a minimum of $85 million per calendar year from 2016 through

2018, or $255 million in total, referred to as “Stipulated Base”, on projects similar to those done under GSMP. Investment associated with Stipulated Base is not recoverable through the ARM but rather must be recovered through a base rate case proceeding. For details on the specific GSMP projects, please see the testimony of Mr. Cardenas.

The Company is proposing rates in this proceeding that would recover all investment associated with GSMP through December 31, 2018. As with respect to revenues associated with the ESAM rate adjustments, all revenues associated with the ARM rate adjustments are included in Operating Revenues, reducing our revenue request in this proceeding. Further, as described in more detail below, a pro forma adjustment is being proposed to annualize the GSMP rate adjustment during the test year to ensure the Company does not double count the revenues associated with the ARM and base rates in this rate case proceeding. In addition, as described in more detail below for the description of Schedule SSJ-15, the Company is proposing a rate base adjustment to exclude the rate base associated with GSMP investments that will be recovered in the third GSMP rate roll-in proceeding, which is anticipated to result in rates effective January 1, 2019, after rates from this rate case proceeding are proposed to be in effect.

In summary, the Company is effectively and reasonably managing the GSMP as supported by the testimony of Mr. Cardenas. The Company is seeking to recover all GSMP investment, net of recoveries through the ARM and the adjustments as part of this rate case pursuant to the GSMP Order. The approximately $255 million in unrecovered Stipulated Base investment represents a major factor driving the Company's need for rate relief in this proceeding.

c. **New Business** - New Business reflects the investment required to connect a new customer to the distribution system. Certain costs incurred to extend service can be charged to the customer, as determined under the appropriate extension of service regulations and the Company's Board-approved Electric and Gas tariffs. The amount of New Business capital has notably increased over the past several years and is now approximately $200 million per year.

d. **Base capital –** In addition to investment in the Energy Strong and GSMP clauses discussed above, due to system needs, we have invested capital at a rate that exceeded depreciation levels approved by the Board in PSE&G's last rate case. This unrecovered capital has lowered our returns and we are seeking recovery of the costs associated with that capital through this base rate case. These investments included accelerating the replacement of the aging cast iron and steel piping in our system and modernizing and improving the performance of our electric system, such as retiring certain older substations and investments in circuits prone to outages. More details concerning PSE&G's base capital investments are discussed by Mr. Cardenas.

B. Depreciation

Q. Please explain the impact of depreciation on PSE&G's need for rate relief.

A. It is widely acknowledged that aging infrastructure is one of our nation's greatest challenges. Since depreciation expense is the way in which a utility recovers the dollars expended for its capital projects, establishing the appropriate depreciation rates for a utility is critical; this allows the Company to, among other things, fund new capital construction. Company witness John Spanos has conducted a detailed evaluation of PSE&G's assets and developed new depreciation rates based on that evaluation. As described in Mr. Spanos' testimony, the Company's current depreciation rates are insufficient, largely due to the fact that the rates are not permitting the Company to recover its cost of removal. As discussed in more detail by Mr. Spanos, prior rate case practices of reducing the cost of removal accrual have unfairly pushed the cost of removal away from customers who benefit from assets during their service life and onto future customers, creating intergenerational inequity. In addition, prior reductions in the accrual for costs of removal have resulted in under-collection of costs of removal. We are proposing new depreciation rates that include more appropriate cost of removal rates that will allow the Company to more fully recover its expected costs as it replaces its aging infrastructure to provide the high levels of service and reliability that our customers expect.

C. Flat Sales Growth

Q. Please explain the impact of sales growth on PSE&G's need for rate relief at this time.

A. Despite PSE&G's expenditure of close to $200 million per year to serve new business, when combining electric and gas together, our current sales volumes are flat compared to sales at the time of our most recent base rate case in 2009. It appears that efficiency gains through greater focus on energy efficiency, solar net metering, and other factors are reducing volumes even as PSE&G's customer count grows slightly. In the past, higher sales growth would often directionally offset increased capital investments and operating costs for a growing system, mitigating rate increases driven by capital investments. In this more energy-efficient economy, customers have benefited from more efficient lighting and appliances and building standards, which has lowered usage and therefore bills. Given the fixed nature of most of our costs, system costs are spread over a static, or sometimes smaller base, thereby requiring a rate increase, even if recovering a comparable amount of costs. As an example of the impact of forces limiting sales growth, relative to our last base rate case filing, the usage for a typical PSE&G residential customer has declined from 7,200 kWh per year to 6,900 kWh per year, a decline of approximately 4%.

D. Storm Cost Recovery

Q. Please explain how PSE&G's unrecovered storm response costs are driving the need for rate relief.

A. PSE&G has incurred approximately $240 million of incremental storm costs since the last rate case, including costs associated with Superstorm Sandy, Hurricane Irene, the October 2011 snowstorm, and other storms. The majority of these costs were already reviewed for prudence by the Board in BPU Docket. No. AX13030196, order dated September 30, 2014. Recovering these costs along with a carrying charge over the next three years would lead to a revenue requirement increase of approximately $85 million per year, which would have led to an incremental rate increase of approximately 2% for electric customers. However, we propose to offset this $240 million of storm costs with certain accumulated deferred income taxes as explained later in my testimony and further in Company witness Mr. Krueger's testimony, thereby offsetting the need to collect these costs from customers.

E. Recovery of the Gas Excess Cost of Removal Refund

Q. Please explain the impact of PSE&G's recovery of excess cost of removal on this rate filing.

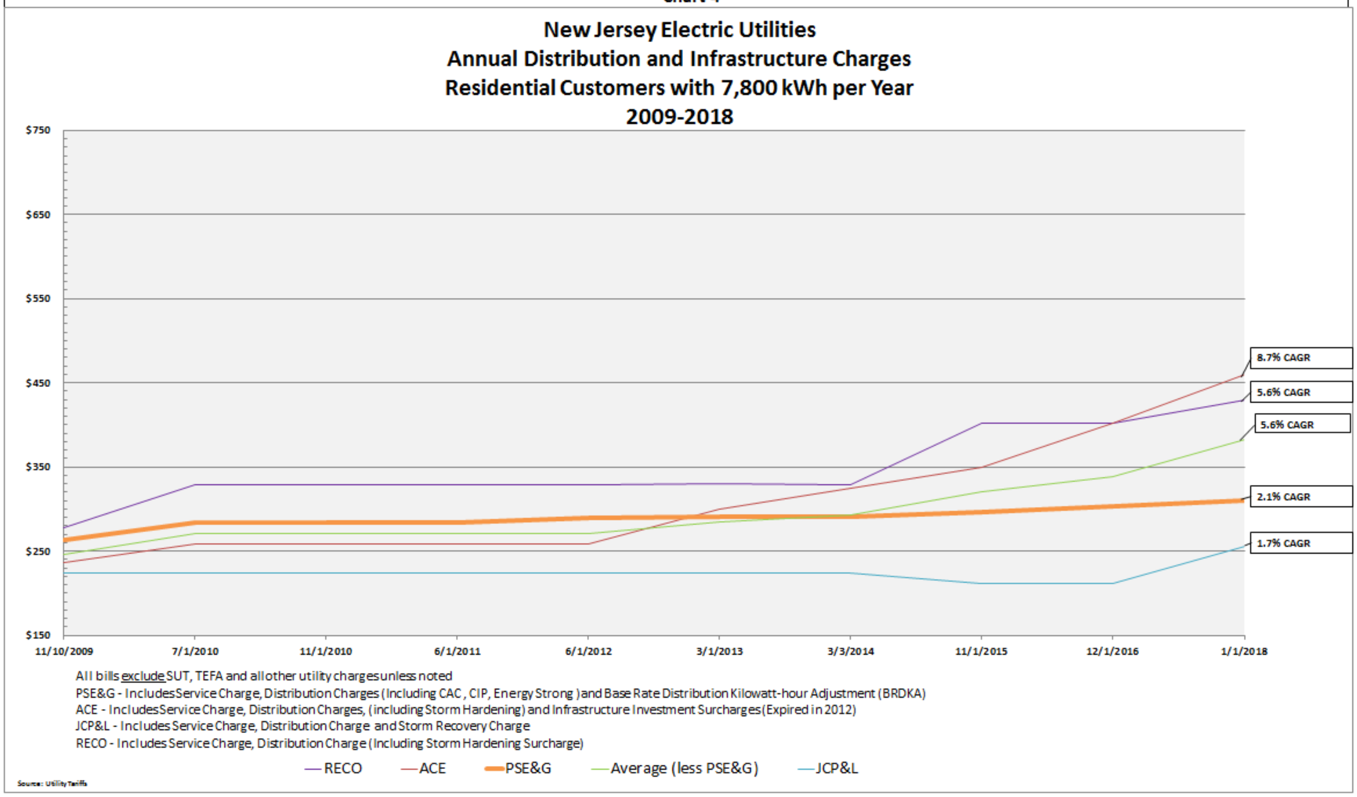
A. In a previous rate case, it was determined that PSE&G collected $66 million in rates that exceeded its costs of removal. In that case, PSE&G was directed to flow this amount back to customers at a rate of $13.2 million per year. PSE&G implemented that order and fully amortized the balance in 2011. PSE&G notified the BPU that the amortization was completed, and requested to defer any additional amortization for recovery in a future rate case. The BPU approved the deferral in its Order issued in January 2013 (BPU Docket No. GF11090539). As a result, prior to the beginning of this rate year (October 1, 2018), PSE&G will have over-refunded to customers approximately $91 million of cost of removal in excess of the amount deemed to be over-recovered in the prior rate case. We are now seeking recovery of this deferral and propose to minimize the rate impact by amortizing it over the next five years.

IV. <u>IMPACT ON CUSTOMERS</u>

Q. How have PSE&G customer rates changed compared to those set in the Company's most recent base rate case, and compared to the rates of other New Jersey utilities?

A. PSE&G's residential distribution rates are the lowest among gas utilities and the second lowest among electric utilities in the State. Additionally, since our last base rate case eight years ago, our electric and gas rates have grown more slowly than the rate compared to the other electric and gas utilities in the State. This is illustrated in the charts below. Even following the rate increase proposed in this case, in light of our cost mitigation efforts, PSE&G's rates will remain in this position relative to our peers.

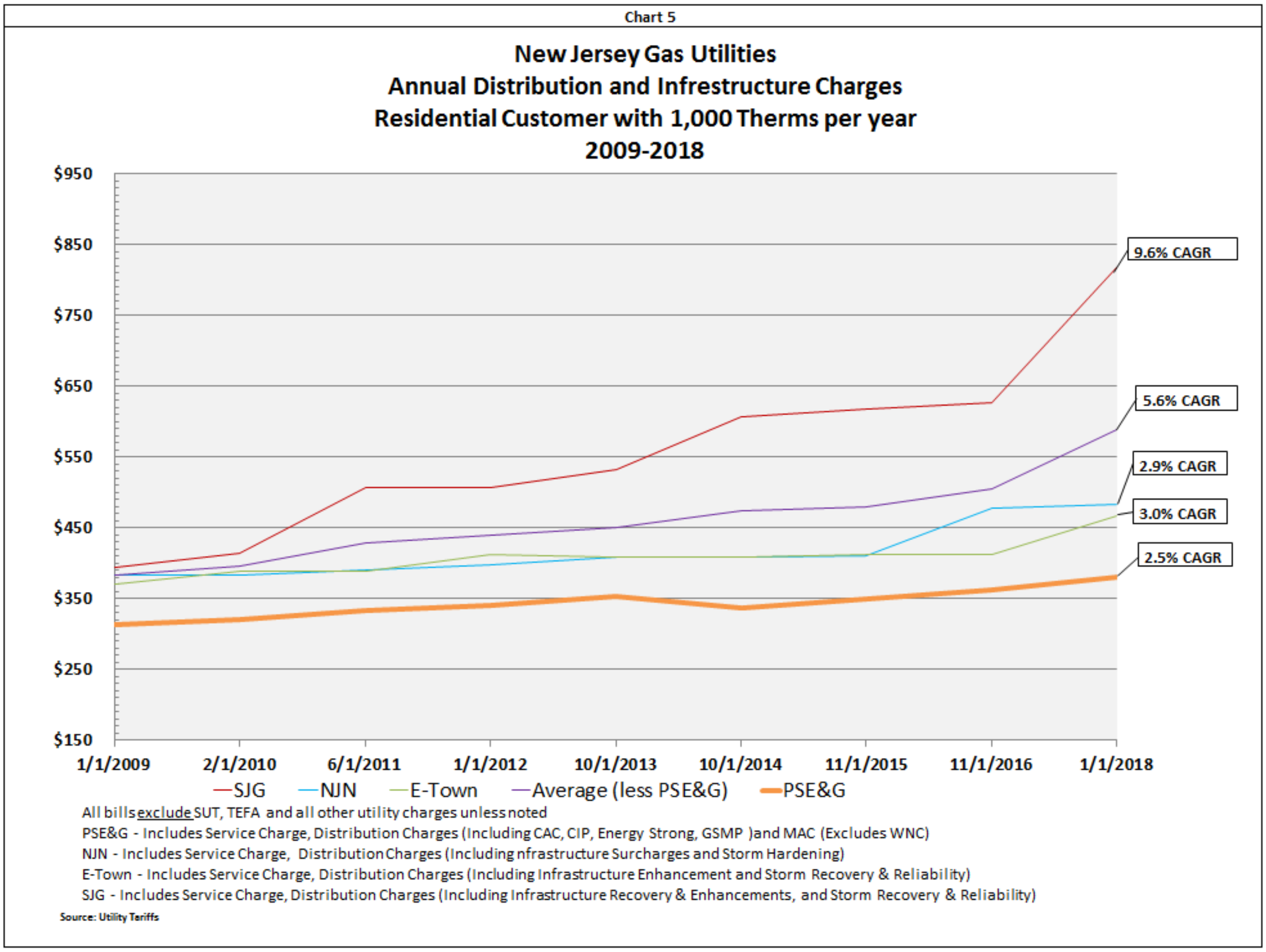
Chart 4



As can be seen in the chart, applying the State-wide average electric usage of 7,800 kWh per year for a typical residential customer to each utility (even though the average usage for PSE&G's typical residential customer is lower), the distribution portion of the bill which is the subject of this proceeding for PSE&G is approximately $311 per year, the second lowest among the State electric utilities and lower than the $382 per year average of the other NJ electric utilities. Further, our compound annual growth rate ("CAGR") of this cost since our last rate case is 2.1%, less than half of the average increase of other New Jersey utilities of approximately 5.6%.

With respect to our gas distribution rates, as can be seen in the chart below, using the State-wide average gas usage for a typical residential customer of 1,000 therms per year, PSE&G's annual distribution bill of $381 is the lowest in the State, far below the annual average of $589 for the other New Jersey gas utilities. PSE&G also has the lowest compound annual growth rate since our last rate case of 2.5%, less than half of the other utilities of approximately 5.6%.

Chart 5



PSE&G is very cognizant of the impact of energy bills on our customers, and we seek to minimize our costs and customer bills while providing high-quality service.

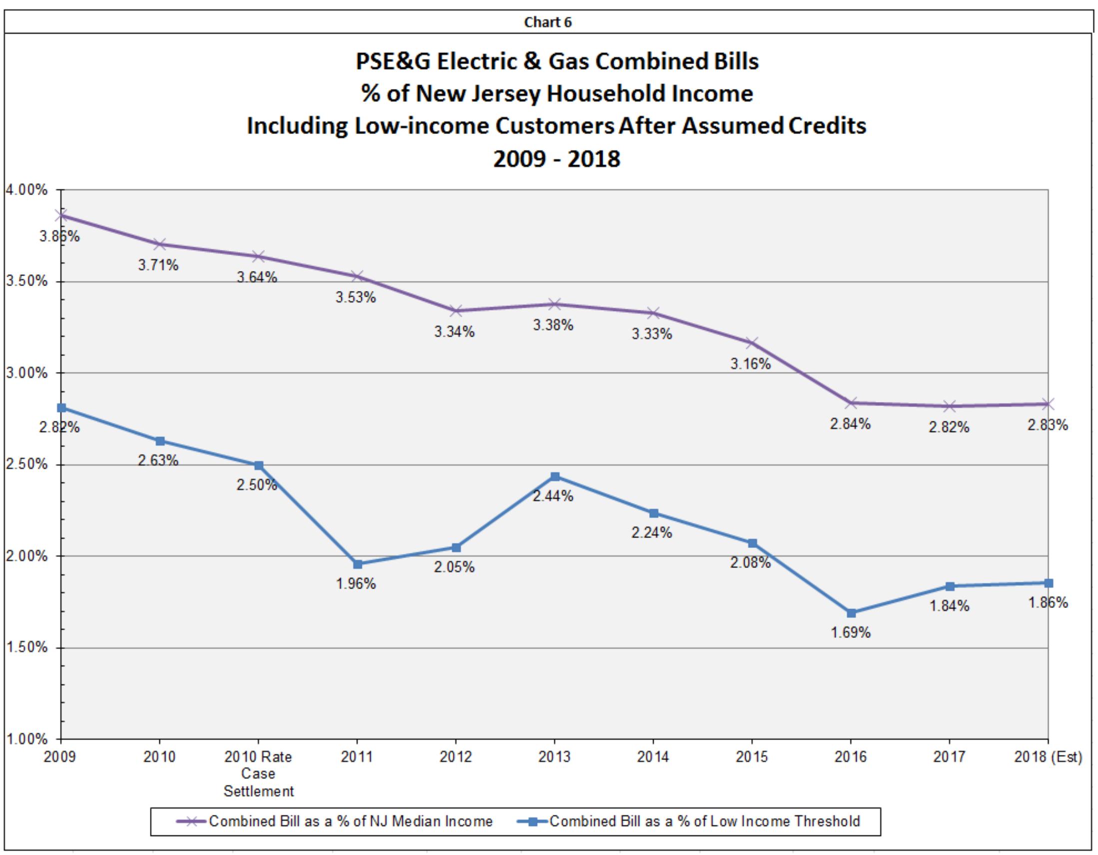
Q. Have you considered the impact of the proposed rates on lower-income customers?

A. Yes. We are very focused on this vulnerable segment of our customer base. In addition to serving these customers through certain energy efficiency programs, such as our multi-family housing programs, we also advocate for various grants provided to lower-income customers, including the Low Income Home Energy Assistance Program ("LIHEAP"), Lifeline and Tenants Lifeline Program ("Lifeline"), and the Universal Service Fund ("USF"). LIHEAP is a Federal Block Grant program that helps low-income individuals and households pay for their winter heating bills, medically necessary cooling benefits, and weatherization. Recipient households must be at or below 200% of the Federal Poverty Level. The Lifeline Program helps customers pay their utility bills with a $225 annual utility credit. To be eligible, a customer must be at or below about 225% of the Federal Poverty Level, at least age 65 or at least age 18 and collecting Social Security Disability. USF is a statewide program administered by the Department of Community Affairs that allows program recipients to pay no more than 3% of their income for electric and 3% for natural gas, or 6% for total electric including electric heating for customers at or below 175% of the Federal Poverty Level.

In addition, the Company promotes the use of these services to our customers through bill inserts and community outreach, conducting this communication in multiple languages where possible and appropriate. PSE&G serves the most diverse demographics in the State and, due to the more urban nature of our customer base, has more customers eligible for these low income programs on a proportionate basis compared with other utilities. Consequently, this customer segment receives special focus.

Q. How will this proposed rate increase impact these customers?

A. As illustrated in the chart below, the relative cost of PSE&G's services to a typical combined (that is, electric and gas) residential lower-income customer is almost half what it was since our last base rate case. This is a result of the lower costs of gas supply as well as PSE&G's success keeping distribution rates low.



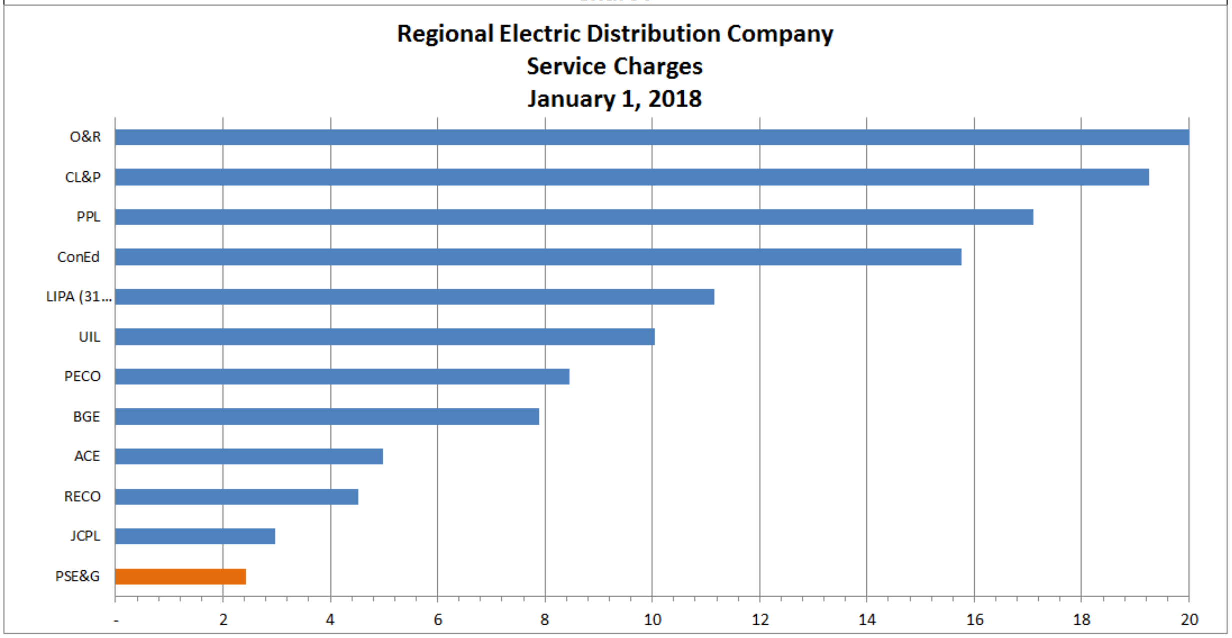
This chart compares the bill as a percentage of income for a typical combined residential customer relative to New Jersey's median income and for low income customers.

As can be seen, for the average residential customer, the cost of our service has declined from approximately 3.9% of median income at the time of our last rate case in 2009 to approximately 2.8% today. For lower income customers, the cost of the bill after LIHEAP, USF and Lifeline grants relative to an income threshold of 175% of the Federal poverty level (the level at which a customer is eligible for these grants), declined from approximately 2.8% of household income at the time of our last base rate case to approximately 1.9% today, a relative decline of approximately 32%. So, even with this proposed rate increase, the cost of electricity and gas for all of our customers, including low income customers, has declined considerably over the past several years.

Q. Are there any other items related to customer impact that you would like to highlight?

A. Yes. Mr. Stephen Swetz's testimony addresses the recovery of the rate increase proposed in this case through fixed and variable rates across customer classes using a cost of service rate design, while also considering PSE&G's present rate design and those of our industry peers. One of the notable proposed changes in our filing is to better align our revenue recovery with our costs to serve our Residential Service (RS) electric customers by lowering the volumetric charges and moving our monthly service charge closer to its actual cost. As shown in the chart below, PSE&G's monthly RS electric service charge is the lowest in the region and does not reflect the proportionate amount of our fixed costs incurred to provide access, metering and customer service to our 1.9 million customers. Further, PSE&G's service charge is the lowest out of 132 electric utilities throughout the country.

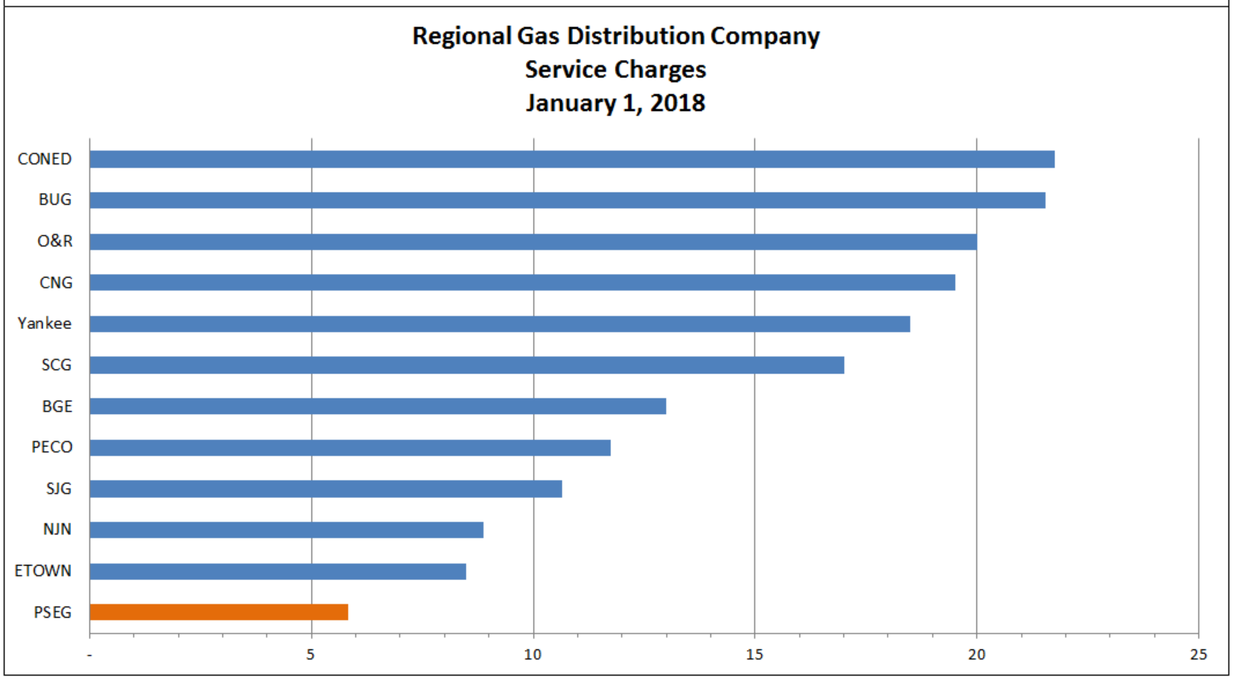
Chart 7



In fact, our monthly RS service charge excluding Sales and Use Tax ("SUT") has decreased from $4.40 in 1982 to its current $2.27. The current monthly fixed cost to provide access, metering and customer service is approximately $8.18 (without SUT). Our proposal is to increase the monthly RS electric service charge over 3 years from the current $2.27 per month to $4.24 per month in year 1, $6.21 per month in year 2 and $8.18 per month in year 3. When the monthly service charge is changed in years 2 and 3, the volumetric rates will be reduced to maintain revenue neutrality with year 1. By spreading the service charge increase over 3 years, the change will be gradual in nature. Also, a service charge that is $8.18 per month will still be lower than industry averages, but more in-line with cost causation to improve cost signals to customers and better match our revenue recovery with cost incurrence.

Similarly, we also propose to increase our monthly Residential gas (RSG) service charges. As shown in the chart below, PSE&G has the lowest residential gas service charge in the region. Further, PSE&G's service charge is the 4th lowest out of 91 gas utilities throughout the country.

Chart 8



The current monthly fixed cost to provide access, metering and customer service is approximately $24.60 (without SUT). Our proposal is to increase the monthly RSG service charge over 3 years from the current $5.46 per month to $7.74 per month in year 1, $10.02 per month in year 2 and $12.30 per month in year 3. When the monthly service charge is changed in years 2 and 3, the volumetric rates will be reduced to maintain revenue neutrality with year 1. As with respect to electric service, by spreading the service charge increase over 3 years, the change will be gradual in nature and at $12.30 month will still be lower than industry averages, but more in-line with cost causation to improve cost signals to customers and better match our revenue recovery with cost incurrence. Mr. Swetz also proposes other changes to better align our rates and tariffs with our costs of service and industry trends.

V. MITIGATION OF THE RATE INCREASES

Q. Mr. Jennings, please describe the impacts of tax reform which have been included in this filing.

A. Federal Tax reform was enacted in December 2017 and has a material impact on the Company's costs and therefore customer rates. The most direct and largest impact was the reduction in the federal income tax rate for corporations from 35% to 21%. We have addressed this change in two steps. First, we have lowered our revenue requirements in this filing to reflect the lower Federal income tax rate, resulting in an estimated reduction of approximately $130 million. Second, we have estimated the impact of the difference in the federal income taxes from January 1, 2018, the effective date of the new federal tax rate, through October 1, 2018, our anticipated new base rate effectiveness date. This difference will be deferred each month from January 2018 until new rates from this proceeding are effective, as a regulatory liability. We propose to return this amount, currently estimated at approximately $100 million, to customers during the first year after rates from this proceeding are implemented. There are several other elements of tax reform that also impact our costs and cash flows and therefore customer rates. Mr. Krueger's testimony outlines several of these, including the loss of bonus depreciation and a calculation of our excess deferred income taxes resulting from the lower federal income tax rate, and the proposed treatment of such amounts. Due to the recent enactment of Federal tax reform, certain aspects continue to be calculated and will be addressed further in our 9+3 update.

Q. Mr. Jennings, you stated that if PSE&G had not taken certain steps to aggressively manage its costs, this proposed rate increase would have been significantly higher. Please discuss the steps that the Company has taken to limit the rate increase.

A. The Company has taken a number of steps to mitigate the magnitude of the rate increases that we are proposing in this proceeding. In addition to incorporating the impacts of tax reform discussed previously, I highlight the following items.

First, we are proposing to flow-back to customers significant tax benefits that offset the recovery of storm costs and would partially offset other rate increases, such as those associated with our GSMP II investments. Second, we have also contained the growth of our distribution-related O&M expenses, including electric and gas distribution operating costs, while reducing certain administrative and general ("A&G") costs, including pension and benefits. Third, our cost of debt has declined significantly due to the recent historically low, abnormal market conditions and our effective capital management. All of these factors have enabled us to reduce the rate request that we otherwise would have made.

A. Tax Benefits Flow-back

Q. Please describe the ratemaking treatment that PSE&G proposes for the federal income tax repair deduction.

A. I will first generally describe how taxes are treated in ratemaking, then discuss this particular tax matter, and finally address our proposed treatment of this issue to offset our revenue requirement. Mr. Krueger's and Mr. Swetz's testimonies address this proposal in more detail.

There are two basic approaches to treating tax benefits the Company receives from accelerated tax deductions. One approach, required for deductions associated with accelerated depreciation claimed pursuant to Internal Revenue Code (Code) sections 167 and 168, is to "normalize" tax benefits associated with temporary differences in the timing of the Company's tax payment obligations by recording deferred taxes as an offset to rate base, which provides the benefits of accelerated depreciation to customers over the depreciable lives of the assets that give rise to the deduction. These normalization rules are not required for deductions claimed under any other section of the Code. The second approach is to flow through tax benefits to customers on a different timeline approved by a utility's regulators. Under the flow through approach, timing and amounts should take into account the facts and circumstances of the deduction, the company's financial situation, the rate impacts, and other considerations.

Q. Please provide a brief summary of the Company's flow through proposal.

A. As Mr. Krueger explains, the rules related to deductions for repairs have been changed by the Internal Revenue Service (IRS). In 2011, for the 2010 tax year, PSE&G changed its method of accounting, claiming larger tax repair deductions, in anticipation of IRS guidance permitting more generous repair deductions. That guidance was finalized by the IRS in 2014 creating the new Safe Harbor Adjusted Repair Expense ("SHARE") deduction, and PSE&G modified its accounting method to reflect the final guidance in that year. Because it is applicable to a broader universe of assets, the SHARE deduction is cumulatively approximately five times greater than the previously applicable repair allowance, which PSE&G had flowed back to customers in accordance with prior Board

Orders. Our election to seek this greater deduction will benefit our customers by providing PSE&G a greater deduction resulting in lower cash taxes, the benefit of which PSE&G can return to customers more promptly. As of September 30, 2018, the day before the effectiveness of new proposed rates, the Accumulated Deferred Income Tax ("ADIT") balance associated with this SHARE is estimated to be approximately $650 million. Absent flowing this deduction back to customers, the SHARE balance will continue to grow as the Company continues to take the deduction.

We propose to flow this benefit to customers in three ways. First, we propose to offset the storm cost recovery of approximately $240 million and other smaller regulatory assets with a portion of the ADIT associated with repair. To the extent that the Board accepts the Company's flow-through proposal, we would not seek to recover storm costs from customers, and deferred storm costs and other regulatory assets have therefore not been included in our revenue requirement calculation here. Second, we propose to flow back the remaining historical accumulated amount of ADIT for the repair deduction over the next five years through a new Tax Adjustment Credit ("TAC"). The proposed amortization schedule would increase each year, resulting in annual rate decreases. These decreases would partially offset other rate increases, such as those associated with our pending GSMP II filing. Third, we propose to return to customers the current period SHARE deduction by flowing back each year the full amount of the deduction, net of the book depreciation on the related property, through the TAC. As described in the testimony of Mr. Krueger, this will involve eliminating the current flow-through of the Asset Depreciation Range ("ADR") Repair Allowance from base rates and flowing back the much larger SHARE deduction through the

TAC. The impact of flowing back this deduction in these manners is reflected in the projected rate schedule below. Future deductions are based on estimated amounts. Details on the purpose of the TAC and the specific flow-back amounts are discussed in Mr. Krueger's testimony. In addition, for a discussion of the cost recovery/refund methodology and associated impacts of the TAC, please see the testimony of Mr. Swetz. These three adjustments result in a material acceleration of the return of tax benefits to customers that reduces our calculation of our revenue requirements and benefits our customers by offsetting the unusual and significant storm costs that were incurred.

As can be seen in the table below, as a result of the increasing amount of flow back each of the next five years, the initial combined revenue increase of approximately 1.2% is reduced to an approximate 0.9% cumulative impact on year five, resulting in an average rate impact over the five year period of approximately 1.4%.

Chart 9

Combined Impact of the Base Rate Case and TAC

Total - SUM YD (5 Years)	Oct18-Sep19	Oct19-Sep20	Oct20-Sep21	Oct21-Sep22	Oct22-Sep23
Annualized Current Revenue ($M)	7,649	7,649	7,649	7,649	7,649
Base Rate Case Revenue Requirement	298	298	298	298	298
Tax Adjustment Clause	(203)	(142)	(179)	(213)	(231)
Revenue Change	95	156	119	85	67
Total Revenue	7,744	7,806	7,769	7,734	7,716
% year-over-year increase: Revenue	**1.2%**	**0.8%**	**-0.5%**	**-0.4%**	**-0.2%**
Cumulative % Increase:	**1.2%**	**2.0%**	**1.6%**	**1.1%**	**0.9%**

Electric - SUM YD (5 Years)	Oct18-Sep19	Oct19-Sep20	Oct20-Sep21	Oct21-Sep22	Oct22-Sep23
Annualized Current Revenue ($M)	5,358	5,358	5,358	5,358	5,358
Base Rate Case Revenue Requirement	111	111	111	111	111
Tax Adjustment Clause	(84)	(18)	(24)	(29)	(32)
Revenue Change	27	93	87	82	79
Total Revenue	5,384	5,450	5,445	5,440	5,437
% year-over-year increase: Revenue	**0.5%**	**1.2%**	**-0.1%**	**-0.1%**	**0.0%**
Cumulative % Increase:	**0.5%**	**1.7%**	**1.6%**	**1.5%**	**1.5%**

Gas - Sum YD (5 Years)	Oct18-Sep19	Oct19-Sep20	Oct20-Sep21	Oct21-Sep22	Oct22-Sep23
Annualized Current Revenue ($M)	2,292	2,292	2,292	2,292	2,292
Base Rate Case Revenue Requirement	187	187	187	187	187
Tax Adjustment Clause	(119)	(123)	(155)	(184)	(199)
Revenue Change	68	63	32	3	(13)
Total Revenue	2,360	2,355	2,324	2,294	2,279
% year-over-year increase: Revenue	**3.0%**	**-0.2%**	**-1.3%**	**-1.3%**	**-0.7%**
Cumulative % Increase:	**3.0%**	**2.8%**	**1.4%**	**0.2%**	**-0.5%**

B. O&M Distribution Expenses Cost Containment Measures

Q. Please describe the actions that the Company has taken to control electric and gas operating distribution-related O&M expenses.

A. While Mr. Cardenas will describe some of these efforts in his testimony, in general, we seek to measure and optimize our distribution-related O&M expenses by regularly benchmarking our costs and setting targets to improve our results year after year. This fosters an environment of continuous improvement, and our ability to achieve these targets has a significant impact on employee compensation, as I discuss further in Section VIII of my testimony. This results in a continuous focus on cost control and operational improvement.

These cost control efforts have helped to offset increases in distribution-related O&M costs due to regulatory requirements – such as tree trimming requirements, and other costs that have materially increased since our last rate case. Mr. Cardenas's testimony on PSE&G's electric and gas operations provides examples of how we seek to manage these costs while obtaining strong operating results. One example of cost containment is on wages.

Q. Has the Company also taken measures to control wages?

A. Yes. In the area of wages and benefits, the Company has controlled distribution-related O&M growth by regularly assessing our compensation levels to keep them competitive with the market while providing incentives to our employees to work efficiently and productively. Our goal, which we have achieved, has been to keep our employee compensation both constrained and effective. With the exception of one year when we did not provide MAST wage increases, we have generally provided average annual merit increases of approximately 3% to our employees. We also manage our union employee costs through a very rigorous collective bargaining process. In addition, I discuss the issue of incentive compensation in section VIII of my testimony.

The focus of the next portion of my testimony will be on A&G costs included in total O&M, including wages and benefits, particularly pensions.

C. A&G Cost Containment Measures –Pension and Benefits

Q. How has PSE&G's control of pension costs mitigated the impact of the rate increase sought in this filing?

A. PSE&G has a long history of successfully controlling pension costs, and the considerable control we have exercised over this expense has translated into a proposed revenue requirement for pension costs of $0. To my knowledge, this is the lowest for any electric or gas utility in the State.

Q. Please describe the steps that the Company has taken to control pension costs.

A. We were among the first utilities in the country to close a Final Average Pay Pension Plan to new entrants and move to a Cash Balance Pension Plan / 401(K) construct for all new hires starting in the mid-1990s. Since our last base rate case, PSE&G has adopted several cost measures that helped to further lower our pension expense. To highlight several:

- Effective January 1, 2012, the Pension Plan was amended with respect to participants who are not subject to a collective bargaining agreement to change the calculation of any future benefit under the Final Average Pay benefit formula from a 5-year final average pay formula to a 7-year final average pay formula. This significantly reduced the pension cost to the Company and our customers.
- In 2016, we changed the discount rate calculation methodology from using a single weighted average discount rate to using the full yield curve, which has resulted in significantly lowering the interest cost component of pension costs;
- In 2017, we merged the Final Average Pay Plan and the Cash Balance Pension Plans. Given the longer duration of the Cash Balance Pension Plan, the amortization period for any unamortized costs was thereby lengthened from approximately seven to approximately 13 years. Given the material unamortized expenses, spreading recovery over a longer time period has significantly reduced our pension expense; and
- Effective January 1, 2018, we adopted newly issued Generally Accepted Accounting Principles ("GAAP") related to accounting for retirement benefits. In

2017, the Financial Accounting Standards Board ("FASB") issued ASU 2017-07 Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost ("ASU 2017-07"). Under ASU 2017-07, only the service cost component of benefit cost is eligible for capitalization. Other "non-service" cost components, which include the net of interest costs, amortizations and actuarial expected returns on pension assets, may not be subject to capitalization, but will be fully recorded as expense (or income if in a credit position). Based on the funding we have made into our pension plan since our last rate case, the strong returns we have achieved and the expected actuarial returns on those pension funds, and the changes we made noted above, the non-service cost components of PSE&G's pensions will result in projected income for our test year. Adopting the new accounting standard serves to lower the overall pension expense for the Company.

Q. Has the Company taken any additional measures regarding pension expense, such as funding the plan?

A. Yes. Since the last rate case, over $700 million has been invested into the pension fund, ensuring our pension obligations are appropriately funded.

Q. Has the management of the returns on the pension funds also lowered expenses?

A. Yes. The management of our pension funds has been exemplary. For the 7-year period ended September 30, 2017, we have been in the top 4% ranking in the Trust Universe Comparison Service ("TUCS") rankings for trust returns. TUCS is a report published by Wilshire, an independent investment consulting firm, designed for trusts to evaluate their performance; the ranking reflects all decisions including asset allocation, policy guidelines, and manager selection. Our asset allocation strategy towards equities of approximately 70%, and our realization of alpha (higher returns than passively managed investments) on investments where we choose to actively manage, has resulted in annualized returns of approximately 11% over the seven years through September 30, 2017, well above industry average and above the benchmark for our asset allocation. This superior management resulted in less costs in our test year due to higher fund balances and a higher assumed rate of return given our current asset allocation strategy, and therefore lower revenue requirements.

Q. Have your successful efforts resulted in other benefits?

A. Yes they have. The funding level (inclusive of the strong returns noted above) that we made reduces our fees/premiums paid to the Pension Benefit Guaranty Corporation ("PBGC") – the government entity that backstops pension obligations. The Company has not paid any variable rate PBGC premiums that could be incurred if we were less funded. If we were to have paid the average PBGC premiums (as a percentage of plan assets), we would have incurred PBGC premium fees of approximately $10 million.

Q. As a result of these measures, what is the pension expense in the test year and are you proposing any *pro forma* adjustments related to pension expense?

A. As a result of these actions, present market conditions and other factors, the actuarial estimate for the test year is approximately $24 million of income from our pension. If not adjusted, this would reduce our revenue requirements. However, we cannot offset such a reduction in revenue requirements and make ourselves whole by taking that cash out of our pension funds. And, any such reduction in our revenue requirement would reduce our operating cash flow and therefore adversely impact our credit metrics. This pension income is an actuarial result of the actions we took as described above to reduce pension costs. As a result, we have made a *pro forma* adjustment to include $0 of pension expense in our revenue requirements.

D. Benefit Cost Containment Measures

Q. Has the Company also taken measures to control increases in the costs of benefits?

A. Yes. To address a long-term trend of rising health-care costs, in 2015 we implemented a new, lower cost health care plan. Our high deductible health savings plan has a lower cost compared to the traditional Health Maintenance Organization ("HMO") plans. We also negotiated changes to the Company's medical and prescription drug plan changes with all unions. Through these negotiations, we increased enrollment into our high deductible health savings and Preferred Provider Organization ("PPO") plans, which lowered costs compared to traditional HMO plans. We also lowered the plan actuarial values to defer the pending so-called "Cadillac tax," a 40 percent excise tax on high-cost employer-sponsored health plans that would be imposed under the Affordable Care Act in 2020. In addition, we did a complete overhaul of the Company wellness program to focus on changing employee behavior to reduce health risks. Employee engagement in the new program increased dramatically from the existing one as evidenced by a greater than 70% participation rate among union employees compared to the prior program's rate of less than 10%. The increased engagement in our wellness programs and restructured aspects of our medical and prescription drug plans has reduced our health care cost trends. As a result of these changes, since 2009 our overall historical medical/RX compound annual growth rate is approximately 5% (and only 2.7% for MAST employees) compared with a national average of 7.7%. Collectively, these items are examples of cost avoidance measures we have taken to mitigate the costs ultimately borne by our customers.

E. Interest Cost Containment Measures

Q. Please describe the steps taken to control the Company's interest costs.

A. As of November 30, 2017, our embedded cost of long term debt was approximately 4.05%. This represents a reduction of over 200 basis points from the embedded cost of long term debt as of December 31, 2009 of 6.145% (which was approved in our 2009 Base Rate Case). This reduction is primarily due to financing in a historically low interest rate environment, as well as improved credit ratings and strong execution. Furthermore, we were able to substantially reduce our embedded long term debt rate while increasing the tenor of our long term debt portfolio. On November 30, 2017, the Weighted Average Maturity ("WAM") of our portfolio was 13.9 years which represents an increase of approximately 1.5 years from the December 31, 2009 WAM of 12.5 years. By reducing the embedded cost while increasing the WAM, customers will benefit from lower rates for a longer period of time, reflecting sound financial management.

F. Summary

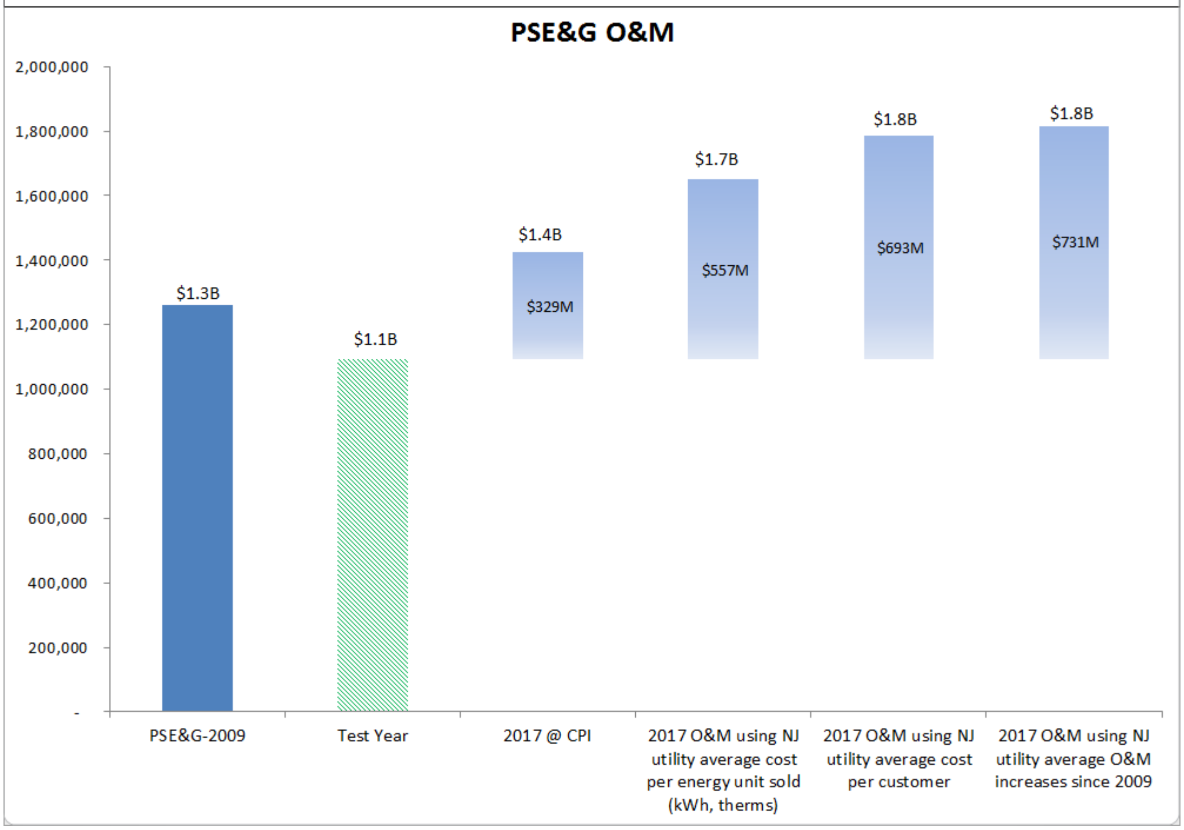
Q. Please summarize the results of your total O&M cost saving measures.

A. As shown in the chart below, if not for the cost savings measures identified above, our total O&M costs in this rate request would be substantially higher. The chart compares the total O&M costs in our last test year with those in our current test year, showing that eight years later they have declined, despite increased regulatory requirements and inflationary pressures. We then compared the total O&M in our test year to several scenarios which considered CPI and the total O&M of the other NJ electric and gas utilities from the benchmarking information prepared by Mr. Adams as follows:

1. <u>CPI -</u> In this scenario, we calculated what our total O&M would have been if our costs from our prior test year in 2009 escalated at CPI of 1.5% from that time through this test year, and noted that the resulting total O&M would have been approximately $300 million higher.
2. <u>Average cost per energy unit sold by other NJ utilities:</u> In this scenario, we calculated the average total O&M costs per energy unit sold (kWh for electric and therms for gas) of the other NJ utilities and applied it to our energy units sold, which implied our total O&M costs would have been approximately $600 million higher if our costs were at the average of the other NJ utilities.
3. <u>Average cost per customer of other NJ utilities:</u> In this scenario, we calculated the average total O&M per customer of the other NJ utilities and applied it to our number of customers, which implied our total O&M costs would have been approximately $700 million higher if our costs were at the average of other NJ utilities.
4. <u>Average rate of O&M increase of other NJ utilities:</u> In this scenario we calculated the escalation of our total O&M costs from our prior rate case in 2009, except instead of growing at CPI, we assumed those costs increased at the rate of the total O&M increase of the other NJ utilities, which was approximately 6% per

year. Our total O&M costs would have been approximately $700 million higher if our costs had escalated at the rate that those costs escalated at other NJ utilities.

Chart 10



The value of our cost control efforts is clearly illustrated and directly benefits our customers in the form of lower revenue requirements in this case. If our costs were reflective of these other scenarios, our revenue increase request of approximately 1.4% could have been approximately 4% or even as high as 10%.

VI. <u>CAPITAL STRUCTURE AND THE COST OF CAPITAL</u>

- **<u>Financial Integrity</u>**

Q. Does PSE&G have a need to maintain sufficient financial integrity to raise capital effectively?

A. Yes, very much so. Our financial integrity depends on an approved return on equity ("ROE") that reflects the cost of capital required by our investors, and a capital structure that is supportive of our credit quality. Our current ROE ranges from 9.75% for infrastructure program investments to 10.3% for base investments in PSE&G's rate base at the time of the last base rate case. As Ms. Bulkley states, the Company's overall ROE should be reset at 10.3%, reflecting current market and business conditions, PSE&G's operating performance, and the Company's long-standing, investment-backed commitment to New Jersey's environmental and energy policy goals.

PSE&G proposes to apply its ROE to a capital structure reflecting a common equity component of 54%, to realize targeted credit statistics and maintain a strong investment grade rating, as discussed further below.

Q. What is the Company's cost of capital and on what capital structure is PSE&G seeking to have those cost rates applied?

A. PSE&G is seeking an overall rate of return of 7.40% that is derived from a capital structure composed of 54% equity, 45.49% debt, and 0.51% customer deposits. The embedded cost rate for our long term debt is 4.05%. Customer deposits are accumulated at a rate of 0.87% as of January 1, 2018. The ROE we are seeking is 10.3%, as discussed in Ms. Bulkley's testimony.

Ms. Bulkley derived her cost of equity using an analysis of a proxy group of companies that possess a similar percentage of operating income from electric utility and gas distribution operations as PSE&G, making them risk comparable to the Company in terms of business mix. Ms. Bulkley then considered the results of the DCF model, a CAPM analysis, and a Bond Yield Plus Risk Premium methodology to produce her range of reasonable equity returns. Ms. Bulkley then further reviewed the benchmarking analysis performed for PSE&G by Mr. Adams. Ms. Bulkley explains that based on the results of Mr. Adams's benchmarking analysis, PSE&G's electric and gas distribution customers' benefit from the Company's efficiency and cost containment efforts. She concludes that PSE&G's reliability is consistently in the top quartile, and its customer satisfaction and cost performance are above that of its peers. Collectively, the benchmarking analysis demonstrates that PSE&G operates more efficiently than other similar electric and gas utilities, supporting an authorized ROE for PSE&G above the proxy group mean and towards the high end of the range of reasonableness established in Ms. Bulkley's testimony.

- **Recognition of a Performance Based ROE**

Q. Is it sound ratemaking practice for the BPU to recognize PSE&G's superior performance when setting a fair rate of return on equity?

A. Yes, it is. It has been recognized that utilities providing excellent service, reliability and efficiency should receive an ROE commensurate with that high performance, including an ROE at the upper end of the range of reasonable rates. In New Jersey specifically, it is established that the caliber of a utility's performance need not be a neutral factor in determining a reasonable rate of return, and superior utility service commands a higher rate of return to recognize the benefits that customers receive from managerial efficiency. Put differently, our State recognizes that if a utility's rates were to be set without an analysis of its service level, then there would be no advantage to skillful, prudent, and economical management. Jurisdictions other than New Jersey also consider a utility's superior performance when determining a reasonable rate of return on equity.

- **Evidence Supporting Superior Performance**

Q. **Are you familiar with the testimony provided by Mr. Adams of Concentric?**

A. Yes, I am.

Q. Does Mr. Adams's analysis warrant Ms. Bulkley's recommendation of an ROE at the high end of the range of reasonableness?

A. Yes. Mr. Adams's testimony compares PSE&G to groups of electric and gas utilities both in New Jersey and outside our state. Comparison groups Mr. Adams utilized included electric and gas utilities in New Jersey, a regional group, a national group, and the ROE proxy group used by Ms. Bulkley. His conclusions are quite remarkable and portray PSE&G as a leader in its class, providing excellent service and reliability to its customers through a very advantageous cost structure.

In the area of electric utility cost containment, Mr. Adams looked at the following criteria:

1. Distribution Operations and Maintenance ("O&M") expense per electric customer;
2. Distribution O&M per MWh sold;
3. Administrative and General ("A&G") expense per electric customer;
4. A&G expense per MWh sold;
5. Salaries, Wages, Pensions, and Benefits expense per employee;

6. Total Non-Production O&M expense per electric customer; and
7. Total Non-Production O&M expense per MWh sold.

PSE&G's expenses were below the groups' mean in every category. In the area of electric reliability, Mr. Adams reviewed PSE&G's reported System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI") compared to New Jersey mean results as reported to the BPU. He also compared PSE&G's SAIFI, CAIDI, and System Average Interruption Duration Index ("SAIDI") to those reported to the Institute of Electrical and Electronics Engineers ("IEEE") over the ten years through 2015. Simply stated, the frequency and average duration of outages for a PSE&G customer is about half that of customers of other New Jersey utilities. Comparisons of PSE&G with regional and national groups led to similar conclusions.

Q. Did Mr. Adams also examine PSE&G's gas business?

A. Yes, he did. He examined the following metrics to evaluate PSEG's gas business performance against that of the peer groups:

1. Distribution O&M expense per gas customer;
2. Distribution O&M per Mcf sold;
3. A&G expense per gas customer;
4. A&G expense per Mcf sold;
5. Total Non-Production O&M expense per gas customer;
6. Total Non-Production O&M expense per Mcf sold.

Q. What did Mr. Adams conclude regarding the Company's gas business?

A. He concluded that PSE&G's gas distribution costs are lower (i.e., better) than the mean for each of the comparison groups and had the lowest growth rate over the ten year period measured.

Q. Did Mr. Adams examine other metrics?

A. He did. In addition to the aforementioned operational metrics, Mr. Adams also evaluated the Company's customer satisfaction based upon JD Power's reported results for the years 2012 through 2016. PSE&G was ranked in the first quartile or at the top of the 2nd quartile by its electric residential and business customers in each of the years 2012 through 2016. In JD Power's 2017 study, PSE&G residential electric customer satisfaction is again ranked in 1st quartile and business electric customer satisfaction is ranked in the 2nd quartile. For gas, PSE&G's residential and business customer satisfaction rating improved year-over-year each year from 2012 to 2016. Residential gas customer satisfaction ranked just below 1st quartile for that same period, but in JD Power's latest 2017 results, PSE&G ranked in 1st quartile and 3rd overall.

Q. In addition to the testimony provided by Mr. Adams, is there other evidence that warrants Ms. Bulkley's determination that PSE&G should earn an ROE at the higher end of the range of reasonableness?

A. Yes, there is. PSE&G is an acknowledged leader in implementing the State's "green" policies toward carbon reduction, energy efficiency and renewable energy. Also, the Company's appliance service business, unique to PSE&G, provides earnings that are used directly for the benefit of our customers, reducing their cost of service. As Mr. Cardenas demonstrates, the Company has a well-established track record of excellent operational performance and PSE&G is especially focused on providing safe and reliable service, controlling costs and delivering a high level of customer satisfaction. Moreover, as I stated previously, the Company has reduced its O&M expense since PSE&G's last base rate case in 2009, to the benefit of our customers. Again, if PSE&G's O&M expense had simply increased at the rate of inflation or was closer to the average of other utilities in the State, this rate request would be hundreds of millions of dollars higher.

Q. You stated that PSE&G is in the forefront of advancing the State's energy efficiency and other goals. Please explain.

A. At the same time that we have been controlling costs and delivering high reliability, we have also been advancing important State goals. More than any other utility, PSE&G has embraced the State's Energy Master Plan, and has proposed and is managing multiple programs to improve the energy efficiency of a number of customer segments to benefit society and the State as a whole – including hospitals, multi-family housing, urban economic development zones, and other customer segments. PSE&G also recently sought and received approval for pilot smart thermostat and data analytic programs for residential customers to begin a focus on lowering these customers' usage and, therefore, bills and emissions. We have also been an outspoken advocate to expand the use of renewables in a smart way. New Jersey has limited renewable resources, and, as the most densely populated state in the country, has limited land available for large solar installations. PSE&G developed several solar programs to deal with these limitations, including our utility-scale solar landfill program, which is cost effective given the scale and utilizes large, otherwise unusable landfills in our space constrained State. We also have a Solar Loan program for customers that can be another avenue for customers to participate in the solar market.

Q. Are there other things that PSE&G has done to advance its customers' interests?

A. Yes. As noted above, we are the only utility in the State that continues to have an Appliance Service Business ("ASB") within the utility structure. As a result of this structure, the majority of the pre-tax earnings of this business are captured in the revenue requirement-setting process of this base rate case. Included in this test year are approximately $36 million of pre-tax earnings that will offset PSE&G's revenue requirement, to the benefit of PSE&G's customers thereby avoiding approximately a 1% rate increase for gas customers. I discuss the ASB in greater detail later in my testimony.

Q. Keeping in mind Ms. Bulkley's recommendation that PSE&G be provided an ROE slightly higher than the midpoint of the range of reasonableness, can you provide context regarding your current distribution rates, including how they compare to your peers, and the rate increase proposed in this filing?

A. Yes. As I demonstrated previously, our Residential distribution rates are the lowest of the gas utilities in the State and the second lowest of the electric utilities in the State. In addition, despite the significant investment in infrastructure programs that PSE&G has undertaken to modernize and improve the reliability of the system, since our last rate case in 2009 our Residential distribution rates have risen at the lowest level compared to the other gas utilities in the State and next to the lowest level compared to the other electric utilities in the State. Our distribution rate increase over this time was largely due to our investment programs and, in aggregate, has been less than half of the rate of increase of the average of the other State utilities.

- **A Credit Supportive Equity Ratio Is Also Warranted and Required**

Q. Please explain the basis for the 54% equity ratio sought by the Company.

A. We are targeting a capital structure having a 54% equity ratio, because we believe that this ratio is important to support PSE&G's current credit ratings. PSE&G is committed to strong investment grade credit ratings in order to ensure consistent access to the capital markets at reasonable costs**.** The current senior secured credit ratings at PSE&G are "A" from S&P and "Aa3" from Moody's; the credit rating outlooks are stable from both rating agencies. PSE&G is currently maintaining an equity ratio range between 53.0% and 53.5%, and we expect to move towards 54% later in 2018. The actual common equity ratio will vary monthly based on monthly earnings and financing activities. The 54% target percentage for the end of 2018 was determined by evaluating the equity level needed to be in the lower half of the range of certain credit statistics (i.e., Funds from Operation to Debt ("FFO to Debt"), or as Moody's calculates, Cash flow from Operating activities – pre working capital ("CFO pre-WC") to Debt) for a sustained period. Moody's credit opinion indicates that the FFO to Debt range for PSE&G's current rating is between 19% and 26%. The 54% equity ratio is expected to result in credit metrics that average towards the low end of the range over the next few years. Over the past few years our credit metrics have been comfortably within the indicated range; however, in the test year and our forecast, FFO to debt declines to the low end of the range of the Moody's indicated range. The credit metrics in the recent past were buoyed by one-time cash tax benefits from bonus depreciation. Due to the loss of bonus depreciation in the Federal tax reform discussed further below, and as the accelerated depreciation tax benefits from bonus depreciation reverses over time, it places notable downward pressure on credit metrics. To that end, due to the impacts from Federal tax reform, our current BPU long-term debt authority of $2.5 billion through the end of 2019 is expected to be insufficient. The Company is still evaluating the amount required in excess of the $2.5 billion. The BPU has recognized the need for utilities to maintain strong credit metrics, to maintain a strong investment grade credit rating to cost-effectively attract capital.

Q. Please explain why you believe that the Company's actions, and that of its parent, represent "sound financial management"?

A. FFO/Debt represents a key credit measure used by the ratings agencies. FFO/Debt is a measure of cash flow leverage and indicates a company's ability to support its debt level. For the purpose of demonstrating sound financial management, we tend to focus on the calculation of FFO to Debt from Moody's more so than S&P's calculation. S&P's analysis follows a "family" approach that develops a corporate credit rating based on a consolidated business and financial profile. S&P's is a top down approach. Moody's, in contrast, analyzes the business and financial profile of an entity and develops an issuer credit rating. Moody's is a bottom up approach. Given this approach, Moody's credit opinion provides the more useful insights into a subsidiary credit rating. In its PSE&G credit opinion from June 2016 Moody's states the following:

- PSE&G's stable rating outlook reflects our expectation that the company will successfully manage its large capital spending program and maintain a consistent financial profile.
- Factors that Could Lead to an Upgrade:
  - Given PSE&G's strong credit rating and its ongoing capex program, an upward movement in ratings is unlikely at this point
  - A sustained improvement in credit metrics, with CFO pre-WC (FFO to Debt) coverage of debt in excess of 26%

- Factors that Could Lead to a Downgrade:
  - PSE&G's CFO pre-WC (FFO to Debt) coverage of debt fell below 19% on a sustained basis
- Financial profile pressure by capex program but expected to remain adequate
  - PSE&G's financial metrics have historically been comfortable for the rating, with CFO Pre-WC coverage of interest and debt ranged from 5.0-6.0x (FFO interest coverage), 22-25% (FFO to debt), respectively.

Below is a table reflecting PSE&G's Senior Secured ratings since 2011:

Year – End	S&P	Moody's
2011	A-	A2
2012	A-	A1 (one notch improvement)
2013	A (one notch improvement)	A1
2014	A	Aa3 (one notch improvement)
2015	A	Aa3
2016	A	Aa3
2017 (Current)	A	Aa3

As can be observed, the last ratings change was in 2013 for S&P and 2014 for Moody's. At S&P, the upgrade was attributed to strong operating performance and healthy credit metrics, among other factors. In 2014, Moody's upgraded the majority of regulated utilities because of their more favorable view of the credit supportiveness of the US regulatory environment at that time. Since 2014, PSE&G's credit ratings have remained unchanged as we have executed our substantial capital programs.

In addition to the comments from rating agencies, the BPU's Chief Economist also recognized PSE&G's sound financial management in the BPU's approval of the Company's long-term debt petition in Docket No. EF17050550 approved on October 20, 2017:

> A review of the various transactions over the last several years shows that the company has been very effective in achieving competitive rates on their debt securities. They [comp]are very favorably with other companies in the market on that date with similar credit ratings. The company does an excellent job of managing its balance sheet. Its debt maturity and capital structure are consistent with sound financial management. Transcript of BPU October 2017 agenda meeting page 3, line 14-23

Q. Has PSE&G managed its finances to maintain its credit ratings?

A. Yes, we have. In fact, the parent company Public Service Enterprise Group ("PSEG" or "Enterprise") has provided contributions that have enabled the utility to keep its financial metrics within acceptable ranges for the desired ratings, as the chart below demonstrates.

<u>Capital Structure Management</u>:

Below is a summary of PSE&G's capital structure since the Company's previous rate case was finalized in 2010:

Year	Dividends from PSE&G to the Parent	Capital Contributions from Parent to PSE&G	Year-End Regulatory Equity Ratio	Moody's FFO to Debt
2011 Actual	$300M	-	51.6%	27.8%
2012 Actual	-	-	51.4%	22.1%
2013 Actual	-	$100M	51.0%	23.8%
2014 Actual	-	$175M	51.6%	28.4%
2015 Actual	-	-	52.3%	25.9%
2016 Actual	-	$250M	52.4%	21.1%
2017 Projected	-	$150M	(53.0% - 53.5%)	19-21%
June 2018 Projected	-	-	54.0%	19-20% (a)
Cumulative	$300M	$675M		

(a) The 2018 projection of FFO to Debt is our estimate using Moody's calculation. The ratio is expected to trend notably lower than 2016 and 2017 due to the loss of bonus depreciation under the recently enacted Federal Tax reform.

- Historical FFO to Debt based on Moody's Financial Metric Database
- The temporary increase to the 2011, 2014 and 2015 FFO/Debt credit metrics was primarily driven by one-time cash tax benefits from bonus depreciation. As the accelerated depreciation tax benefits from bonus depreciation reverse in the future years, it places downward pressure on credit metrics.

As this chart demonstrates, PSE&G's dividend policy to the Parent follows its capital structure objective, which is designed to maintain PSE&G's current credit ratings. Our regulatory equity ratio is calculated as equity / (equity plus long-term debt plus customer deposits). Given the calculation of the equity ratio, it will vary as PSE&G issues long-term debt from time to time and generates earnings and cash flow over the course of a year. Generally, PSE&G has maintained its target regulatory equity ratio. This has been achieved through disciplined financial management, including contributions by the parent. As illustrated in the chart above, PSE&G has not to date provided a dividend to the Parent since 2011 and has received capital contributions totaling $675 million over the same period. This highlights PSE&G's commitment to maintaining the strength of its balance sheet.

During 2016 and 2017, PSE&G received capital contributions from PSEG totaling $400 million, which provided a slight uplift in PSE&G's regulatory equity ratio to the current range of 53.0% to 53.5%. We expect to move to 54% later in 2018 to achieve credit metrics that are consistent with the lower end of the range utilized by Moody's to support our targeted credit rating. The FFO-Debt average over the test period is estimated to be at the low end of Moody's range, supporting the 54% equity component of our capital structure.

Q. Based on the Company's historical equity ratio and recent and projected financial metrics, is it your belief that the forecast 54% equity ratio is warranted and required to support the Company's credit quality?

A. Yes. As previously discussed, we intend to achieve our proposed 54% equity ratio later in 2018. That equity ratio is expected to result in a Moody's FFO/Debt, consistent with the low end of their range for our targeted credit metrics. Accordingly, it would not be appropriate to set an equity ratio below the requested amount as to do so could weaken our credit metrics below Moody's range, putting our targeted credit rating at risk and potentially adversely impacting our financing costs.

VII. GREEN ENABLING MECHANISM ("GEM")

Q. Please provide an overview of the GEM included as part of this filing.

A. As part of this filing we have included the testimony of Dr. Daniel Hansen of Christiansen Associates requesting that PSE&G be permitted to "decouple" revenues from sales volumes through a "Green Enabling Mechanism". Historically, PSE&G has been incented to increase sales volumes, as that increases revenues and therefore earnings. This economic incentive, however, is directly contrary to State policies intended to reduce usage, which in turn reduces overall emissions and customers' bills. Indeed, two of the five overarching goals of New Jersey's Energy Master Plan are to "drive down the cost of energy for all customers" and "reward energy efficiency and energy conservation/reduce peak demand," with one of the stated benefits of the latter being reduced emissions. The GEM directly addresses this conflict by revising our rate design and aligning the interests and objectives of the State, customers, and the Company to pursue conservation and green energy goals. Over the past decade decoupling has become commonplace, and decoupling mechanisms are in effect in the majority of states in the country, including in New Jersey with the Conservation Incentive Programs ("CIPs") in place at South Jersey Gas and New Jersey Natural Gas. In fact, there have been several recent exploratory measures taken by State officials to institute decoupling for all state utilities, such as the recent taskforce spearheaded by Senator Smith.

Importantly, PSE&G believes that there is a significant opportunity to invest more in energy efficient equipment, which would reduce customer usage and customer bills and emissions. Further, we can target these investments to customer segments that would most benefit from these services, and the investments would benefit society as a whole. For the past several years PSE&G has sought and received approval to make certain limited investments in energy efficient equipment such as boilers, chillers, furnaces, and lighting largely targeting hospitals, multi-family housing, businesses in urban economic development zones, and other market segments. We believe that there is significantly more opportunity to expand in these areas and related segments, including but not limited to nursing homes, schools, and municipalities.

Q. But hasn't the Company been making energy efficiency investments, and earning a return on those investments, for several years without a revenue decoupling mechanism?

A. While the Company has recently filed and been approved to implement energy efficiency programs without the requested GEM, those programs are small and had certain features that provided the Company with the opportunity to earn its allowed return even when taking into account the lost revenues caused by the program by successfully managing its expenses. This, however, is not a sustainable methodology for larger energy efficiency investment programs that customers can benefit from and that the Company intends to pursue. Therefore, the GEM that we propose in this case is a prerequisite for future, more comprehensive energy efficiency programs. PSE&G plans to propose a larger Clean Energy Future ("CEF") program in 2018 that will greatly expand its investment in Energy Efficiency ("EE") programs as well as related State policy objectives, in the expectation that the GEM will be approved in this filing and can support implementing that EE program.

Q. Please summarize Mr. Hansen's decoupling testimony.

A. Mr. Hansen's testimony details the key components of the GEM filing, including customer protections that are generally consistent with the New Jersey natural gas companies' CIP mechanisms and with PSE&G's gas Weather Normalization Clause ("WNC"). Mr. Hansen describes how PSE&G's allowed revenue per customer will be established, for each month and each customer class, based on the revenue requirements and billing determinants established in this proceeding, and how those allowed revenue per customer figures will be multiplied by the actual number of customers to get "GEM revenues". The variance between GEM revenues and actual revenues will be deferred and collected or refunded in the following year, similar to how the mechanism works for the other NJ gas utilities. PSE&G will thereby be indifferent to its customers' energy efficiency practices.

VIII. INCENTIVE COMPENSATION

Q. Mr. Jennings, please briefly describe the Company's compensation philosophy.

A. PSE&G maintains a compensation structure designed to attract and retain a talented and diverse workforce to operate safely, reliably, and cost-effectively. Our compensation structure (salary ranges, incentive compensation targets, and related factors) is regularly benchmarked and is aligned with industry standards to enable the Company to attract and retain our management team and overall workforce.

Q. Were your overall compensation costs recently benchmarked?

A. Yes. With the assistance of Mercer Consulting, in late 2014-early 2015, we conducted an evaluation of our compensation structure and costs. Additionally, each year we benchmark the market in which we compete for talent regarding the pricing of key positions, the overall merit budget, and our grade structure pay ranges. Mercer Consulting recently updated its compensation benchmarking market analysis and confirmed that overall cash compensation at PSE&G is slightly below the market median. Also, as seen in Mr. Adams's testimony, our total costs for salaries and wages, which include incentive compensation, are below those of our peers.

Q. Does the Company base part of employee compensation on the achievement of various incentives?

A. Yes. Similar to industry peers and the vast majority of companies, we have a compensation program that is composed of a mix of fixed base pay and incentive pay. The incentive pay is dependent upon achieving established goals. For PSE&G these goals are primarily operational and customer focused. Our incentive pay program is designed to encourage our employees to focus on the goals that have enabled PSE&G to achieve the levels of reliability, safety, and operational excellence that I have described previously. Included in our test year expenses are approximately $30 million associated with incentive compensation. Of that amount, approximately $10 million relates to our long-term incentive program ("LTIP") and approximately $20 million relates to our annual performance incentive plan and management incentive compensation plan ("PIP/MICP"). Of the approximately $20 million that relates to our annual incentive program, approximately $16 million is based on achieving operational metrics.

Q. Please explain why the Board should approve the recovery of PSE&G's incentive compensation at this time?

A. As a preliminary matter, it should be recognized that our incentive compensation program is not a "bonus" program as that term is commonly understood. As I discuss more fully below, it is the combination of fixed compensation and variable compensation that permits the Company to provide a level of overall compensation necessary to attract and retain qualified personnel. In addition, while there are certain metrics that might be characterized as "financial," these metrics actually benefit both shareholders and customers. For example, containing O&M costs in between base rate cases benefits shareholders in the year(s) costs are contained, but also helps keep down test year costs that are ultimately recovered from customers through rate cases, thereby lowering customer rates from what they otherwise would be. Clearly, reducing total O&M expense below 2009 levels is a benefit for customers. As noted previously, if our total O&M costs had simply risen at the rate of inflation, or at the rate of the mean of other electric and gas utilities in the State, this rate request would have been hundreds of millions of dollars higher. That is an incontestable benefit to customers and it was the product of properly incented employees and a properly incented management team. Also, meeting earnings targets enables investors to have confidence in the Company, which helps to keep our cost of capital down. Finally, including financial goals in an at-risk compensation program ensures that employees are properly encouraged to attempt to achieve operational goals in a cost-effective manner. So, fundamentally, we believe that there is benefit for all parties – including, demonstrably, our customers -- when our financial targets are achieved. Nevertheless, as I demonstrate below, the majority of our variable compensation metrics relates to operational metrics that directly benefit our customers and the achievement of which produces tangible, positive effects on the service we offer.

Q. Has the Company taken any steps to modify its incentive compensation structure to better correlate variable compensation to operational performance?

A. Yes, we have. At the time of the last rate case, annual variable compensation for all employee levels was at least partially tied to financial metrics. In response to criticisms made in PSE&G's last base rate case regarding the structure of the variable compensation plan, we modified our annual variable compensation structure so that the majority of the targets relate to operational metrics. Those metrics are focused on Reliability (e.g., SAIDI and other metrics), Customer Satisfaction (JD Power scores and other metrics), and other operational metrics. The metrics have two components that are scored – Part A, which is to compare ourselves to peers, generally with a target of top quartile performance, and Part B, which measures whether we did better than last year, driven by our focus on Continuous

Improvement. As a result, our incentives are clearly aligned with our customers as the metrics are directly focused on providing strong service.

Q. Mr. Jennings, you stated that PSE&G's incentive compensation program employs metrics that directly benefit the Company's customers. Please explain your position.

A. The "scorecard" that the Company employs to determine incentive compensation contains metrics that directly benefit our customers. PSE&G keeps track of many operational and customer service metrics and approximately 15 of them are directly included in the variable compensation calculation. These include important operational and customer-facing metrics such as SAIDI, gas leaks per mile, damages per locate requests, JD Power Customer Satisfaction surveys of our electric and gas customers, and other measures.

Clearly, therefore, PSE&G's employees are provided incentive compensation if they achieve operational targets that benefit our customers. As a result, I believe that our incentive compensation program should be fully recoverable because it delivers clear and tangible benefits to our customers.

Q. Is the incentive compensation program an essential component of overall compensation?

A. Yes. Not only are these programs one of the most important tools our management team uses to attract and retain talent, align interests, incent performance, and ensure the delivery of high quality service to our customers, but they have actually delivered tangible benefits to customers, as I've described above. Our compensation philosophy is to target total compensation at the median of companies we compete with for talent. Without the incentive compensation program, which is a common component of compensation among our peers, we would need to increase our fixed base salary cost to attract and retain the caliber of talent we need to achieve our goals. Taking that approach would result in a similar overall level of compensation and a similar overall level of prudent labor expense, even if key metric(s) were not achieved in a given year; we feel that using incentive compensation is a preferable means to motivating employees to achieve targeted results.

Q. Are there negative consequences associated with the disallowance of some or all of the Company's incentive compensation costs?

A. Yes, very definitely there are. Obviously, to the extent a portion of these costs are disallowed, the Company would not be able to recover its cost of service. But there are also larger ramifications. PSE&G's overall compensation program, including incentive compensation, seeks to set salaries around the mean of companies with whom we compete for our talented workforce. To the extent these costs were not incurred, we would no longer be aligned with industry and regional compensation benchmarks and would therefore expect incremental turnover, inability to attract quality employees, and an ultimate deterioration over time in the service that we deliver. As a result, we believe that our incentive compensation is a prudent cost and are seeking recovery of the entirety of our $30 million of incentive compensation expense.

Q. Has the Board recently commented on its policy related to recovery of incentive compensation?

A: Yes. In the Suez Water Arlington Heights ("SWAH") rate case decided by the Board on November 13, 2017 (Docket No. 16060510), the Board adopted Staff's recommendation to evaluate the issue of the recovery of incentive compensation in a proceeding where the magnitude of the compensation is larger than that at issue in the SWAH case. In SWAH, the Administrative Law Judge ("ALJ") denied recovery of SWAH's requested incentive compensation costs due to the large increase the utility was seeking in that case (118 percent). The ALJ noted, however, that incentive compensation plans are "indeed a part of our economy," and that the economic conditions to which the Board has cited in the past when denying the recovery of certain incentive compensation costs have changed.

While the Board Staff recommended that the Board adopt the ALJ's recommendation to not permit recovery of SWAH's incentive compensation costs, Board Staff urged the Board to "re-examine the whole issue of incentive compensation when the order of magnitude is larger." (BPU October 20, 2017 Agenda Meeting, Transcript, page 25, lines 17-20). Board President Richard S. Mroz noted that the Board has neither "taken a position [nor] established a policy" on utilities' incentive compensation plans that are tied to the company's operational performance. (Transcript, page 25, line 24 to page 26, line 16). President Mroz agreed with Staff's recommendation that the Board evaluate the issues of incentive compensation recovery. (Transcript, page 26, line 23 to page 27, line 4). PSE&G respectfully recommends that the Board utilize this proceeding to articulate a current policy regarding incentive compensation that recognizes incentive compensation should be recoverable where it is an integral component of employee compensation; is consistent with industry standards; is reasonably necessary to retain skilled employees; and is beneficial to customers.

IX. APPLIANCE SERVICE BUSINESS ("ASB")

Q. Please describe how the Company's Appliance Service Business impacts this rate proceeding.

A. PSE&G has had a long history of providing appliance services. These services were originally gas related and were part of the gas utility. These services are offered to retail customers in the PSE&G service territory in accordance with tariffs filed with and approved by the BPU. These services include Appliance Repair Service, Maintenance Services, Replacement Parts Service Contracts, Water Heater Replacement Service, and Central Heater and Central Air Conditioning Replacement. The majority of this work is performed utilizing PSE&G's workforce with the exception of the water heating replacement work, which is performed by contractors retained by the Company.

The revenues and expenses associated with the appliance service business are included in the income statement for the utility, specifically in the gas business. As a result, the net above-the-line margin (revenue less expenses) from operating the appliance service business is credited to ratepayers in a base rate case proceeding. In this current base rate case proceeding, the Company forecasts net margins of $42.5 million from the appliance service business, $36 million of which will directly offset the Company's revenue requirement to the benefit of customers.

Q. How are the margins from the appliance service business to be allocated under the New Jersey Administrative Code?

A. The allocation of the margin above and below the line for the appliance service business is dictated by *N.J.A.C.* 14:4-3.6(r). This section of the BPU regulations require that for gas public utilities, the total margins shall be treated above-the-line for ratemaking purposes and credited to ratepayers. It also indicates that for electric public utilities and related competitive business segments of electric public utilities, 50 percent of the total margins shall be recorded in respective competitive service revenue accounts and treated above-the-line for ratemaking purposes.

Q. How does the Company propose to allocate margins for ASB services?

The Company proposes to allocate the margins for gas and electric services consistent with the above-referenced regulations. As stated above, when the Company first started the appliance service business, it only serviced gas appliances and revenues and costs were charged to the gas business. However, the Company has expanded its Board approved service offerings to also include electric appliances. In this filing, of the $42 million in margin revenue, $29 million relates to gas and is fully credited to the benefit of customers by reducing our revenue requirement, and $13 million relates to electric, half of which is credited to customers and half is below the line and retained by the Company pursuant to BPU regulations. The Company is proposing to appropriately allocate the margins from the appliance service business between electric and gas based on the appliances serviced.

Q. You previously discussed the benefits that customers obtain associated with the Company's ASB. Does the ASB also present challenges to the Company?

A. Yes, it does. While we have successfully grown our Appliance Service Business over the past several years, margins have plateaued as the Company has, to this point, been precluded by the BPU from providing new services or expanding our service territory. In the absence of these new offerings, PSE&G's customer base is generally fully penetrated and saturated with the currently permissible ASB offerings. As a result, there is little upside potential for this business and significant risk that PSE&G will lose money if the ASB program generates less than the margin flowed back to rate payers through this base rate case. We seek recognition of the value that PSE&G's ASB business creates for our customers as one of the many factors supporting an ROE at the higher end of the range, since PSE&G is the only utility in the State that still provides this value to customers. We also expect to be making a separate filing with the Board that will propose new ASB offerings in an effort to create upside potential for managing this business. PSE&G is proud of this business and the value that it generates for customers – both through this financial benefit and through the important services we provide. However, in the absence of such recognition, if there is more risk than reward potential associated with this business, we will be forced to consider restructuring or exiting this business.

X. <u>THE TEST YEAR</u>

Q. Mr. Jennings, please describe the test year that is being utilized in this proceeding.

A. The test year in this proceeding is the twelve-month period beginning July 1, 2017 and ending June 30, 2018. The filing consists of five months of actual data (actuals through November 30, 2017) and seven months of estimated data. Actual data is supported by the Company's accounting records while projected data is based upon the Company's financial and capital budget for the period ending June 30, 2018. The Company will update for actual information during the proceeding. We propose updating our filing with nine months of actual data and three months of forecast data ("9+3 filing") in May 2018, and with twelve months of actual data ("12+0 filing") as soon as practical thereafter. This proposed schedule will facilitate and is consistent with our anticipated rate effective date of October 1, 2018 by ensuring that the Board and the parties will be able to review twelve months of actual information sufficiently in advance of the proposed rate effective date.

XI. REVENUE REQUIREMENTS--ADJUSTMENTS TO BASE ELECTRIC AND GAS DISTRIBUTION RATES

Q. Mr. Jennings, please discuss the schedules that you are providing to support the revenue requirement.

A. The determination of revenue requirements is premised upon the July 2017 through June 2018 test year described above with appropriate *pro forma* adjustments. *Pro forma* adjustments to the test year have been proposed to reflect the expense level of certain items for the twelve months ending September 30, 2019 (the “rate year”). The costs to be covered include expenses of running the business (including O&M expenses and taxes) as well as return of and on the capital invested that is necessary to run the business (i.e., depreciation and amortizations, interest expense, and a fair return on equity invested). Plant additions that are expected to be in service within six months beyond the end of the test year (or through December 31, 2018) have been included in rate base. The rate base through December 31, 2018 includes the investment in Energy Strong and GSMP, including those investments that have been rolled into base rates before or during the test year. As will be described in more detail below, I am proposing a *pro forma* adjustment to operating income to account for rate adjustments associated with Energy Strong and GSMP that will occur during and after the test year to ensure that revenue is taken into account in setting PSE&G’s revenue requirement.

Set forth below is a description of the schedules identified in the introduction section of my testimony. The schedules reflect information for both electric distribution and gas distribution.

Determination of Revenue Requirements—Schedule SSJ-02

Q. Are you presenting a schedule that shows the revenue requirement in this case?

A. Yes. Schedule SSJ-02 shows the determination of the revenue requirement increase being requested in this proceeding. Based upon rate bases of $5.6 billion and $4.0 billion for electric distribution and gas distribution, respectively, pro-forma operating income of $334.7 million and $167.5 million for electric and gas, respectively, and a required rate of return of 7.40%, the increase in required revenue requested is $111.0 million for electric distribution and $186.7 million for gas distribution.

Utility Rate Base—Schedule SSJ-03

Q. Please describe the depiction of the Company's rate base.

A. Schedule SSJ-03 presents projected total electric and gas utility rate bases at June 30, 2018 and December 31, 2018. Electric rate base is expected to be $5.63 billion by June 30, 2018 and $5.60 billion as of December 31, 2018. Similarly, gas rate base is expected to be $3.95 billion by June 30, 2018 and $4.04 billion as of December 31, 2018. The rate bases consist primarily of the utility's investment in distribution plant, net of the accumulated provision for depreciation of utility plant plus distribution working capital, accumulated deferred income taxes, the consolidated tax adjustment and the exclusion of GSMP investment for the third rate adjustment filing as described below. Rate base represents the investment necessary to provide safe, adequate, proper and reliable service to our customers and is therefore a crucial factor in setting future distribution rates. The adjusted rate bases as of June 30, 2018 and December 31, 2018 also reflect the inclusion of Energy Strong and GSMP investment. The components of the Company's distribution rate bases are supported by Schedules SSJ-07 through SSJ-15 and will be addressed below.

Revenue Factor—Schedule SSJ-06

Q. Are you presenting a schedule that depicts the revenue factor for the electric and the gas operation?

A. Yes. The electric revenue factor utilized by the Company in this proceeding is 1.3911. The factor includes the 9% State of New Jersey Corporate Business Tax, the 21% Federal income tax, and the assessments for the Board of 0.2346% and the Division of Rate Counsel (Rate Counsel) of 0.0514%. The gas revenue factor is 1.4174. The higher factor for gas reflects the inclusion of a rate for uncollectibles of 1.86%. Electric uncollectibles are recovered through the Societal Benefits Charge (SBC) and are not in distribution base rates.

Utility Plant In Service—Schedule SSJ-07

Q. Please describe the schedule showing utility plant in service.

A. The electric utility and gas utility plant in service, as shown on Schedule SSJ-07, is estimated to be $9.3 billion and $7.9 billion respectively at June 30, 2018 and $9.5 billion and $8.2 billion respectively at December 31, 2018. From February 2010 through June 30, 2017, gross electric plant in service has increased by approximately $2.5 billion and gross gas plant increased by $2.3 billion. The growth in electric and gas plant investments is discussed in the testimony of Mr. Jorge Cardenas.

Plant-In-Service Additions from June 30, 2017 through December 31, 2018—Schedule SSJ-08

Q. Are you also presenting a schedule that shows additions to plant in service?

A. Yes. Schedule SSJ-08 provides the direct additions to plant in-service from the actual June 30, 2017 balance projected through December 31, 2018. Additions are expected to total approximately $1.0 billion for electric and $1.2 billion for gas. The additions are primarily distribution plant.

Accumulated Depreciation—Schedule SSJ-09

Q. Please describe the schedule that presents Accumulated Depreciation.

A. Electric and gas plant in service have estimated useful lives, which normally extend over many operating periods. The systematic recovery of these investments is accomplished by the recognition in rates of annual depreciation charges, with the accumulated depreciation used to reduce rate base utility plant investments. This has been, and continues to be, an acceptable way of developing rate base because the accumulated depreciation balance recognizes that these amounts have already been charged to our customers.

The accumulated depreciation balance reflects the recognition of annual depreciation charges projected through December 31, 2018 based upon the current BPU-approved electric and gas distribution depreciation rates. Please note that PSE&G is also presenting a study performed by Mr. John Spanos of Gannett Fleming that proposes changes to the existing depreciation rates. The Company has included the annualization of the depreciation expense, described in more detail in schedule SSJ-38, as a rate base deduction using a mid-year convention.

Customer Advances for Construction—Schedule SSJ-10

Q. Is distribution rate base reduced to reflect advances by customers for construction?

A. Yes, it is. Because the costs of construction related to advances made by the Company's electric and gas utility customers are capitalized and included in the distribution rate bases, it is appropriate to reduce distribution plant costs for these advances. As shown on Schedule SSJ-10, electric and gas distribution rate base has been reduced by $25.9 million and $19.7 million, respectively, based upon a 13-month average of the most current available actual advances—the period November 2016 through November 2017. This schedule will be updated for actual test year data as it becomes available.

Working Capital

Q. What is "Working Capital?"

A. Working Capital is the average amount of capital over and above investments in plant and other separately identified rate base items provided by investors of PSE&G to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The Company's proposed working capital allowance is $530.4 million for electric and $292.3 million for gas rate base. Each rate base working capital requirement consists of three components: cash (lead/lag), materials and supplies, and prepayments

Cash (Lead/Lag) Working Capital

Q. Are the amounts shown for Working Capital supported by any analyses?

A. Yes, they are. The cash (Lead/Lag) working capital allowances reflected on Schedule SSJ-03 of $424.1 million and $252.1 million that I have included in the electric and gas rate bases, respectively, are the result of detailed Lead-Lag studies supported by Mr. Harold Walker III, in separate testimony and supporting schedules.

Materials and Supplies—Schedule SSJ-11

Q. How are Materials and Supplies reflected in the filing?

A. I have included $105.2 million and $39.7 million of materials and supplies necessary for ongoing utility electric and gas operations, respectively, in rate base. This is a representative balance of general store items held in inventory for operating and maintenance and capital purposes. It is derived by taking a 13-month average of the most current available actual balances—the period November 2016 through November 2017. This schedule will be updated for actual test year data as it becomes available.

Prepayments—Schedule SSJ-12

Q. Does the Company's filing reflect an allowance for prepayments of costs?

A. Yes, it does. The Company is required to make advance payments for the BPU and Rate Counsel assessments, prior to their being charged to operating expenses. Such prepayments occur every year and therefore require a permanent, ongoing investment by the Company to fund them. Accordingly, I have included the average electric and gas utility prepayment requirements of $1.2 million and $0.4 million, respectively, in rate base. These levels are based upon a 13-month average as of November 2017 and will be updated as data becomes available.

Accumulated Deferred Taxes—Schedule SSJ-13

Q. What are "deferred taxes"?

A. Company witness Mr. Krueger discusses Accumulated Deferred Taxes in his pre-filed testimony. I have incorporated Mr. Krueger's Accumulated Deferred Tax Balance shown on Schedule RCK-4. The net accumulated deferred taxes amount to a $1.7 billion reduction to electric rate base and a $1.8 billion reduction to gas rate base. These amounts are based upon the plant in service balances reflected in the respective rate bases as of December 31, 2018. For more details please reference the testimony of Mr. Krueger.

Consolidated Tax Adjustment—Schedule SSJ-14

Q. Does the Company's filing recognize the Board's most recent policy concerning Consolidated Tax Adjustment ("CTA")?

A. Yes, it does. I believe that, as others representing PSE&G have testified in the past, the imposition of a CTA is a flawed and inappropriate regulatory adjustment. Nevertheless, Company witness Mr. Kruger has calculated a CTA and discusses the basis for that adjustment in his pre-filed testimony. I have incorporated Mr. Krueger's CTA adjustment as shown on Confidential Schedules RCK-6A and RCK-6B. As a result, this adjustment decreases electric distribution rate base by $1.3 million and increases gas distribution rate base by $0.6 million.

For details on the calculation of the Consolidated Tax Adjustment, please see the testimony of Mr. Krueger.

GSMP Roll-in #3 Rate Base Adjustment-Schedule SSJ-15

Q. Why is there a GSMP Roll-in #3 Adjustment?

A. As explained in more detail below in the description of Schedule SSJ-47 (the Energy Strong / GSMP Revenue Adjustment), the rate adjustment for the third GSMP rate adjustment (Roll-in #3) will result in new base rates after the conclusion of this proceeding. Because the Company will recover the GSMP investment for this roll-in in a GSMP rate adjustment proceeding in accordance with the GSMP Order, the GSMP investment for this roll-in period must be excluded from rate base.

Q. What is the adjustment?

A. The adjustment is simply to back out all investment, cost of removal expenditures, accumulated depreciation and accumulated deferred income taxes associated with the GSMP third rate adjustment filing, which is for investment placed in service from October 1, 2017 through September 30, 2018.

Q. What is the impact of this adjustment?

A. As a result of this adjustment, gas rate base has been reduced by $159.5 million as of December 31, 2018.

Electric and Gas Distribution Operating Income

Q. Please describe the schedules for Electric and Gas Operating Income.

A. Schedules SSJ-17 through SSJ-25 present a complete picture of PSE&G's electric and gas distribution operations. These schedules contain sales, distribution operating revenues, and number of billed customers by class of business for the electric and gas distribution businesses of the Company. Also included are O&M expenses by primary function, depreciation and amortization, taxes other than income taxes, and current and deferred income taxes. Schedule SSJ-16 presents the income statements for these business segments. This information has been provided for the twelve-months ending June 30, 2018 which is the test year based on five months actual and seven months estimated data.

Pro-forma Distribution Operating Income—Schedule SSJ-26

Q. Are you proposing to adjust Test Year Operating Income?

A. Yes. Schedule SSJ-26 is a summary of *pro forma* adjustments to the test year electric and gas utility operating income. These *pro formas* adjust test period operating income for known or measurable changes to expense and income levels so as to reflect the expected expense and income levels for the rate year, which is the first twelve months after new rates are set as a result of this proceeding. Adoption of these adjustments by the Board will provide the Company with a realistic opportunity to earn the reasonable return on its electric and gas investment when the rates are in effect.

The Company's revenue requirements determination includes 18 adjustments to its test period electric distribution operating income. The *pro forma* adjustments reduce the test period electric operating income by $53.6 million after-tax. On the gas distribution side there are 21 adjustments that reduce the test period operating income by $115.0 million. Each of the *pro forma* adjustments will be discussed in more detail below.

Adjustment No. 1: Wages—Schedule SSJ-27

Q. Please address your adjustments for Wages.

A. These adjustments to operating income of a reduction of $3.8 million and $4.8 million for electric and gas, respectively, represent the adjustment to the test year to reflect wage increases applicable to the rate year. These increases are to the labor costs applicable to Bargaining Unit employees and Management, Administrative, Secretarial and Technical ("MAST") employees. The increases are based on the employee levels during the test year.

Effective as of March or April 2016 (date differs depending upon the Union), the Company and its Unions reached agreement on six-year contracts that expire on April 30, 2021. These contracts contain agreed-upon annual wage increases of 3.00% each year. The wage increases are effective on May 1st for 2018 and September 1st for 2019. The estimated MAST employee increases for the twelve month period ended June 30, 2018 as well as the rate year ending September 2019 is 3.0%.

I urge the Board to continue its consistent practice of recognizing the importance of test year labor adjustments. The Company's employees are a critical element in meeting the service and reliability needs of our customers, and this adjustment to the test year ensures the Company's rates will reasonably reflect the cost of this workforce when rates are in effect.

Adjustment No. 2: Payroll Taxes—Schedule SSJ-28

Q. Explain the adjustment for Payroll Taxes.

A. The reductions to operating income of $0.257 million and $0.318 million for electric and gas, respectively, result from the increase to operating expense associated with payroll taxes consistent with the wage adjustments made above. This adjustment reflects increases in the Federal Insurance Contribution Act Tax ("FICA") for increases in taxable wages and taxable wage ceiling levels. Based on the Company's historic average, additional payroll taxes for the wage adjustment in Schedule SSJ-27 are calculated utilizing a composite 6.69% tax rate. This schedule will be updated for actual test year data as it becomes available.

Adjustment No. 3: Interest Synchronization (Tax Savings) Schedule—SSJ-29

Q. Please describe the Interest Synchronization Adjustment.

A. The Board, in the past, has adopted an adjustment to synchronize the Federal income tax savings associated with interest in the test year with the tax savings based on interest calculated using the weighted cost of debt in the capital structure utilized to support rate base.

As can be seen on Schedule SSJ-29, the interest-bearing components of our capitalization supporting rate base produce synchronized interest expenses of $3.6 million more than the interest expense in the test year for electric and $2.5 million more than interest expense in the test year for gas, resulting in tax savings of $1.0 million for electric and of $0.7 million for gas.

Adjustment No. 4: Pension and Fringe Benefits—Schedule SSJ-30

Q. Please describe the adjustment for Pension and Fringe Benefits

A. The adjustments to test year operating income for pension costs and fringe benefits amount to a decrease of $7.8 million for electric and $17.0 million for gas, reflecting the expected change in these costs over the test period amounts. The adjustment encompasses expenses associated with pensions, OPEB, medical, dental, thrift, long-term disability, insurance, and workers compensation for employees providing support services to PSE&G.

I have previously described the myriad steps that PSE&G has taken to reduce its pension costs. In this case the combination of all of those factors will drive our pension expense negative during the test year. As a result, we are proposing to set a floor for our pension expense at $0. This is lower than any of the other utilities in the State. It would be inappropriate to have a negative pension expense reduce our revenue requirements, as we cannot access the pension fund itself to make PSE&G whole for the lower revenue requirements.

While I have also previously described the numerous steps PSE&G has taken to reduce fringe benefit costs, these costs have continually increased, in particular medical costs. Other fringe benefit costs are escalated based primarily on estimates from independent actuaries.

It is widely recognized that the cost of benefits has not only risen, but is expected to continue to rise, at a pace that outstrips the general rate of inflation. It is important to adjust test year expenses for these items to properly reflect the level of expenses during the time when new rates are in effect.

I again urge the Board to continue to recognize that the Company's employees are critical to meeting the service and reliability needs of our customers. The ability to offer a package of wages and benefits will allow the Company to attract and retain the skilled employees that are needed. The revenue to cover those costs must be provided.

Adjustment No. 5: Electric / Gas Company Owned Life Insurance ("COLI") Interest Expense—Schedule SSJ-31

Q. Please describe the adjustment required to reflect Company Owned Life Insurance.

A. In an effort to reduce a portion of the expenses associated with certain employee benefit plans, PSE&G has invested in COLI policies. COLI is a corporate owned investment in cash value life insurance, which provides an income stream to the Company.

A portion of the Company's workforce is covered by policies with the Company as owner and beneficiary. The cash value of the insurance contracts earns a return, which the Company utilizes to offset benefit expenses. The Company, as owner, is permitted to borrow against the policy during its life without interfering with the policy's accumulation of earnings. The policy provides life insurance proceeds upon the death of the insured sufficient to settle any outstanding loans.

The earnings associated with the growth in the policy's cash surrender value have produced a net credit to benefits expense. For the test year, the credit to Administrative and General Expense combined with tax savings is $6.3 million for electric distribution and $1.8 million for gas distribution. Interest expense on funds borrowed from the policy is directly related to the $8.0 million in benefits attributable to the policy. My adjustment to the test year, which is in line with prior rate cases, is to include the gross interest cost of $3.3 million for electric and $1.1 million for gas, thereby reducing operating income to properly account for all aspects, both benefits and costs, of the COLI.

Adjustment No. 6: Weather Normalization—Schedule SSJ-32

Q. Is an adjustment necessary to reflect the results of weather normalization?

A. Yes. This pro-forma adjustment is required to adjust test year actual results to reflect normal weather based on weather patterns over a 20-year period as measured at Newark Liberty International Airport. Because actual weather patterns during the time the rates will be in effect are assumed to be normal, this adjustment to the test year is an appropriate rate setting procedure. The use of unadjusted weather-related actual sales levels would result in overstating or understating the revenue requirement compared to normal. The plan data included in our test year is based on a weather normalized sales forecast and requires no adjustment. However, as we move toward the conclusion of the case and provide updates for actual data, the Company will weather-normalize the additional months of actual data as required.

Schedule SSJ-32 shows the adjustments necessary to reflect normal weather for the period July through November 2017. This schedule shows a comparison of the distribution revenue for the first five months actual to that based upon normal weather. Distribution revenue represents the revenue from the sale of a kWh or therm less the variable revenue associated with the commodity, SUT, the Green Programs Recovery Charge ("GPRC"), the Solar Pilot Recovery Charge, and the Societal Benefits Charge ("SBC"). In order to adjust the actual results to a normal sales level, an increase to test period revenue of $5.0 million for electric, is required since the first five months of the test year, July to November 2017, were cooler than normal. This is the same weather impact included in the billing determinants data in the testimony of Mr. Swetz. No adjustment is reflected for gas due to the impact of the Weather Normalization Charge.

Adjustment No. 7: Gains/Losses on Sales of Property—Schedule SSJ-33

Q. Please describe the adjustment to reflect Gains/Losses on Sales of Property.

A. This adjustment allocates one-half of the gain on sales of property, net of associated income taxes, to customers based on a five-year average. The use of a five-year average provides a representative amount of gains for ratemaking purposes, avoiding the distortion that would occur if an abnormally high or low level of gains is recognized in the test period. The Company has included the five-year average for the years 2012 through 2016 as representative and appropriate for this proceeding. The Company will update this figure to calculate the five year average through 2017 once the data is available. The adjustment to operating income for the customers' share of the five-year average gain is an increase of $17,000 for electric and $35,000 for gas.

Adjustment No. 8: Real Estate Taxes—Schedule SSJ-34

Q. Are you presenting an adjustment for Real Estate Taxes?

A. Yes. This adjustment of $0.6 million for electric and $0.3 million for gas increases the test year operating expense to be representative of the level of property tax expense that is expected to be accrued in the twelve-month period following the date new base rates go into effect. The increase in property tax expense between the rate year and the test year is consistent with actual experience. Accordingly, electric and gas operating income is reduced by the aforementioned amounts.

Adjustment No. 9: Insurance—Schedule SSJ-35

Q. Please describe the adjustment necessary to reflect the Company's Insurance Expense.

A. There are items for which PSE&G carries outside insurance policies (i.e., Corporate Property, Excess Liability Insurance and Director's & Officers Insurance) for which it pays premiums of approximately $4.0 million for electric and $2.4 million for gas for the year. This adjustment before taxes of $70,000 for electric and $76,000 for gas increases the test year operating expense to $4.0 million and $2.5 million and is representative of the level of insurance expense that is expected to be accrued in the rate year. The increase in insurance expense between the rate year and the test year reflects input from our insurance carriers and actual experience.

Adjustment No. 10: ASB Margin—Schedule SSJ-36

Q. Please describe the ASB margin adjustments that are necessary to reflect the proposed treatment of PSE&G's appliance service business.

A. As described above, the Company is proposing to allocate its ASB margin by appliance type. As a result, $13 million will be allocated from the gas business to electric. Per the allocation, as required under *N.J.A.C.* 14:4-3.6(r), 50 percent of the electric margins will be treated above the line and returned to customers through this case. Therefore, this reduces gas margin in this case by approximately $13 million and increases electric margin by approximately $6.6 million. After adjusting for tax effect this results in an increase to operating income of $4.8 million for electric and a decrease of $9.5 million to operating income for gas.

Adjustment No. 11: TSG-NF Margin—Schedule SSJ-37

Q. Please describe the adjustment for the TSG-NF Margin.

A. A reduction to gas operating income in the amount of $185,000 is being made. This issue is discussed in the testimony of Mr. Swetz.

Adjustment No. 12: Depreciation Annualization and Proposed Rate Change — Schedule SSJ-38

Q. Are you proposing adjustments related to Depreciation Annualization and to reflect a proposed change in depreciation rates?

A. Yes. This adjustment is to allow for the recovery of the depreciation expense associated with the total investment in Plant in Service in rate base approved in this proceeding. As described above, we are requesting rate base as of December 31, 2018. Essentially, the depreciation expense in the test year represents the depreciation expense on the average plant in service in the test year. The actual depreciation expense as a result of this rate case proceeding will be a full year's depreciation expense on the approved plant in service as of December 31, 2018. To arrive at the appropriate depreciation expense for the approved plant in-service, the depreciation expense in the last month used to determine rate base for this proceeding (December 31, 2018) is annualized by multiplying the balance by twelve. The difference between the annualized depreciation expense and the Test Year depreciation expense produces the pre-tax adjustment. It should be noted that the proposed annualization of depreciation expense is also incorporated in Accumulated Depreciation (Schedule SSJ-09) as a rate base deduction using a mid-year convention. Therefore, this adjustment is simply to sync depreciation expense with the approved rate base balance. Accordingly, test year expense is increased $20.7 million for electric and $19.7 million for gas.

In addition, the Company has proposed new electric and gas distribution depreciation rates, including cost of removal, based on an Electric Depreciation Study and a Gas Depreciation Study, supported by the testimony of Mr. Spanos.

The proposed depreciation rates have also been annualized for estimated electric and gas plant balances for the month prior to the rate year. The difference between the annualized rate year expense based on the proposed rates versus the annualized expense based on current rates is an additional pre-tax adjustment, which increases depreciation expenses by $52.0 million for electric and $67.3 million for gas. As a result, the total annualization of depreciation expense at the proposed depreciation rates results in a reduction to operating income of $52.3 million for electric and $62.6 million for Gas.

Adjustment No. 13: Storm Cost Amortization - Schedule SSJ-39

Q. Please describe the adjustment to normalize Storm Costs.

A. In March 2013, the Board issued an Order (Docket No. AX13030196) establishing a generic proceeding to review the prudence of storm costs by New Jersey utilities in response to multiple Major Storm Events. In response to this Order, in June 2013, PSE&G filed a report detailing its unreimbursed incremental Major Storm Event Costs, requesting the Board review those costs for prudence and subsequent recovery. This adjustment is for the recovery of the incremental O&M associated with major storm events already approved as prudent as well as any deferred incremental O&M costs associated with major storm events that occurred after the Order establishing the prudence of the earlier storms. On September 30, 2014 the Board approved incremental O&M associated with major storms through 2012 of $220.2 million as reasonable and prudent and eligible for rate recovery in a future base rate proceeding. In addition, the Company has incurred $20.7 million of post 2012 incremental storm costs, for a total of $240.9 million. As discussed earlier and in Mr. Krueger's testimony, we propose to offset these costs with certain deferred taxes. Had we not offset these costs with deferred taxes, we would have proposed an increase to our revenue requirements to reflect a three year amortization of $77.8 million for electric and $2.5 million for gas representing deferred storm costs from 2010 through June 2017 inclusive of carrying charges at the WACC for the average unamortized balance. However, since these costs are proposed to be offset with certain deferred taxes, the operating income reduction from the storm cost amortization as shown in Schedule SSJ-39 is not reflected in the *pro forma* adjusted operating income used to set the revenue deficiency in this proceeding.

Adjustment No. 14: Post Rate Case Storm Normalization - Schedule SSJ-40

Q. Is an adjustment required for post rate case Storm Normalization?

A. Yes. This adjustment is for incremental O&M storm costs incurred during the test year. To normalize out the impact of any major storms in the test year, the Company is requesting to remove the incremental expense from the test year. As the Company's forecast assumes normal weather and no major events occurred in July through November 2017, there is currently no adjustment forecasted at this time.

Adjustment No. 15: Recovery of Deferred Excess Cost of Removal Refund– Gas- Schedule SSJ-41

Q. Please describe the adjustment required to recover the Deferred Excess Cost of Removal Refund.

A. The BPU decision in the Company's 2006 gas base rate case, Docket No. GR05100845, adopted a Stipulation of Settlement in which the parties agreed that PSE&G should credit customers for $66.0 million of the Company's reserve covering the costs of removing assets from service that had yet to be used by the Company for their intended purpose. The Stipulation called for the $66.0 million to be returned over sixty months ending November 8, 2011 at an annual rate of $13.2 million.

Subsequently, in the Company's 2009 base rate proceeding in Docket No. GR09050422 dated July 9, 2010, the Company agreed not to change its rates for the expiring amortization without BPU approval and on September 8, 2011, PSE&G requested the authorization to establish a regulatory asset to defer the monthly excess refund. The Board approved the deferral request in Docket No. GF11090539, dated January 23, 2013, and stated the Company may seek recovery in its next base rate case. By the requested rate effectiveness date, the asset will have grown to a $91 million balance.

Consistent with that methodology for establishing the COR recoverable through rates, an adjustment is made to operating income for gas distribution to reflect a decrease in Operating Income of $14.8 million inclusive of carrying charges at the WACC for the average unamortized balance, based on a five (5) year amortization of the excess deferral for the years 2013 through the start of the rate year. This adjustment only applies to the gas distribution business.

Adjustment No. 16: Excess Cost of Removal Test Year Adjustment– Gas- Schedule SSJ-42

Q. Is an adjustment required to remove the excess cost of removal?

A. Yes. In addition to the recovery of the deferred excess cost of removal refund, the test year income statement must be adjusted to remove the $13.2 million excess cost of removal amortization that is still embedded in the test year income statement. This adjustment is not for recovery of the deferral, but to set the appropriate rates for the rate year as a result of this proceeding. As a result of removing the excess cost of removal refund from the income statement through this adjustment, gas only Operating Income decreases by $9.5 million.

Adjustment No. 17: Other Regulatory Assets- Schedule SSJ-43

Q. Please describe the adjustment of Other Regulatory Assets.

A. This adjustment is to recover other regulatory assets deferred for recovery in this base rate case proceeding. The Company is proposing to offset these amounts with the SHARE ADIT as we propose with storm cost recovery. Had we not proposed this approach, we would seek recovery of these regulatory assets over a three (3) year period. The Regulatory Assets currently included are the Long Term Capacity Agreement Pilot Program, the Contact Voltage program, the Newark Breaker Station abandonment costs, and the Cape May Street site. These amortizations represent a decrease to operating income.

The Long Term Capacity Agreement Pilot Program ("LCAPP") was a pilot program to promote the construction of qualified electric generation facilities in the State of New Jersey. Pursuant to *N.J.S.A.* 48:3-98.3b, the LCAPP Law allowed the electric distribution utilities to recover the costs of retaining an LCAPP Agent, legal costs, capacity studies costs and membership fees. PSE&G incurred a total of $562,000 in LCAPP costs.

The Contact Voltage Program was enacted by the BPU in Docket No. EO10100760 and permitted the electric distribution utilities in New Jersey to recover costs associated with testing BPU approved areas of the respective utilities' service territory for contact voltage dangers. The utilities tested for normally non-energized services and ground that became energized due to faulty wiring. The two year pilot reporting initiative encompassed two phases during the 2012-2013 period and reports were provided to the BPU and Rate Counsel. PSE&G spent $46,000 on Contact Voltage testing.

The Newark Breaker Station abandonment costs relate to flood mitigation measures at the Newark Airport Breaker Station. The Board authorized this project as part of the Energy Strong Program. The Port Authority of New York and New Jersey, which owns the Airport, had originally indicated it would pay facility charges to maintain the Newark Airport Breaker Station. However, in January 2016, the Port Authority advised that it was no longer interested in maintaining the facility based upon the Port Authority's updated assessment of its needs. The Port Authority has further advised that it was requiring PSE&G to remove the facilities at the Newark Airport Breaker Station and restore the site (consistent with the PSE&G leases for Port Authority property on which the facilities are located). As a result, PSE&G has abandoned its flood mitigation work at the Newark Airport Breaker Station. The Company spent $669,000 for the flood mitigation measures that were abandoned on the Newark Airport Breaker Station.

"Cape May Street" is a property that encompasses approximately eight acres along Cape May Street in Harrison, Hudson County, New Jersey. As described in detail in our May 4, 2017 filing requesting deferral authority, PSE&G is required to remediate the property as the current owner. The Company currently estimates the cost at $10.4 million. Since our initial filing, the Company has responded to all discovery received to date. The matter is still pending. Site remediation has commenced and is expected to be complete by January 2018 with ongoing ground water monitoring once remediation is complete.

The amortization of these Regulatory Assets would have resulted in an adjustment to electric and gas test year operating income to reflect a decrease in the amount of $512,000 and $2.3 million for electric and gas operating income, respectively. However, since these costs are proposed to be offset with certain deferred taxes, the operating income reduction from the other regulatory asset amortization as shown in Schedule SSJ-43 is not reflected in the *pro forma* adjusted operating income used to set the revenue deficiency in this proceeding.

Adjustment No. 18: Rate Case Expenses – Schedule SSJ-44

Q. How does the Company propose to treat rate case expense?

A. This adjustment seeks recovery of all prudently incurred rate case expenses. As the Company was required to submit this rate case as a result of the Energy Strong Board Order, it is appropriate for the Board to allow for recovery of the expenses required to complete the filing. The Company is seeking to remove all rate case expenses incurred during the test year and recover those expenses as a regulatory asset over a three year period. The adjustment represents an increase in operating income of $38,000 for electric and $60,000 for gas.

Adjustment No. 19: Credit Card Fees – Schedule SSJ-45

Q. Is the Company proposing an adjustment to reflect a requested change to the treatment of credit card fees?

A. Yes, as demographics change and the percentage of customers using the digital platforms for paying their bills increases, the need to eliminate the charge for credit and debit cards becomes more important. Other companies in the utility industry have recognized the need to address this issue and changed the policy to no longer charge customers credit card fees. According to an industry survey of 137 utility companies, 28% offer some form of no-fee credit card payments.

Since 2010, the percent of payments received via check has dropped from over 52% to 32% and continues to decline each year. Currently, while other payment transaction fees are considered normal business expenses and allowed recovery, the credit card and debit card processing fee is not allowed to be recovered through rates and is charged as a pass through fee to customers at the time of payment. This is the number one reason for dissatisfaction as reported by customers when asked about the billing and payments process for PSE&G.

Customers expect seamless electronic payment options. PSE&G provides the ability to pay via its website, mobile web and as well as via text. The Company has expanded customers' ability to communicate and transact business through digital channels and the Board has recognized and encouraged this additional digital access. For payments, these channels lend themselves to payments via credit and debit cards.

Q. Is it equitable to treat credit card payments in a different manner than other forms of payment?

A. No, I do not believe that it is. Within the existing bill and payment options available to customers, there is already a disparity in the unit cost of those transactions, yet credit card fees are the only transaction costs singled out for non-recovery. In-person payments at Customer Service Centers are much more expensive than a mailed in check, and sending a paper bill via mail is more expensive than receiving an email, yet we do not charge individually for these options. The different options are available to all customers who then choose the method that best works for them. The Company proposes treating credit card processing fees as we do the other payment and delivery fees within the billing process.

Therefore, the Company is proposing to assume the cost for credit card transactions rather than requiring the payment from individuals using a credit card. By assuming the credit card payment, the Company anticipates the cost per transaction will be reduced from the current rate of $3.95 per payment to $2.00. However, by incurring the cost of credit card fees, the Company's expenses will be increased compared to the test year, where all credit card fees are paid by individual customers. As a result of this adjustment, a reduction to operating income in the amount of $3.0 million for electric and $1.7 million for gas, is being made.

Adjustment No. 20: Vacation Accrual Reversal – Schedule SSJ-46

Q. Please discuss the adjustment that is necessary to reflect the change to PSEG Corporate Vacation Policy.

A. An adjustment is necessary to remove the impact of an accounting adjustment related to accrued vacation which credits expense for a portion of the test year and then is eliminated entirely on a go forward basis. Under Generally Accepted Accounting Principles ("GAAP"), companies are required to accrue an expense for future compensated absences (i.e., carryover vacation) if those rights to the vacation are vested to the employee. Thus, companies must accrue for vacation earned by an employee during the period earned rather than when it is actually taken in the future. As a result of a change in PSEG Corporate policy regarding vacation earned by salaried ("MAST") employees, the right to carryover vacation to future periods is being eliminated. This creates a one time "credit" to expense which should be removed from revenue requirement as it will be zero commencing April 2018 and for all future periods.

Under the new corporate policy, PSE&G's MAST employees must use their earned vacation during the year and may no longer carry it over for use in the following year effective July 1, 2017. As a result of this policy change, the accrued liability for vacation as of July 1, 2017 reverses from July 2017 through March 2018 creating an expense credit (or income) as the MAST employees actually use their remaining accrued vacation but with no additional expense/liability for future vacation rights. It should be noted that there was no change to the vacation allotted to employees, this is solely a change of when vacation has to be used by which caused an accounting change during the test year that we are normalizing. This adjustment results in a reduction to operating income of $2.2 million for electric and $1.5 million for gas in the test year, which will be zero for all years in the future.

Adjustment No. 21: Energy Strong / GSMP Revenue Adjustment – Schedule SSJ-47

Q. Please discuss the adjustment you are proposing for Energy Strong and GSMP rate adjustments during and after the test year.

A. I am proposing an adjustment to increase test year Operating Income so that it reflects the full annual impact of the Energy Strong and GSMP rate adjustments rolled into rates during or after the test year.

Q. Why is this adjustment necessary?

A. When the Energy Strong and GSMP rate adjustments occur, base rates will be increased to collect the annual revenue requirement as a result of the rate adjustment. At the conclusion of the rate case, the revenue increase will be added to current rates at the time this proceeding is concluded, which will include all ESAM and ARM adjustments by that point.

The revenue increase from the rate case will be based on the operating income during the test year. For the Energy Strong and GSMP rate adjustments that occur during the test year, base rates will be increased for the annual revenue requirement, but only a portion of the revenues from that rate increase will be captured in the test year operating revenue. This adjustment is necessary in order to adjust test year operating revenue to coincide with base rates at the conclusion of the rate case.

Q. When are the remaining Energy Strong and GSMP roll-ins going to occur?

A. For Energy Strong, in accordance with the Energy Strong Order, rates changed September 1, 2017 as a result of the sixth rate adjustment filing (Roll-in # 6). In addition, we have a pending rate adjustment filing (Roll-in #7) for rates effective March 1, 2018 based on plant in-service through November 30, 2017. If necessary, an eighth adjustment filing (Roll-in #8) will be submitted in March 2018 for rates effective September 1, 2018 based on plant in-service through May 31, 2018.

For GSMP, in accordance with the GSMP Order, rates changed January 1, 2018 as a result of the second rate adjustment filing (Roll-in #2) based on plant in-service as of September 30, 2017. The third rate adjustment filing (Roll-in #3) will be submitted in July 2018 based on investment through September 30, 2018 for rates effective January 1, 2019.

Q. How was the adjustment calculated?

A. The goal of the adjustment is to ensure that test year Operating Income reflects the current rates in effect before the proposed rates from this proceeding are implemented. For the base rate changes implemented during the test year, this adjustment multiplies the rates for the adjustment by the billing determinants for the test year prior to the implementation date. Using GSMP as an example, the adjustment would apply the increase in base rates from the GSMP change effective January 1, 2018 to the actual weather normalized billing determinants from July 1, 2017 through December 31, 2017. An adjustment is not needed from January 1, 2018 forward as the revenue will already be included in the test year operating revenue as a result of the GSMP rate adjustment.

Q. How will you adjust for the Energy Strong rate adjustment after the test year?

A. If necessary, the eighth energy strong roll-in will be for rates effective September 1, 2018, which is after the end of the test year. Since the eighth roll-in is based on investment through May 2018 and thus is all included in rate base for the rate case and none of the revenues associated with the rate adjustment will be reflected in test year operating income, the entire rate adjustment revenue requirement can be deducted from the revenue increase in this rate case proceeding.

Q. Do you need to make any adjustments for the third GSMP rate adjustment that will occur after the end of the test year?

A. Yes. As described in Schedule SSJ-15 above, the rate base associated with the third GSMP rate adjustment must be excluded from rate base.

Q. Is an adjustment required for the rate adjustments prior to the start of the test year?

A. No. For all adjustments prior to the start of the test year, the full annual revenue associated with the adjustments will be reflected in the operating income in the test year.

Q. What is the impact of this adjustment?

A. As a result of the proposed adjustment, operating income will increase by $9.1 million for electric and $7.6 million for Gas.

Q. Does this conclude your direct testimony?

A. Yes, it does.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
PROFESSIONAL QUALIFICATIONS
OF
SCOTT JENNINGS
VICE PRESIDENT-UTILITY FINANCE

I have been employed at PSEG for 19 years, serving in a number of financial positions in the company and, since October 2015 have been Vice President – Finance, PSE&G. In this capacity, I am responsible for PSE&G's business planning process, financial reporting and forecasting, and rates teams.

After five years as an auditor in Deloitte's financial services and public utilities practice, I joined PSEG's corporate accounting group in 1998, serving in a variety of roles culminating as the Assistant Controller.

In 2003 I became Controller for PSEG Energy Holdings, which held a portfolio of electric generation and distribution companies in Latin America, Europe, the Middle-East and domestically as well as investments in leveraged leases. I later became Vice President of Finance and President of Energy Holdings' subsidiaries. In these capacities, I was responsible for the sale of over 15 investments with proceeds exceeding $3 billion, restructured several leveraged lease transactions, served on the creditors' committees during lessee bankruptcies, and served on the Boards of Directors of several project companies.

In 2011, I was appointed Vice President – Mergers & Acquisitions and Business Development for PSEG, responsible for exploring strategic growth opportunities, evaluating renewable energy investments and leading various business development activities. In 2013, I was appointed Vice President, Corporate Strategy, responsible for developing the company's growth strategy.

I have a Bachelor of Business Administration degree and a Master of Business Administration degree in accounting from Pace University, New York. I am a certified public accountant and have participated in various leadership courses, including the High Potential Leadership Program at Harvard University. I served on accounting, financial and strategic committees of the Edison Electric Institute, American Gas Association and Electric Power Research Institute and represented PSEG in its collaboration with Princeton's Andlinger Center for Energy and the Environment.

EXHIBIT P-2
SCHEDULE SSJ-02

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DETERMINATION OF REVENUE REQUIREMENTS
($000)

	ELECTRIC	GAS	TOTAL
Rate Base	$ 5,601,592	$ 4,044,023	$ 9,645,615
Rate of Return	7.40%	7.40%	7.40%
Operating Income Requirement	$ 414,518	$ 299,258	$ 713,776
Pro-Forma Operating Income	$ 334,727	$ 167,541	$ 502,268
Operating Income Deficiency	$ 79,791	$ 131,717	$ 211,508
Revenue Factor	1.3911	1.4174	
Revenue Requirements	**$ 110,997**	**$ 186,695**	**$ 297,692**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ELECTRIC RATE BASE
($000)

	Balance at June 30, 2018	Balance at December 31, 2018
Plant In Service	9,285,676	9,450,580
Plant Held for Future Use	1,731	1,731
Accumulated Depreciation Reserve	(2,574,629)	(2,698,549)
Customer Advances	(25,912)	(25,912)
Net Plant	6,686,865	6,727,849
Working Capital:		
Cash (Lead/Lag)	424,075	424,075
Materials and Supplies	105,168	105,168
Prepayments	1,184	1,184
Net Working Capital	530,427	530,427
Deferred Taxes	(1,584,092)	(1,655,398)
Consolidated Tax Adjustment	(1,286)	(1,286)
Total Electric Rate Base	**5,631,913**	**5,601,592**

GAS RATE BASE
($000)

	Balance at June 30, 2018	Balance at December 31, 2018
Plant In Service	7,862,825	8,180,708
Plant Held for Future Use	96	96
Accumulated Depreciation Reserve	(2,383,226)	(2,480,779)
Customer Advances	(19,722)	(19,722)
Net Plant	5,459,973	5,680,303
Working Capital:		
Cash (Lead/Lag)	252,144	252,144
Materials and Supplies	39,734	39,734
Prepayments	433	433
Net Working Capital	292,311	292,311
Deferred Taxes	(1,685,719)	(1,769,690)
Consolidated Tax Adjustment	584	584
GSMP Roll-in #3	(113,686)	(159,485)
Total Gas Rate Base	**3,953,462**	**4,044,023**

* 5 Months Actual - 7 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WEIGHTED AVERAGE COST OF CAPITAL
($000)

	Amount	Percent	Embedded Cost	Weighted Cost
Long-Term Debt	$ 8,308	45.49%	4.05%	1.84%
Customer Deposits	93	0.51%	0.87%	0.00%
Common Equity	9,864	54.00%	10.30%	5.56%
Total	$ 18,265	100.00%		7.40%

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

EMBEDDED COST OF LONG TERM DEBT
AS OF NOVEMBER 30, 2017
INCLUDING NET UNAMORTIZED PREMIUM - INCLUDING AMOUNT DUE WITHIN ONE YEAR

PSE&G LONG TERM DEBT	COST OF BOND YIELD BASIS	PRINCIPAL AMOUNT OUTSTANDING	PLUS NET UNAMORTIZED PREMIUM/ (DISCOUNT)	PLUS NET UNAMORTIZED SELLING EXPENSE	PLUS NET UNAMORTIZED PREMIUM/ (DISCOUNT) & SELLING EXPENSE	PRINCIPAL AMOUNT AND UNAMORTIZED PREMIUM/ (DISCOUNT) & SELLING EXPENSE- NET	WEIGHT IN % OF PRINCIPAL AMOUNT AND UNAMORTIZED PREMIUM/ (DISCOUNT) & SELLING EXPENSE- NET	COST IN PERCENT
SERIES CC DUE 6/1/21	9.462%	$134,380,000.00	($45,107.11)	($2,016.00)	($47,123.11)	$134,332,876.89	1.6294%	0.1542%
SERIES DUE 6/1/37	8.147%	$7,462,900.00	$0.00	$0.00	$0.00	$7,462,900.00	0.0905%	0.0074%
SERIES DUE 7/1/37	5.092%	$7,537,800.00	$0.00	$0.00	$0.00	$7,537,800.00	0.0914%	0.0047%
SERIES A DUE 11/06/20	7.346%	$9,000,000.00	($8,559.48)	($9,870.00)	($18,429.48)	$8,981,570.52	0.1089%	0.0080%
SERIES D DUE 7/1/35	5.452%	$250,000,000.00	($461,562.50)	($1,257,647.42)	($1,719,209.92)	$248,280,790.08	3.0116%	0.1642%
SERIES D DUE 12/1/36	5.921%	$250,000,000.00	($672,391.27)	($1,379,671.93)	($2,052,063.20)	$247,947,936.80	3.0075%	0.1781%
SERIES E DUE 5/1/37	6.005%	$350,000,000.00	($442,261.28)	($1,927,806.39)	($2,370,067.67)	$347,629,932.33	4.2166%	0.2532%
SERIES E DUE 5/1/18	5.638%	$400,000,000.00	($13,281.28)	($114,139.63)	($127,420.91)	$399,872,579.09	4.8503%	0.2735%
SERIES G DUE 11/1/2039	5.581%	$250,000,000.00	($587,522.43)	($1,592,349.51)	($2,179,871.94)	$247,820,128.06	3.0060%	0.1678%
SERIES G DUE 3/1/2040	5.720%	$300,000,000.00	($1,066,465.82)	($1,914,741.47)	($2,981,207.29)	$297,018,792.71	3.6027%	0.2061%
SERIES G DUE 8/15/2020	3.839%	$250,000,000.00	($170,024.74)	($506,700.98)	($676,725.72)	$249,323,274.28	3.0242%	0.1161%
SERIES H DUE 5/1/2042	4.144%	$450,000,000.00	($2,356,296.41)	($3,182,060.30)	($5,538,356.71)	$444,461,643.29	5.3912%	0.2234%
SERIES H DUE 9/1/2042	3.830%	$350,000,000.00	($1,407,385.39)	($2,628,462.49)	($4,035,847.88)	$345,964,152.12	4.1964%	0.1607%
SERIES H DUE 1/1/2043	3.991%	$400,000,000.00	($2,132,385.39)	($2,943,796.90)	($5,076,182.29)	$394,923,817.71	4.7903%	0.1912%
SERIES I DUE 5/15/2023	2.704%	$500,000,000.00	($868,954.32)	($2,052,366.49)	($2,921,320.81)	$497,078,679.19	6.0294%	0.1630%
SERIES I DUE 9/15/2018	2.833%	$350,000,000.00	($15,436.28)	($357,505.88)	($372,942.16)	$349,627,057.84	4.2408%	0.1202%
SERIES I DUE 3/15/2024	4.051%	$250,000,000.00	($13,465.49)	($1,119,841.04)	($1,133,306.53)	$248,866,693.47	3.0187%	0.1223%
SERIES I DUE 6/1/2019	2.364%	$250,000,000.00	($136,076.99)	($498,357.61)	($634,434.60)	$249,365,565.40	3.0247%	0.0715%
SERIES I DUE 6/1/2044	4.216%	$250,000,000.00	($2,096,122.09)	($2,016,341.39)	($4,112,463.48)	$245,887,536.52	2.9825%	0.1257%
SERIES J DUE 8/15/2019	2.570%	$250,000,000.00	($173,959.95)	($565,268.01)	($739,227.96)	$249,260,772.04	3.0234%	0.0777%
SERIES J DUE 8/15/2024	3.476%	$250,000,000.00	($299,948.02)	($1,278,348.04)	($1,578,296.06)	$248,421,703.94	3.0133%	0.1048%
SERIES J DUE 11/15/2024	3.412%	$250,000,000.00	($833,148.82)	($1,341,056.82)	($2,174,205.64)	$247,825,794.36	3.0060%	0.1026%
SERIES K DUE 5/15/2025	3.316%	$350,000,000.00	($268,648.90)	($1,667,882.80)	($1,936,531.70)	$348,063,468.30	4.2219%	0.1400%
SERIES K DUE 5/1/2045	4.240%	$250,000,000.00	($1,138,951.69)	($1,855,270.57)	($2,994,222.26)	$247,005,777.74	2.9961%	0.1270%
SERIES K DUE 11/1/2045	4.318%	$250,000,000.00	($237,423.50)	($1,886,420.34)	($2,123,843.84)	$247,876,156.16	3.0066%	0.1298%
SERIES K 1.90% DUE 2021	2.449%	$300,000,000.00	($309,983.49)	($1,238,678.62)	($1,548,662.11)	$298,451,337.89	3.6201%	0.0887%
SERIES K 3.80% DUE 2046	3.979%	$550,000,000.00	($2,300,188.90)	($4,565,980.15)	($6,866,169.05)	$543,133,830.95	6.5880%	0.2622%
SERIES L 2.25% DUE 2026	2.575%	$425,000,000.00	($1,228,612.28)	($2,707,921.33)	($3,936,533.61)	$421,063,466.39	5.1073%	0.1315%
SERIES L 3.00% DUE 2027	3.336%	$425,000,000.00	($1,174,536.34)	($3,034,795.85)	($4,209,332.19)	$420,790,667.81	5.1040%	0.1703%
TOTAL PSE&G LONG TERM DEBT		**$8,308,380,700.00**	**($20,458,700.16)**	**($43,645,297.96)**	**($64,103,998.11)**	**$8,244,276,701.89**	**100.0000%**	**4.0456%**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

REVENUE FACTOR

	ELECTRIC	GAS
Revenue Increase	100.0000	100.0000
Uncollectible Rate		1.8600
BPU Assessment Rate	0.002346	0.0023
Rate Counsel Assessment Rate	0.000514	0.0005
Income before State of NJ Bus. Tax	99.9971	98.1371
State of NJ Bus. Income Tax	8.9997	8.8323
Income Before Federal Income Taxes	90.9974	89.3048
Federal Income Taxes	19.1095	18.7540
Return	71.8879	70.5508
Revenue Factor	**1.3911**	**1.4174**

EXHIBIT P-2
SCHEDULE SSJ-07

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ELECTRIC UTILITY PLANT IN-SERVICE
($000)

	Test Year June 30, 2018	Six-Months Ending December 31, 2018
Beginning Balance	$ 8,504,329	$ 9,285,676
Total Direct Additions	775,441	186,004
Total Transfers to Plant In-Service	83,335	0
Retirements:		
Distribution	(56,241)	(12,500)
General	(19,148)	(3,924)
Intangible	0	0
Common Plant	(2,040)	(4,675)
Total Retirements	(77,430)	(21,100)
Total Electric Utility Plant In-Service	**$ 9,285,676**	**$ 9,450,580**

GAS UTILITY PLANT IN-SERVICE
($000)

	Test Year June 30, 2018	Six-Months Ending December 31, 2018
Beginning Balance	$ 7,042,792	$ 7,862,825
Total Direct Additions	842,401	332,037
Total Transfers to Plant In-Service	21,566	0
Retirements:		
Production - Gas	0	0
Storage	0	0
Transmission	0	0
Distribution	(34,220)	(6,595)
General	(8,131)	(3,828)
Intangible	0	0
Common Plant	(1,582)	(3,731)
Total Retirements	(43,934)	(14,154)
Total Gas Utility Plant In-Service	**$ 7,862,825**	**$ 8,180,708**

* 5 Months Actual - 7 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ADDITIONS TO ELECTRIC PLANT IN-SERVICE
($000)

	Test Year June 30, 2018	Six-Months Ending December 31, 2018
Distribution	$ 623,888	$ 156,982
General	98,293	12,272
Intangible	6,620	60
Customer Operations	46,180	16,690
Land & Land Rights	460	-
Total Direct Additions	**$ 775,441**	**$ 186,004**

ADDITIONS TO GAS PLANT IN-SERVICE
($000)

	Test Year June 30, 2018	Six-Months Ending December 31, 2018
Production - Gas	$ 524	$ -
Storage	698	-
Transmission	5,720	14,300
Distribution	713,416	295,399
General	84,437	8,682
Intangibles	-	-
Customer Operations	37,606	13,656
Land & Land Rights	12	0
Total Direct Additions	**$ 842,401**	**$ 332,037**

* 5 Months Actual - 7 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ACCUMULATED DEPRECIATION OF ELECTRIC UTILITY PLANT
($000)

	Test Year June 30, 2018	Six-Months Ending December 31, 2018
Beginning Balance	$ 2,467,486	$ 2,574,629
Distribution	210,082	111,144
General	14,650	8,555
Customer Operations	16,217	8,776
Total Charge to Depreciation Expense	240,949	128,475
Amortization of Intangibles	2,156	1,777
Total Depreciation Expense	243,105	130,252
Retirements	(77,409)	(21,100)
Cost of Removal (Net)	(60,937)	(22,611)
Other	2,384	1,021
Net Increase	107,143	87,562
Annualization of Depreciation		36,358
Balance - Accumulated Depreciation	**$ 2,574,629**	**$ 2,698,549**

ACCUMULATED DEPRECIATION OF GAS UTILITY PLANT
($000)

	Test Year June 30, 2018	Six-Months Ending December 31, 2018
Beginning Balance	$ 2,303,502	$ 2,383,226
Production - Gas	-	-
Storage	228	157
Transmission	2,660	1,850
Distribution	127,581	70,116
General	12,654	7,318
Customer Operations	14,179	7,173
Total Charge to Depreciation Expense	157,302	86,614
Amortization of Intangibles	1,289	627
Total Depreciation Expense	158,591	87,241
Retirements	(43,751)	(14,154)
Cost of Removal (Net)	(35,410)	(19,225)
Other	294	155
Net Increase	79,724	54,017
Annualization of Depreciation		43,536
Balance - Accumulated Depreciation	$ 2,383,226	$ 2,480,779

* 5 Months Actual - 7 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CUSTOMER ADVANCES FOR CONSTRUCTION - ELECTRIC DISTRIBUTION *
($000)

Extension of Electric Lines	$	(25,912)
Total Electric Customer Advances for Construction	**$**	**(25,912)**

CUSTOMER ADVANCES FOR CONSTRUCTION - GAS DISTRIBUTION *
($000)

Extensions/Deposits	$	(19,722)
Total Gas Customer Advances for Construction	**$**	**(19,722)**

* 13-month Actual Average Balance (November 2016 - November 2017)

EXHIBIT P-2
SCHEDULE SSJ-11

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WORKING CAPITAL - MATERIALS AND SUPPLIES
($000)

	Electric	Gas
Materials and Supplies *	$ 105,168	$ 39,734
Total Materials and Supplies	**$ 105,168**	**$ 39,734**

* 13-month Actual Average Balance (November 2016 - November 2017)

EXHIBIT P-2
SCHEDULE SSJ-12

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WORKING CAPITAL - PREPAYMENTS
($000)

	Electric	Gas
BPU & Rate Counsel Assessment	1,184	433
Total Prepayments	**$ 1,184**	**$ 433**

* 13-month Actual Average Balance (November 2016 - November 2017)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ACCUMULATED DEFERRED TAXES
($000)

	Test Year June 30, 2018		Balance Ending December 31, 2018	
Electric	$	(1,584,092)	$	(1,655,398)
Gas	$	(1,685,719)	$	(1,769,690)

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-14

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CONSOLIDATED TAX ADJUSTMENT

	Electric	Gas	Total
CTA Adjustment	(1,286)	584	$ (702)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

GSMP ROLL-IN #3 RATE BASE ADJUSTMENT (GAS ONLY)
$000

	Test Year June 30, 2018	Six-Months Ending December 31, 2018
GSMP Roll-in #3		
Plant In-Service as of:	6/30/2018	9/30/2018
Rate Base as of:	6/30/2018	12/31/2018
Gross Plant	122,276	183,581
Cost of Removal Expenditures	7,539	12,154
Accumulated Depreciation	(726)	(2,080)
Accumulated Deferred Taxes	(15,403)	(34,169)
Total	113,686	159,485
Rate Base Reduction	**(113,686)**	**(159,485)**

EXHIBIT P-2
SCHEDULE SSJ-16

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

INCOME STATEMENT
($000)

ELECTRIC		June 30, 2018
Electric Operating Revenues	$	3,354,766
Electric Operating Expenses:		
Operation Expense		2,448,686
Maintenance Expense		124,027
Depreciation Expense		230,143
Amortization of Limited Term Plant		10,306
Amortization of Property Losses		23,619
Taxes Other Than Income Taxes		23,871
Income Taxes [1]		105,832
Accretion Expense		0
Total Electric Utility Operating Expenses		2,966,484
Electric Utility Operating Income	$	388,281

GAS		June 30, 2018
Gas Operating Revenues	$	1,725,435
Gas Operating Expenses:		
Operation Expense		1,135,396
Maintenance Expense		36,618
Depreciation Expense		148,430
Amortization of Limited Term Plant		7,514
Amortization of Regulatory Asset		3,737
Amortization of Property Losses		28,739
Amortization of Excess cost of removal		(13,200)
Taxes Other Than Income Taxes		18,746
Income Taxes [1]		76,956
Total Gas Utility Operating Expenses		1,442,936
Gas Utility Operating Income	$	282,499
Net Utility Operating Income	$	670,781

* 5 Months Actual - 7 Months Forecast

[1] Income Taxes reflect the elimination of the Repair Allowance flow-through as proposed in Schedule RCK-5, Adjustment 1

EXHIBIT P-2
SCHEDULE SSJ-17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DISTRIBUTION SALES BY CLASS OF BUSINESS
(KWh/Therms - 000)

Line		June 30, 2018 Electric	Gas
1	Residential	13,053,695	1,458,897
2	Commercial	23,393,653	888,104
3	Industrial	3,854,117	81,943
4	Firm Transportation Service		24,575
5	Non-Firm Transportation Service		275,009
6	Cogeneration Interruptible		39,932
7	Cogeneration Contracts		0
8	Contract Service Gas		986,250
9	Street Lighting	320,946	578
10	Total Sales to Customers	40,622,411	3,755,287
11	Interdepartmental	9,260	645
12	Total Sales	40,631,671	3,755,931

* 5 Months Actual - 7 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

REVENUE BY CLASS OF BUSINESS
($000)

Line		Electric	June 30, 2018 Gas	Total
1	Residential	$ 1,914,100	$ 1,112,877	$ 3,026,977
2	Commercial	1,458,459	468,256	1,926,715
3	Industrial	144,871	32,851	177,721
4	Firm Transportation Service		3,685	3,685
5	Non-Firm Transportation Service		33,503	33,503
6	Cogeneration Interruptible		13,552	13,552
7	Cogeneration Contracts		-	0
8	Contract Service Gas		9,789	9,789
9	Street Lighting	71,744	392	72,137
10	Total Revenue from Sales to Customers	$ 3,589,175	$ 1,674,905	$ 5,264,080
11	Interdepartmental	1,107	347	1,454
12	Total Revenue from Sales	$ 3,590,282	$ 1,675,252	$ 5,265,533

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-19

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

AVERAGE CUSTOMERS BILLED BY CLASS OF BUSINESS

Line		June 30, 2018 Electric	Gas
1	Residential	1,936,206	1,670,046
2	Commercial	299,071	158,643
3	Industrial	8,412	6,186
4	Firm Transportation Service		36
5	Non-Firm Transportation Service		196
6	Cogeneration Interruptible		13
7	Cogeneration Contracts		0
8	CSG		21
9	Street Lighting	10,134	15
10	Total Customers	2,253,823	1,835,158
11	Interdepartmental	1	1
12	Total Customers	2,253,824	1,835,159

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-20

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

EXPENSES
($000)

Electric

Production Expenses		June 30, 2018
Other Power Supply Expenses:		
Purchased Power	$	1,883,276
System Control/Load Dispatch	$	61
Total Other Power Supply Expenses	$	1,883,337
Distribution		
Operation	$	56,861
Maintenance		124,027
Total Distribution	$	180,889

Gas

Production Expenses		
Gas Supply		
Natural Gas City Gate Purchases	$	746,622
Fuel Gas - Raw Materials		19,060
Other Gas Purchases		(52)
Other Gas Supply Expenses		321
Total Gas Supply	$	765,950
Gas Production		
Operation	$	-
Maintenance		780
Total Gas Production	$	780
Other Power Generation		
Liquefied petroleum gas expenses		297
Total Other Power Generation	$	297
Other Storage		
Operation	$	1,514
Maintenance		199
Total Other Storage	$	1,712
Total Production Expenses	$	768,740
Transmission		
Operation	$	97
Maintenance		4,729
Total Transmission	$	4,826
Distribution		
Operation	$	71,075
Maintenance		30,910
Total Distribution	$	101,985

* 5 Months Actual - 7 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CUSTOMER ACCOUNTS AND INFORMATION
($000)

	June 30, 2018		
	Electric	**Gas**	**Total**
Customer Accounts Expenses			
Operation:			
Meter Reading Expenses	$ 17,537	$ 13,171	$ 30,708
Customer Records and Collection Expenses	$ 71,746	$ 55,458	$ 127,204
Uncollectible Accounts	$ 52,073	$ 28,676	$ 80,749
Misc. Customer Accounts Expenses	$ 99,101	$ 2,324	$ 101,425
Total Customer Accounts Expenses	$ 240,457	$ 99,629	$ 340,086
Cust. Service and Informational Expenses			
Operation:			
Supervision	$ -	$ -	$ -
Customer Assistance Expenses	$ 137,969	$ 90,214	$ 228,183
Misc. Cust. Service and Info. Expenses	$ 1,747	$ 1,165	$ 2,913
Total Cust. Service and Info. Expenses	$ 139,717	$ 91,379	$ 231,096
Sales Expenses			
Operation:			
Demonstration and Selling Expenses	$ 345	$ 334	$ 679
Misc. Sales Expenses	$ 15	$ 12	$ 27
Total Sales Expenses	$ 359	$ 346	$ 706
Total Customer Accounts and Information	$ 380,533	$ 191,354	$ 571,887

* 5 Months Actual - 7 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ADMINISTRATIVE AND GENERAL SALARIES AND EXPENSES
($000)

	June 30, 2018		
	Electric	**Gas**	**Total**
Salaries & Wages	$ 5,832	$ 6,136	$ 11,967
Supplies & Expenses	3,556	2,394	5,950
Outside Services	48,978	42,674	91,652
Property Insurance	1,566	256	1,822
Injuries and Damages	15,101	7,249	22,351
Pensions & Fringe Benefits	32,935	32,695	65,630
Regulatory Expenses	12,898	5,198	18,096
Duplicate Charge	(2,686)	(742)	(3,429)
General Advertising	2,307	1,823	4,131
Other Miscellaneous General	2,067	1,845	3,912
Rents	5,402	5,580	10,982
Maintenance	(0)	-	(0)
Total Administrative and General Salaries & Expenses	$ 127,955	$ 105,109	$ 233,063

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-23

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DEPRECIATION AND AMORTIZATION
($000)

ELECTRIC

Line		June 30, 2018
	Depreciation	
1	Electric	$230,143
	Amortization	
2	Electric	$33,924
	Total Electric Depreciation and Amortization	**$264,067**

GAS

Line		June 30, 2018
	Depreciation	
1	Gas	$148,430
	Amortization	
2	Gas	$26,790
	Total Gas Depreciation and Amortization	**$175,220**

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-24

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

TAXES OTHER THAN INCOME TAXES
($000)

Line		Electric	June 30, 2018 Gas	Total
1	Real Estate	$ 13,068	$ 4,900	$ 17,968
2	FICA	380	481	861
3	State Unemployment	10,005	12,840	22,845
4	Federal Unemployment	54	69	123
5	Miscellaneous Municipal and State Taxes	364	456	820
6	Total	$ 23,871	$ 18,746	$ 42,617

* 5 Months Actual - 7 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CURRENT AND DEFERRED INCOME TAXES
($000)

	June 30, 2018		
	Electric	**Gas**	**Total**
Net Income Taxes	$ 105,832	$ 76,956	$ 182,788

* 5 Months Actual - 7 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-26

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PRO-FORMA DISTRIBUTION OPERATING INCOME
($000)

#		Schedule #	Electric	Gas	Total
Test Year Distribution Operating Income			**$ 388,281**	**$ 282,499**	**$ 670,781**
#	**Pro-Forma Adjustments:**	**Schedule #**			
1	Wages	SSJ-27	$ (3,832)	$ (4,752)	$ (8,584)
2	Payroll Taxes	SSJ-28	(257)	(318)	(575)
3	Interest Synchronization (Tax Savings)	SSJ-29	998	709	1,707
4	Pension & Fringe Benefits	SSJ-30	(7,833)	(17,022)	(24,854)
5	COLI Interest Expense	SSJ-31	(3,316)	(1,051)	(4,367)
6	Weather Normalization	SSJ-32	4,959	-	4,959
7	Gains/Losses on Sales of Property	SSJ-33	17	35	52
8	Real Estate Taxes	SSJ-34	(641)	(320)	(961)
9	Insurance	SSJ-35	(51)	(55)	(105)
10	ASB Margin	SSJ-36	4,757	(9,514)	(4,757)
11	TSGNF Margin Sharing	SSJ-37	-	(185)	(185)
12	Depreciation Rate Change	SSJ-38	(52,276)	(62,596)	(114,871)
13	Storm Cost Amortization*	SSJ-39	-	-	-
14	Post Rate Case Storm Cost Normalization	SSJ-40	-	-	-
15	Excess COR Refund Recovery	SSJ-41	-	(14,825)	(14,825)
16	Excess COR Test Year Adjustment	SSJ-42	-	(9,489)	(9,489)
17	Regulatory Assets*	SSJ-43	-	-	-
18	Rate Case Expenses	SSJ-44	38	60	98
19	Credit Card Fees	SSJ-45	(3,048)	(1,670)	(4,718)
20	Vacation Accrual	SSJ-46	(2,200)	(1,528)	(3,728)
21	Energy Strong / GSMP Revenue Adjustment	SSJ-47	9,129	7,563	16,692
	Total Pro-Forma Adjustments		**$ (53,555)**	**$ (114,958)**	**$ (168,513)**
Total Pro-Forma Distribution Operating Income			**$ 334,727**	**$ 167,541**	**$ 502,268**

* Per the Direct Testimony of Mr. Krueger, the Storm Cost amortization and Regulatory Assets are offset by a credit to ADIT; See Schedule RCK-5, Adjustment 2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 1
Wages
($000)

	Electric	Gas	Total
Bargaining Unit Employees	$ 3,299	$ 4,092	$ 7,392
MAST Employees	2,030	2,518	4,549
Operating Expense Increase before Taxes	$ 5,330	$ 6,611	$ 11,940
Income Taxes	1,498	1,858	3,356
Operating Income Increase (Decrease) After Taxes	**$ (3,832)**	**$ (4,752)**	**$ (8,584)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 2
Payroll Taxes
($000)

	Electric	Gas	Total
Bargaining Unit Employees	$ 221	$ 274	$ 495
MAST Employees	136	169	305
Operating Expense Increase before Taxes	$ 357	$ 443	$ 799
Income Taxes	100	124	225
Operating Income Increase (Decrease) After Taxes	**$ (257)**	**$ (318)**	**$ (575)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 3
Interest Synchronization (Tax Savings)
($000)

Electric Rate Base				$ 5,601,592
	Percent	**Embedded Cost**	**Weighted Cost**	
Debt Components:				
Long Term Debt	45.49%	4.05%	1.84%	
Customer Deposits	0.51%	0.87%	0.00%	
Total Weighted Cost of Debt				1.84%
Annualized Interest Expense				$ 103,332
Less: Test Period Interest Expense				99,781
Net Interest Expense Increase / (Decrease)				$ 3,550
Income Tax Rate				28.11%
Operating Income Increase (Decrease) After Taxes				$ 998

Gas Rate Base				$ 4,044,023
	Percent	**Embedded Cost**	**Weighted Cost**	
Debt Components:				
Long Term Debt	45.49%	4.05%	1.84%	
Customer Deposits	0.51%	0.87%	0.00%	
Total Weighted Cost of Debt				1.84%
Annualized Interest Expense				$ 74,599
Less: Test Period Interest Expense				72,076
Net Interest Expense Increase / (Decrease)				$ 2,523
Income Tax Rate				28.11%
Operating Income Increase (Decrease) After Taxes				$ 709

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 4
Pension and Fringe Benefits
($000)

	Electric	Gas	Total
Rate Year			
Medical	$ 15,182	$ 20,316	$ 35,497
Dental/Vision	$ 803	$ 1,074	$ 1,877
Pensions	$ -	$ -	$ -
Group Life	$ 337	$ 451	$ 788
Disability	$ 144	$ 193	$ 337
Thrift & Savings	$ 4,511	$ 6,037	$ 10,548
Workers Compensation	$ 1,752	$ 2,345	$ 4,097
Benefits Outside Services	$ 1,460	$ 1,954	$ 3,415
Benefits Other	$ 363	$ 486	$ 849
OPEB	$ 23,364	$ 23,935	$ 47,298
	$ 47,916	$ 56,791	$ 104,707
Less: Test Year			
Medical	$ 13,841	$ 16,789	$ 30,630
Dental/Vision	$ 695	$ 844	$ 1,539
Pensions	$ (12,844)	$ (11,602)	$ (24,446)
Group Life	$ 334	$ 407	$ 740
Disability	$ 134	$ 163	$ 298
Thrift & Savings	$ 4,135	$ 5,033	$ 9,168
Workers Compensation	$ 1,344	$ 1,640	$ 2,984
Benefits Outside Services	$ 1,579	$ 1,928	$ 3,507
Benefits Other	$ 289	$ 353	$ 641
OPEB	$ 27,515	$ 17,559	$ 45,074
	$ 37,021	$ 33,113	$ 70,134
Increase in Test Year Operating Expenses	$ 10,895	$ 23,678	$ 34,573
Income Taxes	$ 3,063	$ 6,656	$ 9,718
Operating Income Increase (Decrease) After Taxes	**$ (7,833)**	**$ (17,022)**	**$ (24,854)**

EXHIBIT P-2
SCHEDULE SSJ-31

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 5
COLI Interest Expense
($000)

	Electric	Gas	Total
Net Credit in Test Year			
Administrative & General Expenses	(5,619)	(1,559)	(7,179)
Tax Savings on COLI	(650)	(206)	(856)
Interest Charges	3,316	1,051	4,367
Net Benefit	$ (2,954)	$ (714)	$ (3,668)
Operating Income Increase (Decrease) After Taxes	**$ (3,316)**	**$ (1,051)**	**$ (4,367)**

EXHIBIT P-2
SCHEDULE SSJ-32

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 6
Weather Normalization
($000)

	Electric	Gas*	Total
Actual Distribution Revenues	$ 967,317	$ -	$ 967,317
Weather Normalized Distribution Revenues	$ 974,215	-	974,215
Increase (Decrease) in Test Year Margin Revenue	$ (6,898)	$ -	$ (6,898)
Income Taxes	(1,939)	-	(1,939)
Operating Income Increase (Decrease) After Taxes	$ 4,959	$ -	$ 4,959

* Reflects impact of Weather Normalization Charge

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 7
Gains/Losses on Sales of Property
($000)

	Electric	Gas	Total
Five-Year Average - Book Gain/(Loss)	$ 46	$ 99	$ 145
Income Taxes	13	28	41
Net Income/(Loss)	$ 33	$ 71	$ 104
Operating Income Increase (Decrease) After Taxes	**$ 17**	**$ 35**	**$ 52**

EXHIBIT P-2
SCHEDULE SSJ-34

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 8
Real Estate Taxes
($000)

	Electric	Gas	Total
Rate Year Property Taxes	$ 13,960	$ 5,345	$ 19,305
Test Year Property Taxes	$ 13,068	$ 4,900	$ 17,968
Operating Expense Increase Before Taxes	$ 892	$ 445	$ 1,337
Income Taxes	251	125	376
Operating Income Increase (Decrease) After Taxes	**$ (641)**	**$ (320)**	**$ (961)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 9
Insurance
($000)

	Electric	Gas	Total
Insurance Premium Expense	$ 4,025	$ 2,489	$ 6,513
Test Year Insurance Premium Expense	3,954	2,413	6,367
Operating Expense Increase Before Taxes	$ 70	$ 76	$ 146
Income Taxes	20	21	41
Operating Income Increase (Decrease) After Taxes	**$ (51)**	**$ (55)**	**$ (105)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 10
ASB Margin
($000)

	Electric	Gas	Total
ASB Margin by Appliance	$ 13,234	$ 29,295	$ 42,529
ASB Margin % Above-the-Line per N.J.A.C. 14:4-3.6	50%	100%	
Above the Line ASB Margin	$ 6,617	$ 29,295	$ 35,912
ASB Margin in Test Year	$ -	$ 42,529	$ 42,529
ASB Above-the-Line Margin	$ 6,617	$ (13,234)	$ (6,617)
Income Taxes	1,860	(3,720)	(1,860)
Operating Income Increase (Decrease) After Taxes	**$ 4,757**	**$ (9,514)**	**$ (4,757)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 11
TSG-NF Margin - Gas
($000)

	Electric	Gas	Total
Operating Income Decrease Before Taxes	$ -	$ (258)	$ (258)
Income Taxes	-	73	73
Operating Income Increase (Decrease) After Taxes	**$ -**	**$ (185)**	**$ (185)**

EXHIBIT P-2
SCHEDULE SSJ-38

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 12
Depreciation Rate Change
($000)

	Electric	Gas	Total
Annualization of Depreciation Expense	$ 250,868	$ 168,174	$ 419,042
Test Year Depreciation Expense	$ 230,143	$ 148,430	$ 378,573
Annualization of Current Depreciation Rates	$ 20,725	$ 19,744	$ 40,469
Depreciation Expense at Proposed Rates	$ 302,859	$ 235,501	$ 538,360
Operating Expense Increase (Decrease) for Proposed Rates	$ 51,991	$ 67,327	$ 119,318
Operating Income Increase (Decrease) Before Taxes	$ (72,716)	$ (87,071)	$ (159,788)
Income Taxes	$ (20,441)	$ (24,476)	$ (44,916)
Operating Income Increase (Decrease) After Taxes	**$ (52,276)**	**$ (62,596)**	**$ (114,871)**

EXHIBIT P-2
SCHEDULE SSJ-39

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 13
Recovery of Storm Cost Regulatory Asset
($000)

	Electric		Gas		Total	
Storm Cost Recovery						
2010-2012 Deferred Storm Costs*	$	212,697	$	7,545	$	220,242
Post 2012 Deferred Incremental Storm Costs	$	20,636	$	20	$	20,656
Total Storm Cost Regulatory Asset	$	233,333	$	7,565	$	240,898
Amortization Period		3		3		3
Annual Storm Cost Amortization	$	77,778	$	2,522	$	80,299
Average Deferred Balance During Test Year	$	116,667	$	3,783	$	120,449
Deferred Tax Benefit	$	(32,795)	$	(1,063)	$	(33,858)
Average Net of Tax Deferred Cost Balance	$	83,872	$	2,719	$	86,591
Weighted Average Cost of Capital		7.40%		7.40%		7.40%
Annual Amortization Carrying Charge	$	6,206	$	201	$	6,408
Operating Expense Increase Before Taxes	$	83,984	$	2,723	$	86,707
Income Taxes	$	23,608	$	765	$	24,373
Operating Income Increase (Decrease) After Taxes	**$**	**(60,376)**	**$**	**(1,958)**	**$**	**(62,334)**

*Approved as prudent in BPU Docket. No. Ax13030196 on 9/30/14

* Per the Direct Testimony of Mr. Krueger, the Storm Cost amortization and Regulatory Assets are offset by a credit to ADIT; See Schedule RCK-5, Adjustment 2

EXHIBIT P-2
SCHEDULE SSJ-40

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 14
Post Rate Case Storm Cost Normalization
($000)

	Electric	Gas	Total
Test Year incremental O&M	$ -	$ -	$ -
Amortization Period	3	3	3
Annual Storm Cost Amortization	$ -	$ -	$ -
Test Year incremental O&M	$ -	$ -	$ -
Operating Expense Increase Before Taxes	$ -	$ -	$ -
Income Taxes	$ -	$ -	$ -
Operating Income Increase (Decrease) After Taxes	**$ -**	**$ -**	**$ -**

EXHIBIT P-2
SCHEDULE SSJ-41

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 15
Recovery of Deferred Excess COR Refund
($000)

	Electric		Gas		Total
One-time Reg Asset Adjustment					
November 9, 2011 - December 31, 2012	$ -	$	15,107	$	15,107
Annual Excess COR Amortization Deferral					
2013	$ -	$	13,200	$	13,200
2014	-	$	13,200		13,200
2015	-	$	13,200		13,200
2016	-	$	13,200		13,200
2017	-	$	13,200		13,200
2018 *	-	$	9,900		9,900
Total Deferred Excess COR Amortization**	$ -	$	91,007	$	91,007
Amortization Period	5		5		5
Operating Expense Increase Before Taxes	$ -	$	18,201	$	18,201
Average Deferred Balance During Test Year	$ -	$	45,504	$	45,504
Deferred Tax Benefit	$ -	$	(12,791)	$	(12,791)
Average Net of Tax Deferred Cost Balance	$ -	$	32,712	$	32,712
Weighted Average Cost of Capital	7.40%		7.40%		7.40%
Annual Amortization Carrying Charge	$ -	$	2,421	$	2,421
Operating Expense Increase Before Taxes	$ -	$	20,622	$	20,622
Income Taxes	$ -	$	5,797	$	5,797
Operating Income Increase (Decrease) After Taxes	**$ -**	**$**	**(14,825)**	**$**	**(14,825)**

* Reflects amortization until rate effective date of new rates forecasted as of October 1, 2018
** Per BPU Docket No. GF11090539 1/23/2013

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 16
Excess COR Refund in Test Year
($000)

	Electric	Gas	Total
Excess COR Amortization			
Test Year Excess COR Refund	$ -	$ (13,200)	$ (13,200)
Operating Expense Increase Before Taxes	$ -	$ 13,200	$ 13,200
Income Taxes	$ -	$ 3,711	$ 3,711
Operating Income Increase (Decrease) After Taxes	**$ -**	**$ (9,489)**	**$ (9,489)**

EXHIBIT P-2
SCHEDULE SSJ-43

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 17
Amortization of Other Regulatory Assets
($000)

		Electric		Gas		Total
Regulatory Assets / (Liabilities)						
Long Term Capacity Agreement Pilot Program	$	562	$	-	$	562
Contact Voltage	$	46	$	-	$	46
Newark Breaker Project	$	669	$	-	$	669
Cape May Street	$	861	$	9,510	$	10,371
Total Regulatory Assets / (Liabilities)	$	2,138	$	9,510	$	11,648
Amortization Period		3		3		3
Annual Amortization	$	713	$	3,170	$	3,883
Test Year Expense	$	-	$	-	$	-
Operating Expense Increase Before Taxes	$	713	$	3,170	$	3,883
Income Taxes	$	200	$	891	$	1,091
Operating Income Increase (Decrease) After Taxes	**$**	**(512)**	**$**	**(2,279)**	**$**	**(2,791)**

* Per the Direct Testimony of Mr. Krueger, the Storm Cost amortization and Regulatory Assets are offset by a credit to ADIT; See Schedule RCK-5, Adjustment 2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 18
Rate Case Expenses
($000)

	Electric	Gas	Total
Rate Case Expenses	$ 1,122	$ 679	$ 1,801
Amortization Period	3	3	3
Annual Amortization	$ 374	$ 226	$ 600
Test Year Rate Case Expense	$ 427	$ 309	$ 737
Operating Expense Decrease Before Taxes	$ 53	$ 83	$ 136
Income Taxes	$ 15	$ 23	$ 38
Operating Income Increase (Decrease) After Taxes	**$ 38**	**$ 60**	**$ 98**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 19
Credit Card Fees
($000)

	Electric	Gas	Total
Operating Expense Increase Before Taxes	$ 4,240	$ 2,323	$ 6,562
Income Taxes	1,192	653	1,845
Operating Income Increase (Decrease) After Taxes	**$ (3,048)**	**$ (1,670)**	**$ (4,718)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 20
Vacation Accrual
($000)

	Electric	Gas	Total
Operating Income Decrease Before Taxes	$ (3,060)	$ (2,125)	$ (5,186)
Income Taxes	860	597	1,458
Operating Income Increase (Decrease) After Taxes	**$ (2,200)**	**$ (1,528)**	**$ (3,728)**

EXHIBIT P-2
SCHEDULE SSJ-47

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 21
Energy Strong / GSMP Revenue Adjustment
($000)

	Electric	Gas	Total
ES Roll-in #6 (Annualizing Revenue from Jul17 - Aug17)	6,990	104	7,094
ES Roll-in #7 (Annualizing Revenue from Jul17 - Feb18)	5,709	-	5,709
ES Roll-in #8 (Eliminate Revenue Requirement)	-	-	-
GSMP Roll-in 2 (Annualizing Revenue from Jul17 - Dec17)	-	10,416	10,416
Operating Revenue Increase Before Taxes	12,699	10,520	23,219
Income Taxes	(3,570)	(2,957)	(6,527)
Operating Income Increase (Decrease) After Taxes	**$ 9,129**	**$ 7,563**	**$ 16,692**