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. ER18010029 and GR18010030

DIRECT TESTIMONY
OF
SCOTT JENNINGS
12+0 UPDATE

VICE PRESIDENT – UTILITY FINANCE

August 8, 2018
P-2 R-2

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DIRECT TESTIMONY
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VICE-PRESIDENT – UTILITY FINANCE
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I. INTRODUCTION

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 are the key points in your testimony?

A. I will first provide some context of customer bills: a) how bills have changed since the Company's last rate case; b) how the Company's bills compare to income of median and low income families; c) how the monthly fixed service charges compare to PSE&G's actual costs and the industry; d) how PSE&G's distribution costs compare with other New Jersey utilities; and e) how PSE&G's distribution costs and operating performance compare with other utilities.

I will then discuss the key drivers of our rate request, particularly capital investments the Company has made in the distribution system. I will also discuss the several key factors that mitigated the Company's rate increase request, namely cost control efforts to keep O&M expenses flat over the past nine years, flowing back certain tax benefits, lower pension costs, lower financing costs, margins from the appliance service business, and other factors. I will also explain why recovery of incentive compensation is appropriate, integral to strong operating performance, and benefits customers. I will then discuss the Company's ROE and capital structure request, which are critical to recognize market conditions and operating performance and to preserve the Company's credit ratings. I will also give an overview of the Company's proposal to decouple its revenues from customer usage to better align the Company's interests with the interests of its customers, and to support State policy and the environment.

Finally, I support the calculations of the Company's revenue request in this proceeding.

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

A. This filing was made, in part, to comply with the New Jersey Board of Public Utilities ("BPU" or "the Board") order approving PSE&G's 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, required the Company to make a base rate case filing by no later than February 1, 2018. This filing seeks approval to increase PSE&G's annual revenue requirement as discussed later in my testimony.

Q. What is the rate increase being sought?

A. PSE&G is seeking to increase its base delivery rates by approximately 3% relative to overall revenues. This amount is net of certain tax benefits the Company proposes to flow through to customers as discussed later in my testimony. The ongoing rate change is approximately $272 million, or approximately 3.6% relative to overall revenues, comprised of an increase of approximately $147 million, or 2.7%, for electric distribution and approximately $125 million, or 6.1%, for gas distribution. For the fourth quarter of 2018, we will provide a credit of approximately $39 million ($8 million electric, $31 million gas) related to the overcollection of income tax expense during the first quarter of 2018 prior to the implementation of lower rates due to Tax Reform.

Q. What are the key drivers behind the rate increase?

A. The rate increase is primarily due to capital investments made to upgrade, modernize, and harden the Company's distribution facilities and a proposed change in depreciation rates to reflect a proposed change in the recovery methodology for future costs of removal of equipment. This rate case provides PSE&G with the opportunity to recover those just and reasonable costs and earn a fair return on the capital invested in the distribution system. This rate increase is largely offset by the flow back of certain tax benefits discussed later in my testimony.

Q. Can you please explain the changes in your revenue request and the key drivers of those changes from your original 5+7 filing and 9+3 update compared to this 12+0 update?

Yes. This filing is consistent with the Company's 9+3 filing, with some minor updates to replace planned costs with actual costs. The original 5+7 filing requested a revenue increase effective October 1, 2018, net of the proposed Tax Adjustment Credit ("TAC") impacts, of

$95 million, which was approximately 1% of overall revenues. There are several notable changes to the Company's original revenue request, mostly due to the impacts of federal tax reform. The 5+7 original filing request assumed the Company would lower rates due to tax reform through this base rate case proceeding. Subsequent to the Company's filing, the BPU issued an order requiring New Jersey utilities to lower their rates effective April 1, 2018. PSE&G complied with that order, accelerating the reduction that was planned for the rate case. That change resulted in an annualized rate reduction of approximately $114 million, or an approximate 2% rate decrease on April 1, 2018. Since that rate change was implemented outside of the rate case, it is no longer included as an offset to the Company's revenue request. In addition, in the original 5+7 filing, PSE&G assumed that prior to the new lower rates due to tax reform, it would overcollect income tax expense through September 30, 2018 (the date prior to which the Company assumed new rates would be effective) and then refund that amount over the next twelve months. With new rates being placed in effect April 1, 2018, that overcollection only occurs in the 1st quarter of 2018 (rather than over the first nine months); hence the amount to be refunded through the TAC is lower. In addition to this tax reform item, due to the short period between the enactment of tax reform and the Company's filing, PSE&G did not have the ability to incorporate the loss of bonus depreciation into its rate base projections. This filing now reflects the loss of bonus deprecation, which results in lower deferred taxes and consequently higher rate base and therefore higher revenue requirements. There were also some other less impactful changes, which are included in the schedule updates as part of this 12+0 testimony. As a result, the Company's original request for a revenue increase of approximately $95 million, or approximately 1%, is being modified to a request for a revenue increase of approximately $272 million or approximately 3.6% of overall revenues. Simply stated, the majority of this change is due to timing, specifically the accelerated return to customers of the rate reduction for changes to federal taxes.

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

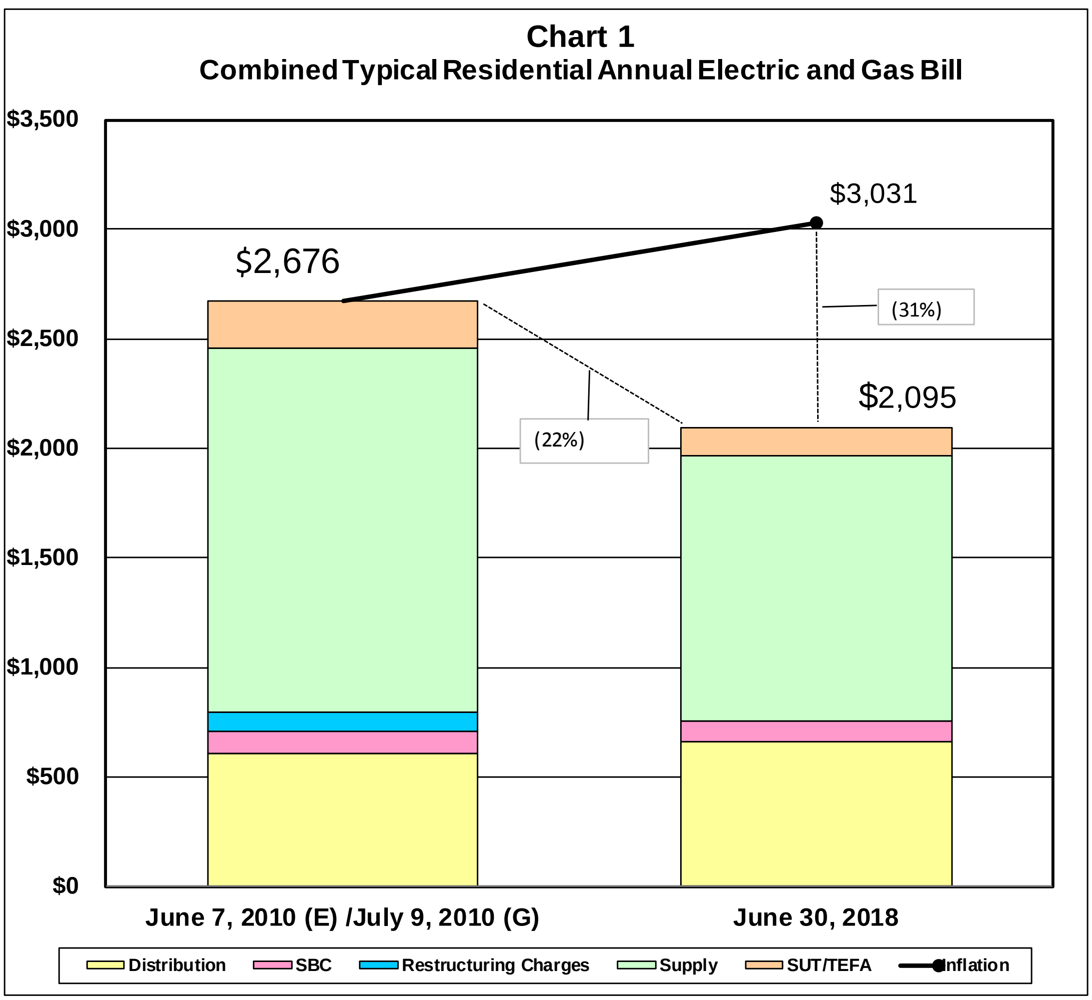
A. Yes. I sponsor the following schedules that were prepared or compiled under my direction and supervision; these Schedules supersede the Schedules submitted with my original 5+7 and 9+3 testimonies:

- Schedule SSJ-1 R-2: Credentials
- Schedule SSJ-2 R-2: Determination of Revenue Requirements
- Schedule SSJ-3 R-2: Rate Base
- Schedule SSJ-4 R-2: Weighted Average Cost of Capital
- Schedule SSJ-5 R-2: Long Term Debt
- Schedule SSJ-6 R-2: Revenue Factor
- Schedules SSJ-7 R-2 through 15 R-2: Support for components of rate base
- Schedule SSJ-16 R-2: Income Statement
- Schedules SSJ-17 R-2 through 25 R-2: Support for components of the income statement
- Schedule SSJ-26 R-2: Pro-forma Distribution Operating Income
- Schedules SSJ-27 R-2 through 49 R-2: Support for pro-forma adjustments to test year operating income

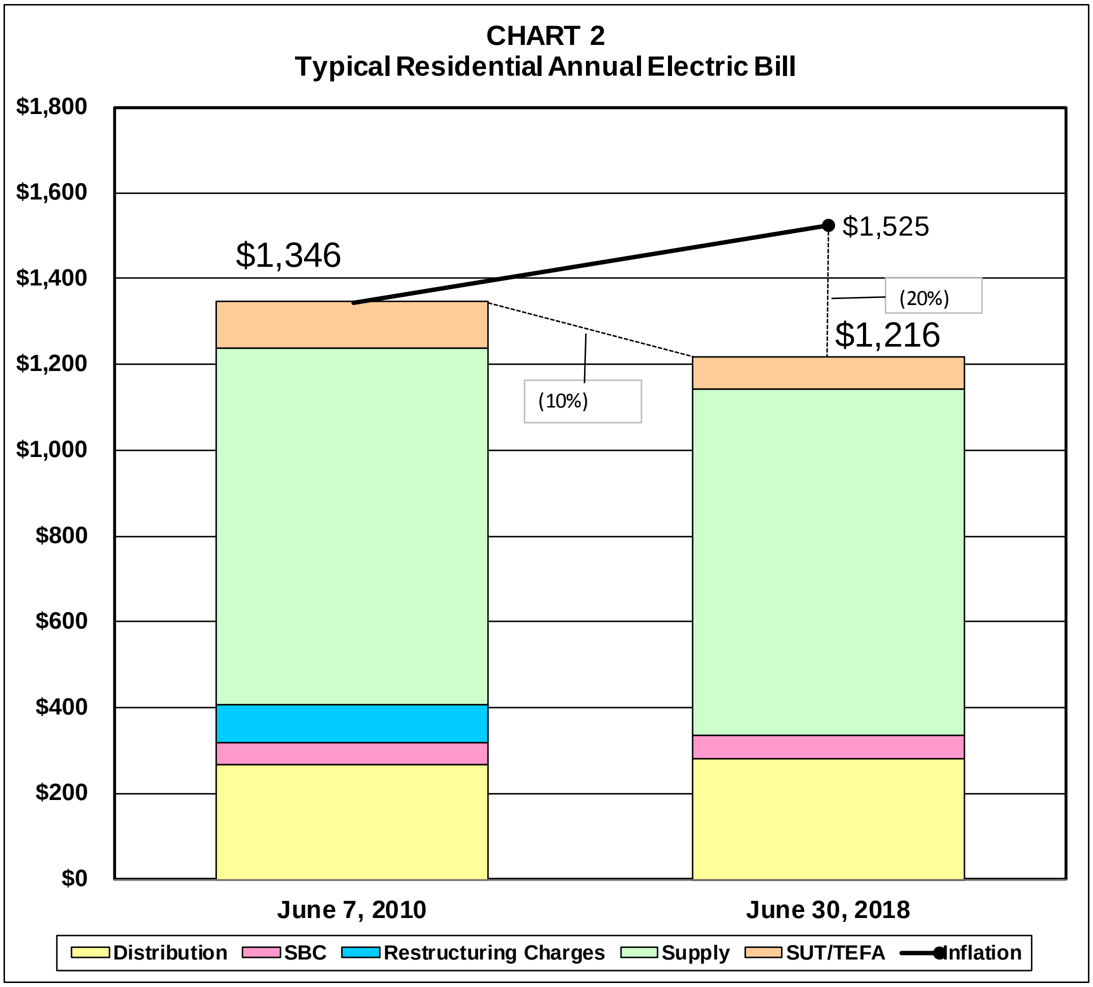
II. IMPACT ON CUSTOMERS

Q. Can you provide context regarding this requested rate increase? How have PSE&G's rates changed over the past decade and since the last rate case eight years ago?

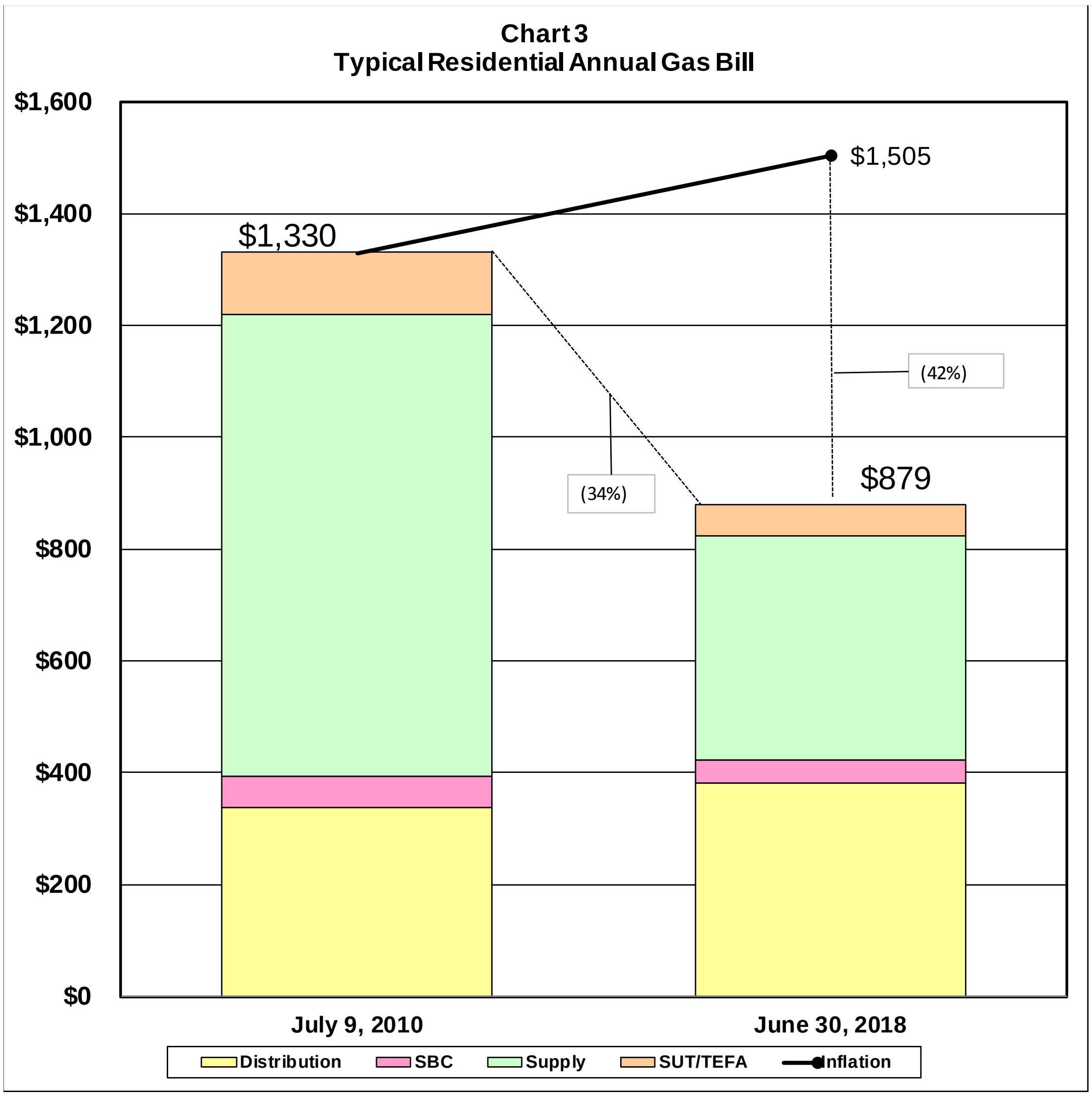
A. Relative to this proposed moderate 3% revenue increase, it is important to note that since the Company's last base rate case in 2010, overall bills for a typical residential electric and gas customer have declined by more than 20% on an absolute basis and more than 30% on an inflation adjusted basis. The declines are primarily due to lower supply costs and continuous cost control efforts, all while making substantial capital investments needed to upgrade, modernize, and harden the electric and gas distribution systems.



For PSE&G's electric only typical residential customers, bills are 10% lower than they were after the Company's last base rate case, and 20% lower adjusted for inflation.



For PSE&G's gas only typical residential customers, bills are 34% lower than they were after the Company's last base rate case, and 42% lower adjusted for inflation. In addition to these decreases, the Company has provided customers with approximately $700 of bill credits over the past several years.



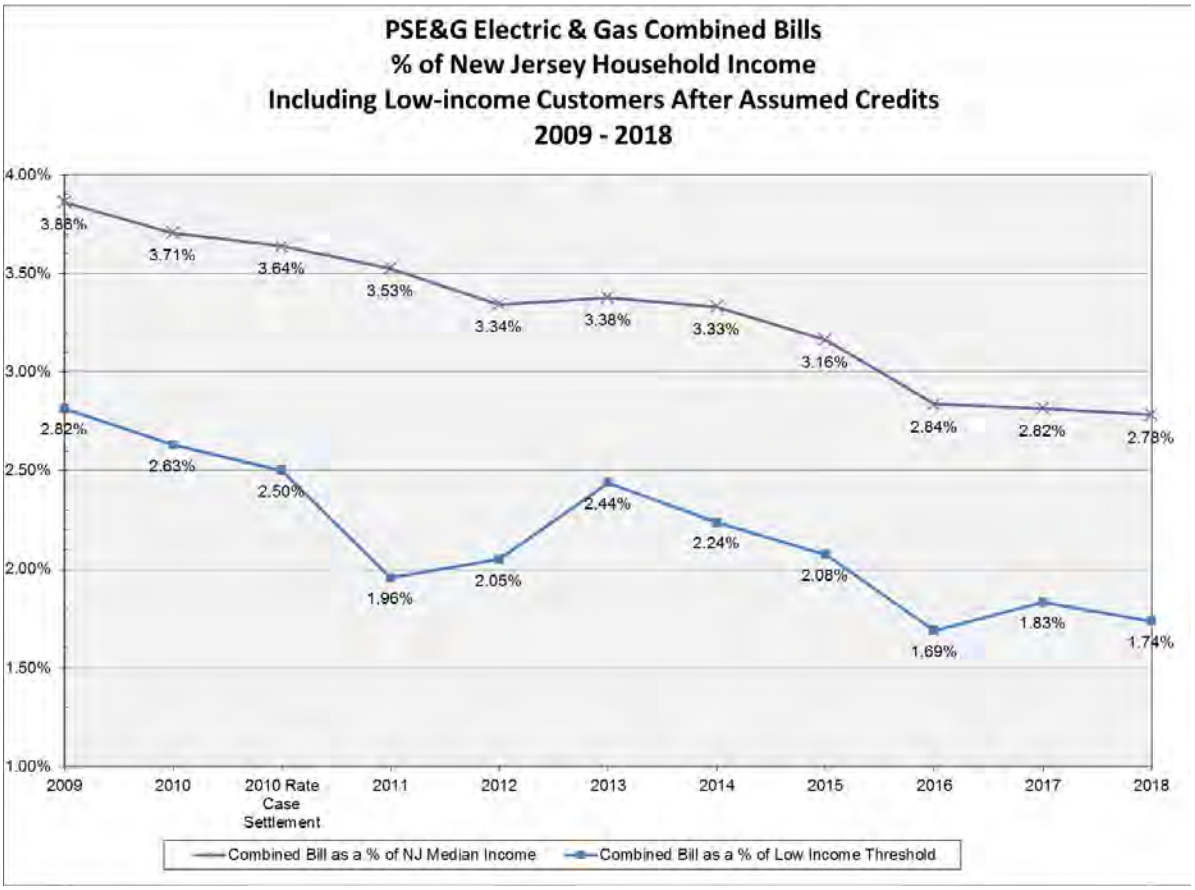
Q. Have you considered the impact of the proposed rates on lower-income customers?

A. Yes. The Company is very focused on this vulnerable segment of its customer base. In addition to serving these customers through certain energy efficiency programs, such as the Company's multi-family housing programs, PSE&G also advocates 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.

The Company promotes the use of these services to its 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 about 40% lower than what it was since the Company's 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.

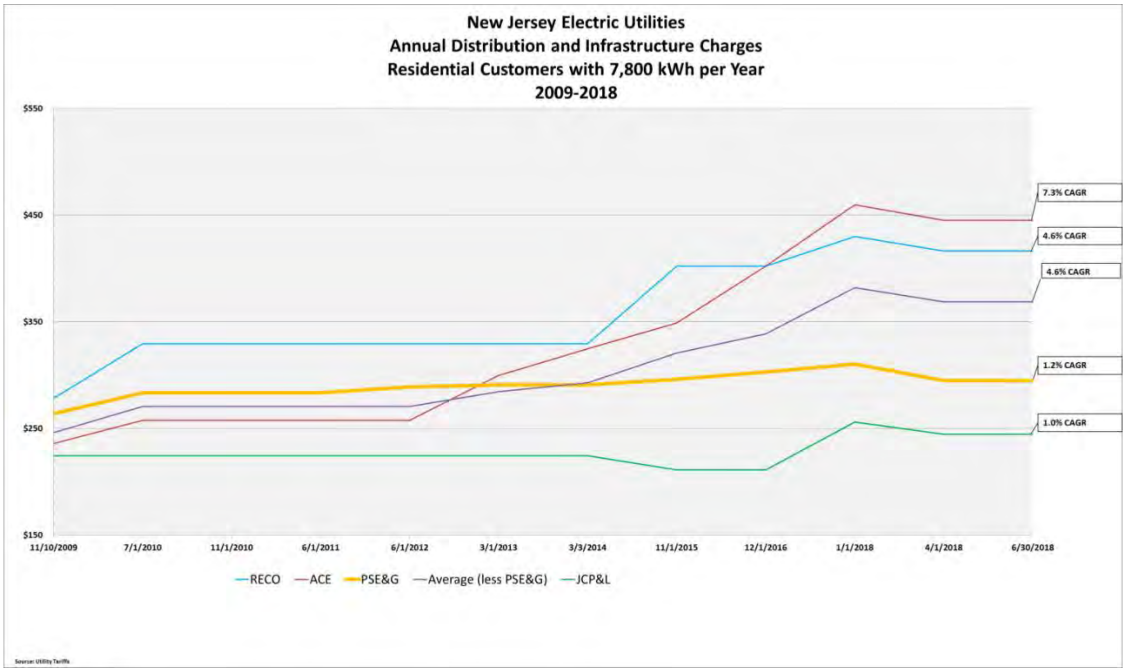


This chart compares the bill as a percentage of income for a typical combined residential customer relative to New Jersey's median income and for low income customers. As can be seen, for the average residential customer, the cost of service has declined from approximately 3.9% of median income at the time of the Company's 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 the Company's last base rate case to approximately 1.7% today, a relative decline of approximately 40%. 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.

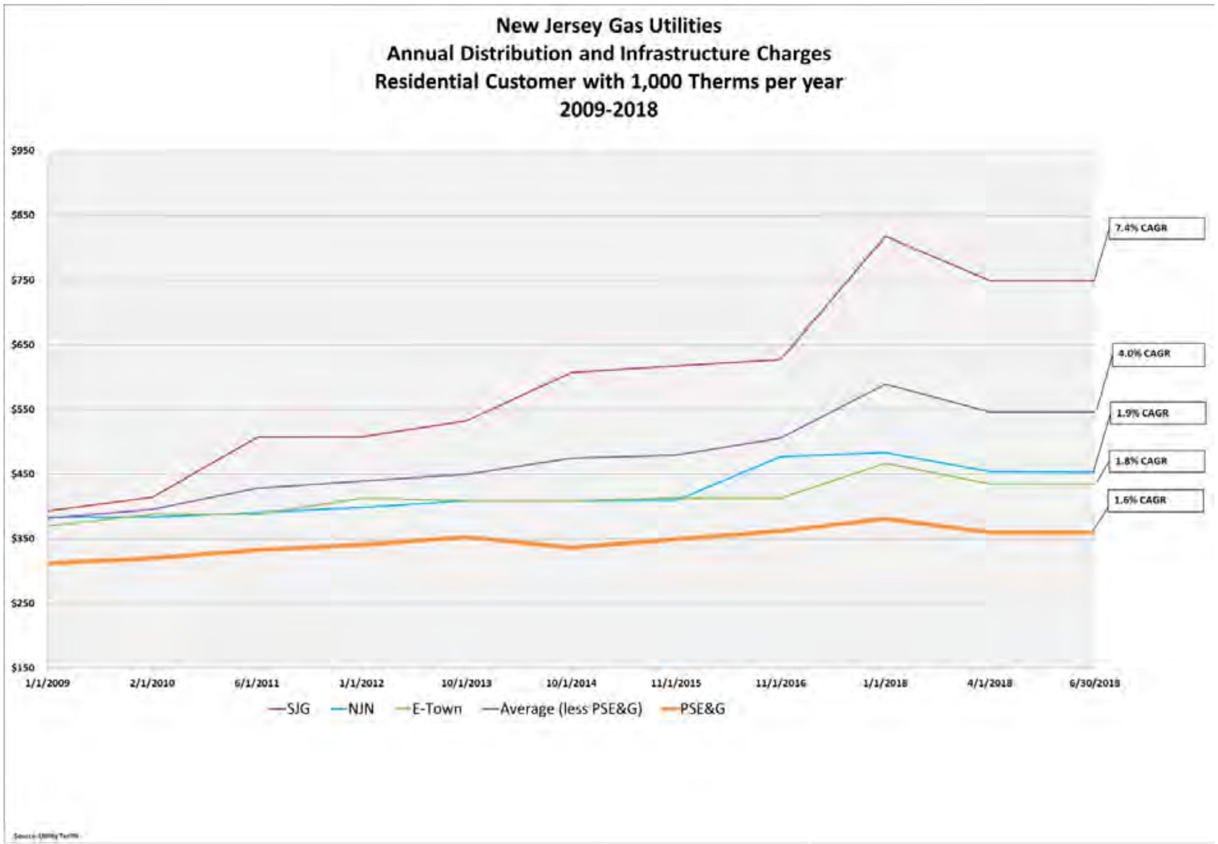
Q. That addresses the decline in your overall rate. This case addresses distribution rates. How do PSE&G's distribution rates compare to the other NJ utilities?

A. As of June 30, 2018, PSE&G's distribution rates continue to be the lowest in the State for gas customers and the second lowest for electric customers as illustrated in the charts below. Further, the Company's rates have increased at a very low rate compared with other New Jersey utilities and compared to inflation. This is primarily due to the Company's efforts to control costs. In fact, PSE&G has reduced total O&M expense since its last test year in 2009. PSE&G takes very seriously its responsibility to customers to manage costs prudently and be good stewards of the electric and gas distribution systems and the customer funds needed to operate and maintain them effectively. This is achieved by regularly benchmarking costs and performance and incenting employees to improve results relative to past performance and to benchmarks.

As can be seen in the chart below, 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 that is the subject of this proceeding for PSE&G, inclusive of all of the Company's infrastructure programs such as Energy Strong and the Gas System Modernization program, is approximately $295 per year, the second lowest among the State electric utilities and 20% lower than the $369 per year average of the other NJ electric utilities. Further, these costs have only increased 1.2% on an annual basis, which is about ¼ of the average increase of electric utilities in the State other than PSE&G.



With respect to 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 $360 is the lowest in the State, 34% less than the annual average of $546 for the other New Jersey gas utilities. PSE&G also has the lowest compound annual growth rate since our last rate case of 1.6%, less than half of the other utilities, which went up on average approximately 4% per year.

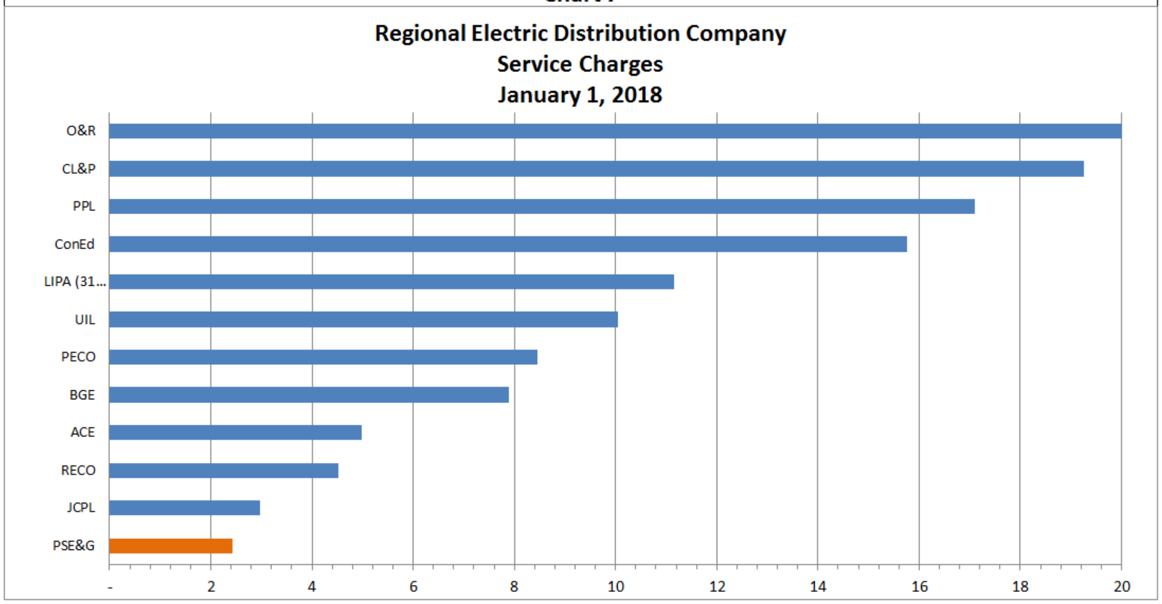


PSE&G is very cognizant of the impact of energy bills on its customers, and seeks to minimize costs and customer bills while providing high-quality service.

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

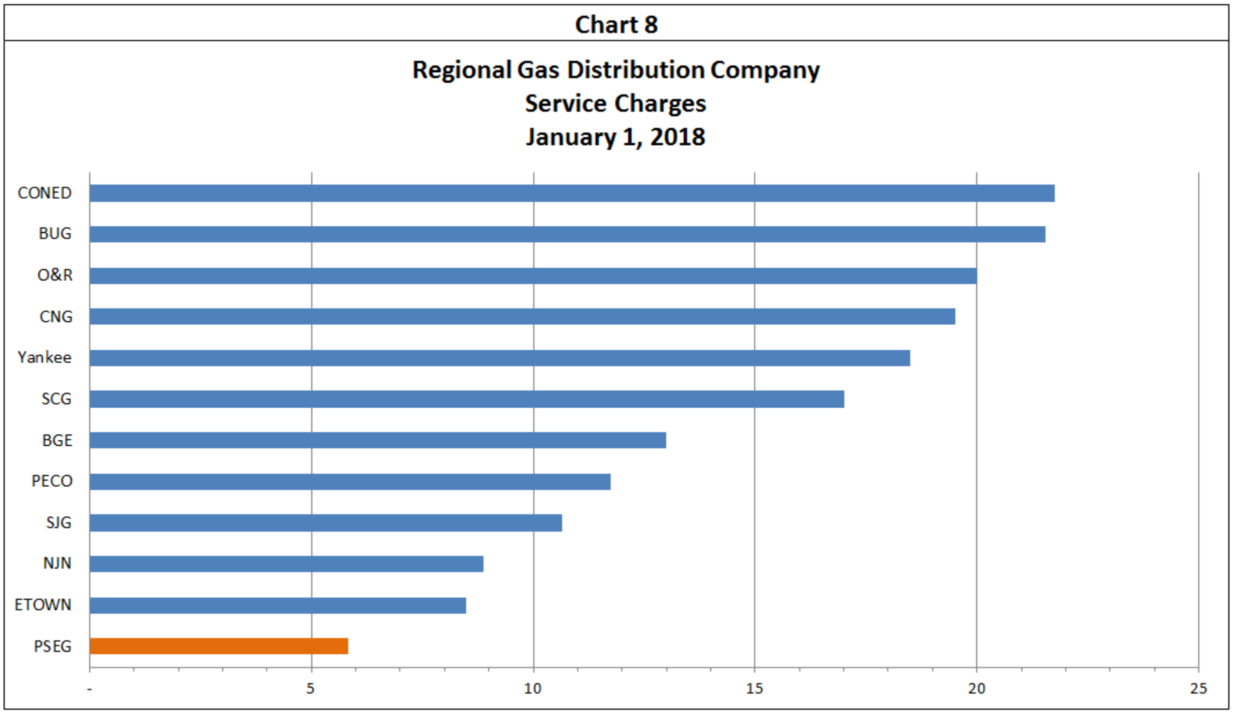
A. Yes. Mr. Stephen Swetz's testimony addresses the recovery of the rate increase proposed in this case through fixed and variable rates across customer classes using a cost of service rate design, while also considering PSE&G's present rate design and those of industry peers. One of the notable proposed changes in the Company's filing is to better align revenue recovery with costs to serve Residential Service (RS) electric customers by lowering the volumetric charges and moving the 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 fixed costs incurred to provide access, metering and customer service to customers. Not only is PSE&G's service charge the lowest in the region, it is the lowest out of 132 electric utilities throughout the country, a clear outlier and not reflective of true costs and appropriate economic signals.

Chart 7



In fact, the Company's 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 $8.04 (without SUT). The Company's proposal is to increase the monthly RS electric service charge over 3 years from the current $2.27 per month to $4.19 per month in year 1, $6.11 per month in year 2 and $8.03 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 $8.03 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 revenue recovery with cost incurrence.

Similarly, the Company also proposes 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.



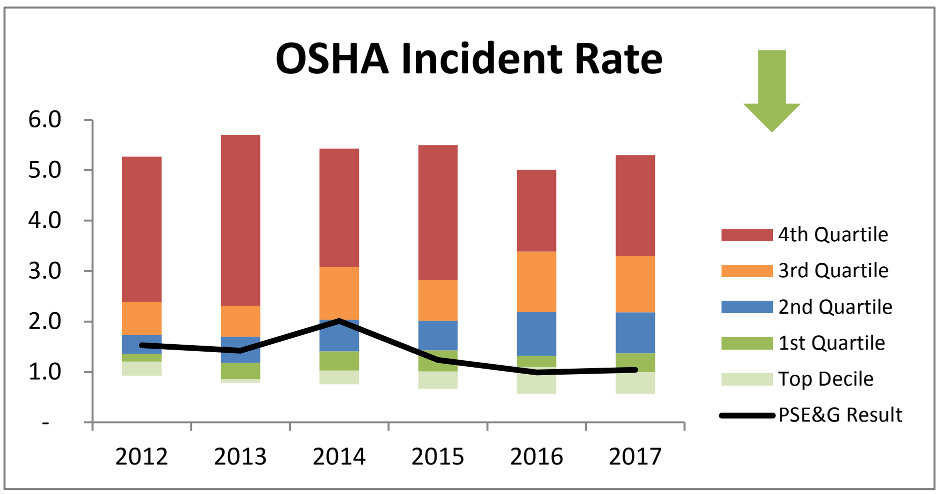
The current monthly fixed cost to provide access, metering and customer service is approximately $24.87 (without SUT). The Company's proposal is to increase the monthly RSG service charge over 3 years from the current $5.46 per month to $7.79 per month in year 1, $10.12 per month in year 2 and $12.45 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 $12.45 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. Mr.

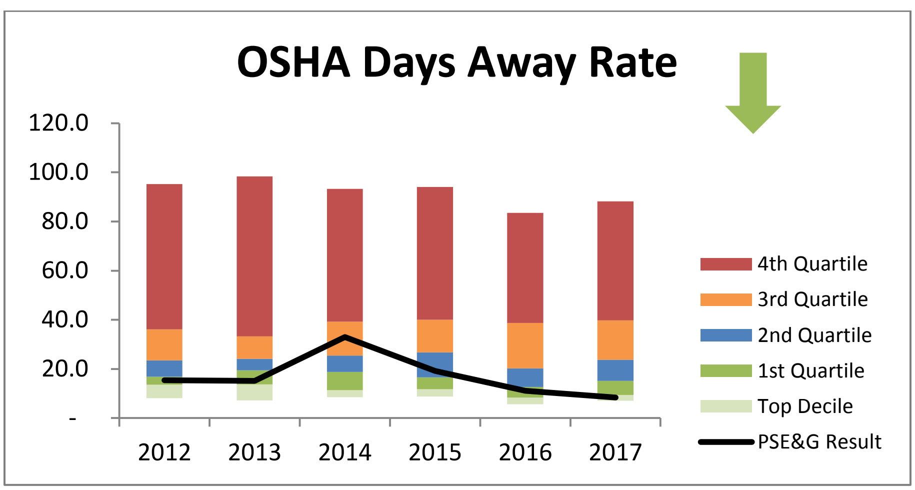
Swetz also proposes other changes to better align rates and tariffs with costs of service and industry trends.

Q. The rate stability and low cost compared to the last base rate case and other New Jersey utilities is impressive, but has that come at the expense of safety, reliability or customer satisfaction?

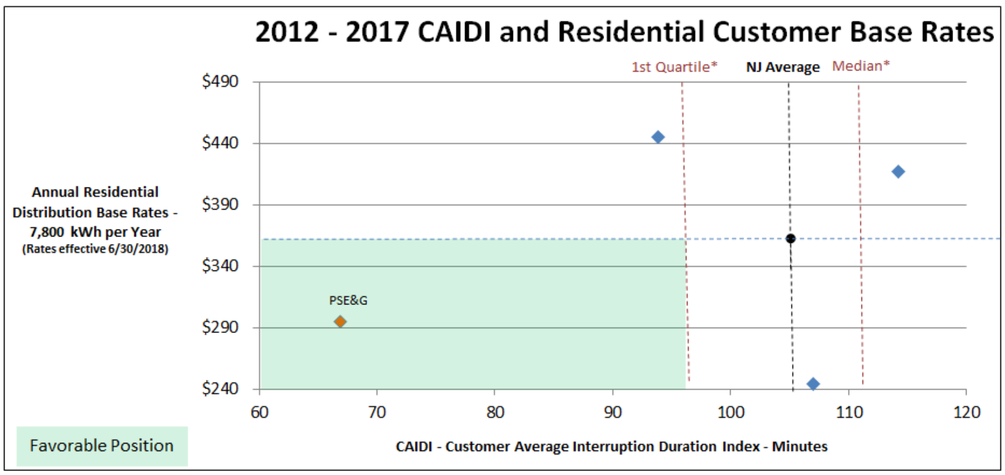
A. The Company has been able to maintain these low rates while performing at a high level overall and compared to peers.

- With respect to safety, PSE&G continues to perform at top decile levels for both OSHA Incidents and Severity measures as illustrated in the charts below:



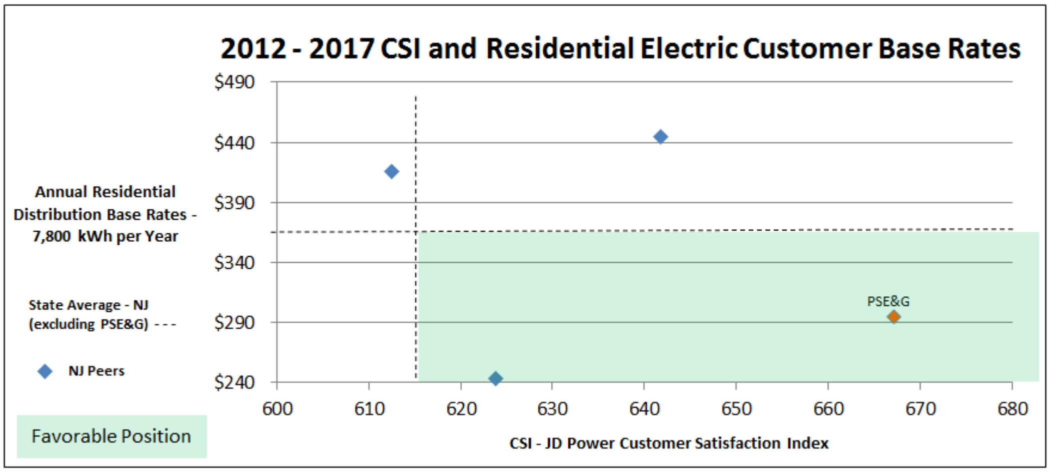


- With respect to reliability, the chart below illustrates that the Company's performance is a good value relative to other New Jersey utilities. PSE&G is well above the New Jersey utilities in reliability as measured by the Customer Average Interruption Duration Index (CAIDI) and also notably within the 1st quartile on a national basis, while PSE&G's distribution rates are well below the State average.

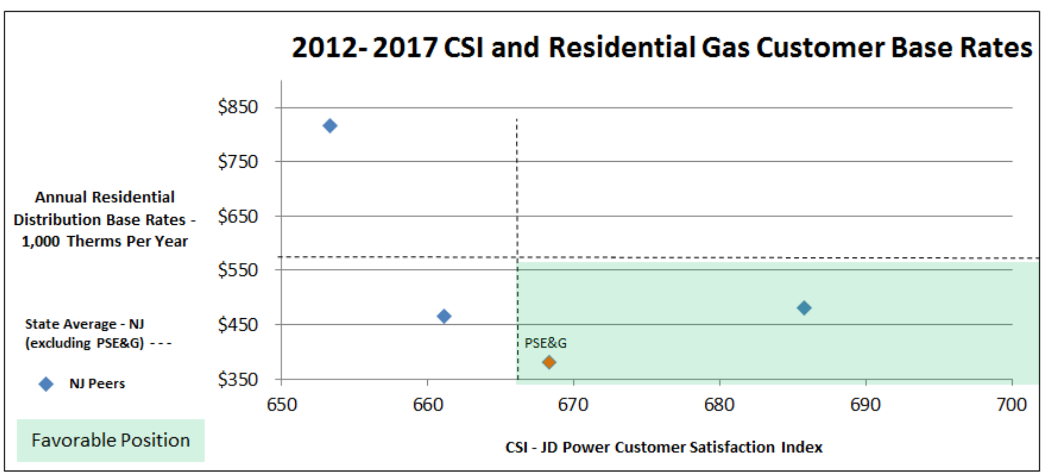


*IEEE Benchmark Year 2017 - Results for 2016 Data

- Similarly, the below charts demonstrate that PSE&G's customer satisfaction is delivered at a good price compared to peers. Specifically, electric residential customer satisfaction is the highest in the State while distribution rates are well below average:



And for gas, PSE&G has the second highest residential customer satisfaction while having the lowest distribution rates in the State.



In addition to these results, Mr. Jorge Cardenas provides testimony regarding PSE&G's outstanding storm response, which has been recognized by customers.

Q. How are those results being addressed in this base rate case proceeding?

A. The Company is requesting recognition of its safety, reliability and customer satisfaction results, delivered at low operating costs relative to peers. PSE&G documented these results extensively in Mr. Adams' benchmarking testimony. The Company is requesting recognition of these results through a) its ROE compared with its peers, and b) recognition of the value of incentive compensation that incents these results while controlling costs.

III. FACTORS DRIVING THE NEED FOR RATE RELIEF

Q. You mentioned 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 the Company's last base rate case filing, so PSE&G has 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 the Company's financial results well below its authorized rate of return and that represent the primary drivers of the rate increase sought in this filing. These factors include:

- Unrecovered Capital Investments;
- Insufficient Depreciation and Cost of Removal Rates;
- 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 capital investment made under the Energy Strong Program and the Gas System Modernization Program ("GSMP") since the conclusion of its last base rate case in 2010, the Company has also invested a substantial amount of capital to maintain, upgrade and harden its distribution system that has not yet 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, to the extent that 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 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, aside from the Energy Strong Program and GSMP investments, the Company has invested capital in excess of its depreciation expense and therefore needs to recover those capital investments. A primary driver of the requested increase is directly related to obtaining a return of and on these unrecovered capital investments.

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

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 the Company's 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 High Pressure Cast Iron (“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. The Company is proposing rates in this proceeding that would recover all investment associated with GSMP through December 31, 2018. This is expressly provided for in the GSMP Stipulation approved by the BPU, specifically, paragraph 20 which stated the following *“The Parties further agree that the required annual Stipulated Base spending for 2016 through 6 months after the end of the Test Year used* *in the Next Base Case is subject to prudence review and, unless disallowed as unreasonable or imprudent, shall be included in rate base and rates as a result of the Next Base Case"*.

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 PSE&G's 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, PSE&G has 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 the Company's returns and thus it is 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 the Company's system and modernizing and improving the performance of the 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. Insufficient Depreciation and Cost of Removal Rates

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

A. It is widely acknowledged 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 Mr. 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. The Company is 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 its 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, current sales volumes are roughly flat compared to sales at the time of the Company's most recent base rate case in 2009. It appears 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 the Company's 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 6,920 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 $266 million of incremental storm costs since the last rate case, including costs associated with Superstorm Sandy, Hurricane Irene, the October 2011 snowstorm, the March 2018 storms and other major storm events, almost all of which were declared States of Emergency by the Governor. The majority of these costs were already reviewed for prudence by the Board in BPU Docket. No. AX13030196, order dated September 30, 2014. The remainder of the costs are discussed in further detail in Mr. Cardenas' testimony and in the response to PS-INF-0007. Recovering these costs along with a carrying charge over the next three years would lead to a revenue requirement increase of approximately $90 million per year, which would have led to an incremental rate increase of more than 2% for electric customers. However, the Company proposes to offset this $266 million of storm costs with certain excess 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 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 ($77 million net of a tax adjustment for Tax Reform) of cost of removal in excess of the amount deemed to be over-recovered in the prior rate case. The Company is now seeking recovery of this deferral and proposes to minimize the rate impact by amortizing it over the next five years.

IV. MITIGATION OF THE RATE INCREASES

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 made to enable the Company to reduce its total O&M expense since its last test year in 2009. The Company takes very seriously its responsibility to customers to manage its 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 – that is, generally, top quartile in the industry, as noted above and more comprehensively 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. 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. 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 Reform and Tax Adjustment Credit

Q. Mr. Jennings, please describe the impacts of tax reform that 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%. Effective April 1, 2018, during the pendency of this base rate case, the Company lowered its rates by approximately 2% as a result of the lower taxes in its operating costs. Between the January 1, 2018 effectiveness of the lower tax rate and the April 1, 2018 effectiveness of the lower rates charged to customers (the "stub period"), we collected approximately $30 million of revenues related to the prior tax rate. We have recorded that amount as a regulatory liability to be returned to customers, with interest. In this filing we propose to return that amount at the conclusion of this rate case over a three month period.

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.

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.

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. PSE&G's election to seek this greater deduction will benefit 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.

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

A. We propose to flow this benefit to customers in three ways. First, we propose to offset the storm cost recovery of approximately $266 million and other smaller regulatory assets with a portion of the excess deferred income taxes caused by Tax Reform. 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 unprotected excess deferred income taxes over the next five years through a new Tax Adjustment Credit ("TAC"). 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 this manner 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 PSE&G's revenue requirements and benefits customers by offsetting the unusual and significant storm costs that were incurred.

Combined Electric and Gas	Annual*
Base Rate Case Revenue Requirement (annualized)	419
Tax Adjustment Credit	(147)
Revenue Change	272
Cumulative % Increase:	**3.6%**
Electric	**Annual***
Base Rate Case Revenue Requirement	173
Tax Adjustment Clause	(26)
Revenue Change	147
Cumulative % Increase:	**2.7%**
Gas	**Annual***
Base Rate Case Revenue Requirement	247
Tax Adjustment Clause	(121)
Revenue Change	125
Cumulative % Increase:	**6.1%**

* Does not reflect $39M refund in 2018 for the overcollection of income tax expense from January 1, 2018 through March 31, 2018.

Q. Does the flow-back of tax benefits through the TAC require the Company to make any offsetting adjustments to its rate base and return on rate base?

A. Yes. As discussed more fully in Mr. Krueger's and Mr. Swetz' testimony, the taxes that we propose to flow back reduce our rate base and therefore reduce our revenue requirements in this case. As a consequence, we propose a return on the amounts we flow back over the next several years. Customers enjoy the benefit of lower rates when the Company holds these deferred taxes as a reduction of rate base. Once the Company flows those excess taxes to customers there is no longer a reduction of rate base and a return should be provided. The Company is not requesting a return on any amounts flowed back that had not reduced rate base in the test period, nor the current period SHARE deductions.

Q. Why do you propose to provide these benefits through a clause mechanism rather than base rates?

A. Mr. Krueger discusses this in his testimony. There are three primary reasons a clause is the appropriate mechanism and base rates would not be appropriate. First, there are several aspects of tax reform that require clarifying guidance from the IRS. That guidance could result in several changes, including reclassifying excess deferred taxes between protected and unprotected status. If some of the protected amounts could be reclassified to unprotected, PSE&G could flow back more through the clause. If some of the unprotected amounts were determined to be protected, we could reduce the amount flowed through the clause. Conversely if this flowback were done as an amortization in base rates, and we returned amounts that were later determined to be protected, we would have to seek to change base rates to avoid a violation of the IRS normalization rules, a critical issue. Second, we have estimated flowing these amounts back over a five year period through the clause. However, it is uncertain when PSE&G's next base rate case will be filed. If the case is filed earlier, those rates will be reset with only a portion of this amount being flowed back. The proposed clause provides greater certainty that the full amount will be flowed back over five years. Finally, we have estimated the amount of SHARE deductions we expect in the future. Actual amounts will vary. PSE&G wants to ensure the full amount of those deductions are flowed to customers. It is most effective and timely to do that through a clause.

Q. Can you discuss how you propose to treat any remaining SHARE deferred taxes?

A. Yes. After we complete the flowback of excess deferred taxes, we propose to return any remaining SHARE deferred tax balance in a future period to be agreed with the parties.

Returning this amount earlier would have an adverse impact on our credit measures.

Q. Can you please explain how the Company has adjusted its proposal to flow benefits back to customers through the TAC since filing this case?

A. Yes. The original 5+7 filing contemplated returning the SHARE deferred tax balance. The Company had proposed to apply a portion of that balance to immediately offset certain regulatory assets, predominantly deferred storm costs, thereby avoiding any rate increases to recover those costs. PSE&G then proposed to return the remaining balance in a measured fashion over a five year period to maintain rate stability and to mitigate potentially adverse impacts on credit statistics. In this 12+0 update filing, with the implementation of tax reform, the Company proposes to first address the excess deferred taxes caused by the reduction in the federal tax rate. PSE&G proposes to handle the excess deferred taxes in the same manner that it had proposed regarding the SHARE balance, namely to use the unprotected excess deferred taxes to offset the storm and other regulatory costs and then return the remaining balance (including any protected excess deferred taxes that become unprotected) over the next five years. Once that amortization is complete, the Company will propose to return the remaining SHARE balance over an appropriate time period. The timing and amount of flow back of these excess deferred tax balances are again managed to maintain rate stability and mitigate potentially adverse impacts on the Company's credit statistics, resulting in a simpler, consistent amortization profile.

The Company is also proposing to use the TAC to refund the protected excess deferred balance, which as discussed in the testimony of Mr. Krueger, must be returned using the Average Rate Assumption Method (ARAM). The Company also continues to propose refunding the ongoing SHARE tax benefits to customers via the TAC as proposed in the original 5+7 filing. As discussed previously, the TAC credit for the overcollection of revenues prior to implementing the lower rates due to tax reform has been reduced as it only relates to the first quarter of 2018 as opposed to the first nine months due to the earlier implementation of new base rates on April 1, 2018. In accordance with the Board's order on tax reform, the Company is accruing interest at a short-term rate on the income tax overcollection, which will be returned to customers via the TAC. Finally, there were incremental storm costs incurred in March 2018 that added to the regulatory asset balance to recover, thereby reducing the balance available to be returned to customers in future periods.

For details on both the protected and unprotected excess deferred balance and the incremental SHARE deduction, please see the testimony of Mr. Krueger. For details on the calculation of the TAC, proposed rates, and bill impacts, see the testimony of Mr. Swetz.

B. Cost Containment Measures – O&M

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 VI 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 PSE&G's treatment of wages.

Q. Has the Company 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 since our last rate case when we did not provide MAST wage increases, PSE&G has generally provided average annual merit increases of approximately 3% to our employees. We also manage our union employee costs through a 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. PSE&G was 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 March 2010, a cap was introduced on overtime included in pensionable wages for MAST employees, limiting overtime to 20% of base pay to be eligible pay. Similarly, effective 1/1/2012, for Choices employees covered under the collective bargaining agreement with UWUA Local 601, a cap of overtime earnings at 10% of base pay to be included in pensionable earnings was implemented;
- 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 Plan 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, PSE&G 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). Adopting the new accounting standard serves to lower the overall pension expense for the Company.

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.

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 most recently available period ended March 31, 2018, we have been in the top 3% 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 9.5% over the seven years through March 31, 2018, 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 PSE&G were less funded. If we were to have paid the average PBGC premiums (as a percentage of plan assets), PSE&G 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 actual test year reflects approximately $29 million of income from our pension. If not adjusted, this would reduce our revenue requirements. However, the Company cannot offset such a reduction in revenue requirements and make itself whole by taking that cash out of the pension funds. And, any such reduction in revenue requirement would reduce operating cash flow and therefore adversely impact PSE&G's credit metrics. This pension income is an actuarial result of the actions PSE&G 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 PSE&G's 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 PSE&G 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 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. These steps 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 2022. To further mitigate the escalating costs of healthcare, we have rigorously renegotiated key vendor contracts with partners who provide various benefit administration services.

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 June 30, 2018, PSE&G's embedded cost of long term debt was approximately 3.96%. This represents a reduction of over 200 basis points from the embedded cost of long term debt as of December 31, 2009 of 6.15% (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 June 30, 2018, the Weighted Average Maturity ("WAM") of our portfolio was 15 years which represents an increase of 2.5 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. Appliance Service Business

Q. Has the Company's Appliance Service Business helped to reduce rates?

A. Yes. **PSE&G is** 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 $43 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.

G. Summary Impact of Cost Savings

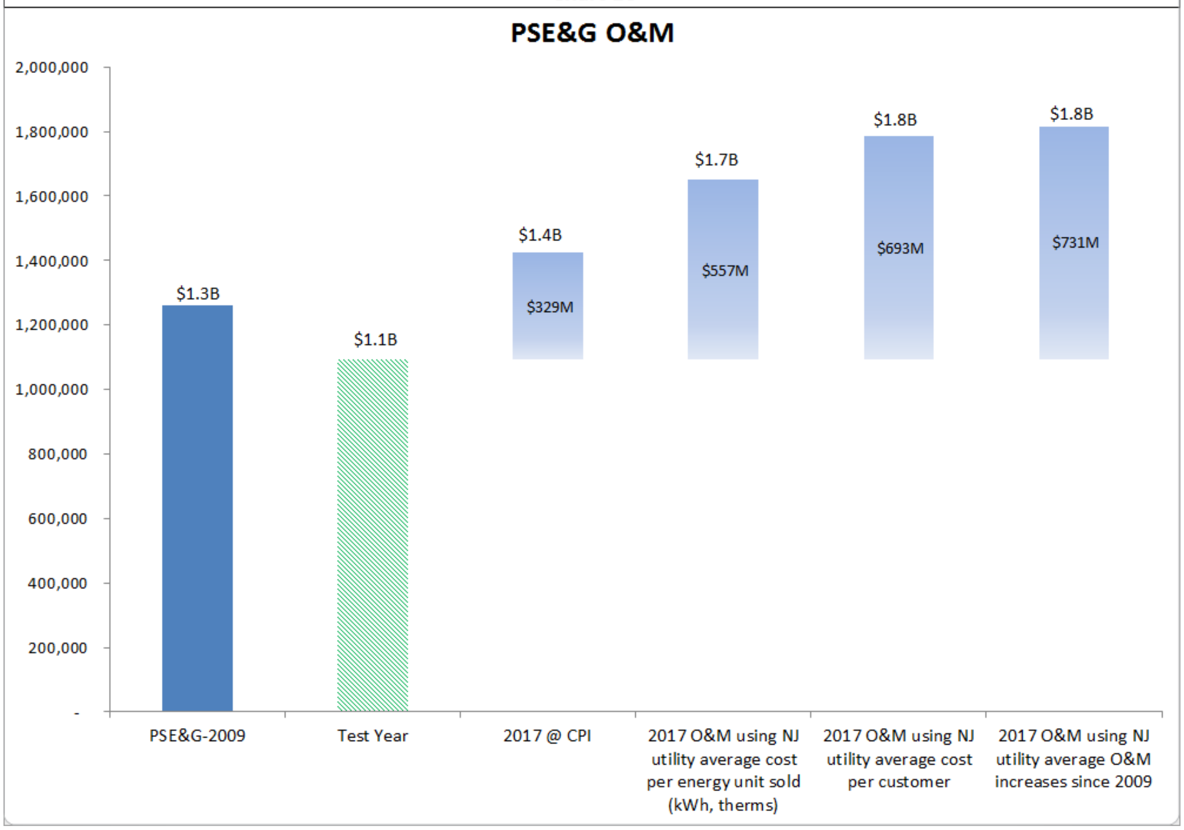
Q. Please summarize the results of your total O&M cost saving measures.

A. As shown in the chart below, if not for the cost savings measures identified above, PSE&G's total O&M costs in this rate request would be substantially higher. The chart compares the total O&M costs in the last test year with those in the 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. CPI - 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. Average cost per energy unit sold by other NJ utilities: 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. Average cost per customer of other NJ utilities: In this scenario, we calculated the average total O&M per customer of the other NJ utilities and applied it to PSE&G's 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. Average rate of O&M increase of other NJ utilities: 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 PSE&G's 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 3% could have been from more than 5% to over 10%.

V. CAPITAL STRUCTURE AND THE COST OF CAPITAL

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 7.36% that is derived from a capital structure composed of 54% equity, 45.53% debt, and 0.47% customer deposits. The embedded cost rate for our long term debt is 3.96%. 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.

- **Return on Equity**

Q. How did Mrs. Bulkley determine an appropriate cost of equity?

A. 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.

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.

Q. What is your view relative to these amounts?

A. The Company's position is that 10.3% is an appropriate ROE and is slightly above the midpoint of our proxy group. Also, relative to recent New Jersey settlements, the Company believes that a) market conditions have meaningfully changed over the past year since several of these settlements were reached, most notably evidenced by the increase in US 10 year Treasury yields moving from approximately 2.4% at December 31, 2017 to approximately 3% currently, and b) the relative performance and relative lower rates of the Company compared to other New Jersey utilities should be considered.

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 and above other New Jersey utilities?

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. While we always seek to continuously improve, 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 lower than (i.e., better than) 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") for the period 2009 through 2016. 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 2017. 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 2017. Residential gas customer satisfaction ranked just below 1st quartile from 2012 to 2016, 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. 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.

Q. There have been significant market factor changes over the past several months; has this caused any changes in the Company's filing?

A. While there have been notable market condition changes, the Company is not proposing to change the ROE request of 10.3%. There has been an increase in certain market conditions, notably highlighted by the increase in the US 10 year Treasury yield, which increased from approximately 2.4% at December 31, 2017 to hover close to 3% in recent months. This is a material increase, and was faster paced and of a sharper magnitude than expected. Further, the increase in the US Treasury yield drove a corresponding decrease in the stock prices of most utilities. These changes could indicate a higher ROE than the Company's original request is warranted. However, the Company proposes to maintain the ROE request at the current 10.3% level proposed in the original 5+7 testimony.

b. Capital Structure and Credit Ratings

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 has been gradually increasing its equity ratio to lessen the negative effect of tax reform on our credit statistics, increasing the rate to 53.6% at June 20, 2018, and we expect to move towards 54% later in 2018. The actual common equity ratio will vary monthly based on monthly earnings, cash flows and financing activities. The 54% target percentage for the end of 2018 was determined by evaluating the equity level needed to be towards the low end 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 at, or slightly below, 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 at, or slightly below, 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, and as PSE&G flows back excess deferred income taxes to customers, it places notable downward pressure on credit metrics. 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. What key metrics and factors do the rating agencies assess in determining the Company's credit rating?

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 Moody's credit opinion on PSE&G from June 2018 (attached as Appendix SSJ-C), they state the following:

> **Rating outlook**
>
> PSE&G's stable rating outlook is based on the existing suite of regulatory recovery mechanisms provided by the BPU, a supportive regulatory and political environment in New Jersey, and our expectation that the company will successfully manage its

large capital spending program. However, we expect PSE&G's financial profile will become weaker over the next 12-18 months.

Factors that could lead to an upgrade

Given PSE&G's strong credit rating and its ongoing capital investment program, an upward movement in ratings is unlikely at this point. However, a sustained improvement in credit metrics, with CFO pre-WC to debt in excess of 26%, could lead to a rating upgrade. Also, if there is a significant tangible improvement in its regulatory environment, resulting in shorter regulatory lag for the cost recovery and an accelerated increase in cash flow, for example, a rating upgrade could be considered.

Factors that could lead to a downgrade

A rating downgrade could be considered if the regulatory relationship became more contentious and regulatory lag increases. If PSE&G's CFO pre-WC to debt falls below 19% on a sustained basis or its financial profile weakens due to higher leverage, for example, a rating downgrade could be possible.

Also, as with the rest of the utility industry, PSE&G's cash flow will be negatively impacted by federal tax reform, particularly from a lower deferred tax contribution to cash flow from operations and the return of excess deferred tax liabilities to customers…..We expect the annual CFO pre-WC to debt to fall below 19% in 2018 and remain weak over the next 12-18 months, unless the company takes further mitigating actions or the rate case outcome results in higher cash flow.

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.

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.

Q. Has the BPU commented on your financial management practices?

A. 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 20, 2017 agenda meeting, page 3, lines 14-23.

Q. Please provide a summary of PSE&G's capital structure since its last base rate case.

A. 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 Actual	-	$150M	53.0%	20.1%
June 2018 LTM	-	-	53.6%	~19% (a)
Cumulative	$300M	$675M		

(a) This represents our estimate of Moody's calculation of FFO to Debt. The ratio trended notably lower due to the loss of bonus depreciation under the recently enacted Federal Tax reform. In 2019 it will reduce further due to the flowback of excess deferred income taxes. To illustrate the impact of tax reform, in 2017 our FFO was $1.8B and our Debt was $9B resulting in a FFO/Debt ratio of 20.1%. With the flowback of approximately $150M of tax benefits proposed in the TAC, FFO would decrease to $1.65B and debt would increase to approximately $9.1B, resulting in a *pro forma* FFO/debt ratio of 18.3%, a decline of approximately 1.8%.

- 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 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 low 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 or slightly below 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 further weaken our credit metrics below Moody's range, putting our targeted credit rating at additional risk and potentially adversely impacting our financing costs.

Q. Why is it important to maintain the Company's current credit ratings?

A. PSE&G has approximately $9 billion of long term debt outstanding. A reduction in the Company's credit ratings could adversely impact the pricing of those securities. Capital losses by existing bondholders would be viewed unfavorably and could possibly impact the market's receptivity to future bond offerings. PSE&G wants to maximize participation in future bond offerings to maximize the demand for its bonds so it can continue to achieve the best pricing outcome.

PSE&G also has sizable capital requirements and several billion dollars of long term debt maturing in the coming years, so accessing the capital markets on reasonable terms to address these financings will be critical. The Company has had a strong history of raising low cost financing, which has directly benefited customers in the form of lower interest expense – both in its infrastructure filings as well as this base rate case proceeding. As noted in the original 5+7 filing, the Company's cost of debt has declined from over 6% in 2009 to less than 4% today, while the Company increased the weighted average maturity of its portfolio from 12.5 years to approximately 15 years. This value is translating into lower customer rates than otherwise would have occurred. Conversely, a reduction in PSE&G's credit rating would drive incremental interest expenses, which would ultimately flow through rates to customers. Overall, preserving the Company's current credit ratings is the most desirable course of action for the reasons cited above.

Q. Have there been any changes related to credit considerations since the original 5+7 filing?

A. Yes. While tax reform is a material benefit for customers, it does have a negative impact on utilities' credit positions. As discussed in Mr. Krueger's testimony, the implementation of lower tax rates gives rise to excess deferred taxes. As those taxes are flowed back to customers, it reduces a utility's operating cash flows. This impact is in addition to the loss of bonus depreciation discussed previously. These decreases weaken a utility's credit statistics, notably its FFO/Debt ratios discussed in my original testimony. This issue has been highlighted by the rating agencies in their reports. On January 19, 2018, due to the expected impacts of tax reform, Moody's changed its ratings outlook on 25 US regulated utilities. Their report, attached as Appendix SSJ-A, states in part, "Over the next 12 to 18 months, Moody's will continue to monitor the financial impact of tax reform on each company, including its regulatory approach to rate treatment and any changes to corporate finance strategies."

To mitigate the impact of these weaker credit metrics, many utilities are seeking to increase the equity portion of their capitalization structure. While these actions could partially mitigate the impacts, it does not assure that the utility would be able to maintain its credit rating. See the report from S&P dated January 24, 2018, attached as Appendix SSJ-B, which states in part, "Regulators must also recognize that tax reform is a strain on utility credit quality, and we expect companies to request stronger capital structures and other means to offset some of the negative impact." S&P went on to note that "More equity may make sense and be necessary to protect ratings if financial metrics are already under pressure and regulators are aggressive in lowering customer rates." Rating agencies will be closely monitoring regulatory relations and treatment especially given the impacts of tax reform.

This will be a component of rating agencies' credit profile assessment. Not achieving a higher equity ratio could be scrutinized and viewed as a further credit negative by the rating agencies in their credit assessments.

Q. Is PSE&G subject to these credit considerations?

A. Yes. The Company is proposing to flow back the excess deferred taxes as outlined in the TAC table above. This is a significant benefit for customers and the Company has the financial wherewithal to return these deferred taxes as proposed in its filing. However, this flow back of excess deferred taxes will negatively impact cash flow, and PSE&G's resulting FFO/Debt ratios. The Company now expects these ratios to range between 17-19% in 2018 and 2019. As outlined in my original 5+7 testimony, this ratio is well below recent years' results, below our recent projections, and below Moody's range of 19-26% for the Company's targeted credit rating.

Q. What is PSE&G proposing to address these credit considerations?

A. PSE&G has been increasing the equity portion of its capitalization structure, from 51.2% in prior years to approximately 53%-53.5% currently, and is planning to increase to 54% by year-end. The Company has requested regulatory approval of a 54% equity component in the original 5+7 rate case filing. PSE&G will maintain its equity ratios in line with what is approved in this proceeding. The Company also proposed to amortize the excess deferred tax balances through the TAC over a five year period to smooth the impact over several years. While these actions do not assure that the Company will be able to retain its current ratings, they are positive actions and PSE&G anticipates that regulatory recognition of these concerns will be viewed as supportive. As stated before, PSE&G has the ability to return these excess deferred taxes as proposed and is comfortable with its credit position as filed.

Q. Given the meaningful impact of tax reform and the importance of maintaining the Company's credit rating, are you proposing a change to PSE&G's capital structure request in the original 5+7 filing?

A. No. While these are important changes, the Company is prepared to maintain its request for a 54% equity component of the capital structure. The factors summarized above further amplify the importance of this request. The Company believes this equity ratio, coupled with a 10.3% ROE, the tax flow back schedule outlined in the TAC, and the recovery of operating costs included in its filing provide a reasonable course that balances customer rates and stability, credit considerations, and shareholder return. Reductions to these factors would adversely impact the Company's ability to retain its current ratings.

VI. 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 aligned with 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 $36 million associated with incentive compensation. Of that amount, approximately $10 million is provided to Officers and relates to a mix of targets, including operational performance, but mostly weighted towards financial results. Of the remaining $26 million, $20 million relates to achieving operational metrics and strategic goals, with the remainder related to achieving financial goals, all of which ultimately benefits customers as discussed separately.

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, 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 $36 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, Docket No. 16060510, 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.

VII. 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 $52 million from the appliance service business, $43 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 $52 million in margin revenue, $34 million relates to gas and is fully credited to the benefit of customers by reducing our revenue requirement, and $18 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 customers 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.

VIII. STORM COSTS

Q. Is an adjustment required for test year storm cost normalization?

A. Yes. As discussed in my 9+3 update testimony, an adjustment for incremental O&M Major Storm Event costs incurred during the test year is necessary. The Company has incurred approximately $25 million of test year electric incremental Major Storm Event costs. As discussed earlier and in Mr. Krueger's testimony, we propose to offset these costs with certain excess deferred taxes. Supporting cost detail on the individual storms included in the test year storm costs was included with and itemized in the initial filing, the 9+3 update and in the response to PS-INF-0007.

Q. What is the definition of a "Major Storm Event"?

A. A Major Storm Event is defined under N.J.A.C. 14:5-1.2 and includes a weather event such as a thunderstorm, tornado, hurricane, heat wave, snow or ice storm which either affects at least ten percent of the customers in one of the Company's operating areas or results in the declaration of a state of emergency.

Q. How does the Company propose to account for the O&M costs associated with Major Storm Events in periods beyond the test year?

A. Consistent with the way in which the Company has accounted for incremental O&M costs associated with Major Storm Events since 2010, the Company proposes to defer these costs for future recovery in a manner to be determined by the BPU. Under the revised base rates proposed in this proceeding, the Company will no longer have any allowance for O&M costs associated with Major Storm Events in its base rates. Instead, all such costs will be recovered on a deferred basis. The use of deferred accounting for the costs ensures that customers will pay no more and no less than the Company's actual costs associated with events that are beyond the Company's control and impossible to predict.

IX. <u>GREEN ENABLING MECHANISM</u> ("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 overall economics provided the Company with the opportunity to earn its allowed return even when taking into account the lost revenues caused by the programs. 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 and satisfy 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.

Q. Have there been any other external changes that occurred subsequent to your original 5+7 filing that have a bearing on this proceeding that you'd like to highlight?

A. Yes. Subsequent to the original 5+7 filing in January, new legislation A-3723 was passed by the New Jersey Assembly and Senate related to the utility's role in advancing energy efficiency. This legislation requires utilities to achieve 2% reductions in annual electric and 0.75% reductions in annual gas usage and requires that the electric and gas utilities make filings with the BPU to propose the programs necessary to achieve these targets, and among other things, recover "the revenue impact of sales losses resulting from implementation of the energy efficiency and peak demand reduction schedules." The Company's GEM proposal precisely addresses this legal requirement regarding the revenue impact of sales losses. PSE&G expects to be making a Clean Energy Future filing in the near future to begin the process of investing to reduce customer usage and bills and achieve the requirements of this legislation.

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 consisted of five months of actual data (actuals through November 30, 2017) and seven months of estimated data. Actual data was supported by the Company's accounting records while projected data was 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 updated our filing with nine months of actual data and three months of forecast data ("9+3 filing") in May 2018, and are now updating with twelve months of actual data ("12+0 filing"). This 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 R-2

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

A. Yes. Schedule SSJ-02 R-2 shows the determination of the revenue requirement increase being requested in this proceeding. Based upon rate bases of $5.7 billion and $4.2 billion for electric distribution and gas distribution, respectively, pro-forma operating income of $293.0 million and $138.2 million for electric and gas, respectively, and a required rate of return of 7.36%, the increase in required revenue requested is $172.7 million for electric distribution and $246.8 million for gas distribution.

Utility Rate Base—Schedule SSJ-03 R-2

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

A. Schedule SSJ-03 R-2 presents projected total electric and gas utility rate bases at June 30, 2018 and December 31, 2018. Electric rate base is expected to be $5.65 billion by June 30, 2018 and $5.66 billion as of December 31, 2018. Similarly, gas rate base is expected to be $4.09 billion by June 30, 2018 and $4.24 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 R-2 through SSJ-15 R-2 and will be addressed below.

Revenue Factor—Schedule SSJ-06 R-2

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 1.3944. The factor includes the 9% State of New Jersey Corporate Business Tax, the 21% Federal income tax, and the assessments for the Board of 0.1924% and the Division of Rate Counsel (Rate Counsel) of 0.0528%. The gas revenue factor is 1.4172. The higher factor for gas reflects the inclusion of a rate for uncollectibles of 1.60%. Electric uncollectibles are recovered through the Societal Benefits Charge (SBC) and are not in distribution base rates.

Utility Plant In Service—Schedule SSJ-07 R-2

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 R-2, is estimated to be $9.3 billion and $8.0 billion respectively at June 30, 2018 and $9.5 billion and $8.3 billion respectively at December 31, 2018.

Plant-In-Service Additions from June 30, 2017 through December 31, 2018—Schedule SSJ-08 R-2

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

A. Yes. Schedule SSJ-08 R-2 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 $1.1 billion for electric and $1.4 billion for gas. The additions are primarily distribution plant.

Accumulated Depreciation—Schedule SSJ-09 R-2

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 R-2, as a rate base deduction using a mid-year convention.

Customer Advances for Construction—Schedule SSJ-10 R-2

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 R-2, electric and gas distribution rate base has been reduced by $27.3 million and $18.0 million, respectively, based upon a 13-month average of the most current available actual advances—the period June 2017through June 2018 .

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 $507.1 million for electric rate base and $294.4 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 R-2 of $398.2 million and $256.6 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 R-2

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

A. I have included $108.2 million and $37.6 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 June 2017 through June 2018.

Prepayments—Schedule SSJ-12 R-2

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 $0.7 million and $0.3 million, respectively, in rate base. These levels are based upon a 13-month average as of June 2018.

Accumulated Deferred Taxes—Schedule SSJ-13 R-2

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 R-2. The net accumulated deferred taxes amount to a $1.7 billion reduction to electric rate base and a $1.7 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 R-2

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 R-2 and RCK-6B R-2. As a result, this adjustment decreases electric distribution rate base by $0.5 million and gas distribution rate base by $0.2 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 R-2

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

A. As explained in more detail below in the description of Schedule SSJ-47 R-2 (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 $200.7 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 R-2 through SSJ-25 R-2 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 R-2 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 twelve months of actual data.

Pro-forma Distribution Operating Income—Schedule SSJ-26 R-2

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

A. Yes. Schedule SSJ-26 R-2 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 a 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 $63.5 million after-tax. On the gas distribution side there are 19 adjustments that reduce the test period operating income by $136.0 million. Each of the *pro forma* adjustments will be discussed in more detail below.

Adjustment No. 1: Wages—Schedule SSJ-27 R-2

Q. Please address your adjustments for Wages.

A. These adjustments to operating income of a reduction of $3.6 million and $4.7 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 labor charges to electric distribution and gas distribution 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 R-2

Q. Explain the adjustment for Payroll Taxes.

A. The reductions to operating income of $0.253 million and $0.332 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 R-2 are calculated utilizing a composite 7.06% tax rate.

Adjustment No. 3: Interest Synchronization (Tax Savings) Schedule—SSJ-29 R-2

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 R-2, the interest-bearing components of our capitalization supporting rate base produce synchronized interest expenses of $5.3 million more than the interest expense in the test year for electric and $3.6 million more than interest expense in the test year for gas, resulting in tax savings of $1.5 million for electric and of $1.0 million for gas.

Adjustment No. 4: Pension and Fringe Benefits—Schedule SSJ-30 R-2

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 $12.4 million for electric and $22.0 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 R-2

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 $5.2 million for electric distribution and $1.3 million for gas distribution. Interest expense on funds borrowed from the policies is directly related to the $6.5 million in benefits attributable to the policies. My adjustment to the test year, which is in line with prior rate cases, is to include the gross interest cost of $3.2 million for electric and $1.0 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 R-2

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. Schedule SSJ-32 R-2 shows the adjustments necessary to reflect normal weather for the period July 2017 through June 2018. This schedule shows a comparison of the distribution revenue for the actual twelve months with 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 $0.2 million for electric, is required since the test year, July 2017 to June 2018, was 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 R-2

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 ending June 2018 as representative and appropriate for this proceeding. 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 R-2

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

A. Yes. This adjustment of $0.06 million for electric and $0.37 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 R-2

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 $2.3 million for gas for the year. This adjustment before taxes of $131,000 for electric and $144,000 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-36R-2

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, $18.3 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 $18.3 million and increases electric margin by approximately $9.2 million. After adjusting for tax effect this results in an increase to operating income of $6.6 million for electric and a decrease of $13.2 million to operating income for gas.

Adjustment No. 11: TSG-NF Margin—Schedule SSJ-37 R-2

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

A. A reduction to gas operating income in the amount of $403,000 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 R-2

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 R-2) 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 $22.3 million for electric and $26.7 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 $59.9 million for electric and $81.1million for gas. As a result, the total annualization of depreciation expense at the proposed depreciation rates results in a reduction to operating income of $59.1 million for electric and $77.5 million for Gas.

Adjustment No. 13: Storm Cost Amortization - Schedule SSJ-39 R-2

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 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 $20.4 million of post 2012 incremental storm costs through June 30, 2017, as well as $0.271 million of trailing costs due to a late bill submitted by Florida Power and Light for mutual aid rendered during Superstorm Sandy, 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 $84.0 million for electric and $2.7 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 R-2 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 R-2

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. The Company has incurred $25.2 million of test year electric incremental Major Storm Event costs through the end of the test year. As discussed 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 $8.42 million per year.

Adjustment No. 15: Recovery of Deferred Excess Cost of Removal Refund– Gas- Schedule SSJ-41 R-2

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 $76.6 million balance, net of a tax adjustment in December 2017 as a result of the decrease in the federal tax rate as a result of the 2017 Tax Cuts and Jobs Act.

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 $17.4 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: Test Year Amortization Adjustments - Schedule SSJ-42 R-2

Q. Is an adjustment required to remove expiring amortizations?

A. Yes. The test period contains three amortizations that will not continue into the rate year. 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. The second amortization is for Medicare, which ends in December 2018 and as such will no longer be required for recovery. Therefore, we are excluding this cost. The final amortization is for Energy Efficiency TrakSmart Software Assets, which are recovered in the Green Program Recovery Charge. As a result of these amortization adjustments, electric operating income increases $2.2 million and gas operating income decreases $8.8 million.

Adjustment No. 17: Other Regulatory Assets- Schedule SSJ-43 R-2

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 was required to remediate the property as the current owner. The Cape May Street soil remediation project was completed in March 2018. Ground water monitoring at this site is ongoing. The total expenditures as of June 30, 2018 are approximately $11M. Future costs for ground water monitoring and regulatory filings are estimated to be approximately $0.6M. Discovery is complete with respect to the Company's deferral authority filing. Rate Counsel has opposed PSE&G's filing; the Company has requested that the Board either hold the deferral proceeding in abeyance pending resolution of the recovery of the remediation costs in this base rate case, or, alternatively, merge the deferral proceeding into this base rate case.

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 $536,000 and $2.5 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 R-2 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 R-2

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 a decrease in operating income of $15,000 for electric and an increase of $25,000 for gas.

Adjustment No. 19: Credit Card Fees – Schedule SSJ-45 R-2

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 30% 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 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 $2.9 million for electric and $1.6 million for gas, is being made.

Adjustment No. 20: Vacation Accrual Reversal – Schedule SSJ-46 R-2

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 $1.5 million for electric and $2.4 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 R-2

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. What are the Energy Strong and GSMP roll-ins that have occurred or will occur during this proceeding?

A. In accordance with the Energy Strong Order, rates changed September 1, 2017 as a result of the sixth rate adjustment filing (Roll-in # 6), and rates changed March 1, 2018 as a result of the seventh rate adjustment filing (Roll-in #7). An eighth adjustment filing (Roll-in #8) was submitted in March 2018 for rates effective September 1, 2018 based on plant in-service through May 31, 2018.

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) was 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. The eighth and final 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 R-2 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 $9.6 million for electric and $7.3 million for Gas.

Adjustment No. 22: BPU/Rate Counsel Assessment 1 ***– Schedule SSJ-48 R-2***

Q. Why is the Company proposing a BPU/Rate Counsel Assessment Adjustment?

A. The Company is required to make payments for operating costs such as funding for the BPU and Rate Counsel assessments every year. These payments are based on prior years' intrastate revenue. These costs have been volatile and the test year expense is not reflective of recent history. The Company has included a two year historic average as a basis for the expected rate year expense as compared to the test year expense. This *pro forma* results in a decrease to operating income of $0.7 million for electric and $0.3 million for gas.

Adjustment No. 23: Test Year Corrections – Schedule SSJ-49 R-2

Q. What are the test year correction adjustments?

A. This schedule seeks to make two adjustments to test year operating income. First, In June 2018, a credit of $98,933 was booked to cancel Street Lighting Service (SLG) revenues for service provided during the period of 11/211/2017 through 4/24/2018. The customer was rebilled in July 2018 at a total amount of $135,153, which comprised the rebilling of the $98,933 that was cancelled as well as billing of $36,220 for service provided during the period 4/25/2018 to 6/22/2018. Because the bills were cancelled in June 2018 (in the test year) and the rebill occurred in July 2018 (outside of the test year), test year revenues are understated. As a result, this adjustment adds the $135,153 in revenues back to the test year. The second adjustment reallocates 2018 service company costs to electric distribution and gas distribution. As noted in the response to S-OCI-PSEG-AFF-0077, The Company inadvertently used the incorrect allocated headcount number for the allocation of PSE&G costs among the non-tariff appliance service business and transmission. By correcting the allocation, Service Company costs to electric distribution decrease by $469,094 and gas distribution costs decrease by $923,943. Therefore, the total corrections after tax result in an operating income increase of $337,232 for electric and $761,384 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.

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Regulated Utilities - US

Tax reform is credit negative for sector, but impact varies by company

The wide-ranging tax legislation passed by the US Congress on December 20, 2017 cut the statutory corporate tax rate to 21% from 35%. The legislation was broadly credit positive for corporate cash flows but for regulated investor-owned utilities, which include electric, gas and water utilities, the effect was the opposite.

» **The legislation is credit negative for investor-owned utilities.** A lower tax rate will reduce the difference between the amount that utilities collect from rate payers to cover taxes and their payments to tax authorities, reducing cash flow.

» **Tax reform is neutral for earnings but negative for cash flow.** Utilities collect revenue based on book tax but cash tax is much lower. A lower tax rate lowers revenue, while loss of bonus depreciation increases cash tax.

» **Cash flow to debt ratio could decline by 150-250 basis points.** We estimate that regulated utilities could experience a decline in the ratio of cash flow from operations pre-working capital to debt (CFO pre-WC/debt) of 150 bps to 250 bps, assuming no corrective action is taken.

» **Utilities with weaker than expected financials are most affected.** The potential for lower cash flows hurts the credit profile of numerous regulated utilities that already have weakening financial projections. Major holding companies affected include American Electric Power Company (AEP, Baa1 stable), Consolidated Edison, Inc. (ConEd A3 negative), Dominion Energy (Dominion, Baa2 negative), Duke Energy Corporation (Duke, Baa1 negative), Entergy Corporation (Entergy, Baa2 negative) and The Southern Company (Southern, Baa2 negative).

» **Most utilities are still well positioned within their credit profiles.**The vast majority of utilities and their holding companies are well positioned within their credit profiles thanks to supportive regulatory relationships and a capital structure balanced between both debt and equity.

Tax reform negatively affects utility cash flows

For the investor-owned utilities sector, the 2017 tax reform legislation will have an overall negative credit impact on regulated operating companies and their holding companies. Moody's calculates that the recent changes in tax laws will dilute a utility's ratio of cash flow before changes in working capital to debt by approximately 150-250 basis points on average, depending to some degree on the size of the company's capital expenditure program.

Although the regulated utility sector is carved out in terms of the treatment of interest deductibility and expensing of capital expenditures, from an earnings perspective the effect on regulated entities is neutral because savings on the lower tax expense are passed on to their customers, as required by regulation. However, from a cash flow perspective, the legislation is credit negative.

Investor-owned utilities' rates, revenue and profits are heavily regulated. The rate regulators allow utilities to charge customers based on a cost-plus model, with tax expense being one of the pass-through items. In practice, regulated utilities collect revenues from customers based on book tax expense but typically pay much less tax in cash. Under the new tax regime, utilities will collect less revenue associated with tax expenses and pay out more cash tax, squeezing its cash flows.

With the lower tax rate and the loss of bonus depreciation treatment, utility cash flows will be negatively affected by three tax dynamics:

1. A fall in the tax rate means that regulated entities will collect less revenue from customers for the purpose of tax expense compensation. Going to a tax rate of 21% from 35% represents about a 40% fall in revenue collection related to tax expense. Although this revenue is ultimately paid out as an expense, under the new law utilities will lose the timing benefit, thereby reducing cash that may have been carried over many years.
2. The loss of bonus depreciation treatment means that most utilities will start paying cash tax in 2019 or 2020, earlier than under the current tax law. The loss of bonus depreciation treatment means that utilities can claim less in depreciation expenses and will therefore have higher taxable income. We still expect utilities to pay little or no cash tax in 2018 because most have significant accumulated net operating losses driven by past claims of bonus depreciation.
3. Lowering the tax rate also means that utilities will have over-collected for tax expense in the past because they charged for future tax expense, assuming a 35% tax rate. As utilities refund the excess collection to customers, it will reduce cash flows, likely spread out over the remaining life of the assets associated with the depreciation.

Significant credit deterioration for many utilities

Since the tax reform was passed at the end of last year, numerous utilities will experience a weakening in their credit profiles because of declining financial metrics (see Exhibit 1). Major holding companies affected include AEP, ConEd, Dominion, Duke, Entergy and Southern.

Exhibit 1

Utilities with weakened, or weakening, financial profiles due to tax reform

Company	Senior Unsecured Rating	CFO pre-WC / Debt 3-yr Avg as of 3Q17	CFO Pre-WC / Debt 2018-2019[1]	Downgrade Guidance
Holding Companies				
Consolidated Edison, Inc.	A3 / Negative	21.2%	15-18%	18%
American Electric Power Company, Inc.	Baa1 / Stable	20.8%	15-17%	15%
Duke Energy Corporation	Baa1 / Negative	14.7%	13-15%	15%
Dominion Energy, Inc.	Baa2 / Negative	12.9%	12-15%	15%
Entergy Corporation	Baa2 / Negative	18.0%	13-15%	15%
Southern Company (The)	Baa2 / Negative	13.8%	13-15%	15%
Vertically Integrated				
Alabama Power Company	A1 / Negative	25.7%	20-22%	22%
Public Service Company of Oklahoma	A3 / Negative	18.2%	15-18%	19%
Avista Corp.	Baa1 / Negative	20.6%	15-17%	17%
Southwestern Public Service Company	Baa1 / Negative	22.2%	16-18%	18%
Local Distribution Companies				
New Jersey Natural Gas Company	Aa2 / Negative[2]	25.3%	17-20%	20%
Brooklyn Union Gas Company, The	A2 / Negative	12.2%	14-17%	17%
KeySpan Gas East Corporation	A2 / Negative	15.8%	15-18%	17%
Piedmont Natural Gas Company, Inc.	A2 / Negative	20.9%	14-17%	17%
ONE Gas, Inc	A2 / Negative	22.0%	16-19%	20%
South Jersey Gas Company	A2 / Negative	18.1%	15-17%	20%
Wisconsin Gas LLC	A2 / Negative	25.5%	16-19%	19%
Questar Gas Company	A2 / Negative	22.2%	17-20%	20%
Northwest Natural Gas Company	A3 / Negative	18.3%	14-17%	16%
Transmission & Distribution				
Consolidated Edison Company of New York, Inc.	A2 / Negative	21.7%	19-21%	20%
Orange and Rockland Utilities, Inc.	A3 / Negative	19.8%	15-17%	17%
Water				
American Water Works Company, Inc.[3]	A3 / Negative	17.2%	14-16%	15%

[1] 2018-2019 Moody's estimates are pro forma for tax reform and do not incorporate current rate plan collection at 35%.
[2] Senior Secured Rating.
[3] The Regulated Water Utilities Methodology uses FFO to net debt as a key cash flow metric.
Source: Moody's Investors Service

Tax reform mainly affects companies that already had limited cushion in their credit profile. The tax reform usually resulted in a further 150-250 bps drop in CFO pre-WC/debt.

Moody's expects that most utilities will attempt to manage any negative financial implications of tax reform through regulatory channels. Corporate financial policies could also change. The actions taken by utilities will be incorporated into our credit analysis on a prospective basis. It is conceivable that some companies will sufficiently defend their credit profiles.

In practice, we believe that most companies will actively manage their cash flow to debt ratios by issuing more equity or obtaining relief by working through regulatory channels. For example, to offset a decline in cash flow, utilities could propose to regulators additional investments that benefit customers or accelerate recovery of regulatory assets. Some of the corporate measures could have a more immediate boost to projected metrics than certain regulatory provisions, which may take time to approve and implement. They could also propose to increase the equity layer in rates or the level of the authorized return on equity. In these cases, a cooperative regulatory relationship matters most for a given utility.

The majority of US regulated utilities and utility holding companies continue to maintain stable credit profiles despite weakening financials. Some of the larger holding companies in this category include PPL Corp. (Baa2 stable), Fortis Inc. (Baa3 stable) and Xcel Energy, Inc. (A3 stable) and Alliant Energy Corporation (Baa1 stable). We did not take action on NiSource, Inc. (Baa2 stable), despite the fact that they are weakly positioned even before the tax reform, because we believe that the management will address their financial ratios sufficiently in a timely manner to strengthen their credit profile.

Several companies were already on negative outlook or on review for downgrade before the effects of tax reform occurred, including Emera Inc. (Baa3 negative), Georgia Power Company (A3 negative), NorthWestern Corporation (Baa1 negative), OGE Energy Corp (A3 negative), SCANA Corporation (SCANA, Baa3 RUR-down), Sempra Energy (Baa1 negative), WEC Energy Group, Inc. (A3 negative), and WGL Holdings, Inc. (A3 negative).

Company-specific comments

All companies below have had their outlooks revised to negative due to the recent tax reform, except AEP, whose outlook was revised to stable from positive.

American Electric Power

AEP will continue to produce CFO pre-WC to debt in the mid-teens range, incorporating the effects of tax reform.

AEP could strengthen its credit profile if there are credit supportive regulatory actions at the state level to mitigate the impact of tax reform, or if there is a change in AEP's corporate finance policies such that cash-flow credit metrics could be sustained near their recent levels, in the high-teens range.

AEP could weaken its credit profile if a more contentious regulatory environment were to develop in any of its key jurisdictions; if ongoing capital investments cannot be recovered on a timely basis; or if recent tax reform or other developments cause a sustained deterioration in financial metrics—if, for example, the ratio of CFO pre-WC to debt were to remain below 15%.

American Water Works Company, Inc.

American Water Work Company, Inc.'s (American Water, A3 negative) cash flow to debt metrics were already expected to decline due to debt-funded growth and dividends over the next five years. Now, in the absence of any corrective action, the incremental deterioration in metrics due to tax reform could affect its credit quality.

American Water's debt is expected to increase due to its $8.0-$8.6 billion 5-year capital program, dividend growth approaching 10% and no additional equity issuance through 2022. Following the company's 11 December guidance call, we project funds from operations (FFO) to net debt ratios will decline from current levels. Using LTM 3Q17 as a base, we project that FFO to net debt will fall from 17% to 16% over the next couple of years. Losing an estimated $150 million of cash flow to deferred taxes, as a result of tax reform, will further pressure FFO to net debt to around 15%, a level that we have highlighted as potentially affecting the company's credit profile.

American Water's credit profile could be maintained if its FFO to net debt and RCF to net debt were to stabilize around 16% and 11%, respectively, and without an increase in parent debt levels (currently at around 23% of consolidated debt).

Avista Corp.

Avista Corp. (Avista, Baa1 negative) has over the last few years maintained steady credit metrics with CFO pre-WC to debt consistently in the 18-20% range. However, deferred income taxes have constituted a significant portion of Avista's operating cash flow, about a third in 2016. Further, Avista has experienced delays with its Washington rate case, presenting uncertainty around the utility's regulatory relationships and future financial profile.

The negative outlook reflects the expected reduced contribution of deferred taxes to operating cash flow and regulatory uncertainty related to the Washington rate case. We expect weaker credit metrics going forward, with CFO pre-WC to debt falling to or below the

17%, which would represent a significant credit deterioration in the absence of actions to mitigate tax reform impacts and without adequate regulatory relief in Washington.

In addition, Avista's credit profile would be negatively affected by any indication that it would be required to support Hydro One Ltd.'s (not rated) acquisition debt. The credit profile could be stabilized if Avista receives sufficient regulatory relief and if state-level regulatory and corporate financial actions are taken to offset the negative tax reform impact such that CFO pre-WC to debt remains consistently at or above 18%.

Brooklyn Union Gas Company

Brooklyn Union Gas Company (KEDNY, A2 negative) has been weakly positioned against our guidance for several years, with CFO pre-WC to debt of 13.7% in the year to March 2017 and 7.9% in the year to March 2016, compared with guidance in the mid to high teens.

Since deferred taxes represented 18% of KEDNY's CFO pre-WC in the year to March 2017, we expect that the lower corporate tax rate will translate into a lower revenue requirement, making it more difficult for the company to maintain its current credit profile in absent of significant mitigating actions or relief offered by the New York Public Service Commission (NYPSC). The credit profile could be maintained if the National Grid Plc (Baa1 stable) chose to reduce leverage at KEDNY or if the NYPSC allowed the company to offset the customer benefit of the lower tax rate with some other allowances.

Consolidated Edison, Inc.

Consolidated Edison Company of New York's (CECONY, A2 negative) is Consolidated Edison's principle subsidiary and contributed about 90% of consolidated cash flows. Deferred taxes have represented nearly 20% of CECONY CFO over the past three years; therefore the tax rate reduction to 21% will reduce this deferred tax benefit and CECONY's cash flow generation over the next several years. While the utility is expected to maintain relatively stable financial metrics, such as CFO to debt at around 20%, in the remaining two years of its current rate plan, we expect tax reform will have negative cash flow implications over the longer term, all else being equal.

When normalizing CECONY's cash flow for the new tax law, we see the potential for the company to generate CFO pre-WC to debt in the high-teens range on an ongoing basis. This reflects a 21% tax rate, reduced revenue requirement, low cash tax payments and normalized refunds of excess deferred tax liabilities to customers.

We see uncertainty over the amount and pace of any "unprotected" deferred tax liability refunds that CECONY may be required to pay, over the nature and timing of customer benefits and over the potential to offset cash flow leakage with some other cash-generative measure. The NYPSC is investigating methods of approaching the tax reform and we expect increasing clarity in the coming months.

Dominion Energy, Inc.

Dominion's (Baa2 negative) CFO pre-WC to debt ratios have been weak for its rating since 2012, for which we had expected an upward trend to begin in 2018. However, the impact of tax reform will offset the improvement we expected, as the utility base of the company will have less deferred tax benefit to boost cash flow. We see a risk that CFO pre-WC to debt will remain around 14% until that time.

The acquisition of SCANA would keep Dominion's metrics lower for longer, since they will have sizeable customer credits. SCANA has its own cash leakage from tax reform, and incremental debt is to be issued in the SCANA family.

Duke Energy Corporation

Duke's consolidated cash flow credit metrics are currently weakly positioned and likely to be incrementally pressured by tax reform. We currently expect the company's CFO pre-WC to debt ratio will remain below 15% through 2019 without assuming any action to counter the effects of the tax reform.

The company's credit profile could be strengthened if Duke achieves credit supportive outcomes in its current rate proceedings and if it is able to mitigate the cash-flow impact of tax reform through regulatory treatment or financial policies such that it can sustain a ratio of CFO pre-WC to debt above 15%, for example. In the longer term, a ratio of CFO pre-WC to debt closer to 20% could result in a material improvement in the credit profile.

Duke's credit profile could weaken if there were a deterioration in the regulatory relationship at one or more of its key utility subsidiaries; if recent tax reform or other developments cause the ratio of CFO pre-working capital to debt to remain below 15% for an extended period; or if parent company debt levels rise above 35% of total Moody's adjusted consolidated debt for an extended period.

Entergy Corporation

Entergy's (Baa2 negative) CFO pre-WC to debt through LTM was 15%, which is on the low end of the financial range expected for its credit profile. We consistently normalize Entergy's cash flow for variability in tax payments and deferred tax contributions to CFO. However, recent federal tax reform has brought incremental risks to the company's financial profile.

The primary risk relates to the revaluation of deferred tax liabilities and ensuing customer refunds for the excess amounts collected. At 30 September 2017, Entergy had roughly $7.5 billion of deferred tax liabilities on its balance sheet, which we estimate will fall to around $4.5 billion under a 21% tax rate. The $3.0 billion of excess deferred taxes will likely be refunded to customer. However, the timing and source of financing of this refund is uncertain. This carries the risk of reducing cash flow beyond our typical sensitivities and increasing the funding needs of the consolidated entity.

Keyspan Gas East Corporation

Deferred taxes have been a strong contributor to Keyspan Gas East Corporation's (KEDLI, A2 negative) CFO pre-WC to debt ratio, accounting for 22% of CFO pre-WC in 2017. The lowering of the corporate tax rate and the attendant decline in cash-flow will result in credit deterioration for KEDLI in the absence of any mitigating action by the company or additional allowances offered by the NYPSC.

The company's credit profile could be maintained if the National Grid group chose to reduce leverage at KEDLI or if the NYPSC chose to offset the customer benefit of the lower tax rate with some other allowances.

New Jersey Natural Gas Company

New Jersey Natural Gas's (NJNG, Aa2 secured rating, negative) metrics are projected to weaken because of the expected funding of its capital plans primarily with debt, compounded by the estimated cash flow impact of tax reform. The lower projected cash flows combined with increasing absolute debt levels will result in CFO pre-WC/debt to range in the 18% to 19% range over the next two years.

NJNG's credit profile could weaken if there is a significant deterioration in NJNG's business profile, in its regulatory environment or an increase in regulatory lag. The profile could also be negatively affected if NJNG reports CFO pre-WC to debt below 20% for an extended period of time. NJNG's credit profile could be strengthened by demonstrated consistency in the company's current regulatory framework or if there are mitigating regulatory actions or corporate fiscal policies such that its CFO pre-WC to debt ratio is maintained above 20%.

Northwest Natural Gas Company

Northwest Natural Gas Company's (A3 negative) current financial profile is strong, with CFO pre-WC to debt around 19% through 30 September 2017. However, the combination of tax reform impacts to deferred tax cash flow and rate relief needed through a general rate case could reduce this metric to below 16% over the next two years.

The company has a rate case filing currently outstanding with the Oregon Public Utility Commission and could receive the necessary rate relief to maintain cash flow to debt ratios in the high-teen's range, which would support its current credit profile.

ONE Gas, Inc.

We expect the ONE Gas, Inc.'s (A2 negative) already weak cash flow to debt ratios will further deteriorate with the reduction in the corporate tax rate and the loss of bonus depreciation. We anticipate that its CFO pre-W/C to debt will be in the 17%-18% range without any offsetting action.

The credit profile could improve if regulatory actions are taken at the state level to mitigate the cash flow impact of tax reform and if the company makes changes to its corporate financial policies such that financial metrics improve, including a CFO pre-WC to debt ratio consistently at or above 22%.

ONE Gas' credit profile could weaken if CFO pre-WC to debt is sustained below 20%; if there is a significant decline in the support provided by the utility's regulators; or if the company pursues an aggressive dividend payout policy as it executes its elevated capital program.

Piedmont Natural Gas Company

We expect that tax reform legislation will pressure Piedmont Natural Gas Company's (Piedmont, A2 negative) financial metrics, which in the absence of mitigation measures could adversely affect Piedmont's ability to maintain CFO pre-WC to debt ratio above 17%.

Piedmont's credit profile could be stabilized if the company is able to mitigate the cash flow impacts of tax reform through regulatory treatment or financial policies. For example, if the company is able to sustain a ratio of CFO pre-WC near 20%. In the longer term, a ratio of CFO pre-WC to debt above 23% could also boost credit quality.

Piedomont's credit profile could weaken if there were to be a significant deterioration in the company's regulatory environments, or if recent tax reform or other developments cause the ratio of CFO pre-WC to debt ratio to remain below 17% for an extended period.

Public Service Company of Oklahoma

Public Service Company of Oklahoma's (PSO, A3 negative) historically strong financial metrics have been negatively impacted by a combination of lower load growth, elevated capital expenditures for environmental compliance and increased regulatory lag. We expect that tax reform will add downward pressure on the utility's cash flow credit metrics. We anticipate the company's CFO pre-WC to debt ratio will remain below 19%, which is weak for PSO's current credit quality.

PSO's credit profile would stabilize if there were to be an increase in cash flow or a reduction in leverage, or if the company is able to mitigate the cash flow impact of tax reform such that we could expect key financial credit metrics to strengthen with, for example, a ratio of CFO pre-WC to debt remaining in the low 20% range. In the longer term, a ratio of CFO pre-WC to debt sustained above 25% could boost the profile.

PSO's credit profile could weaken if the regulatory environment took a more adversarial tone; if there were a significant increase in capital or operating expenditures that were not able to be recovered on a timely basis; or if key financial credit metrics exhibited a sustained deterioration over a period of time–for example, a ratio of CFO pre-WC to debt remaining below 19%.

Questar Gas Company

Questar Gas Company's (Questar Gas, A2 negative) financial profile is expected to decline amid a rate freeze through 2020. While the company will continue to recover costs through decoupling and infrastructure riders, we see cash flow to debt metrics declining from 22% through LTM 3Q17 to the high-teens range because of increasing debt and a lack of general rate increases. We expect that cash leakage from tax reform impacts will be implemented at the end of this rate freeze, which will reduce cash that Questar Gas collects from customers and will keep the company's cash flow to debt metrics lower for longer.

South Jersey Gas Company

South Jersey Gas Company's (South Jersey Gas, A2 negative) debt coverage metrics have weakened over the last few years in part due to a significant increase in environmental remediation costs. The negative outlook is based on our expectation that South Jersey Gas' already weak credit metrics will be sustained in the mid-to-high teens as a result of the negative cash flow impact of tax reform.

South Jersey Gas' credit profile can be maintained with further improvements in regulatory transparency and if state-level regulatory or corporate financial policy actions are taken to alleviate the negative impacts of tax reform such that CFO pre-WC to debt is maintained at or above 22% on a consistent basis.

The credit profile would be negatively affected if CFO pre-WC to debt remains below 20% on a sustained basis; if there is pressure to support debt incurred by the parent to acquire Elizabethtown Gas and Elkton Gas; if South Jersey Gas' regulatory jurisdiction becomes less credit supportive; or if the company and its affiliates fail to maintain adequate liquidity across the utility family.

The Southern Company

Tax reform will pressure Southern's financial metrics. Absent mitigation measures, it will hinder Southern's ability to maintain CFO pre-working capital to debt at or above 15%.

Southern's credit profile would be strengthened if there are credit supportive regulatory actions at the state level to mitigate the impact of tax reform, or if parent level debt is reduced or cash flow coverage metrics improve materially, including CFO pre-WC to debt in the high teens to 20%.

Southern's credit profile is heavily dependent on the credit quality of the Alabama Power Company (A1 negative), Georgia Power Company (A3 negative) and Southern Company Gas/Southern Company Gas Capital (Baa1 stable) subsidiaries. It could also suffer if there are additional delays or cost increases at the Vogtle nuclear project, or if recent tax reform legislation or other developments cause consolidated coverage metrics to show a sustained decline, including CFO pre-WC to debt below 15%.

Southwestern Public Service Company

Southwestern Public Service Company (SPS, Baa1 negative) faces lower financial metrics because of tax reform as well as a deteriorating regulatory environment in New Mexico. The company's CFO pre-WC to debt ratio has been 20% or above in the past few years, but we estimate that CFO pre-WC to debt will fall below 18% without any corrective action. SPS' parent company Xcel Energy has indicated that it plans to work directly with regulators of their operating utilities to offset the cash-flow impact of tax reform, including the potential for a higher equity layer, a higher authorized return on equity and accelerated recovery of regulatory assets. SPS' credit profile would strengthen if the company succeeds in bolstering its CFO pre-WC to debt ratio to above 20% on completion of its material capital program.

Wisconsin Gas LLC

Wisconsin Gas LLC's (A2 negative) CFO pre-WC to debt metric has averaged around 25% in the past three years, but tax reform could cause it to decline to 16% to 19%. We believe that Wisconsin Gas has a reasonable chance of receiving regulatory support because Wisconsin Public Service Commission approved the company filing a plan for accelerated recovery of regulatory assets for Wisconsin Electric Power Company (A2 stable), Wisconsin Gas' sister company, to offset the effect of tax reform.

Moody's related publications

» Corporate tax cut is credit positive, while effects of other provisions vary by sector (21 December 2017)

» Trump Tax Blueprint Would Raise US Debt, But Be Credit Positive for Many Sectors (9 May 2017)

» Tax Reform Likely to Increase Credit Risk, Impact Dependent on Regulatory Response (15 March 2017)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

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U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound

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U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound

*(**Editor's Note:** This article is part of a series addressing the potential credit implications of U.S. tax reform on corporate, infrastructure, financial services, and U.S. public finance entities.)*

The recently enacted federal tax package will provide a modest economic uplift according to S&P Global economists (see "A Tax Package For The New Year: Its Impact On U.S. GDP Growth," Jan. 8, 2018), and it will be beneficial for the credit quality of most corporate issuers (see "U.S. Tax Reform: An Overall (But Uneven) Benefit For U.S. Corporate Credit Quality," Dec. 18, 2017). But what does it mean for the S&P Global Ratings' ratings on U.S. utilities and their holding companies?

The main features of the corporate tax package are a lower tax rate, more favorable treatment of earnings repatriated from overseas, a move from a worldwide tax system to a territory-based tax system, immediate expensing of capital investment, and limits on the deductibility of interest expense. For U.S. utilities and for most utility holding companies that have mainly domestic operations, foreign earnings repatriation and the taxation approach to those earnings are a non-issue. However, the tax package has important implications for utilities mostly because of rate regulation, but also since special provisions in the tax legislation for regulated utilities regarding interest deductibility and capex expensing distinguish them from most of corporate America.

Overview

- While most of corporate America is bullish about the new tax regime, we believe the effect on creditworthiness of regulated utilities and their holding companies could be negative.
- The effect will depend on the reaction of utility regulators and, ultimately, the utility companies after the regulators have acted.
- The lower statutory corporate tax rate will eventually benefit ratepayers, not utilities. The degree of benefit or burden to holding companies will depend on each company's tax position and will suffer from the benefit at the utility subsidiaries going to ratepayers.
- The accelerated deductibility of capital expenditures is not available to utilities, and the loss of that kind of stimulus is negative for cash flow.
- Few U.S. utility holding companies will be affected by foreign earnings or the deemed repatriation of previously untaxed foreign earnings.
- Limits on the deductibility of interest expense have little effect, as utilities are exempt and holding companies can participate in that exemption.

Credit Implications Vary For U.S. Utilities

The reality for U.S. utilities and utility holding companies is that they have historically used the tax code as a source of cash flow through the interactions of tax accounting, regulatory accounting, and as opportunities to defer cash taxes from economic stimulus provisions. The attractiveness of tax credits for specific types of investments for companies with such reliable earnings profiles has long been apparent. One reason we have relied more on after-tax credit metrics using funds from operations (FFO) as a base instead of pretax measures like EBITDA is that the former captured the true cash flow of a utility better than the latter. As we have noted in the past, utilities are susceptible to weakening FFO-based credit metrics in the absence of bonus depreciation or other economic stimulus built into the tax code.

We will address the three primary areas of tax reform for utilities in turn. Early analysis suggests that utility and holding company credit quality could be marginally and negatively affected by the new tax code, but for most issuers the magnitude will be mild enough to allow them, if so desired, to offset the effect enough to preserve ratings. Much will depend on the regulatory response. For companies skirting the edge of our financial risk profile requirements, the path to ratings stability will be trickier and steeper. Our approach as the impact of the corporate tax package unfolds will be measured:

- Taxes, as accounting and ratemaking matters, are extremely complex and will require some time for issuers and regulators to fully understand the implications, especially at the holding company level. As we observe the decisions made by each company and update our models, we will allow sufficient time for companies to react to the changes.
- To the extent tax reform has some one-time, up-front effect on earnings or prompts write-offs, we are likely to look past that and concentrate on the ongoing, forward-looking impact on credit metrics.
- Each company's tax situation is unique, as is the regulatory environments in which they operate. While we see a general effect of tax reform, ultimately the rating impact will be issuer-specific and will depend on the details of its tax positions at both the utility and holding company, the regulatory response to the new tax code, and how the company responds to those two things in its future financial policy.
- The impact will almost certainly differ between a holding company and its utilities. Holding companies do not directly share the same tax attributes as their utility subsidiaries and are the actual entity that pays taxes on a consolidated basis. Utilities are almost uniformly treated as stand-alone entities by regulators when calculating the revenues needed to cover the cost of service. Changes in things like corporate tax rates can therefore have decidedly different effects on the unregulated parent and the regulated subsidiary. Since our rating methodology is primarily focused on the entire group, the impact of tax reform on the holding companies is going to be the most impactful on the ratings within the group for most issuers. Although there may be no rating implications, we may revise the stand-alone credit profiles (SACP) of a holding company's utility subsidiaries that we do not consider insulated. And the ratings on utilities and other subsidiaries that differ from the parent due to insulation or a lesser group status could also be directly affected.

The Influence Of Key U.S. Tax Reform Provisions On U.S. Regulated Utilities and Holding Companies

Tax provision	Benefit or burden?	Primary relevance to utilities or holding companies?	Effect
Lower corporate tax rate	Burden	Both	For utilities, revenue requirement is reduced. The benefit of lower rate is passed onto ratepayers. Holding companies lose the cash flow from the difference between statutory rate and their effective tax rate.
Loss of accelerated deductibility of capital expenditures	Burden	Both	Utilities are exempted and therefore lose the opportunity to gain cash flow from tax-based stimulus. Effect on holding companies depends on mix of utility and non-utility operations.
Elimination of tax on foreign earnings and upon repatriation going forward	Benefit	Holding company	Limited to the few that have overseas investments.
Deemed tax on previously earned profits held overseas	Burden (limited to eight years)	Holding company	Limited to the few that have overseas investments.

The Influence Of Key U.S. Tax Reform Provisions On U.S. Regulated Utilities and Holding Companies (cont.)

Tax provision	Benefit or burden?	Primary relevance to utilities or holding companies?	Effect
Limit on interest deduction	Benefit	Both	Utilities not burdened (exempted). Holding companies are not burdened to the extent they can allocate a portion of their debt to utility operations, but the allocation method is unclear.

Source S&P Global Ratings.

Lower tax rates

The central feature of the corporate tax package is a lower tax rate. The current 35% statutory tax rate is now 21%, and that move has various ratemaking consequences for utilities. For most utilities, rates charged to customers reflect the statutory rate. Any unpaid deferred taxes over the years have been accrued for eventual return to ratepayers, and in the mean time are a low-cost source of capital in the mechanics of ratemaking. The new, lower statutory rate means (1) rates must be lowered to reflect the new rate, and (2) the excess deferred tax balance created by the difference in tax rates must be returned to ratepayers. The speed at which it is returned will be determined by the regulator with potentially significant negative cash flow effects. Normalization rules will restrict the regulators, but some of the deferred tax difference will not be protected by the transition rules and could be tapped earlier to reduce rates. Regulators will also be mindful of the higher future costs associated with rapid reversal of deferred taxes, as they have been a low-cost source of capital to the benefit of ratepayers that must be replaced with some combination of debt and equity if erased too quickly.

Both of those tasks will be handled by the regulator, with the timing and result affected by the utility's strategy and relationship with its regulators. That strategy, and the utility's ability to manage the process and outcome, are crucial factors in determining the impact on ratings coming out of tax reform. The challenge is that regulators think about and set rates primarily on earnings, not cash flow. To the extent that tax reform leads to lower cash flows, which we think will be the case in most instances, we will look for the utility to make a case for countervailing steps to offset some or all of the diminished cash flow. A stronger capital structure, using the extra revenues related to the difference between the 21% and 35% tax rates to support greater rate-base investment or rate recovery of other expenses such as unfunded pension obligations or nuclear decommissioning funds, or some combination of these could sustain or lessen the impact on credit metrics.

At the parent companies, which often have a mix of regulated and unregulated companies, the effect of lower tax rates could be more mixed and will depend greatly on each company's particular circumstance. They rarely pay anything close to the statutory rate due to careful tax planning. An important focus is on those holding companies that have significant non-utility operations. How to allocate parent debt between utility and non-utility operations is an unresolved issue (see next section), but overall many investments and activities on the non-utility side have been driven by tax considerations. A holding company's tax characteristics, including such things as net operating loss carryovers and unused tax credits, affect how much in actual taxes they're paying now. Lower tax rates will slow the realization of those and other tax benefits, and that could pressure credit metrics when combined with any negative cash-flow effects at the utility level.

Interest expense deductibility

The second big aspect of tax reform for utilities is interest deductibility. U.S. utilities and utility holding companies are typically more leveraged than their counterparts elsewhere in corporate ratings, so the loss or limit on deducting interest for tax purposes would have been more impactful for utilities. The new tax package offers a special carve-out that allows utilities to fully deduct all interest expense and holding companies to allocate a portion of the interest on parent debt associated with their utilities to qualify for a deduction as well. The manner of that allocation is still somewhat imprecise, and greater clarity is expected when the Treasury Department implements the legislation.

Loss of bonus depreciation or other tax stimulus

The preservation of most interest deductibility for the capital-intensive, more-levered utilities and utility holding companies came at a price. In exchange for this treatment, utilities forego the opportunity to participate in the stimulus feature of tax reform, full expensing of capital spending at least for the next five years. With the absence of any bonus depreciation provisions for utilities, a powerful generator of cash flow will now cease that, in combination with the lower tax rate, will have very real consequences for cash-based credit metrics. Utilities however have been modifying their capital spending plans over the past few years to factor in phasing out of bonus depreciation. We noted in a commentary many years ago (see "How Will Bonus Depreciation Affect The Credit Quality of U.S. Electric Utilities?" May 9, 2011) that the loss of bonus depreciation could result in two to three percentage-point reductions in a typical FFO-to-debt calculation. Now that the time of no tax stimulus in the tax code has come to pass, utilities will have to grapple with this lack of cash flow from tax timing differences. While the lower statutory rate would have diminished the power of this cash-flow source anyway, its absence will make the challenge more acute, especially for those issuers that are already edging toward ratings downgrade FFO-to-debt triggers.

Utilities' Response To The New Tax Laws May Help Preserve Credit Quality

The impact of tax reform on utilities is likely to be negative to varying degrees depending on a company's tax position going into 2018, how its regulators react, and how the company reacts in return. It is negative for credit quality because the combination of a lower tax rate and the loss of stimulus provisions related to bonus depreciation or full expensing of capital spending will create headwinds in operating cash-flow generation capabilities as customer rates are lowered in response to the new tax code. The impact could be sharpened or softened by regulators depending on how much they want to lower utility rates immediately instead of using some of the lower revenue requirement from tax reform to allow the utility to retain the cash for infrastructure investment or other expenses. Regulators must also recognize that tax reform is a strain on utility credit quality, and we expect companies to request stronger capital structures and other means to offset some of the negative impact.

Finally, if the regulatory response does not adequately compensate for the lower cash flows, we will look to the issuers, especially at the holding company level, to take steps to protect credit metrics if necessary. Some deterioration in the ability to deduct interest expense could occur at the parent, making debt there relatively more expensive. More equity may make sense and be necessary to protect ratings if financial metrics are already under pressure and regulators are aggressive in lowering customer rates. It will probably take the remainder of this year to fully assess the financial impact on each issuer from the change in tax liabilities, the regulatory response, and the company's ultimate response.

We have already witnessed differing responses. We revised our outlook to negative on PNM Resources Inc. and its subsidiaries on Jan. 16 after a Public Service Co. of New Mexico rate case decision incorporated tax savings with no offsetting measures taken to alleviate the weaker cash flows. It remains to be seen whether PNM will eventually do so, especially as it is facing other regulatory headwinds. On the other hand, FirstEnergy Corp. issued $1.62 billion of mandatory convertible stock and $850 million of common equity on Jan. 22 and explicitly referenced the need to support its credit metrics in the face of the new tax code in announcing the move. That is exactly the kind of proactive financial management that we will be looking for to fortify credit quality and promote ratings stability.

Related Criteria And Research

Related Research

- FirstEnergy Corp.'s Convertible Preferred Stock Issuance Rated 'BB'; Other Ratings Affirmed, Jan. 22, 2018
- PNM Resources Inc. And Subs Outlooks Revised To Negative On New Mexico Regulatory Order, Effects Of New U.S. Tax Code, Jan. 16, 2018
- A Tax Package For The New Year: Its Impact On U.S. GDP Growth, Jan. 8, 2018
- U.S. Tax Reform: An Overall (But Uneven) Benefit For U.S. Corporate Credit Quality, Dec. 18, 2017
- How Will Bonus Depreciation Affect The Credit Quality of U.S. Electric Utilities? May 9, 2011

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7 June 2018

Update

Rate this Research

RATINGS

Public Service Electric and Gas Company

Domicile	New Jersey, United States
Long Term Rating	A2
Type	LT Issuer Rating
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Public Service Electric and Gas Company

Update to credit analysis

Summary

Public Service Electric and Gas Company's (PSE&G) credit profile is supported by its low-risk transmission and distribution (T&D) business model and consistent regulatory environments in New Jersey and under the Federal Energy Regulatory Commission (FERC). PSE&G is pursuing a significant capital investment over the next five years that will grow its rate base. It is planning $12 billion - $15.5 billion of capital investments that would increase its rate base to approximately $24.5-$27.5 billion by 2022.

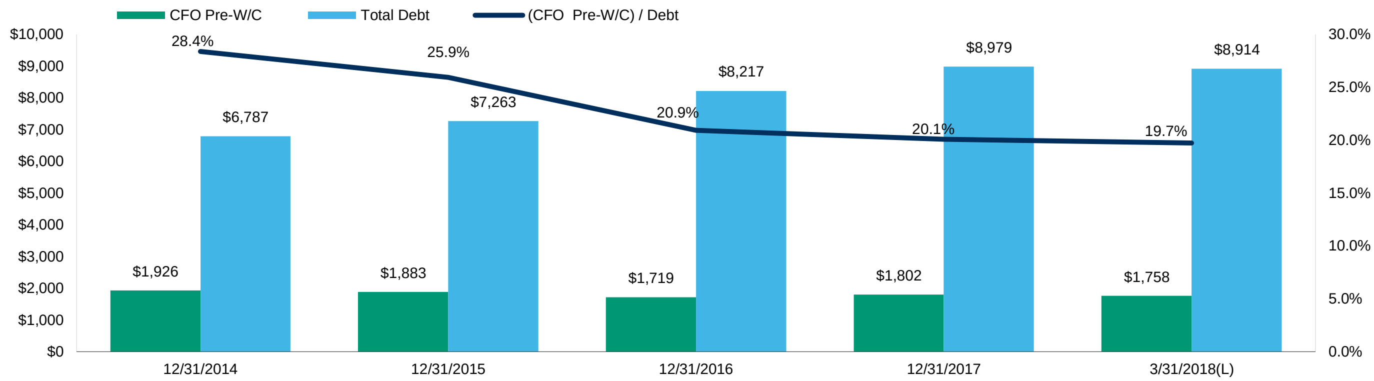
Overall, we expect PSE&G's credit profile to weaken over the next 2-3 years. Its robust capital investment program is likely to increase the company's leverage in the near-term to fund the higher investments. We expect its cash flows to increase as well based on the regulatory mechanisms that provide fairly contemporaneous cost recovery, shortening regulatory lag. However, we believe that leverage will increase at a faster rate than cash flow, pressuring its key cash flow to debt metrics. PSE&G has not paid dividends to its parent Public Service Enterprise Group (PSEG, Baa1 stable) over the last several years. We expect that PSE&G to continue to limit its dividends to the parent to maintain its capital structure through this period of heavy capital investment.

PSE&G filed a general distribution rate case with the New Jersey Board of Public Utilities (BPU) in January 2018. The company has requested that customer refunds related to the US Jobs and Tax Cut Act be used to offset the base rate increase requested, mitigating the impact. We estimate that the tax reform impact on PSE&G will be about a 200-300 basis point decrease to its cash flow from operation before changes in working capital (CFO pre-WC) to debt ratio. Also, the rate case is likely to determine the timing of customer refunds related to the excess deferred income tax liabilities. PSE&G expects the rate case to be concluded in the fourth quarter of 2018.

Exhibit 1

Historical CFO pre-WC, Total Debt and CFO pre-WC to Debt

($MM)



Source: Moody's Financial Metrics™

Credit strengths

» Low-risk business as a regulated T&D utility

» Supportive regulatory environment

Credit challenges

» Large capital investment program

» Weakening financial profile

Rating outlook

PSE&G's stable rating outlook is based on the existing suite of regulatory recovery mechanisms provided by the BPU, a supportive regulatory and political environment in New Jersey, and our expectation that the company will successfully manage its large capital spending program. However, we expect PSE&G's financial profile will become weaker over the next 12-18 months.

Factors that could lead to an upgrade

Given PSE&G's strong credit rating and its ongoing capital investment program, an upward movement in ratings is unlikely at this point. However, a sustained improvement in credit metrics, with CFO pre-WC to debt in excess of 26%, could lead to a rating upgrade. Also, if there is a significant tangible improvement in its regulatory environment, resulting in shorter regulatory lag for the cost recovery and an accelerated increase in cash flow, for example, a rating upgrade could be considered.

Factors that could lead to a downgrade

A rating downgrade could be considered if the regulatory relationship became more contentious and regulatory lag increases. If PSE&G's CFO pre-WC to debt falls below 19% on a sustained basis or its financial profile weakens due to higher leverage, for example, a rating downgrade could be possible.

Key indicators

Exhibit 2

Public Service Electric and Gas Company Indicators

	Dec-14	Dec-15	Dec-16	Dec-17	Mar-18 LTM
CFO pre-WC + Interest / Interest	7.0x	6.4x	5.7x	5.7x	5.5x
CFO pre-WC / Debt	28.4%	25.9%	20.9%	20.1%	19.7%
CFO pre-WC – Dividends / Debt	28.4%	25.9%	20.9%	20.1%	19.7%
Debt / Capitalization	37.5%	36.4%	36.2%	40.7%	39.7%

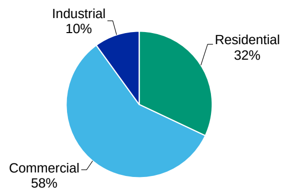
Source: Moody's Financial Metrics™. All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.

Profile

Public Service Electric and Gas Company (PSE&G, A2 stable) is the largest regulated T&D utility in New Jersey with about 2.2 million electric and 1.8 million gas customers, accounting for about 70% of the state's population. PSE&G is a wholly-owned subsidiary of Public Service Enterprise Group Incorporated (PSEG, Baa1 stable) and it accounted for approximately 55% of PSEG's CFO pre-WC as of latest twelve months (LTM) ending 31 March 2018. PSEG also owns PSEG Power LLC (PSEG Power, Baa1 stable), a merchant generator with about 10.6 GW of generation capacity located in PJM and New England.

Exhibit 3

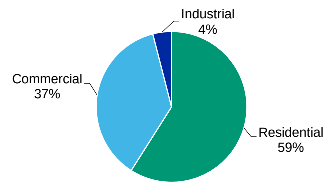
2017 Electric Customer Sales Mix



Source: Company Reports

Exhibit 4

2017 Gas Customer Sales Mix



Source: Company Reports

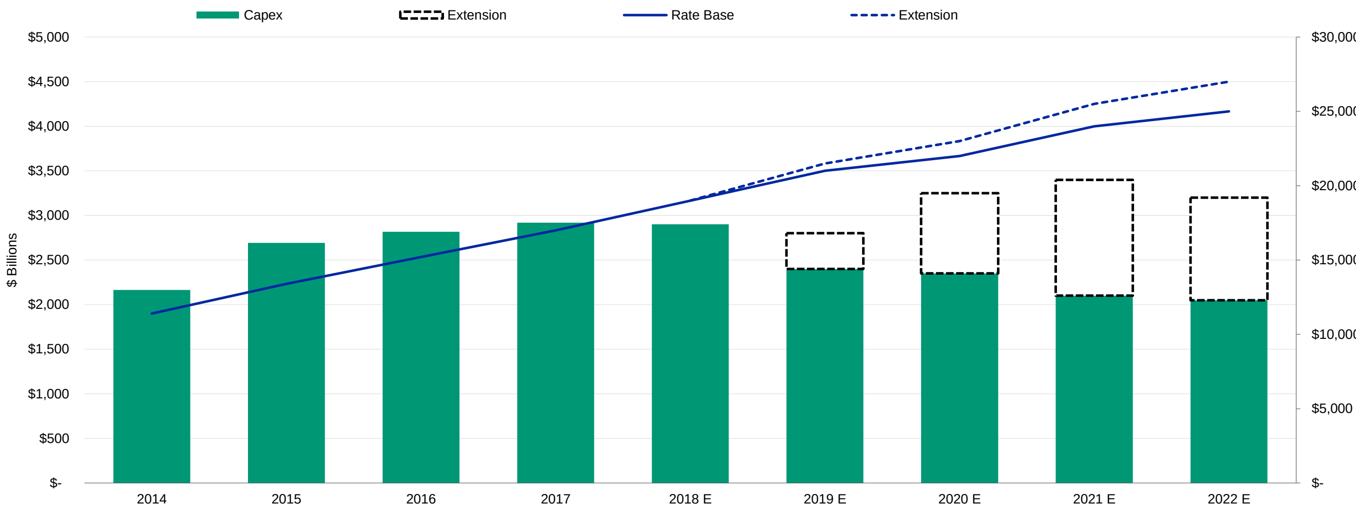
Detailed credit considerations

Robust capital investment program to grow rate base by 8%-10%

At its most recent investor day presentation on 31 May 2018, PSE&G announced that it plans to increase its rate base by 8%-10% through 2022. Its capital investments will remain elevated over the next several years driven by the Gas System Modernization Program (GSMP) II, Energy Strong Program II, and the Clean Energy Future filing (expansion of current energy efficiency programs, electric vehicle programs, energy storage, LED street lights). In 2017, the utility spent about $2.9 billion in capital expenditures and capital investments for the 2018-2022 period are expected to range between $12 billion - $15.5 billion, which is based on the potential extension and expansion of current programs, subject to state approval.

Under the base scenario, PSE&G would have a rate base of roughly $25 billion by 2022, compared to $17 billion at the end of 2017, representing an approximately 8% CAGR. Transmission assets would account for as much as 48% of the company's rate base. Our expectation is that the company will not have enough internal sources to fund these capital investments, especially in the near-term, which will lead to higher debt issuance. As of year end 2017, PSE&G's reported debt balance was approximately $8.6 billion, up from $7.8 billion in 2016 and $7 billion in 2015.

Exhibit 5
Historical and Projected Capital Expenditure and Rate Base



Extension is based on the approval of Energy Strong and Clean Energy Future
Source: Company Reports

The drivers for the elevated capital investment program are the planned approximately $6 billion investment for transmission reliability enhancement and infrastructure replacement, approximately $2 billion for gas distribution investments including GSMP, $3 billion for electric distribution programs including the Energy Strong II, and $2.9 billion for the Clean Energy Future.

PSE&G expects to execute its capital investment plan with limited effect on customer rates. While declining gas prices over the last several years have played an important role, the expiration of stranded cost transition charges in 2015 (an adder to rates that had been in place since 2000, when New Jersey transitioned to competitive electric generation) and the expiry of certain legacy, high cost non-utility generator power purchase agreements also contribute to alleviating rate pressure going forward.

Weak financial profile pressured by capital investment program

PSE&G's financial metrics have historically been consistent, ranging around the mid-20% level. However, its CFO pre-WC to debt weakened over the last couple of years to about 20% due to the elevated capital investment program. For the LTM period ending 31 December 2016 and 2017, PSE&G's annual CFO pre-WC to debt ratio was 20.9% and 20.1%, respectively. Also, as with the rest of the utility industry, PSE&G's cash flow will be negatively impacted by federal tax reform, particularly from a lower deferred tax contribution to cash flow from operations and the return of excess deferred tax liabilities to customers. PSE&G's CFO pre-WC to debt ratio as of 31 March 2018 was 19.7%. PSE&G has not been paying dividends to PSEG for the last several years and, as a result, its retained cash flow to debt ratio has been relatively strong.

A combination of the large capital investment program, the expiry of collections related to stranded cost recovery, and tax reform will weaken the utility's credit profile going forward. We expect the annual CFO pre-WC to debt to fall below 19% in 2018 and remain weak over the next 12-18 months, unless the company takes further mitigating actions or the rate case outcome results in higher cash flow. We recognize the stable regulatory environment and the robust regulatory mechanisms that will recover over 90% of its investments in rates on a contemporaneous basis through a capital rider clause or FERC formula rates.

Low risk T&D utility operations with supportive regulatory environments

PSE&G operates electric and natural gas distribution and electric transmission businesses in New Jersey. As a wires and pipes-only utility, PSE&G does not have any direct commodity price volatility exposure. PSE&G retains replacement risk if a Basic Generation Service (BGS) provider were to default on its obligation, but any costs would be recoverable in rates. However, the electric distribution business retains volume exposure between rate cases while gas distribution benefits from a weather normalization clause.

PSE&G's electricity and gas distribution activities are regulated by the BPU, and its electricity transmission business is regulated by FERC. PSE&G has a constructive regulatory environment with timely pass through and recovery of costs. Its storm response, reputation for reliability and outage rates compare favorably to in-state peers, allowing the company to maintain positive relationships with major stakeholders in the rate making process. PSE&G's last rate case in 2010 resulted in a negotiated settlement with an allowed ROE of 10.3% on a 51.2% common equity.

In January 2018, PSE&G filed a general rate case with the BPU, requesting an annual revenue increase of approximately 1.2% for its electric and gas operations. In March 2018, the BPU approved interim rate reductions for PSE&G, reflecting the reduction in the federal corporate tax rate, including a reduction to PSE&G's current base electric and gas revenues effective April 2018 by $71 million and $43 million, respectively. As a result of the base rate reduction implemented in April 2018, PSE&G's requested revenue requirements in its filing have increased to $134 million in annual electric revenues ($5.7 billion in rate base) and $108 million in annual gas revenues ($4.2 billion in rate base). The rate request is based on a 10.3% allowed ROE and 54% equity layer. PSE&G anticipates a decision by the BPU later this year and that new base rates will go into effect by late 2018. The company is aiming to pursue decoupling of electric and gas revenues from sales volumes, which would be a credit positive, if approved.

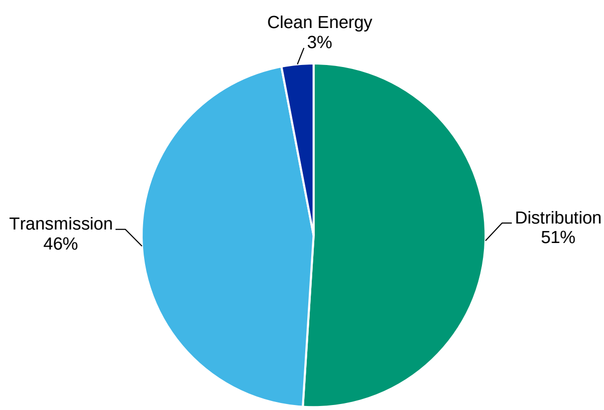
PSE&G has also filed for a variety of recovery mechanisms and programs in 2018 such as the GSMP II and Energy Strong II. In January 2018, the BPU approved the IIP, which is meant to make the regulatory planning process more efficient and accelerate the recovery of investments to reduce regulatory lag. In May 2018, the BPU approved the GSMP II, which provides $1.9 billion to PSE&G to be invested over a five year time frame starting in 2019. Semi-annually, recovery of 84% of costs will be provided based on the clause mechanism. The filing for Energy Strong II is expected to take place shortly and is meant to upgrade substations, strengthen gas systems, and initiate grid modernization.

FERC regulation on transmission is increasingly important given the growing share of transmission in rate base. Because the FERC rate setting processes do not require rate hearings at the state commission level, and since they work to ensure timely recovery through mechanisms such as forward looking formula rates, we generally consider revenues determined under this FERC regulatory framework to be more stable and predictable than the regulated utility businesses.

Over the past five years, the transmission business has grown strongly to approximately 46% of rate base at the end of 2017 from about 28% in 2012.

Exhibit 6

PSE&G 2017 Rate Base Total Estimated Around $17 billion



Source: Company Reports

In April 2018, the governor of New Jersey signed the Clean Energy Bill, which is a credit positive for PSE&G. The goal of this bill is for all New Jersey electric utilities to source 21% of their energy from clean sources by 2020 and 50% by 2030. PSE&G is required to have an annual energy efficiency filing to recover reasonable and prudent costs, including return on capital and the revenue impact of sales losses. Offshore wind obligations will increase to 3,500 MW by 2030, from 1,100 MW currently. The clean energy bill will also establish a cost-effective energy efficiency program.

Liquidity analysis

We expect PSE&G's liquidity profile to be adequate over the next 12-18 months. PSE&G's commercial paper rating is P-1.

As of 31 March 2018, the company had $48 million of cash on hand and a $600 million 5-year revolving credit facility that matures in March 2022, of which $584 million was available. PSE&G also has access, if required, to PSEG's $1.5 billion revolving credit facility. There is no material adverse change clause that could prevent borrowings under the facility. The only covenant is a maximum debt to capitalization covenant of 65%, where PSE&G has ample headroom. The credit agreement contains cross defaults to certain indebtedness of PSE&G or its major subsidiaries (as defined), but there is no cross default to indebtedness of PSEG, PSEG Power or other affiliates.

For 31 March 2018, PSE&G generated roughly $1.9 billion of cash from operations, incurred approximately $2.9 in capital investments, and made no dividend distributions, resulting in negative free cash flow of roughly $1 billion. We anticipate PSE&G to be free cash flow negative over the next few years, given the size of the current capital investment program.

PSE&G's next upcoming debt maturities are $350 million in senior notes due in September 2018 and $250 million in senior notes due in June 2019.

Rating methodology and scorecard factors

Exhibit 7

Rating Factors				
Public Service Electric and Gas Company				
Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 3/31/2018		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	5.9x	A	4.5x - 5x	A
b) CFO pre-WC / Debt (3 Year Avg)	21.8%	A	16% - 20%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	21.8%	A	16% - 20%	A
d) Debt / Capitalization (3 Year Avg)	37.4%	Aa	36% - 40%	Aa
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A2		A2
HoldCo Structural Subordination Notching	0	0	0	0
a) Indicated Rating from Grid		A2		A2
b) Actual Rating Assigned		A2		A2

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2018(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics™

Appendix

Exhibit 8

Cash Flow and Credit Measures [1]

CF Metrics	2014	2015	2016	2017	LTM
As Adjusted					
FFO	**2,013**	**1,927**	**1,849**	**1,956**	**1,911**
+/- Other	(87)	(44)	(130)	(154)	(153)
CFO Pre-W/C	**1,926**	**1,883**	**1,719**	**1,802**	**1,758**
+/- ΔWC	(137)	177	109	(35)	71
CFO	**1,789**	**2,060**	**1,828**	**1,767**	**1,829**
- Div	-	-	-	-	-
- Capex	2,120	2,627	2,750	2,846	2,848
FCF	**(331)**	**(567)**	**(922)**	**(1,079)**	**(1,019)**
(CFO Pre-W/C) / Debt	28.4%	25.9%	20.9%	20.1%	19.7%
(CFO Pre-W/C - Dividends) / Debt	28.4%	25.9%	20.9%	20.1%	19.7%
FFO / Debt	29.7%	26.5%	22.5%	21.8%	21.4%
RCF / Debt	29.7%	26.5%	22.5%	21.8%	21.4%

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months.
Source: Moody's Financial Metrics™

Exhibit 9

Peer Comparison [1]

	Public Service Electric and Gas Company A2 Stable			NSTAR Electric Company A2 Stable			United Illuminating Company Baa1 Stable			Connecticut Light and Power Company Baa1 Stable			Virginia Electric and Power Company A2 Stable		
(in US millions)	FYE Dec-15	FYE Dec-16	LTM Mar-18	FYE Dec-15	FYE Dec-16	LTM Mar-18	FYE Dec-15	FYE Dec-16	FYE Dec-17	FYE Dec-15	FYE Dec-16	LTM Mar-18	FYE Dec-15	FYE Dec-16	FYE Dec-17
Revenue	6,221	6,234	6,253	3,042	2,981	3,017	888	867	921	2,806	2,887	2,940	7,622	7,588	7,556
CFO Pre-W/C	1,719	1,802	1,758	826	748	741	214	212	234	700	798	728	2,561	2,936	2,931
Total Debt	8,217	8,979	8,914	3,030	3,356	3,489	1,055	1,073	1,165	3,250	3,558	3,977	12,239	12,155	13,275
(CFO Pre-W/C) / Debt	20.9%	20.1%	19.7%	27.3%	22.3%	21.2%	20.3%	19.8%	20.1%	21.5%	22.4%	18.3%	20.9%	24.2%	22.1%
(CFO Pre-W/C - Dividends) / Debt	20.9%	20.1%	19.7%	16.8%	14.2%	10.4%	14.7%	19.8%	9.4%	15.3%	15.2%	11.6%	16.9%	24.2%	13.1%
Debt / EBITDA	3.7x	3.6x	3.5x	3.1x	3.2x	3.5x	5.5x	4.2x	3.8x	3.4x	3.4x	3.8x	3.7x	3.4x	3.2x
Debt / Book Capitalization	36.2%	40.7%	39.7%	34.8%	41.5%	42.3%	44.7%	43.5%	48.9%	37.2%	42.9%	45.2%	44.6%	41.9%	47.2%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade.
Source: Moody's Financial Metrics™

Ratings

Exhibit 10

Category	Moody's Rating
PUBLIC SERVICE ELECTRIC AND GAS COMPANY	
Outlook	Stable
Issuer Rating	A2
Senior Secured	Aa3
Pref. Stock	Baa1
Commercial Paper	P-1
PARENT: PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	
Outlook	Stable
Senior Unsecured	Baa1
Subordinate Shelf	(P)Baa2
Pref. Shelf	(P)Baa3
Commercial Paper	P-2

Source: Moody's Investors Service

REPORT NUMBER 1124947

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Moody's
INVESTORS SERVICE

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DETERMINATION OF REVENUE REQUIREMENTS
($000)

	ELECTRIC	GAS	TOTAL
Rate Base	$ 5,664,074	$ 4,242,984	$ 9,907,058
Rate of Return	7.36%	7.36%	7.36%
Operating Income Requirement	$ 416,876	$ 312,284	$ 729,159
Pro-Forma Operating Income	$ 293,014	$ 138,161	$ 431,176
Operating Income Deficiency	$ 123,861	$ 174,122	$ 297,984
Revenue Factor	1.3944	1.4172	
Revenue Requirements	**$ 172,712**	**$ 246,766**	**$ 419,478**

EXHIBIT P-2
SCHEDULE SSJ-03 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ELECTRIC RATE BASE
($000)

	Balance at June 30, 2018	Balance at December 31, 2018
Plant In Service	9,320,113	9,491,280
Plant Held for Future Use	495	495
Accumulated Depreciation Reserve	(2,510,143)	(2,638,063)
Customer Advances	(27,335)	(27,335)
Net Plant	6,783,130	6,826,377
Working Capital:		
Cash (Lead/Lag)	398,198	398,198
Materials and Supplies	108,159	108,159
Prepayments	707	707
Net Working Capital	507,064	507,064
Deferred Taxes	(1,639,028)	(1,668,820)
Consolidated Tax Adjustment	(547)	(547)
Total Electric Rate Base	**5,650,619**	**5,664,074**

GAS RATE BASE
($000)

	Balance at June 30, 2018	Balance at December 31, 2018
Plant In Service	7,951,934	8,316,563
Plant Held for Future Use	96	96
Accumulated Depreciation Reserve	(2,343,203)	(2,449,834)
Customer Advances	(18,028)	(18,028)
Net Plant	5,590,800	5,848,798
Working Capital:		
Cash (Lead/Lag)	256,585	256,585
Materials and Supplies	37,565	37,565
Prepayments	257	257
Net Working Capital	294,407	294,407
Deferred Taxes	(1,652,271)	(1,699,368)
Consolidated Tax Adjustment	(154)	(154)
GSMP Roll-in #3	(138,958)	(200,699)
Total Gas Rate Base	**4,093,824**	**4,242,984**

* 12 Months Actual - 0 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WEIGHTED AVERAGE COST OF CAPITAL
($Millions)

	Amount	Percent	Embedded Cost	Weighted Cost
Long-Term Debt	$ 8,958	45.53%	3.96%	1.80%
Customer Deposits	92	0.47%	0.87%	0.00%
Common Equity	10,623	54.00%	10.30%	5.56%
Total	$ 19,674	100.00%		7.36%

EXHIBIT P-2
SCHEDULE SSJ-05 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

EMBEDDED COST OF LONG TERM DEBT
AS OF JUNE 30, 2018
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	9.448%	$134,380,000.00	($37,589.18)	($1,680.00)	($39,269.18)	$134,340,730.82	1.5119%	0.1428%
SERIES DUE 6/1/37	8.136%	$7,462,900.00	$0.00	$0.00	$0.00	$7,462,900.00	0.0840%	0.0068%
SERIES DUE 7/1/37	5.085%	$7,537,800.00	$0.00	$0.00	$0.00	$7,537,800.00	0.0848%	0.0043%
SERIES A DUE 11/06/20	7.334%	$9,000,000.00	($6,847.77)	($7,896.00)	($14,743.77)	$8,985,256.23	0.1011%	0.0074%
SERIES D DUE 7/1/35	5.443%	$250,000,000.00	($446,250.00)	($1,215,924.48)	($1,662,174.48)	$248,337,825.52	2.7948%	0.1521%
SERIES D DUE 12/1/36	5.912%	$250,000,000.00	($651,747.64)	($1,337,313.60)	($1,989,061.24)	$248,010,938.76	2.7911%	0.1650%
SERIES E DUE 5/1/37	5.996%	$350,000,000.00	($428,974.44)	($1,869,889.44)	($2,298,863.88)	$347,701,136.12	3.9131%	0.2346%
SERIES G DUE 11/1/2039	5.572%	$250,000,000.00	($571,884.99)	($1,549,967.59)	($2,121,852.58)	$247,878,147.42	2.7896%	0.1554%
SERIES G DUE 3/1/2040	5.711%	$300,000,000.00	($1,038,506.00)	($1,864,542.30)	($2,903,048.30)	$297,096,951.70	3.3435%	0.1909%
SERIES G DUE 8/15/2020	3.823%	$250,000,000.00	($133,366.37)	($397,453.24)	($530,819.61)	$249,469,180.39	2.8075%	0.1073%
SERIES H DUE 5/1/2042	4.136%	$450,000,000.00	($2,300,002.62)	($3,106,038.34)	($5,406,040.96)	$444,593,959.04	5.0035%	0.2069%
SERIES H DUE 9/1/2042	3.823%	$350,000,000.00	($1,374,214.70)	($2,566,512.21)	($3,940,726.91)	$346,059,273.09	3.8946%	0.1489%
SERIES H DUE 1/1/2043	3.983%	$400,000,000.00	($2,082,795.01)	($2,875,336.48)	($4,958,131.49)	$395,041,868.51	4.4458%	0.1771%
SERIES I DUE 5/15/2023	2.689%	$500,000,000.00	($776,041.71)	($1,832,917.96)	($2,608,959.67)	$497,391,040.33	5.5977%	0.1505%
SERIES I DUE 9/15/2018	2.805%	$350,000,000.00	($4,021.94)	($93,153.19)	($97,175.13)	$349,902,824.87	3.9378%	0.1105%
SERIES I DUE 3/15/2024	4.035%	$250,000,000.00	($12,216.48)	($1,015,968.88)	($1,028,185.36)	$248,971,814.64	2.8019%	0.1131%
SERIES I DUE 6/1/2019	2.335%	$250,000,000.00	($83,255.98)	($304,910.14)	($388,166.11)	$249,611,833.89	2.8091%	0.0656%
SERIES I DUE 6/1/2044	4.208%	$250,000,000.00	($2,049,985.87)	($1,971,961.17)	($4,021,947.04)	$245,978,052.96	2.7683%	0.1165%
SERIES J DUE 8/15/2019	2.542%	$250,000,000.00	($114,558.93)	($372,249.73)	($486,808.66)	$249,513,191.34	2.8080%	0.0714%
SERIES J DUE 8/15/2024	3.461%	$250,000,000.00	($273,865.60)	($1,167,187.34)	($1,441,052.94)	$248,558,947.06	2.7973%	0.0968%
SERIES J DUE 11/15/2024	3.396%	$250,000,000.00	($763,304.01)	($1,228,632.90)	($1,991,936.91)	$248,008,063.09	2.7911%	0.0948%
SERIES K DUE 5/15/2025	3.300%	$350,000,000.00	($247,637.21)	($1,518,860.85)	($1,766,498.06)	$348,233,501.94	3.9190%	0.1293%
SERIES K DUE 5/1/2045	4.233%	$250,000,000.00	($1,114,718.67)	($1,814,351.79)	($2,929,070.46)	$247,070,929.54	2.7806%	0.1177%
SERIES K DUE 11/1/2045	4.310%	$250,000,000.00	($232,462.39)	($1,846,248.53)	($2,078,710.92)	$247,921,289.08	2.7901%	0.1203%
SERIES K 1.90% DUE 2021	2.421%	$300,000,000.00	($255,049.73)	($1,019,165.90)	($1,274,215.63)	$298,725,784.37	3.3619%	0.0814%
SERIES K 3.80% DUE 2046	3.972%	$550,000,000.00	($2,252,692.36)	($4,471,697.36)	($6,724,389.72)	$543,275,610.28	6.1141%	0.2428%
SERIES L 2.25% DUE 2026	2.560%	$425,000,000.00	($1,147,093.01)	($2,528,248.83)	($3,675,341.84)	$421,324,658.16	4.7416%	0.1214%
SERIES L 3.00% DUE 2027	3.321%	$425,000,000.00	($1,102,097.96)	($2,847,627.82)	($3,949,725.78)	$421,050,274.22	4.7385%	0.1574%
SERIES L 3.60% DUE 2047	3.747%	$350,000,000.00	($250,647.99)	($3,036,539.93)	($3,287,187.92)	$346,712,812.08	3.9019%	0.1462%
SERIES M 3.70% DUE 2028	4.043%	$375,000,000.00	($1,402,808.68)	($2,770,796.20)	($4,173,604.88)	$370,826,395.12	4.1733%	0.1687%
SERIES M 4.05% DUE 2048	4.239%	$325,000,000.00	($2,001,314.84)	($2,911,662.15)	($4,912,976.99)	$320,087,023.01	3.6023%	0.1527%
TOTAL PSE&G LONG TERM DEBT		**$8,958,380,700.00**	**($23,155,952.08)**	**($49,544,734.34)**	**($72,700,686.42)**	**$8,885,680,013.58**	**100.0000%**	**3.9567%**

EXHIBIT P-2
SCHEDULE SSJ-06 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

REVENUE FACTOR

	ELECTRIC	GAS
Revenue Increase	100.0000	100.0000
Uncollectible Rate		1.6000
BPU Assessment Rate	0.192361	0.1924
Rate Counsel Assessment Rate	0.052845	0.0528
Income before State of NJ Bus. Tax	99.7548	98.1548
State of NJ Bus. Income Tax	8.9779	8.8339
Income Before Federal Income Taxes	90.7769	89.3209
Federal Income Taxes	19.0631	18.7574
Return	71.7137	70.5635
Revenue Factor	**1.3944**	**1.4172**

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	$ 8,528,853	$ 9,320,113
Total Direct Additions	909,005	192,267
Total Transfers to Plant In-Service	(1,039)	0
Retirements:		
Distribution	(98,541)	(12,500)
General	(16,956)	(3,924)
Intangible	0	0
Common Plant	(1,208)	(4,675)
Total Retirements	(116,705)	(21,100)
Total Electric Utility Plant In-Service	**$ 9,320,113**	**$ 9,491,280**

GAS UTILITY PLANT IN-SERVICE
($000)

	Test Year June 30, 2018	Six-Months Ending December 31, 2018
Beginning Balance	$ 7,053,104	$ 7,951,934
Total Direct Additions	971,902	378,782
Total Transfers to Plant In-Service	5,199	0
Retirements:		
Production - Gas	(32)	0
Storage	0	0
Transmission	0	0
Distribution	(69,116)	(6,595)
General	(6,840)	(3,828)
Intangible	(1,284)	0
Common Plant	(997)	(3,731)
Total Retirements	(78,270)	(14,154)
Total Gas Utility Plant In-Service	**$ 7,951,934**	**$ 8,316,563**

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	$	719,243	$	157,935
General		36,314		12,272
Intangible		805		60
Customer Operations		152,115		22,000
Land & Land Rights		527		-
Total Direct Additions	**$**	**909,005**	**$**	**192,267**

ADDITIONS TO GAS PLANT IN-SERVICE
($000)

	Test Year June 30, 2018		Six-Months Ending December 31, 2018	
Production - Gas	$	663	$	-
Storage		3,355		-
Transmission		-		14,300
Distribution		808,670		337,800
General		33,351		8,682
Intangibles		-		-
Customer Operations		125,844		18,000
Land & Land Rights		18		0
Total Direct Additions	**$**	**971,902**	**$**	**378,782**

* 12 Months Actual - 0 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-09 R-2

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	$ 2,459,438	$ 2,510,143
Distribution	208,011	111,078
General	16,730	6,062
Customer Operations	17,710	10,815
Total Charge to Depreciation Expense	242,451	127,955
Amortization of Intangibles	1,343	1,440
Total Depreciation Expense	243,794	129,395
Retirements	(116,708)	(21,100)
Cost of Removal (Net)	(79,631)	(22,496)
Other	3,250	1,021
Net Increase	50,706	86,820
Annualization of Depreciation		41,100
Balance - Accumulated Depreciation	**$ 2,510,143**	**$ 2,638,063**

ACCUMULATED DEPRECIATION OF GAS UTILITY PLANT
($000)

	Test Year June 30, 2018	Six-Months Ending December 31, 2018
Beginning Balance	$ 2,301,681	$ 2,343,203
Production - Gas	-	-
Storage	149	170
Transmission	1,841	1,152
Distribution	123,325	67,961
General	14,547	8,622
Customer Operations	16,594	8,849
Total Charge to Depreciation Expense	156,456	86,753
Amortization of Intangibles	1,278	991
Total Depreciation Expense	157,734	87,745
Retirements	(78,238)	(14,154)
Cost of Removal (Net)	(39,770)	(21,019)
Other	1,797	155
Net Increase	41,523	52,727
Annualization of Depreciation		53,904
Balance - Accumulated Depreciation	$ 2,343,203	$ 2,449,834

* 12 Months Actual - 0 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

Extension of Electric Lines	$	(27,335)
Total Electric Customer Advances for Construction	**$**	**(27,335)**

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

Extensions/Deposits	$	(18,028)
Total Gas Customer Advances for Construction	**$**	**(18,028)**

* 13-month Actual Average Balance (June 2017 - June 2018)

EXHIBIT P-2
SCHEDULE SSJ-11 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WORKING CAPITAL - MATERIALS AND SUPPLIES
($000)

	Electric	Gas
Materials and Supplies *	$ 108,159	$ 37,565
Total Materials and Supplies	**$ 108,159**	**$ 37,565**

* 13-month Actual Average Balance (June 2017 - June 2018)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WORKING CAPITAL - PREPAYMENTS
($000)

	Electric	Gas
BPU & Rate Counsel Assessment	707	257
Total Prepayments	**$ 707**	**$ 257**

* 13-month Actual Average Balance (June 2017 - June 2018)

EXHIBIT P-2
SCHEDULE SSJ-13 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ACCUMULATED DEFERRED TAXES
($000)

	Test Year June 30, 2018		Balance Ending December 31, 2018	
Electric	$	(1,639,028)	$	(1,668,820)
Gas	$	(1,652,271)	$	(1,699,368)

* 12 Months Actual - 0 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-14 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CONSOLIDATED TAX ADJUSTMENT

	Electric	Gas	Total
CTA Adjustment	(547)	(154)	$ (701)

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	138,182	199,487
Cost of Removal Expenditures	4,867	9,482
Accumulated Depreciation	(925)	(2,407)
Accumulated Deferred Taxes	(3,167)	(5,862)
Total	138,958	200,699
Rate Base Reduction	**(138,958)**	**(200,699)**

EXHIBIT P-2
SCHEDULE SSJ-16 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

INCOME STATEMENT
($000)

ELECTRIC		**June 30, 2018**
Electric Operating Revenues	$	3,039,214
Electric Operating Expenses:		
Operation Expense		$2,152,236
Maintenance Expense		$108,616
Depreciation Expense		$225,699
Amortization of Limited Term Plant		$9,402
Amortization of Property Losses		$24,239
Taxes Other Than Income Taxes		$23,745
Income Taxes [1]		$138,793
Accretion Expense		$0
Total Electric Utility Operating Expenses		$2,682,729
Electric Utility Operating Income	$	356,485

GAS	**June 30, 2018**
Gas Operating Revenues	$1,727,468
Gas Operating Expenses:	
Operation Expense	$1,137,619
Maintenance Expense	37,740
Depreciation Expense	142,124
Amortization of Limited Term Plant	7,507
Amortization of Regulatory Asset	33,414
Amortization of Property Losses	-
Amortization of Excess cost of removal	-
Taxes Other Than Income Taxes	18,967
Income Taxes [1]	75,911
Total Gas Utility Operating Expenses	$1,453,281
Gas Utility Operating Income	$274,187
Net Utility Operating Income	$630,671

* 12 Months Actual - 0 Months Forecast

[1] Income Taxes reflect the elimination of the Repair Allowance flow-through as proposed in Schedule RCK-4 R-1, Adjustment 1

EXHIBIT P-2
SCHEDULE SSJ-17 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

Line		June 30, 2018 Electric	Gas
1	Residential	13,229,351	1,514,898
2	Commercial	23,599,675	955,730
3	Industrial	3,793,571	89,114
4	Firm Transportation Service		26,298
5	Non-Firm Transportation Service		142,922
6	Cogeneration Interruptible		42,350
7	Cogeneration Contracts		0
8	Contract Service Gas		784,013
9	Street Lighting	331,934	442
10	Total Sales to Customers	40,954,531	3,555,768
11	Interdepartmental	9,212	614
12	Total Sales	40,963,744	3,556,381

* 12 Months Actual - 0 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-18 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

REVENUE BY CLASS OF BUSINESS
($000)

Line		Electric	June 30, 2018 Gas	Total
1	Residential	$ 1,934,022	$ 1,121,374	$ 3,055,396
2	Commercial	1,485,607	537,492	2,023,100
3	Industrial	147,403	37,494	184,897
4	Firm Transportation Service		4,211	4,211
5	Non-Firm Transportation Service		18,823	18,823
6	Cogeneration Interruptible		20,943	20,943
7	Cogeneration Contracts		-	0
8	Contract Service Gas		8,452	8,452
9	Street Lighting	68,673	395	69,069
10	Total Revenue from Sales to Customers	$ 3,635,705	$ 1,749,184	$ 5,384,890
11	Interdepartmental	1,253	504	1,756
12	Total Revenue from Sales	$ 3,636,958	$ 1,749,688	$ 5,386,646

* 12 Months Actual - 0 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-19 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

AVERAGE CUSTOMERS BILLED BY CLASS OF BUSINESS

Line		June 30, 2018 Electric	Gas
1	Residential	1,940,974	1,674,212
2	Commercial	297,848	158,816
3	Industrial	8,571	6,234
4	Firm Transportation Service		41
5	Non-Firm Transportation Service		187
6	Cogeneration Interruptible		16
7	Cogeneration Contracts		0
8	CSG		23
9	Street Lighting	10,309	15
10	Total Customers	2,257,702	1,839,544
11	Interdepartmental	1	1
12	Total Customers	2,257,703	1,839,545

* 12 Months Actual - 0 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-20 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

EXPENSES
($000)

Electric

Production Expenses		June 30, 2018
Other Power Supply Expenses:		
Purchased Power	$	1,595,596
System Control/Load Dispatch	$	134
Total Other Power Supply Expenses	$	1,595,730
Distribution		
Operation	$	65,146
Maintenance		108,616
Total Distribution	$	173,761

Gas

Production Expenses		
Gas Supply		
Natural Gas City Gate Purchases	$	789,447
Fuel Gas - Raw Materials		(4,317)
Other Gas Purchases		(459)
Other Gas Supply Expenses		-
Total Gas Supply	$	784,671
Gas Production		
Operation	$	-
Maintenance		834
Total Gas Production	$	834
Other Power Generation		
Liquefied petroleum gas expenses		285
Total Other Power Generation	$	285
Other Storage		
Operation	$	1,643
Maintenance		233
Total Other Storage	$	1,876
Total Production Expenses	$	787,666
Transmission		
Operation	$	216
Maintenance		3,213
Total Transmission	$	3,429
Distribution		
Operation	$	75,567
Maintenance		33,460
Total Distribution	$	109,026

* 12 Months Actual - 0 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	$ 17,071	$ 12,784	$ 29,854
Customer Records and Collection Expenses	$ 72,270	$ 53,657	$ 125,928
Uncollectible Accounts	$ 50,178	$ 28,593	$ 78,771
Misc. Customer Accounts Expenses	$ 92,268	$ (9,990)	$ 82,277
Total Customer Accounts Expenses	$ 231,787	$ 85,044	$ 316,831
Cust. Service and Informational Expenses			
Operation:			
Supervision	$ -	$ -	$ -
Customer Assistance Expenses	$ 134,589	$ 90,378	$ 224,967
Misc. Cust. Service and Info. Expenses	$ 1,707	$ 1,295	$ 3,002
Total Cust. Service and Info. Expenses	$ 136,296	$ 91,673	$ 227,969
Sales Expenses			
Operation:			
Demonstration and Selling Expenses	$ 527	$ 403	$ 930
Misc. Sales Expenses	$ 58	$ 48	$ 106
Total Sales Expenses	$ 585	$ 451	$ 1,036
Total Customer Accounts and Information	$ 368,668	$ 177,168	$ 545,836

* 12 Months Actual - 0 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-22 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ADMINISTRATIVE AND GENERAL SALARIES AND EXPENSES
($000)

	June 30, 2018		
	Electric	**Gas**	**Total**
Salaries & Wages	$ 7,168	$ 7,522	$ 14,689
Supplies & Expenses	1,967	1,276	3,243
Outside Services	51,307	40,874	92,181
Property Insurance	1,529	241	1,770
Injuries and Damages	12,761	5,480	18,242
Pensions & Fringe Benefits	31,416	31,418	62,835
Regulatory Expenses	11,251	4,053	15,304
Duplicate Charge	(2,741)	(768)	(3,509)
General Advertising	1,604	1,332	2,936
Other Miscellaneous General	2,854	2,507	5,361
Rents	3,576	4,135	7,711
Maintenance	0	-	0
Total Administrative and General Salaries & Expenses	$ 122,693	$ 98,070	$ 220,763

* 12 Months Actual - 0 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-23 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DEPRECIATION AND AMORTIZATION
($000)

ELECTRIC

Line		June 30, 2018
	Depreciation	
1	Electric	$225,699
	Amortization	
2	Electric	$33,640
	Total Electric Depreciation and Amortization	**$259,340**

GAS

Line		June 30, 2018
	Depreciation	
1	Gas	$142,124
	Amortization	
2	Gas	$40,920
	Total Gas Depreciation and Amortization	**$183,044**

* 12 Months Actual - 0 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-24 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

TAXES OTHER THAN INCOME TAXES
($000)

Line		June 30, 2018		
		Electric	**Gas**	**Total**
1	Real Estate	$ 12,980	$ 4,537	$ 17,516
2	FICA	293	392	685
3	State Unemployment	10,240	13,727	23,967
4	Federal Unemployment	56	75	132
5	Miscellaneous Municipal and State Taxes	176	236	412
6	Total	$ 23,745	$ 18,967	$ 42,712

* 12 Months Actual - 0 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-25 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CURRENT AND DEFERRED INCOME TAXES
($000)

	Electric	June 30, 2018 Gas	Total
Net Income Taxes	$ 138,793	$ 75,911	$ 214,704

* 12 Months Actual - 0 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PRO-FORMA DISTRIBUTION OPERATING INCOME
($000)

#		Schedule #	Electric	Gas	Total
Test Year Distribution Operating Income			**$ 356,485**	**$ 274,187**	**$ 630,671**
#	**Pro-Forma Adjustments:**	**Schedule #**			
1	Wages	SSJ-27 R-2	$ (3,586)	$ (4,697)	$ (8,283)
2	Payroll Taxes	SSJ-28 R-2	(253)	(332)	(585)
3	Interest Synchronization (Tax Savings)	SSJ-29 R-2	1,498	1,001	2,499
4	Pension & Fringe Benefits	SSJ-30 R-2	(12,418)	(21,992)	(34,410)
5	COLI Interest Expense	SSJ-31 R-2	(3,155)	(1,010)	(4,164)
6	Weather Normalization	SSJ-32 R-2	126	-	126
7	Gains/Losses on Sales of Property	SSJ-33 R-2	17	35	52
8	Real Estate Taxes	SSJ-34 R-2	(60)	(366)	(425)
9	Insurance	SSJ-35 R-2	(95)	(103)	(198)
10	ASB Margin	SSJ-36 R-2	6,589	(13,177)	(6,589)
11	TSGNF Margin Sharing	SSJ-37 R-2	-	(403)	(403)
12	Depreciation Rate Change	SSJ-38 R-2	(59,093)	(77,502)	(136,596)
13	Storm Cost Amortization*	SSJ-39 R-2	-	-	-
14	Post Rate Case Storm Cost Normalization*	SSJ-40 R-2	-	-	-
15	Excess COR Refund Recovery	SSJ-41 R-2	-	(12,476)	(12,476)
16	Test Year Amortization Adjustments	SSJ-42 R-2	2,249	(8,806)	(6,557)
17	Regulatory Assets*	SSJ-43 R-2	-	-	-
18	Rate Case Expenses	SSJ-44 R-2	(15)	25	10
19	Credit Card Fees	SSJ-45 R-2	(2,939)	(1,623)	(4,563)
20	Vacation Accrual	SSJ-46 R-2	(1,508)	(2,406)	(3,915)
21	Energy Strong / GSMP Revenue Adjustment	SSJ-47 R-2	9,579	7,323	16,902
22	BPU / Rate Counsel Assessment	SSJ-48 R-2	(742)	(278)	(1,021)
23	Test Year Corrections	SSJ-49 R-2	337	761	1,099
	Total Pro-Forma Adjustments		**$ (63,470)**	**$ (136,025)**	**$ (199,496)**
Total Pro-Forma Distribution Operating Income			**$ 293,014**	**$ 138,161**	**$ 431,176**

* Per the Direct Testimony of Mr. Krueger, the Storm Cost amortization and Regulatory Assets are offset by a credit to ADIT; See Schedule RCK-7 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 1
Wages
($000)

	Electric	Gas	Total
Bargaining Unit Employees	$ 3,077	$ 4,030	$ 7,107
MAST Employees	1,912	2,504	4,415
Operating Expense Increase before Taxes	$ 4,989	$ 6,533	$ 11,522
Income Taxes	1,402	1,837	3,239
Operating Income Increase (Decrease) After Taxes	**$ (3,586)**	**$ (4,697)**	**$ (8,283)**

EXHIBIT P-2
SCHEDULE SSJ-28 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 2
Payroll Taxes
($000)

	Electric	Gas	Total
Bargaining Unit Employees	$ 217	$ 284	$ 502
MAST Employees	135	177	312
Operating Expense Increase before Taxes	$ 352	$ 461	$ 813
Income Taxes	99	130	229
Operating Income Increase (Decrease) After Taxes	**$ (253)**	**$ (332)**	**$ (585)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

	Percent	Embedded Cost	Weighted Cost	
Electric Rate Base				$ 5,664,074
Debt Components:				
Long Term Debt	45.53%	3.96%	1.80%	
Customer Deposits	0.47%	0.87%	0.00%	
Total Weighted Cost of Debt				1.81%
Annualized Interest Expense				$ 102,280
Less: Test Period Interest Expense				96,952
Net Interest Expense Increase / (Decrease)				$ 5,327
Income Tax Rate				28.11%
Operating Income Increase (Decrease) After Taxes				$ 1,498

	Percent	Embedded Cost	Weighted Cost	
Gas Rate Base				$ 4,242,984
Debt Components:				
Long Term Debt	45.53%	3.96%	1.80%	
Customer Deposits	0.47%	0.87%	0.00%	
Total Weighted Cost of Debt				1.81%
Annualized Interest Expense				$ 76,618
Less: Test Period Interest Expense				73,056
Net Interest Expense Increase / (Decrease)				$ 3,562
Income Tax Rate				28.11%
Operating Income Increase (Decrease) After Taxes				$ 1,001

EXHIBIT P-2
SCHEDULE SSJ-30 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

	Electric	Gas	Total
Rate Year			
Medical	$ 16,705	$ 22,355	$ 39,060
Dental/Vision	$ 884	$ 1,183	$ 2,066
Pensions	$ -	$ -	$ -
Group Life	$ 371	$ 496	$ 867
Disability	$ 159	$ 212	$ 371
Thrift & Savings	$ 4,965	$ 6,645	$ 11,610
Workers Compensation	$ 1,929	$ 2,581	$ 4,510
Benefits Outside Services	$ 1,608	$ 2,152	$ 3,760
Benefits Other	$ 399	$ 535	$ 934
OPEB	$ 24,489	$ 25,211	$ 49,700
	$ 51,510	$ 61,369	$ 112,879
Less: Test Year			
Medical	$ 13,837	$ 17,206	$ 31,043
Dental/Vision	$ 636	$ 777	$ 1,414
Pensions	$ (15,530)	$ (13,209)	$ (28,739)
Group Life	$ 338	$ 407	$ 745
Disability	$ 141	$ 171	$ 312
Thrift & Savings	$ 4,422	$ 5,135	$ 9,557
Workers Compensation	$ 1,023	$ 1,220	$ 2,243
Benefits Outside Services	$ 1,329	$ 1,484	$ 2,813
Benefits Other	$ 410	$ 452	$ 862
OPEB	$ 27,629	$ 17,134	$ 44,763
	$ 34,236	$ 30,778	$ 65,014
Increase in Test Year Operating Expenses	$ 17,274	$ 30,591	$ 47,865
Income Taxes	$ 4,856	$ 8,599	$ 13,455
Operating Income Increase (Decrease) After Taxes	**$ (12,418)**	**$ (21,992)**	**$ (34,410)**

EXHIBIT P-2
SCHEDULE SSJ-31 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 5
COLI Interest Expense
($000)

	Electric		Gas		Total	
Net Credit in Test Year						
Administrative & General Expenses	(4,543)		(1,098)		(5,641)	
Tax Savings on COLI	(675)		(216)		(892)	
Total Benefit	(5,218)		(1,314)		(6,532)	
Interest Charges	3,155		1,010		4,164	
Net Benefit	$ (2,064)		$ (304)		$ (2,368)	
Operating Income Increase (Decrease) After Taxes		**$ (3,155)**		**$ (1,010)**		**$ (4,164)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 6
Weather Normalization
($000)

	Electric	Gas*	Total
Actual Distribution Revenues	$ 949,119	$ -	$ 949,119
Weather Normalized Distribution Revenues	$ 949,294	-	949,294
Increase (Decrease) in Test Year Margin Revenue	$ (175)	$ -	$ (175)
Income Taxes	(49)	-	(49)
Operating Income Increase (Decrease) After Taxes	$ 126	$ -	$ 126

* 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	$	98	$	145
Income Taxes		13		28		41
Net Income/(Loss)	$	33	$	71	$	104
Operating Income Increase (Decrease) After Taxes	**$**	**17**	**$**	**35**	**$**	**52**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 8
Real Estate Taxes
($000)

	Electric	Gas	Total
Rate Year Property Taxes	$ 13,063	$ 5,045	$ 18,108
Test Year Property Taxes	$ 12,980	$ 4,537	$ 17,516
Operating Expense Increase Before Taxes	$ 83	$ 508	$ 591
Income Taxes	23	143	166
Operating Income Increase (Decrease) After Taxes	**$ (60)**	**$ (366)**	**$ (425)**

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	3,893	2,345	6,238
Operating Expense Increase Before Taxes	$ 131	$ 144	$ 275
Income Taxes	37	40	77
Operating Income Increase (Decrease) After Taxes	**$ (95)**	**$ (103)**	**$ (198)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 10
ASB Margin
($000)

	Electric	Gas	Total
ASB Margin by Appliance	$ 18,330	$ 34,002	$ 52,331
ASB Margin % Above-the-Line per N.J.A.C. 14:4-3.6	50%	100%	
Above the Line ASB Margin	$ 9,165	$ 34,002	$ 43,166
ASB Margin in Test Year	$ -	$ 52,331	$ 52,331
ASB Above-the-Line Margin	$ 9,165	$ (18,330)	$ (9,165)
Income Taxes	2,576	(5,152)	(2,576)
Operating Income Increase (Decrease) After Taxes	**$ 6,589**	**$ (13,177)**	**$ (6,589)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

	Electric	Gas	Total
Operating Income Decrease Before Taxes	$ -	$ (561)	$ (561)
Income Taxes	-	158	158
Operating Income Increase (Decrease) After Taxes	**$ -**	**$ (403)**	**$ (403)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 12
Depreciation Rate Change
($000)

	Electric	Gas	Total
Annualization of Depreciation Expense	$ 248,042	$ 168,858	$ 416,900
Test Year Depreciation Expense	$ 225,699	$ 142,124	$ 367,823
Annualization of Current Depreciation Rates	$ 22,343	$ 26,734	$ 49,077
Depreciation Expense at Proposed Rates	$ 307,899	$ 249,931	$ 557,830
Operating Expense Increase (Decrease) for Proposed Rates	$ 59,857	$ 81,073	$ 140,930
Operating Income Increase (Decrease) Before Taxes	$ (82,200)	$ (107,807)	$ (190,007)
Income Taxes	$ (23,106)	$ (30,305)	$ (53,411)
Operating Income Increase (Decrease) After Taxes	**$ (59,093)**	**$ (77,502)**	**$ (136,596)**

EXHIBIT P-2
SCHEDULE SSJ-39 R-2

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	$	20,365	$	20	$	20,385
FP&L Late Bill - Superstorm Sandy Mutual Aid	$	271	$	-	$	271
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		7.36%		7.36%		7.36%
Annual Amortization Carrying Charge	$	6,173	$	200	$	6,373
Operating Expense Increase Before Taxes	$	83,951	$	2,722	$	86,673
Income Taxes	$	23,599	$	765	$	24,364
Operating Income Increase (Decrease) After Taxes	**$**	**(60,352)**	**$**	**(1,957)**	**$**	**(62,309)**

*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-7 R-2

EXHIBIT P-2
SCHEDULE SSJ-40 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 14
Test Year Storm Cost Normalization
($000)

	Electric	Gas	Total
Test Year incremental O&M*	$ 25,247	$ -	$ 25,247
Amortization Period	3	3	3
Annual Storm Cost Amortization	$ 8,416	$ -	$ 8,416
Test Year incremental O&M	$ -	$ -	$ -
Operating Expense Increase Before Taxes	$ 8,416	$ -	$ 8,416
Income Taxes	$ 2,366	$ -	$ 2,366
Operating Income Increase (Decrease) After Taxes	**$ (6,050)**	**$ -**	**$ (6,050)**

* Per the Direct Testimony of Mr. Krueger, the Storm Cost amortization and Regulatory Assets are offset by a credit to ADIT; See Schedule RCK-7 R-2

EXHIBIT P-2
SCHEDULE SSJ-41 R-2

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 Refund 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
2017 * Tax adjustment; see note below	-	$ (14,373)	(14,373)
2018 **	-	$ 9,900	9,900
Total Deferred Excess COR Amortization**	$ -	$ 76,634	$ 76,634
Amortization Period	5	5	5
Operating Expense Increase Before Taxes	$ -	$ 15,327	$ 15,327
Carrying Charge:			
Average Deferred Balance During Test Year	$ -	$ 38,317	$ 38,317
Deferred Tax Benefit	$ -	$ (10,771)	$ (10,771)
Average Net of Tax Deferred Cost Balance	$ -	$ 27,546	$ 27,546
Weighted Average Cost of Capital	7.36%	7.36%	7.36%
Annual Amortization Carrying Charge	$ -	$ 2,027	$ 2,027
Adjustment Summary			
Operating Expense Increase Before Taxes	$ -	$ 17,354	$ 17,354
Income Taxes	$ -	$ 4,878	$ 4,878
Operating Income Increase (Decrease) After Taxes	**$ -**	**$ (12,476)**	**$ (12,476)**

* Tax Adjustment in December 2017 reflects the impact associated with decreasing the associated ADIT liability offset to the regulatory asset as a result in the decrease in the Federal tax rate from the 2017 Tax Cuts and Jobs Act
** 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
Test Year Amortization Adjustments
($000)

	Electric	Gas	Total
Test Year Amortizations			
Test Year Excess COR Refund	$ -	$ (13,200)	$ (13,200)
Medicare Amortization	$ 2,912	$ 774	$ 3,686
Energy Efficiency Traksmart Software Assets	$ 217	$ 177	$ 394
Test Year Amortizations Total	$ 3,129	$ (12,249)	$ (9,120)
Operating Expense Increase Before Taxes	$ (3,129)	$ 12,249	$ 9,120
Income Taxes	$ (879)	$ 3,443	$ 2,564
Operating Income Increase (Decrease) After Taxes	**$ 2,249**	**$ (8,806)**	**$ (6,557)**

EXHIBIT P-2
SCHEDULE SSJ-43 R-2

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	$	961	$	10,616	$	11,576
Total Regulatory Assets / (Liabilities)	$	2,238	$	10,616	$	12,854
Amortization Period		3		3		3
Annual Amortization	$	746	$	3,539	$	4,285
Test Year Expense	$	-	$	-	$	-
Operating Expense Increase Before Taxes	$	746	$	3,539	$	4,285
Income Taxes	$	210	$	995	$	1,204
Operating Income Increase (Decrease) After Taxes	**$**	**(536)**	**$**	**(2,544)**	**$**	**(3,080)**

* Per the Direct Testimony of Mr. Krueger, the Storm Cost amortization and Regulatory Assets are offset by a credit to ADIT; See Schedule RCK-7 R-2

EXHIBIT P-2
SCHEDULE SSJ-44 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 18
Rate Case Expenses
($000)

	Electric	Gas	Total
Rate Case Expenses	$ 682	$ 387	$ 1,069
Amortization Period	3	3	3
Annual Amortization	$ 227	$ 129	$ 356
Test Year Rate Case Expense	$ 207	$ 164	$ 371
Operating Expense Decrease Before Taxes	$ (20)	$ 35	$ 14
Income Taxes	$ (6)	$ 10	$ 4
Operating Income Increase (Decrease) After Taxes	**$ (15)**	**$ 25**	**$ 10**

EXHIBIT P-2
SCHEDULE SSJ-45 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 19
Credit Card Fees
($000)

	Electric	Gas	Total
Operating Expense Increase Before Taxes	$ 4,089	$ 2,258	$ 6,347
Income Taxes	1,149	635	1,784
Operating Income Increase (Decrease) After Taxes	**$ (2,939)**	**$ (1,623)**	**$ (4,563)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 20
Vacation Accrual
($000)

	Electric	Gas	Total
Operating Income Decrease Before Taxes	$ (2,098)	$ (3,347)	$ (5,445)
Income Taxes	590	941	1,531
Operating Income Increase (Decrease) After Taxes	**$ (1,508)**	**$ (2,406)**	**$ (3,915)**

EXHIBIT P-2
SCHEDULE SSJ-47 R-2

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	99	7,089
ES Roll-in #7 (Annualizing Revenue from Jul17 - Feb18)	5,741	-	5,741
ES Roll-in #8 (Eliminate Revenue Requirement)	594	120	715
GSMP Roll-in 2 (Annualizing Revenue from Jul17 - Dec17)	-	9,967	9,967
Operating Revenue Increase Before Taxes	13,325	10,186	23,511
Income Taxes	(3,746)	(2,863)	(6,609)
Operating Income Increase (Decrease) After Taxes	**$ 9,579**	**$ 7,323**	**16,902**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 22
BPU/Rate Counsel Assessment
($000)

Electric

	BPU	Rate Counsel	Total
Estimated Assessment	$ 9,699	$ 2,366	$ 12,065
Less: Assessment Included in Test Year Operating Expenses	8,655	2,378	11,032
Operating Expense Increase Before Taxes	$ 1,044	$ (12)	$ 1,033
Income Taxes	294	(3)	290
Operating Income Increase (Decrease) After Taxes	$ (751)	$ 8	$ (742)

Gas

	BPU	Rate Counsel	Total
Estimated Assessment	$ 3,540	$ 863	$ 4,403
Less: Assessment Included in Test Year Operating Expenses	3,150	865	4,016
Operating Expense Increase Before Taxes	$ 390	$ (2)	$ 387
Income Taxes	109	(1)	109
Operating Income Increase (Decrease) After Taxes	$ (280)	$ 2	$ (278)

EXHIBIT P-2
SCHEDULE SSJ-49 R-2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 23
Test Year Correction Adjustments
($000)

	Electric	Gas	Total
Test Year Amortizations			
Gas Street Light Cancel / Rebill	$ -	$ (135)	$ (135)
Service Company Utility Allocation	$ (469)	$ (924)	$ (1,393)
Operating Expense Increase Before Taxes	$ (469)	$ (1,059)	$ (1,528)
Income Taxes	$ (132)	$ (298)	$ (430)
Operating Income Increase (Decrease) After Taxes	**$ 337**	**$ 761**	**$ 1,099**