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 & GR18010030

DIRECT TESTIMONY
OF
SCOTT JENNINGS
9+3 UPDATE

VICE PRESIDENT – UTILITY FINANCE

May 14, 2018
P-2 R-1

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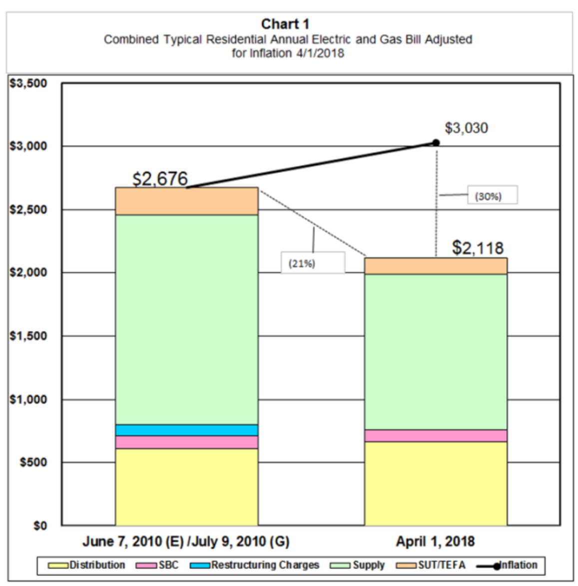
DIRECT TESTIMONY
OF
SCOTT JENNINGS
VICE-PRESIDENT – UTILITY FINANCE
PSEG SERVICES COMPANY

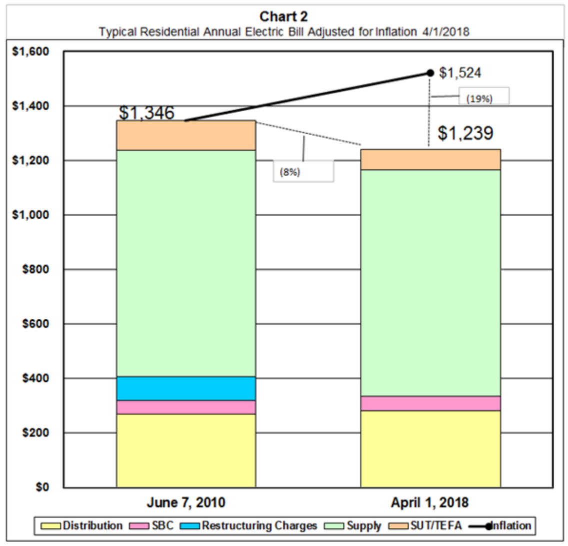
I. INTRODUCTION

Q. In your initial testimony you discussed the changes in PSE&G's rates since the last base rate case and compared to other NJ utilities. Have there been changes since your testimony was filed?

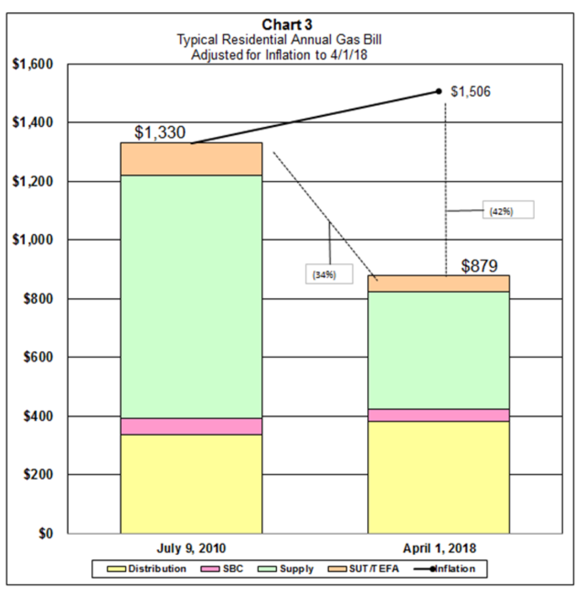
A. Yes. Since the Company filed its petition in January 2018, it has implemented certain rate changes approved by the BPU, most notably lower rates to account for lower tax rates provided by the Tax Reform Act. See Board Order dated March 26, 2018 in Docket No. AX18010001. As a result, the Company's rates as of April 1, 2018 declined by approximately 2% compared to January 1, 2018. PSE&G's rates are now 21% lower for a combined electric and gas typical residential customer than they were after the Company's last base rate case as shown in the chart below. Further, adjusted for inflation, they are now 30% lower.



For PSE&G's electric only typical residential customers, bills are 8% lower than they were after the Company's last base rate case, and 19% lower adjusted for inflation.

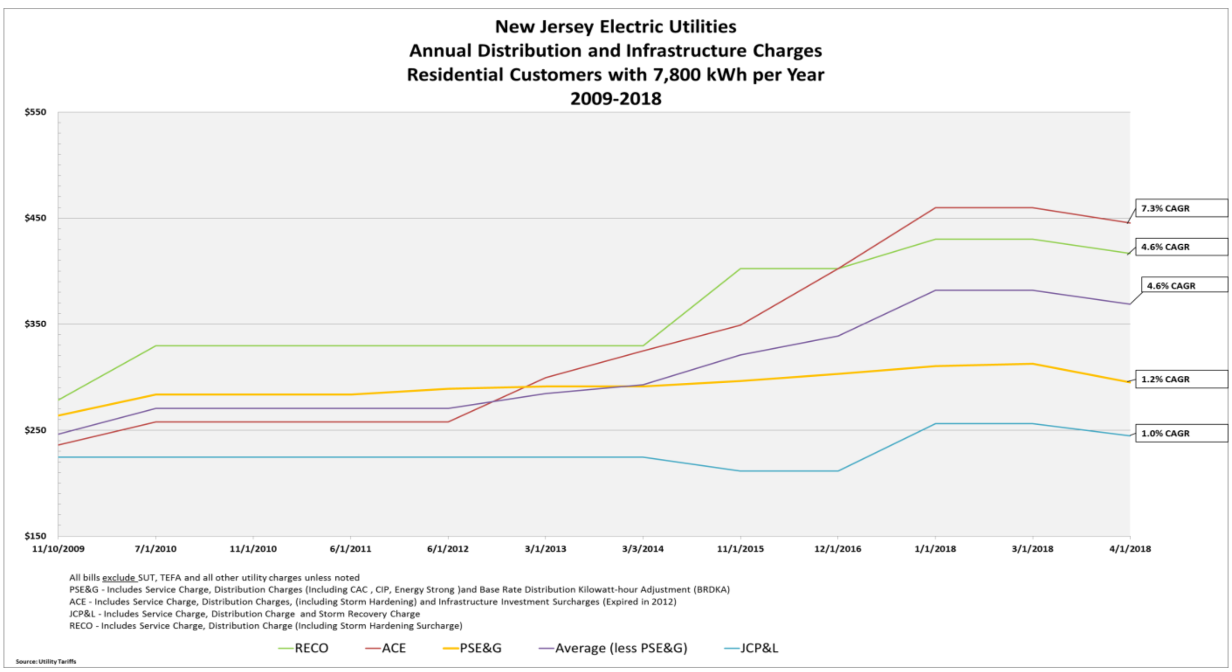


For PSE&G's gas only typical residential customers, bills are 34% lower than they were after the Company's last base rate case, and 42% lower adjusted for inflation. In addition to these decreases, the Company has provided these customers $681 of bill credits over the past several years.

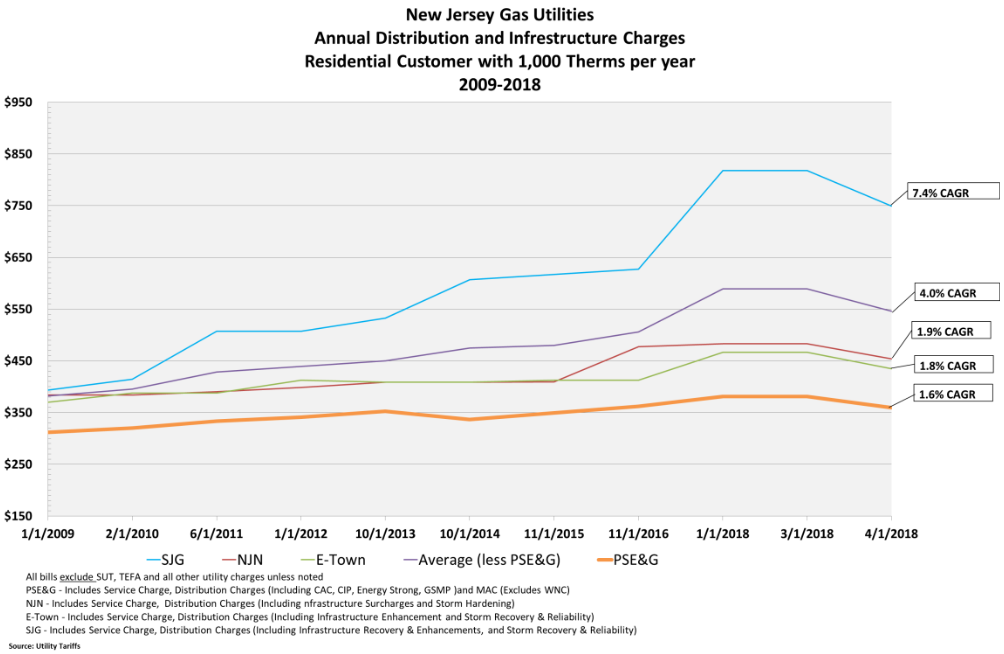


Q. That addresses the decline in your overall rate. How do PSE&G's distribution rates compare to the other NJ utilities?

A. As of April 1, 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. Specifically for electric distribution and infrastructure charges for typical residential electric customers, PSE&G's charges are the second lowest in the State. These charges are approximately 27% lower than the State average and 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.



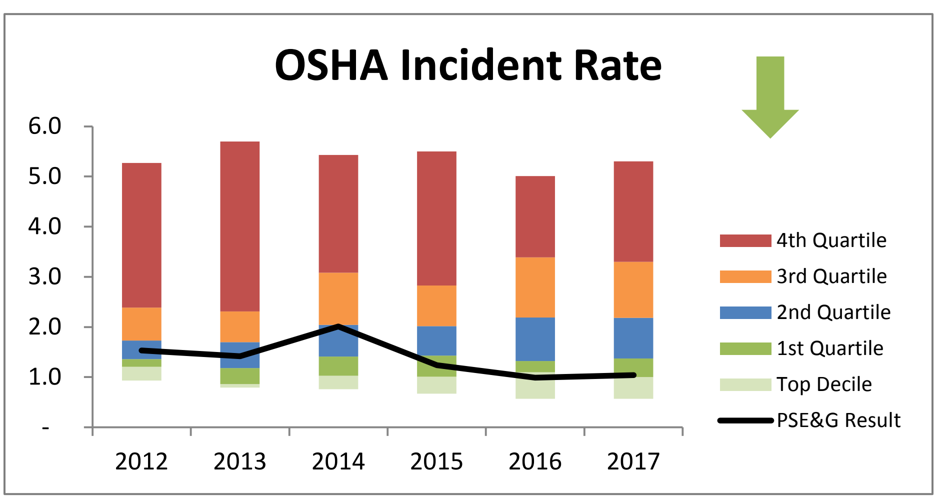
With respect to gas distribution and infrastructure charges for typical residential gas customers, PSE&G's charges are the lowest in the State, approximately 34% lower than the State average and have only increased 1.6% on an annual basis, which is well under half of the average increase of gas utilities in the State other than PSE&G.

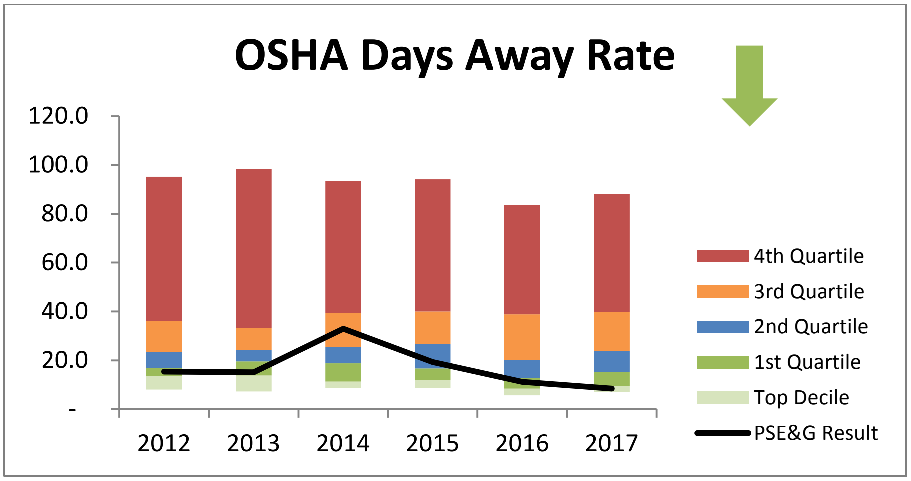


Q. The rate stability and low cost compared to the last base rate case and other New Jersey utilities is impressive, but has that come at the expense of safety, reliability or customer satisfaction?

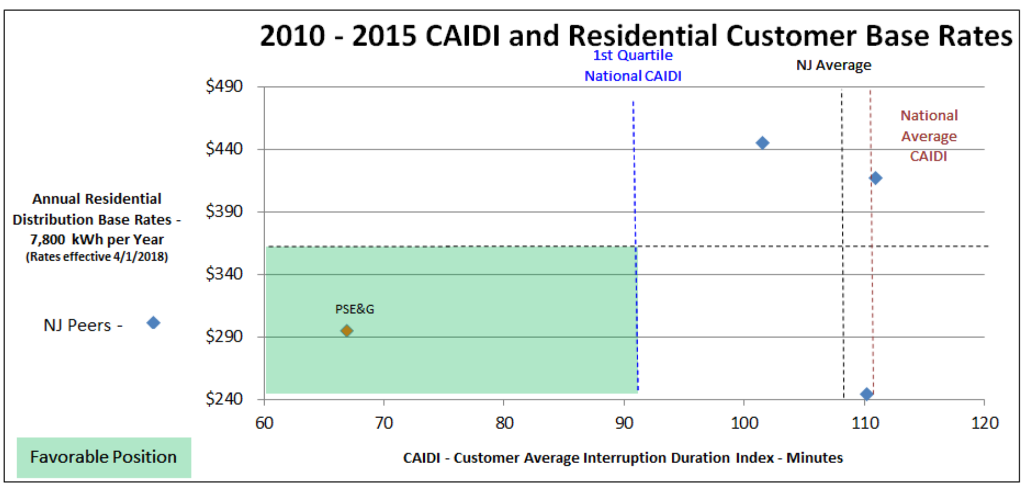
A. The Company has been able to maintain these low rates while performing at a high level overall and compared to peers.

- 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:

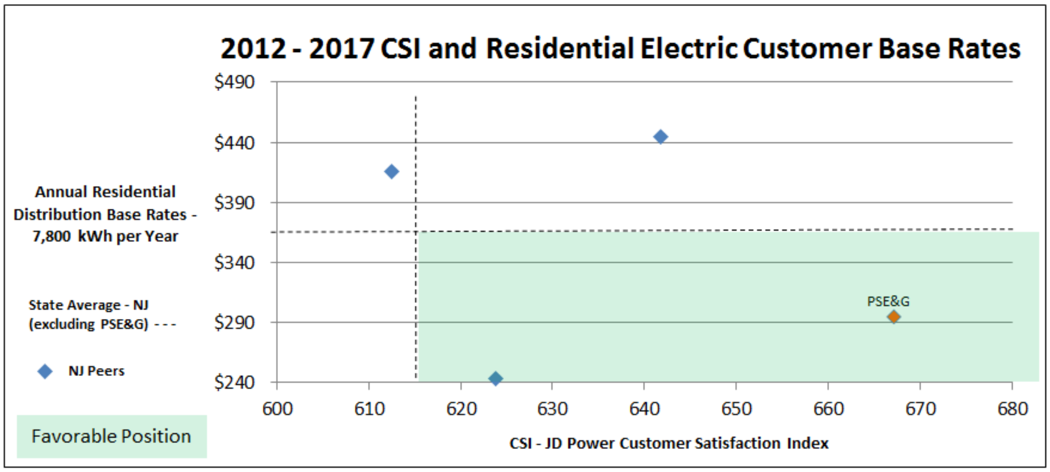


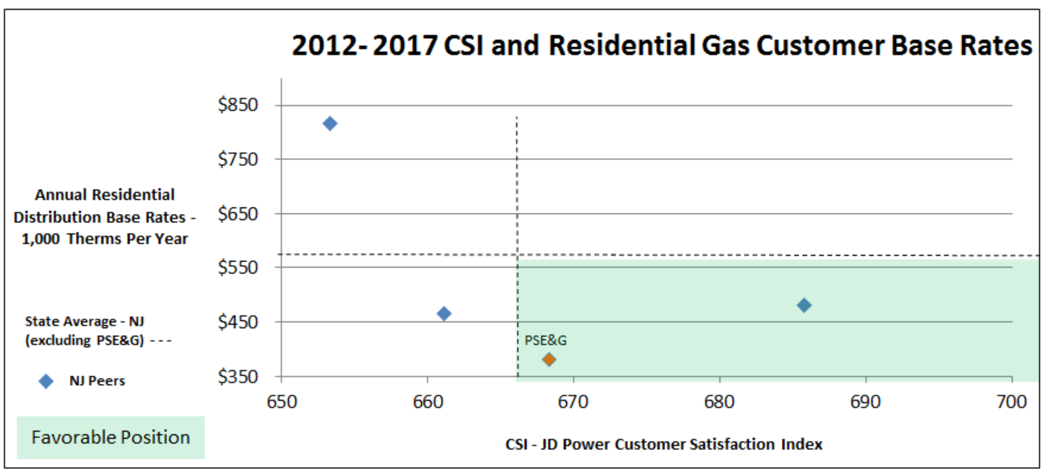


- With respect to reliability – the chart below illustrates that the Company's reliability is a good value relative to other New Jersey utilities. PSE&G is well above the New Jersey utilities in reliability as measured by the Customer Average Interruption Duration Index (CAIDI) and also notably within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



- Similarly, the below charts demonstrate that PSE&G's customer satisfaction is delivered at a good price compared to peers:





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 to peers, and b) recognition of the value of incentive compensation that incents these results while controlling costs.

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

A. Yes. The original 5+7 filing requested a revenue increase, net of the proposed Tax Adjustment Credit (TAC) impacts, of $95 million, which was about 1% of overall revenues. There are several notable changes to the Company's 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 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, resulting in higher rate base and therefore higher revenue requirements. There were also some other less impactful changes, which are included in the schedule updates that are included in my 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 $241 million or approximately 3% of overall revenues. Simply stated, the majority of this change is due to the accelerated return to customers of the rate reduction for changes to federal taxes.

Q. Can you please explain the proposed changes in the TAC?

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 over a five year period, mitigating the impact of other rate increases (such as from the proposed extension of the Gas System Modernization Program (GSMP II)) in a measured fashion to maintain rate stability and to mitigate potentially adverse impacts on credit statistics. Now, in this 9+3 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 balance multiple objectives: a) maintain rate stability, b) mitigate future increases from other programs and c) mitigate potentially adverse impacts on the Company's credit statistics.

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 incremental 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.

Q. As a result of these changes what is the proposed TAC flowback, by year?

A. Please see the following table which outlines the amount by year:

Total - SUM YD (5 Years)	Oct18-Sep19	Oct19-Sep20	Oct20-Sep21	Oct21-Sep22	Oct22-Sep23
Annualized Current Revenue ($M)	7,481	7,481	7,481	7,481	7,481
Base Rate Case Revenue Requirement	437	437	437	437	437
Tax Adjustment Clause	(196)	(136)	(192)	(200)	(92)
Revenue Change	241	301	246	237	346
Total Revenue	7,722	7,782	7,727	7,718	7,826
% year-over-year increase: Revenue	**3.2%**	**0.8%**	**-0.7%**	**-0.1%**	**1.4%**
Cumulative % Increase:	**3.2%**	**4.0%**	**3.3%**	**3.2%**	**4.6%**

Electric - SUM YD (5 Years)	Oct18-Sep19	Oct19-Sep20	Oct20-Sep21	Oct21-Sep22	Oct22-Sep23
Annualized Current Revenue ($M)	5,436	5,436	5,436	5,436	5,436
Base Rate Case Revenue Requirement	200	200	200	200	200
Tax Adjustment Clause	(66)	(29)	(19)	(18)	(17)
Revenue Change	134	171	181	182	183
Total Revenue	5,570	5,607	5,617	5,619	5,620
% year-over-year increase: Revenue	**2.5%**	**0.7%**	**0.2%**	**0.0%**	**0.0%**
Cumulative % Increase:	**2.5%**	**3.1%**	**3.3%**	**3.3%**	**3.3%**

Gas - Sum YD (5 Years)	Oct18-Sep19	Oct19-Sep20	Oct20-Sep21	Oct21-Sep22	Oct22-Sep23
Annualized Current Revenue ($M)	2,045	2,045	2,045	2,045	2,045
Base Rate Case Revenue Requirement	238	238	238	238	238
Tax Adjustment Clause	(130)	(107)	(173)	(183)	(75)
Revenue Change	108	130	65	55	162
Total Revenue	2,152	2,175	2,109	2,100	2,207
% year-over-year increase: Revenue	**5.3%**	**1.1%**	**-3.0%**	**-0.5%**	**5.1%**
Cumulative % Increase:	**5.3%**	**6.3%**	**3.3%**	**2.8%**	**8.0%**

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 approximately 3% in April 2018. 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 (e.g., the Utilities SPDR ETF decreased approximately 10% from December 2017 through March and April 2018). These changes could indicate a higher ROE than the

Company's original request is warranted. However, at this juncture, Ms. Bulkley proposes to maintain the ROE request at the current 10.3% level proposed in the original 5+7 testimony. Ms. Bulkley will continue to monitor market conditions over the course of this proceeding and update in the 12+0 filing, if appropriate.

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. 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. 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 approximately 6% in 2009 to approximately 4% today, while the Company increased the weighted average maturity of its portfolio from 12.5 years to approximately 14 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. 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.

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. In the original 5+7 filing, the Company proposed a "Green Enabling Mechanism" or "GEM" to decouple revenues to support future energy efficiency filings. 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 Filing in the near future to begin the process of investing to reduce customer usage and bills and achieve the requirements of this legislation.

II. 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 9+3 updated revenue requirement schedules that reflect information for both electric distribution and gas distribution.

Determination of Revenue Requirements—Schedule SSJ-02 R-1

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

A. Yes. Schedule SSJ-02 R-1 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 $275.9 million and $140.6 million for electric and gas, respectively, and a required rate of return of 7.39%, the increase in required revenue requested is $200.0 million for electric distribution and $237.6 million for gas distribution.

Utility Rate Base—Schedule SSJ-03 R-1

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

A. Schedule SSJ-03 R-1 presents projected total electric and gas utility rate bases at June 30, 2018 and December 31, 2018. Electric rate base is expected to be $5.68 billion by June 30, 2018 and $5.67 billion as of December 31, 2018. Similarly, gas rate base is expected to be $4.04 billion by June 30, 2018 and $4.17 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, a 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-1 through SSJ-15 R-1 and will be addressed below.

Revenue Factor—Schedule SSJ-06 R-1

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 1.4200. The higher factor for gas reflects the inclusion of a rate for uncollectibles of 1.80%. 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-1

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-1, is estimated to be $9.4 billion and $7.9 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-1

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

A. Yes. Schedule SSJ-08 R-1 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 $1.3 billion for gas. The additions are primarily distribution plant.

Accumulated Depreciation—Schedule SSJ-09 R-1

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-1, as a rate base deduction using a mid-year convention.

Customer Advances for Construction—Schedule SSJ-10 R-1

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-1, electric and gas distribution rate base has been reduced by $26.4 million and $18.7 million, respectively, based upon a 13-month average of the most current available actual advances—the period March 2017 through March 2018. This schedule will be updated for actual test year data as it becomes available.

Working Capital

Q. What is "Working Capital?"

A. Working Capital is the average amount of capital over and above investments in plant and other separately identified rate base items provided by investors of PSE&G to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The Company's proposed working capital allowance is $513.3 million for electric and $289.5 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-1 of $405.0 million and $249.8 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-1

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

A. I have included $107.3 million and $39.3 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 March 2017 through March 2018. This schedule will be updated for actual test year data as it becomes available.

Prepayments—Schedule SSJ-12 R-1

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

A. Yes, it does. The Company is required to make advance payments for the BPU and Rate Counsel assessments, prior to their being charged to operating expenses. Such prepayments occur every year and therefore require a permanent, ongoing investment by the Company to fund them. Accordingly, I have included the average electric and gas utility prepayment requirements of $1.0 million and $0.4 million, respectively, in rate base. These levels are based upon a 13-month average as of March 2018 and will be updated as data becomes available.

Accumulated Deferred Taxes—Schedule SSJ-13 R-1

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-1. The net accumulated deferred taxes amount to a $1.6 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-1

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-1 and RCK-6B R-1. As a result, this adjustment decreases electric distribution rate base by $0.6 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-1

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-1 (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 $215.5 million as of December 31, 2018.

Electric and Gas Distribution Operating Income

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

A. Schedules SSJ-17 R-1 through SSJ-25 R-1 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-1 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 nine months actual and three months estimated data.

Pro-forma Distribution Operating Income—Schedule SSJ-26 R-1

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

A. Yes. Schedule SSJ-26 R-1 is a summary of *pro forma* adjustments to the test year electric and gas utility operating income. These *pro formas* adjust test period operating income for known or measurable changes to expense and income levels so as to reflect the expected expense and income levels for the rate year, which is the first twelve months after new rates are set as a result of this proceeding. Adoption of these adjustments by the Board will provide the Company with a realistic opportunity to earn the reasonable return on its electric and gas investment when the rates are in effect.

The Company's revenue requirements determination includes 20 adjustments to its test period electric distribution operating income. The *pro forma* adjustments reduce the test period electric operating income by $58.3 million after-tax. On the gas distribution side there are 21 adjustments that reduce the test period operating income by $125.2 million. Each of the *pro forma* adjustments will be discussed in more detail below.

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

Q. Please address your adjustments for Wages.

A. These adjustments to operating income of a reduction of $3.1 million and $4.8 million for electric and gas, respectively, represent the adjustment to the test year to reflect wage increases applicable to the rate year. These increases are to the labor costs applicable to Bargaining Unit employees and Management, Administrative, Secretarial and Technical ("MAST") employees.

In 2016, the Company and its Unions executed extension agreements on 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 or 2nd (date differs depending upon the Union) 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-1

Q. Explain the adjustment for Payroll Taxes.

A. The reductions to operating income of $0.219 million and $0.331 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-1 are calculated utilizing a composite 6.95% tax rate. This schedule will be updated for actual test year data as it becomes available.

Adjustment No. 3: Interest Synchronization (Tax Savings) Schedule—SSJ-29 R-1

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-1, the interest-bearing components of our capitalization supporting rate base produce synchronized interest expenses of $6.9 million more than the interest expense in the test year for electric and $0.7 million more than interest expense in the test year for gas, resulting in tax savings of $1.9 million for electric and of $0.2 million for gas.

Adjustment No. 4: Pension and Fringe Benefits—Schedule SSJ-30 R-1

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 $23.0 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 described in my initial testimony the myriad of 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 described in my initial testimony 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-1

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 $5.9 million for electric distribution and $1.6 million for gas distribution. Interest expense on funds borrowed from the policy is directly related to the $7.5 million in benefits attributable to the policy. My adjustment to the test year, which is in line with prior rate cases, is to include the gross interest cost of $3.2 million for electric and $0.9 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-1

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

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

Schedule SSJ-32 R-1 shows the adjustments necessary to reflect normal weather for the period July through March 2018. This schedule shows a comparison of the distribution revenue for the first nine months of actual data to that based upon normal weather. Distribution revenue represents the revenue from the sale of a kWh 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 $4.2 million for electric, is required since the first nine months of the test year, July to March 2018, were cooler than normal. This is the same weather impact included in the billing determinants data in the testimony of Mr. Swetz. No adjustment is reflected for gas due to the impact of the Weather Normalization Charge.

Adjustment No. 7: Gains/Losses on Sales of Property—Schedule SSJ-33 R-1

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

A. This adjustment allocates one-half of the gain on sales of property, net of associated income taxes, to customers based on a five-year average. The use of a five-year average provides a representative amount of gains for ratemaking purposes, avoiding the distortion that would occur if an abnormally high or low level of gains is recognized in the test period. The Company has included the five-year average for the years 2013 through 2017 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-1

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

A. Yes. This adjustment of $0.5 million for electric and $0.5 million for gas decreases the test year operating income 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.

Adjustment No. 9: Insurance—Schedule SSJ-35 R-1

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 $3.9 million for electric and $2.4 million for gas for the test year. These premiums are increasing to $4.0 million for electric and $2.5 million for gas. This adjustment results in a decrease to operating income of $87,000 for electric and $78,000 for gas. The increase in insurance expense between the rate year and the test year reflects input from our insurance carriers and actual experience.

Adjustment No. 10: ASB Margin—Schedule SSJ-36 R-1

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 in my original testimony, the Company has allocated its ASB margin by appliance type. As a result, $15.3 million of margin relates 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 $15.3 million and increases electric margin by approximately $7.7 million. After adjusting for tax effect this results in an increase to operating income of $5.5 million for electric and a decrease of $11.0 million to operating income for gas.

Adjustment No. 11: TSG-NF Margin—Schedule SSJ-37 R-1

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

A. A reduction to gas operating income in the amount of $260,000 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-1

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-1) 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 $21.6 million for electric and $23.5 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 $57.3 million for electric and $69.1 million for gas. As a result, the total annualization of depreciation expense at the proposed depreciation rates results in a reduction to operating income of $56.8 million for electric and $66.6 million for Gas.

Adjustment No. 13: Storm Cost Amortization - Schedule SSJ-39 R-1

Q. Please describe the adjustment to normalize Storm Costs.

A. In March 2013, the Board issued an Order (Docket No. AX13030196) establishing a generic proceeding to review the prudence of storm costs by New Jersey utilities in response to multiple Major Storm Events. In response to this Order, in June 2013, PSE&G filed a report detailing its unreimbursed incremental Major Storm Event costs, requesting the Board review those costs for prudence and subsequent recovery. This adjustment is for the recovery of the incremental O&M associated with major storm events already approved as prudent as well as any deferred incremental O&M costs associated with major storm events that occurred after the Order establishing the prudence of the earlier storms. On September 30, 2014 the Board approved incremental O&M associated with major storms through 2012 of $220.2 million as reasonable and prudent and eligible for rate recovery in a future base rate proceeding. In addition, the Company has incurred $20.7 million of post 2012 incremental storm costs through the start of the test year, for a total of $240.9 million. As discussed in Mr. Krueger's testimony, the Company proposes to offset these costs with certain deferred taxes. Had the Company not offset these costs with deferred taxes, it would have proposed an increase to its revenue requirements to reflect a three year amortization of $77.8 million for electric and $2.5 million for gas representing deferred storm costs from 2010 through June 2017 plus 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-1 is not reflected in the *pro forma* adjusted operating income used to set the revenue deficiency in this proceeding.

Adjustment No. 14: Test Year Storm Normalization - Schedule SSJ-40 R-1

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

A. Yes. This adjustment is for incremental O&M Major Storm Event costs incurred during the test year. To normalize out the impact of major storms in the test year, the Company is requesting to remove the incremental expense. The Company has incurred $24.5 million of test year electric incremental Major Storm Event costs. As discussed in Mr. Krueger's testimony, we propose to offset these costs with certain deferred taxes.

Adjustment No. 15: Recovery of Deferred Excess Cost of Removal Refund– Gas- Schedule SSJ-41 R-1

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 million balance, which has been updated from my original testimony to reflect the impact of decreasing the associated ADIT liability offset to the regulatory asset 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 $12.5 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 Adjustment - Schedule SSJ-42 R-1

Q. Is an adjustment required to normalize amortization expenses?

A. Yes. There are three amortizations that need to be normalized out of the test year. First, 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-1

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 excess unprotected deferred income taxes 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 Company currently estimates the cost at $11.2 million. Since our initial filing, the Company has responded to all discovery received to date. The matter is still pending. Site remediation is complete.

The amortization of these Regulatory Assets would have resulted in an adjustment to electric and gas test year operating income to reflect a decrease in the amount of $528,000 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-1 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-1

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

A. This adjustment seeks recovery of all prudently incurred rate case expenses. As the Company was required to submit this rate case as a result of the Energy Strong Board Order, it is appropriate for the Board to allow for recovery of the expenses required to complete the filing. The Company is seeking to remove all rate case expenses incurred during the test year and recover those expenses as a regulatory asset over a three year period. The adjustment represents an increase in operating income of $77,000 for electric and $33,000 for gas.

Adjustment No. 19: Credit Card Fees – Schedule SSJ-45 R-1

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

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

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

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

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

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

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

Adjustment No. 20: Vacation Accrual Reversal – Schedule SSJ-46 R-1

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-1

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. 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) will be submitted in July 2018 based on investment through September 30, 2018 for rates effective January 1, 2019.

Q. How was the adjustment calculated?

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

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

A. The eighth energy strong roll-in is 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-1 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 – Schedule SSJ-48 R-1

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 of $1.0 million for electric and an increase of $9,000 for gas.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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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.

REPORT NUMBER 1109347

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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

Only a rating committee may determine a rating action and this report does not constitute a rating action.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DETERMINATION OF REVENUE REQUIREMENTS
($000)

	ELECTRIC	GAS	TOTAL
Rate Base	$ 5,672,132	$ 4,165,739	$ 9,837,871
Rate of Return	7.39%	7.39%	7.39%
Operating Income Requirement	$ 419,171	$ 307,848	$ 727,019
Pro-Forma Operating Income	$ 275,892	$ 140,559	$ 416,451
Operating Income Deficiency	$ 143,278	$ 167,289	$ 310,567
Revenue Factor	1.3944	1.4200	
Revenue Requirements	**$ 199,787**	**$ 237,550**	**$ 437,338**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ELECTRIC RATE BASE
($000)

	Balance at June 30, 2018	Balance at December 31, 2018
Plant In Service	9,367,658	9,501,367
Plant Held for Future Use	495	495
Accumulated Depreciation Reserve	(2,541,074)	(2,667,560)
Customer Advances	(26,354)	(26,354)
Net Plant	6,800,726	6,807,948
Working Capital:		
Cash (Lead/Lag)	404,990	404,990
Materials and Supplies	107,301	107,301
Prepayments	999	999
Net Working Capital	513,290	513,290
Deferred Taxes	(1,628,866)	(1,648,550)
Consolidated Tax Adjustment	(555)	(555)
Total Electric Rate Base	**5,684,594**	**5,672,132**

GAS RATE BASE
($000)

	Balance at June 30, 2018	Balance at December 31, 2018
Plant In Service	7,927,499	8,251,685
Plant Held for Future Use	96	96
Accumulated Depreciation Reserve	(2,362,297)	(2,462,602)
Customer Advances	(18,696)	(18,696)
Net Plant	5,546,602	5,770,484
Working Capital:		
Cash (Lead/Lag)	249,813	249,813
Materials and Supplies	39,302	39,302
Prepayments	364	364
Net Working Capital	289,479	289,479
Deferred Taxes	(1,641,956)	(1,678,546)
Consolidated Tax Adjustment	(157)	(157)
GSMP Roll-in #3	(153,965)	(215,522)
Total Gas Rate Base	**4,040,004**	**4,165,739**

* 9 Months Actual - 3 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-04 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WEIGHTED AVERAGE COST OF CAPITAL
($Millions)

	Amount		Percent	Embedded Cost	Weighted Cost
Long-Term Debt	$	8,658	45.51%	4.03%	1.83%
Customer Deposits		93	0.49%	0.87%	0.00%
Common Equity		10,273	54.00%	10.30%	5.56%
Total	$	19,024	100.00%		7.39%

EXHIBIT P-2
SCHEDULE SSJ-05 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

EMBEDDED COST OF LONG TERM DEBT
AS OF MARCH 31, 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	9.454%	$134,380,000.00	($40,811.15)	($1,824.00)	($42,635.15)	$134,337,364.85	1.5633%	0.1478%
SERIES DUE 6/1/37	8.140%	$7,462,900.00	$0.00	$0.00	$0.00	$7,462,900.00	0.0868%	0.0071%
SERIES DUE 7/1/37	5.088%	$7,537,800.00	$0.00	$0.00	$0.00	$7,537,800.00	0.0877%	0.0045%
SERIES A DUE 11/06/20	7.339%	$9,000,000.00	($7,581.36)	($8,742.00)	($16,323.36)	$8,983,676.64	0.1045%	0.0077%
SERIES D DUE 7/1/35	5.447%	$250,000,000.00	($452,812.50)	($1,233,805.74)	($1,686,618.24)	$248,313,381.76	2.8897%	0.1574%
SERIES D DUE 12/1/36	5.916%	$250,000,000.00	($660,594.91)	($1,355,467.17)	($2,016,062.08)	$247,983,937.92	2.8858%	0.1707%
SERIES E DUE 5/1/37	6.000%	$350,000,000.00	($434,668.80)	($1,894,710.99)	($2,329,379.79)	$347,670,620.21	4.0459%	0.2428%
SERIES E DUE 5/1/18	5.628%	$400,000,000.00	($2,655.92)	($22,828.07)	($25,483.99)	$399,974,516.01	4.6546%	0.2620%
SERIES G DUE 11/1/2039	5.576%	$250,000,000.00	($578,586.75)	($1,568,131.27)	($2,146,718.02)	$247,853,281.98	2.8843%	0.1608%
SERIES G DUE 3/1/2040	5.715%	$300,000,000.00	($1,050,488.78)	($1,886,056.23)	($2,936,545.01)	$297,063,454.99	3.4570%	0.1976%
SERIES G DUE 8/15/2020	3.830%	$250,000,000.00	($149,077.10)	($444,273.70)	($593,350.80)	$249,406,649.20	2.9024%	0.1112%
SERIES H DUE 5/1/2042	4.139%	$450,000,000.00	($2,324,128.53)	($3,138,619.18)	($5,462,747.71)	$444,537,252.29	5.1732%	0.2141%
SERIES H DUE 9/1/2042	3.826%	$350,000,000.00	($1,388,430.71)	($2,593,062.33)	($3,981,493.04)	$346,018,506.96	4.0267%	0.1541%
SERIES H DUE 1/1/2043	3.986%	$400,000,000.00	($2,104,048.03)	($2,904,676.66)	($5,008,724.69)	$394,991,275.31	4.5966%	0.1832%
SERIES I DUE 5/15/2023	2.695%	$500,000,000.00	($815,861.40)	($1,926,967.33)	($2,742,828.73)	$497,257,171.27	5.7867%	0.1560%
SERIES I DUE 9/15/2018	2.818%	$350,000,000.00	($8,913.80)	($206,447.20)	($215,361.00)	$349,784,639.00	4.0705%	0.1147%
SERIES I DUE 3/15/2024	4.042%	$250,000,000.00	($12,751.77)	($1,060,485.52)	($1,073,237.29)	$248,926,762.71	2.8968%	0.1171%
SERIES I DUE 6/1/2019	2.348%	$250,000,000.00	($105,893.55)	($387,816.20)	($493,709.75)	$249,506,290.25	2.9035%	0.0682%
SERIES I DUE 6/1/2044	4.212%	$250,000,000.00	($2,069,758.54)	($1,990,981.26)	($4,060,739.80)	$245,939,260.20	2.8620%	0.1205%
SERIES J DUE 8/15/2019	2.555%	$250,000,000.00	($140,016.51)	($454,971.85)	($594,988.36)	$249,405,011.64	2.9024%	0.0741%
SERIES J DUE 8/15/2024	3.468%	$250,000,000.00	($285,043.78)	($1,214,827.64)	($1,499,871.42)	$248,500,128.58	2.8918%	0.1003%
SERIES J DUE 11/15/2024	3.403%	$250,000,000.00	($793,237.50)	($1,276,814.58)	($2,070,052.08)	$247,929,947.92	2.8852%	0.0982%
SERIES K DUE 5/15/2025	3.307%	$350,000,000.00	($256,642.22)	($1,582,727.40)	($1,839,369.62)	$348,160,630.38	4.0516%	0.1340%
SERIES K DUE 5/1/2045	4.236%	$250,000,000.00	($1,125,104.25)	($1,831,888.41)	($2,956,992.66)	$247,043,007.34	2.8749%	0.1218%
SERIES K DUE 11/1/2045	4.314%	$250,000,000.00	($234,588.58)	($1,863,465.02)	($2,098,053.60)	$247,901,946.40	2.8849%	0.1244%
SERIES K 1.90% DUE 2021	2.434%	$300,000,000.00	($278,592.77)	($1,113,242.78)	($1,391,835.55)	$298,608,164.45	3.4750%	0.0846%
SERIES K 3.80% DUE 2046	3.975%	$550,000,000.00	($2,273,048.02)	($4,512,104.27)	($6,785,152.29)	$543,214,847.71	6.3215%	0.2513%
SERIES L 2.25% DUE 2026	2.567%	$425,000,000.00	($1,182,029.84)	($2,605,251.33)	($3,787,281.17)	$421,212,718.83	4.9017%	0.1258%
SERIES L 3.00% DUE 2027	3.328%	$425,000,000.00	($1,133,142.98)	($2,927,842.69)	($4,060,985.67)	$420,939,014.33	4.8985%	0.1630%
SERIES L 3.60% DUE 2047	3.750%	$350,000,000.00	($252,778.14)	($3,062,346.23)	($3,315,124.37)	$346,684,875.63	4.0344%	0.1513%
TOTAL PSE&G LONG TERM DEBT		**$8,658,380,700.00**	**($20,161,288.19)**	**($45,070,377.05)**	**($65,231,665.24)**	**$8,593,149,034.76**	**100.0000%**	**4.0261%**

EXHIBIT P-2
SCHEDULE SSJ-06 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

REVENUE FACTOR

	ELECTRIC	GAS
Revenue Increase	100.0000	100.0000
Uncollectible Rate		1.7960
BPU Assessment Rate	0.192361	0.1924
Rate Counsel Assessment Rate	0.052845	0.0528
Income before State of NJ Bus. Tax	99.7548	97.9588
State of NJ Bus. Income Tax	8.9779	8.8163
Income Before Federal Income Taxes	90.7769	89.1425
Federal Income Taxes	19.0631	18.7199
Return	71.7137	70.4226
Revenue Factor	**1.3944**	**1.4200**

EXHIBIT P-2
SCHEDULE SSJ-07 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ELECTRIC UTILITY PLANT IN-SERVICE
($000)

	Test Year June 30, 2018	Six-Months Ending December 31, 2018
Beginning Balance	$ 8,504,199	$ 9,367,658
Total Direct Additions	968,550	154,809
Total Transfers to Plant In-Service	(2,441)	0
Retirements:		
Distribution	(84,287)	(12,500)
General	(17,573)	(3,924)
Intangible	0	0
Common Plant	(791)	(4,675)
Total Retirements	(102,651)	(21,100)
Total Electric Utility Plant In-Service	**$ 9,367,658**	**$ 9,501,367**

GAS UTILITY PLANT IN-SERVICE
($000)

	Test Year June 30, 2018	Six-Months Ending December 31, 2018
Beginning Balance	$ 7,042,922	$ 7,927,499
Total Direct Additions	943,174	338,340
Total Transfers to Plant In-Service	5,242	0
Retirements:		
Production - Gas	(32)	0
Storage	0	0
Transmission	0	0
Distribution	(53,285)	(6,595)
General	(8,630)	(3,828)
Intangible	(1,284)	0
Common Plant	(609)	(3,731)
Total Retirements	(63,840)	(14,154)
Total Gas Utility Plant In-Service	**$ 7,927,499**	**$ 8,251,685**

EXHIBIT P-2
SCHEDULE SSJ-08 R-1

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	$ 782,161	$ 129,644
General	94,138	9,030
Intangible	7,426	60
Customer Operations	84,357	16,076
Land & Land Rights	468	-
Total Direct Additions	**$ 968,550**	**$ 154,809**

ADDITIONS TO GAS PLANT IN-SERVICE
($000)

	Test Year June 30, 2018	Six-Months Ending December 31, 2018
Production - Gas	$ 634	$ -
Storage	1,542	-
Transmission	2,750	14,300
Distribution	820,829	303,937
General	46,697	6,951
Intangibles	-	-
Customer Operations	70,705	13,153
Land & Land Rights	18	0
Total Direct Additions	**$ 943,174**	**$ 338,340**

* 9 Months Actual - 3 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ACCUMULATED DEPRECIATION OF ELECTRIC UTILITY PLANT
($000)

	Test Year June 30, 2018	Six-Months Ending December 31, 2018
Beginning Balance	$ 2,467,034	$ 2,541,074
Distribution	208,699	110,686
General	15,961	8,555
Customer Operations	16,891	8,677
Total Charge to Depreciation Expense	241,550	127,918
Amortization of Intangibles	1,744	1,777
Total Depreciation Expense	243,294	129,695
Retirements	(102,652)	(21,100)
Cost of Removal (Net)	(69,509)	(22,611)
Other	2,907	1,021
Net Increase	74,039	87,005
Annualization of Depreciation		39,482
Balance - Accumulated Depreciation	**$ 2,541,074**	**$ 2,667,560**

ACCUMULATED DEPRECIATION OF GAS UTILITY PLANT
($000)

	Test Year June 30, 2018	Six-Months Ending December 31, 2018
Beginning Balance	$ 2,303,972	$ 2,362,297
Production - Gas	-	-
Storage	178	157
Transmission	2,207	1,850
Distribution	125,674	70,192
General	13,812	7,318
Customer Operations	15,424	7,092
Total Charge to Depreciation Expense	157,294	86,608
Amortization of Intangibles	1,334	627
Total Depreciation Expense	158,628	87,236
Retirements	(63,808)	(14,154)
Cost of Removal (Net)	(38,006)	(19,225)
Other	1,511	155
Net Increase	58,325	54,012
Annualization of Depreciation		46,293
Balance - Accumulated Depreciation	$ 2,362,297	$ 2,462,602

* 9 Months Actual - 3 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-10 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

Extension of Electric Lines	$	(26,354)
Total Electric Customer Advances for Construction	**$**	**(26,354)**

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

Extensions/Deposits	$	(18,696)
Total Gas Customer Advances for Construction	**$**	**(18,696)**

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WORKING CAPITAL - MATERIALS AND SUPPLIES
($000)

	Electric	Gas
Materials and Supplies *	$ 107,301	$ 39,302
Total Materials and Supplies	**$ 107,301**	**$ 39,302**

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

EXHIBIT P-2
SCHEDULE SSJ-12 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

WORKING CAPITAL - PREPAYMENTS
($000)

	Electric	Gas
BPU & Rate Counsel Assessment	999	364
Total Prepayments	**$ 999**	**$ 364**

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

EXHIBIT P-2
SCHEDULE SSJ-13 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ACCUMULATED DEFERRED TAXES
($000)

	Test Year June 30, 2018		Balance Ending December 31, 2018	
Electric	$	(1,628,866)	$	(1,648,550)
Gas	$	(1,641,956)	$	(1,678,546)

* 9 Months Actual - 3 Months Forecast

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CONSOLIDATED TAX ADJUSTMENT

	Electric	Gas		Total
CTA Adjustment	(555)	(157)	$	(712)

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	151,182	212,487
Cost of Removal Expenditures	7,045	11,660
Accumulated Depreciation	(942)	(2,530)
Accumulated Deferred Taxes	(3,320)	(6,096)
Total	153,965	215,522
Rate Base Reduction	**(153,965)**	**(215,522)**

EXHIBIT P-2
SCHEDULE SSJ-16 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

INCOME STATEMENT
($000)

ELECTRIC		**June 30, 2018**
Electric Operating Revenues	$	3,177,239
Electric Operating Expenses:		
Operation Expense		$2,302,202
Maintenance Expense		$116,431
Depreciation Expense		$227,223
Amortization of Limited Term Plant		$9,761
Amortization of Property Losses		$23,967
Taxes Other Than Income Taxes		$24,294
Income Taxes [1]		$139,146
Accretion Expense		($0)
Total Electric Utility Operating Expenses		$2,843,024
Electric Utility Operating Income	$	334,215

GAS	**June 30, 2018**
Gas Operating Revenues	$1,707,504
Gas Operating Expenses:	
Operation Expense	$1,127,071
Maintenance Expense	37,896
Depreciation Expense	144,795
Amortization of Limited Term Plant	7,732
Amortization of Regulatory Asset	28,245
Amortization of Property Losses	5,199
Amortization of Excess cost of removal	-
Taxes Other Than Income Taxes	18,789
Income Taxes [1]	71,990
Total Gas Utility Operating Expenses	$1,441,718
Gas Utility Operating Income	$265,786
Net Utility Operating Income	$600,001

* 9 Months Actual - 3 Months Forecast

[1] Income Taxes reflect the adjustments as proposed in Schedule RCK-3 R-1

EXHIBIT P-2
SCHEDULE SSJ-17 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

Line		June 30, 2018 Electric	Gas
1	Residential	13,153,323	1,491,303
2	Commercial	23,539,083	926,258
3	Industrial	3,822,969	84,073
4	Firm Transportation Service		23,726
5	Non-Firm Transportation Service		206,116
6	Cogeneration Interruptible		39,844
7	Cogeneration Contracts		0
8	Contract Service Gas		871,332
9	Street Lighting	335,850	626
10	Total Sales to Customers	40,851,225	3,643,278
11	Interdepartmental	9,597	599
12	Total Sales	40,860,822	3,643,877

* 9 Months Actual - 3 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-18 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

REVENUE BY CLASS OF BUSINESS
($000)

			June 30, 2018	
Line		**Electric**	**Gas**	**Total**
1	Residential	$ 1,926,473	$ 1,106,261	$ 3,032,734
2	Commercial	1,476,753	520,913	1,997,666
3	Industrial	145,870	36,171	182,040
4	Firm Transportation Service		3,944	3,944
5	Non-Firm Transportation Service		25,480	25,480
6	Cogeneration Interruptible		19,253	19,253
7	Cogeneration Contracts		-	0
8	Contract Service Gas		8,504	8,504
9	Street Lighting	71,113	474	71,587
10	Total Revenue from Sales to Customers	$ 3,620,209	$ 1,720,999	$ 5,341,208
11	Interdepartmental	1,212	477	1,689
12	Total Revenue from Sales	$ 3,621,421	$ 1,721,476	$ 5,342,897

* 9 Months Actual - 3 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-19 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

AVERAGE CUSTOMERS BILLED BY CLASS OF BUSINESS

		June 30, 2018	
Line		**Electric**	**Gas**
1	Residential	1,936,239	1,670,221
2	Commercial	298,102	158,559
3	Industrial	8,454	6,201
4	Firm Transportation Service		38
5	Non-Firm Transportation Service		184
6	Cogeneration Interruptible		12
7	Cogeneration Contracts		0
8	CSG		22
9	Street Lighting	10,202	16
10	Total Customers	2,252,996	1,835,252
11	Interdepartmental	1	1
12	Total Customers	2,252,997	1,835,253

* 9 Months Actual - 3 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-20 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

EXPENSES
($000)

Electric

Production Expenses		June 30, 2018
Other Power Supply Expenses:		
Purchased Power	$	1,739,481
System Control/Load Dispatch	$	129
Total Other Power Supply Expenses	$	1,739,610
Distribution		
Operation	$	65,531
Maintenance		116,431
Total Distribution	$	181,962

Gas

Production Expenses		
Gas Supply		
Natural Gas City Gate Purchases	$	788,158
Fuel Gas - Raw Materials		(17,165)
Other Gas Purchases		(71)
Other Gas Supply Expenses		144
Total Gas Supply	$	771,065
Gas Production		
Operation	$	-
Maintenance		842
Total Gas Production	$	842
Other Power Generation		
Liquefied petroleum gas expenses		319
Total Other Power Generation	$	319
Other Storage		
Operation	$	1,572
Maintenance		249
Total Other Storage	$	1,821
Total Production Expenses	$	774,048
Transmission		
Operation	$	164
Maintenance		4,221
Total Transmission	$	4,385
Distribution		
Operation	$	71,646
Maintenance		32,585
Total Distribution	$	104,231

* 9 Months Actual - 3 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-21 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CUSTOMER ACCOUNTS AND INFORMATION
($000)

	June 30, 2018		
	Electric	**Gas**	**Total**
Customer Accounts Expenses			
Operation:			
Meter Reading Expenses	$ 17,190	$ 12,899	$ 30,090
Customer Records and Collection Expenses	$ 71,801	$ 54,541	$ 126,342
Uncollectible Accounts	$ 50,038	$ 27,614	$ 77,652
Misc. Customer Accounts Expenses	$ 95,056	$ (5,883)	$ 89,173
Total Customer Accounts Expenses	$ 234,085	$ 89,171	$ 323,256
Cust. Service and Informational Expenses			
Operation:			
Supervision	$ -	$ -	$ -
Customer Assistance Expenses	$ 134,673	$ 89,991	$ 224,664
Misc. Cust. Service and Info. Expenses	$ 1,708	$ 1,211	$ 2,919
Total Cust. Service and Info. Expenses	$ 136,381	$ 91,203	$ 227,583
Sales Expenses			
Operation:			
Demonstration and Selling Expenses	$ 400	$ 351	$ 751
Misc. Sales Expenses	$ 42	$ 34	$ 76
Total Sales Expenses	$ 442	$ 386	$ 828
Total Customer Accounts and Information	$ 370,908	$ 180,759	$ 551,667

* 9 Months Actual - 3 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-22 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ADMINISTRATIVE AND GENERAL SALARIES AND EXPENSES
($000)

	June 30, 2018		
	Electric	**Gas**	**Total**
Salaries & Wages	$ 7,150	$ 7,387	$ 14,536
Supplies & Expenses	2,674	1,976	4,650
Outside Services	50,904	43,309	94,212
Property Insurance	1,520	247	1,767
Injuries and Damages	15,357	6,733	22,090
Pensions & Fringe Benefits	30,651	29,632	60,283
Regulatory Expenses	11,567	4,034	15,600
Duplicate Charge	(2,644)	(757)	(3,401)
General Advertising	1,950	1,596	3,545
Other Miscellaneous General	2,613	2,443	5,056
Rents	4,412	4,946	9,358
Maintenance	(0)	-	(0)
Total Administrative and General Salaries & Expenses	$ 126,152	$ 101,545	$ 227,697

* 9 Months Actual - 3 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-23 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DEPRECIATION AND AMORTIZATION
($000)

ELECTRIC

Line		June 30, 2018
	Depreciation	
1	Electric	$227,223
	Amortization	
2	Electric	$33,728
	Total Electric Depreciation and Amortization	**$260,951**

GAS

Line		June 30, 2018
	Depreciation	
1	Gas	$144,795
	Amortization	
2	Gas	$41,176
	Total Gas Depreciation and Amortization	**$185,972**

* 9 Months Actual - 3 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-24 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

TAXES OTHER THAN INCOME TAXES
($000)

Line		June 30, 2018 Electric		June 30, 2018 Gas		June 30, 2018 Total	
1	Real Estate	$	13,215	$	4,676	$	17,891
2	FICA		393		498		891
3	State Unemployment		10,345		13,191		23,536
4	Federal Unemployment		69		89		158
5	Miscellaneous Municipal and State Taxes		271		336		607
6	Total	$	24,294	$	18,789	$	43,084

* 9 Months Actual - 3 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-25 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CURRENT AND DEFERRED INCOME TAXES
($000)

	June 30, 2018		
	Electric	**Gas**	**Total**
Net Income Taxes	$ 139,146	$ 71,990	$ 211,136

* 9 Months Actual - 3 Months Forecast

EXHIBIT P-2
SCHEDULE SSJ-26 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PRO-FORMA DISTRIBUTION OPERATING INCOME
($000)

#		Schedule #	Electric	Gas	Total
Test Year Distribution Operating Income			**$ 334,215**	**$ 265,786**	**$ 600,001**
#	**Pro-Forma Adjustments:**	**Schedule #**			
1	Wages	SSJ-27 R-1	$ (3,148)	$ (4,769)	$ (7,917)
2	Payroll Taxes	SSJ-28 R-1	(219)	(331)	(550)
3	Interest Synchronization (Tax Savings)	SSJ-29 R-1	1,949	191	2,140
4	Pension & Fringe Benefits	SSJ-30 R-1	(12,409)	(22,998)	(35,407)
5	COLI Interest Expense	SSJ-31 R-1	(3,173)	(933)	(4,106)
6	Weather Normalization	SSJ-32 R-1	4,198	-	4,198
7	Gains/Losses on Sales of Property	SSJ-33 R-1	17	35	52
8	Real Estate Taxes	SSJ-34 R-1	(535)	(481)	(1,016)
9	Insurance	SSJ-35 R-1	(87)	(78)	(165)
10	ASB Margin	SSJ-36 R-1	5,507	(11,015)	(5,507)
11	TSGNF Margin Sharing	SSJ-37 R-1	-	(260)	(260)
12	Depreciation Rate Change	SSJ-38 R-1	(56,767)	(66,561)	(123,328)
13	Storm Cost Amortization*	SSJ-39 R-1	-	-	-
14	Post Rate Case Storm Cost Normalization*	SSJ-40 R-1	-	-	-
15	Excess COR Refund Recovery	SSJ-41 R-1	-	(12,482)	(12,482)
16	Test Year Amortization Adjustments	SSJ-42 R-1	2,249	(8,806)	(6,557)
17	Regulatory Assets*	SSJ-43 R-1	-	-	-
18	Rate Case Expenses	SSJ-44 R-1	77	33	109
19	Credit Card Fees	SSJ-45 R-1	(3,041)	(1,679)	(4,721)
20	Vacation Accrual	SSJ-46 R-1	(1,490)	(2,424)	(3,915)
21	Energy Strong / GSMP Revenue Adjustment	SSJ-47 R-1	9,579	7,323	16,902
22	BPU / Rate Counsel Assessment	SSJ-48 R-1	(1,029)	9	(1,021)
	Total Pro-Forma Adjustments		**$ (58,323)**	**$ (125,227)**	**$ (183,550)**
Total Pro-Forma Distribution Operating Income			**$ 275,892**	**$ 140,559**	**$ 416,451**

* 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-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 1
Wages
($000)

	Electric	Gas	Total
Bargaining Unit Employees	$ 2,697	$ 4,086	$ 6,783
MAST Employees	1,682	2,548	4,230
Operating Expense Increase before Taxes	$ 4,379	$ 6,634	$ 11,013
Income Taxes	1,231	1,865	3,096
Operating Income Increase (Decrease) After Taxes	**$ (3,148)**	**$ (4,769)**	**$ (7,917)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 2
Payroll Taxes
($000)

	Electric	Gas	Total
Bargaining Unit Employees	$ 187	$ 284	$ 471
MAST Employees	117	177	294
Operating Expense Increase before Taxes	$ 304	$ 461	$ 765
Income Taxes	86	130	215
Operating Income Increase (Decrease) After Taxes	**$ (219)**	**$ (331)**	**$ (550)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

	Percent	Embedded Cost	Weighted Cost	
Electric Rate Base				$ 5,672,132
Debt Components:				
Long Term Debt	45.51%	4.03%	1.83%	
Customer Deposits	0.49%	0.87%	0.00%	
Total Weighted Cost of Debt				1.84%
Annualized Interest Expense				$ 104,176
Less: Test Period Interest Expense				97,244
Net Interest Expense Increase / (Decrease)				$ 6,933
Income Tax Rate				28.11%
Operating Income Increase (Decrease) After Taxes				$ 1,949

	Percent	Embedded Cost	Weighted Cost	
Gas Rate Base				$ 4,165,739
Debt Components:				
Long Term Debt	45.51%	4.03%	1.83%	
Customer Deposits	0.49%	0.87%	0.00%	
Total Weighted Cost of Debt				1.84%
Annualized Interest Expense				$ 76,509
Less: Test Period Interest Expense				75,829
Net Interest Expense Increase / (Decrease)				$ 680
Income Tax Rate				28.11%
Operating Income Increase (Decrease) After Taxes				$ 191

EXHIBIT P-2
SCHEDULE SSJ-30 R-1

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	$	13,790	$	16,690	$	30,480
Dental/Vision	$	676	$	802	$	1,478
Pensions	$	(15,960)	$	(14,605)	$	(30,565)
Group Life	$	339	$	397	$	736
Disability	$	141	$	164	$	304
Thrift & Savings	$	4,465	$	5,059	$	9,523
Workers Compensation	$	1,104	$	1,274	$	2,378
Benefits Outside Services	$	1,490	$	1,638	$	3,127
Benefits Other	$	394	$	419	$	813
OPEB	$	27,810	$	17,541	$	45,351
	$	34,248	$	29,379	$	63,627
Increase in Test Year Operating Expenses	$	17,261	$	31,991	$	49,252
Income Taxes	$	4,852	$	8,993	$	13,845
Operating Income Increase (Decrease) After Taxes	**$**	**(12,409)**	**$**	**(22,998)**	**$**	**(35,407)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 5
COLI Interest Expense
($000)

	Electric		Gas		Total	
Net Credit in Test Year						
Administrative & General Expenses	(5,276)		(1,424)		(6,700)	
Tax Savings on COLI	(612)		(180)		(792)	
Total Benefit	(5,888)		(1,604)		(7,492)	
Interest Charges	3,173		933		4,106	
Net Benefit	$ (2,715)		$ (670)		$ (3,385)	
Operating Income Increase (Decrease) After Taxes		**$ (3,173)**		**$ (933)**		**$ (4,106)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 6
Weather Normalization
($000)

	Electric	Gas*	Total
Actual Distribution Revenues	$ 951,664	$ -	$ 951,664
Weather Normalized Distribution Revenues	$ 957,503	-	957,503
Increase (Decrease) in Test Year Margin Revenue	$ (5,840)	$ -	$ (5,840)
Income Taxes	(1,642)	-	(1,642)
Operating Income Increase (Decrease) After Taxes	$ 4,198	$ -	$ 4,198

* Reflects impact of Weather Normalization Charge

EXHIBIT P-2
SCHEDULE SSJ-33 R-1

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	$ 13,960	$ 5,345	$ 19,305
Test Year Property Taxes	$ 13,215	$ 4,676	$ 17,891
Operating Expense Increase Before Taxes	$ 745	$ 669	$ 1,414
Income Taxes	209	188	397
Operating Income Increase (Decrease) After Taxes	**$ (535)**	**$ (481)**	**$ (1,016)**

EXHIBIT P-2
SCHEDULE SSJ-35 R-1

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		3,904		2,381		6,284
Operating Expense Increase Before Taxes	$	121	$	108	$	229
Income Taxes		34		30		64
Operating Income Increase (Decrease) After Taxes	**$**	**(87)**	**$**	**(78)**	**$**	**(165)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 10
ASB Margin
($000)

	Electric	Gas	Total
ASB Margin by Appliance	$ 15,322	$ 29,228	$ 44,550
ASB Margin % Above-the-Line per N.J.A.C. 14:4-3.6	50%	100%	
Above the Line ASB Margin	$ 7,661	$ 29,228	$ 36,889
ASB Margin in Test Year	$ -	$ 44,550	$ 44,550
ASB Above-the-Line Margin	$ 7,661	$ (15,322)	$ (7,661)
Income Taxes	2,153	(4,307)	(2,153)
Operating Income Increase (Decrease) After Taxes	**$ 5,507**	**$ (11,015)**	**$ (5,507)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

	Electric	Gas	Total
Operating Income Decrease Before Taxes	$ -	$ (362)	$ (362)
Income Taxes	-	102	102
Operating Income Increase (Decrease) After Taxes	**$ -**	**$ (260)**	**$ (260)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 12
Depreciation Rate Change
($000)

	Electric	Gas	Total
Annualization of Depreciation Expense	$ 248,863	$ 168,273	$ 417,136
Test Year Depreciation Expense	$ 227,223	$ 144,795	$ 372,018
Annualization of Current Depreciation Rates	$ 21,640	$ 23,477	$ 45,118
Depreciation Expense at Proposed Rates	$ 306,187	$ 237,382	$ 543,569
Operating Expense Increase (Decrease) for Proposed Rates	$ 57,323	$ 69,110	$ 126,433
Operating Income Increase (Decrease) Before Taxes	$ (78,964)	$ (92,587)	$ (171,551)
Income Taxes	$ (22,197)	$ (26,026)	$ (48,223)
Operating Income Increase (Decrease) After Taxes	**$ (56,767)**	**$ (66,561)**	**$ (123,328)**

EXHIBIT P-2
SCHEDULE SSJ-39 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

		Electric		Gas		Total
Storm Cost Recovery						
2010-2012 Deferred Storm Costs*	$	212,697	$	7,545	$	220,242
Post 2012 Deferred Incremental Storm Costs	$	20,636	$	20	$	20,656
Total Storm Cost Regulatory Asset	$	233,333	$	7,565	$	240,898
Amortization Period		3		3		3
Annual Storm Cost Amortization	$	77,778	$	2,522	$	80,299
Average Deferred Balance During Test Year	$	116,667	$	3,783	$	120,449
Deferred Tax Benefit	$	(32,795)	$	(1,063)	$	(33,858)
Average Net of Tax Deferred Cost Balance	$	83,872	$	2,719	$	86,591
Weighted Average Cost of Capital		7.39%		7.39%		7.39%
Annual Amortization Carrying Charge	$	6,198	$	201	$	6,399
Operating Expense Increase Before Taxes	$	83,976	$	2,723	$	86,699
Income Taxes	$	23,606	$	765	$	24,371
Operating Income Increase (Decrease) After Taxes	**$**	**(60,370)**	**$**	**(1,957)**	**$**	**(62,328)**

*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-1

EXHIBIT P-2
SCHEDULE SSJ-40 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

	Electric	Gas	Total
Test Year incremental O&M*	$ 24,554	$ -	$ 24,554
Amortization Period	3	3	3
Annual Storm Cost Amortization	$ 8,185	$ -	$ 8,185
Test Year incremental O&M	$ 24,554	$ -	$ 24,554
Operating Expense Increase Before Taxes	$ 16,370	$ -	$ 16,370
Income Taxes	$ 4,601	$ -	$ 4,601
Operating Income Increase (Decrease) After Taxes	**$ (11,768)**	**$ -**	**$ (11,768)**

* 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-1

EXHIBIT P-2
SCHEDULE SSJ-41 R-1

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	7.39%		7.39%		7.39%
Annual Amortization Carrying Charge	$ -	$	2,036	$	2,036
Adjustment Summary					
Operating Expense Increase Before Taxes	$ -	$	17,362	$	17,362
Income Taxes	$ -	$	4,881	$	4,881
Operating Income Increase (Decrease) After Taxes	**$ -**	**$**	**(12,482)**	**$**	**(12,482)**

* 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-1

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	$	928	$	10,250	$	11,178
Total Regulatory Assets / (Liabilities)	$	2,205	$	10,250	$	12,455
Amortization Period		3		3		3
Annual Amortization	$	735	$	3,417	$	4,152
Test Year Expense	$	-	$	-	$	-
Operating Expense Increase Before Taxes	$	735	$	3,417	$	4,152
Income Taxes	$	207	$	960	$	1,167
Operating Income Increase (Decrease) After Taxes	**$**	**(528)**	**$**	**(2,456)**	**$**	**(2,985)**

* 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-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 18
Rate Case Expenses
($000)

	Electric	Gas	Total
Rate Case Expenses	$ 1,443	$ 453	$ 1,896
Amortization Period	3	3	3
Annual Amortization	$ 481	$ 151	$ 632
Test Year Rate Case Expense	$ 588	$ 197	$ 784
Operating Expense Decrease Before Taxes	$ 107	$ 46	$ 152
Income Taxes	$ 30	$ 13	$ 43
Operating Income Increase (Decrease) After Taxes	**$ 77**	**$ 33**	**$ 109**

EXHIBIT P-2
SCHEDULE SSJ-45 R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 19
Credit Card Fees
($000)

	Electric	Gas	Total
Operating Expense Increase Before Taxes	$ 4,230	$ 2,336	$ 6,566
Income Taxes	1,189	657	1,846
Operating Income Increase (Decrease) After Taxes	**$ (3,041)**	**$ (1,679)**	**$ (4,721)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Adjustment No. 20
Vacation Accrual
($000)

	Electric	Gas	Total
Operating Income Decrease Before Taxes	$ (2,073)	$ (3,372)	$ (5,445)
Income Taxes	583	948	1,531
Operating Income Increase (Decrease) After Taxes	**$ (1,490)**	**$ (2,424)**	**$ (3,915)**

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	714
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**

EXHIBIT P-2
SCHEDULE SSJ-48 R-1

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	8,322	2,311	10,633
Operating Expense Increase Before Taxes	$ 1,377	$ 55	$ 1,432
Income Taxes	387	15	403
Operating Income Increase (Decrease) After Taxes	$ (990)	$ (40)	$ (1,029)

Gas

	BPU	Rate Counsel	Total
Estimated Assessment	$ 3,540	$ 863	$ 4,403
Less: Assessment Included in Test Year Operating Expenses	3,482	933	4,415
Operating Expense Increase Before Taxes	$ 58	$ (70)	$ (12)
Income Taxes	16	(20)	(3)
Operating Income Increase (Decrease) After Taxes	$ (42)	$ 50	$ 9