STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC & GAS COMPANY FOR APPROVAL OF THE SECOND ENERGY STRONG PROGRAM (ENERGY STRONG II)

BPU Docket Nos. EO18060629 and GO18060630

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
REBUTTAL TESTIMONY
OF
STEPHEN SWETZ
SENIOR DIRECTOR – CORPORATE RATES AND REVENUE REQUIREMENTS

April 18, 2019

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INTRODUCTION

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

A. My name is Stephen Swetz, and I am the Senior Director – Corporate Rates and Revenue Requirements for PSEG Services Corporation. My principal place of business is 80 Park Plaza, Newark, New Jersey 07102. My professional experience and responsibilities are described in Schedule SS-ESII-1, which was submitted along with my direct testimony.

Q. Have you testified previously in this proceeding?

A. Yes. On June 8, 2018, I submitted direct testimony on behalf of Public Service Electric & Gas Company ("PSE&G" or the "Company") in support of PSE&G's Petition requesting the New Jersey Board of Public Utilities ("BPU" or "Board") approve PSE&G's proposed Energy Strong II Program ("ES II" or the "Program").

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

A. In my direct testimony, I provided the details for the calculations of the Program's revenue requirements, the associated cost recovery methodology, and rate design for the ES II Petition filed with the Board. My direct testimony also provided detailed schedules setting forth the projected revenue requirements, rates, and bill impacts over the Program's life.

Q. What is the purpose of your rebuttal testimony?

A. In my rebuttal testimony, I respond to certain assertions in the direct testimonies of Rate Counsel Witnesses Andrea C. Crane and David E. Dismukes, both testimonies dated as of March 1, 2019.

Q. Please summarize your rebuttal testimony.

A. The recommendations in Ms. Crane's and Dr. Dismukes' testimonies that the Board should deny PSE&G's ES II Petition or approve a significantly smaller program than proposed should be rejected.

Contrary to the assertions of Rate Counsel's witnesses, PSE&G has demonstrated ES II, as proposed, is a reasonable and prudent continuation of the Energy Strong Program ("ES"), which was approved by the Board in Docket No. EO13020155 & GO13020156 on May 21, 2014. Moreover, ES II is consistent with the Board's Infrastructure Investment Program ("IIP") regulations (N.J.A.C. 14:3-2A), and will enable the Company to complete on a timely basis important infrastructure replacements and upgrades that are in the best interest of our customers and the State of New Jersey.

In reference to Dr. Dismukes' testimony, I will demonstrate the Program is in fact cost beneficial and should not be rejected, but instead should be undertaken as proposed. I will also address Ms. Crane's two main assertions in support of her position that the Program should be rejected. First, Ms. Crane's view that ES II improperly benefits shareholders by "shifting risk to ratepayers" is unfounded. In fact, PSE&G still retains all the risks it would have if the Program was completed through a base rate case rather than an infrastructure recovery clause. Instead of risk shifting, ES II will immediately provide benefits to

PSE&G's customers as the Program's investment is placed in service while providing PSE&G *an opportunity* to earn its fair rate of return on its investments as authorized by the Board. Second, and equally important, I address Ms. Crane's view that accelerated cost recovery is not necessary, and that the cost of an investment program such as ES II could be recovered through a traditional rate case proceeding. As I will show below, undertaking ES II through a traditional base rate case would have a negative impact on the Company's allowed rate of return and credit metrics.

While Ms. Crane recommends outright rejection of the program, both she and Dr. Dismukes also propose adjustments to the Company's cost recovery mechanism if the Board approves the Program. These adjustments are inconsistent with the IIP regulations, as well as the cost recovery mechanisms approved by the Board in all prior infrastructure programs. I will address each proposed adjustment and why it should be rejected later in my testimony.

ES II SHOULD BE APPROVED UNDER THE IIP REGULATIONS

Q. Is the ES II program consistent with the IIP regulations?

A. Yes. ES II is, in fact, consistent with the IIP Regulations, which allows for and encourages the acceleration of investment to promote the timely rehabilitation and replacement of infrastructure related to reliability, resiliency, and/or safety to provide safe and adequate service. ES II addresses these criteria as stated in the IIP Regulations.

Q. What are Dr. Dismukes' and Ms. Crane's recommendations with regard to ES II?

A. Both Dr. Dismukes and Ms. Crane recommend ES II be rejected in its entirety. Dr. Dismukes asserts the Program is not cost-beneficial and states the costs, along with the

Company's other proposed filings, represent a burden to customers. Meanwhile, Ms. Crane's position is based upon her view that the Program will shift risk from shareholders to customers, and accelerated recovery is not necessary as the proposed investments can be made through the traditional base rate case process without harm to shareholders.

Q. Do you agree with their recommendations?

A. I do not agree with either of their recommendations. I address each argument against the ES II Program below.

ES II is cost-beneficial

Q. Can you comment on Dr. Dismukes claim that ES II will result in negative net economic benefits and should be rejected?

A. In his testimony, Dr. Dismukes presents the results of what his alternative cost benefit analysis based on the use of "the IMPLAN" model. (Dismukes Direct p. 37). The analysis purports to compare the positive economic impacts associated with ES II construction expenditures and energy savings to the negative economic impacts associated with rate increases. Dr. Dismukes states that the IMPLAN model is based upon "input-output accounting [that] describes commodity flows from producers to intermediate and final consumers." According to Dr. Dismukes, "[t]he commodity flows between industries are what drive the economic multipliers." Dismukes Direct, pp. 37-38. Within Dr. Dismukes's analysis, the "multiplier effect", or the "economic multipliers" of the construction spending, energy savings and the rate impacts associated with the system replacement and upgrade from ES II result in calculated direct, indirect and induced impacts of the Program's "costs and benefits" to the New Jersey economy. Dr. Dismukes concludes that the estimated negative economic impact from the rate increase would be greater than the positive economic impact from program construction expenditures, resulting in an overall or net negative economic impact on the State.

Q. Do you agree with Dr. Dismukes' economic impact analysis and rejection of ESII?

A. No. As explained in more detail in the Cost Benefit Analysis Panel's Rebuttal Testimony ("CBA Rebuttal Testimony"), Dr. Dismukes' analysis significantly understates the benefits of the Program by both ignoring the value of lost load and not including unquantified benefits, such as the risk reduction of replacing aging substations and improvements to safety.

Q. Does it make sense to impose a strict "pass" or "fail" test in considering the type of cost-benefit analysis PSE&G has submitted in this case?

A. It does not. First, a cost-benefit analysis for infrastructure programs relies on several assumptions, and the results can vary significantly based on those assumptions. Assumptions can therefore be made/modified to achieve a desired result. It should be noted, Dr. Dismukes has acknowledged that for every public utility infrastructure program he has analyzed using the IMPLAN model, he has concluded that the infrastructure program results in a negative economic benefit.[1] Second, looking only at quantifiable benefits, and ignoring other benefits as described in the CBA Rebuttal Testimony like risk reduction, can understate the value of

[1] *See* Rate Counsel discovery response to PSE&G-RC-DED-2(b).

an infrastructure program.

Q. Has Dr. Dismukes understated the value of PSE&G infrastructure investment in the past?

A. Yes he has, most recently with respect to the Company's extension of the Gas System Modernization Program ("GSMP II"), which was approved by the Board in Docket No. GR17070776 on May 22, 2018. Even with the national recognition of the need to replace cast iron mains, Dr. Dismukes argued in that case that the program resulted in negative net benefits and should have been rejected based on his IMPLAN model. This is not surprising since in Dr. Dismukes' analysis, the benefits of the program were based on GSMP II construction expenditures and rate impacts, without taking into account all the benefits of a replaced system.

I do agree that costs and impacts to customers need to be evaluated in reviewing an infrastructure program. However, particularly for programs with potentially large qualitative benefits, they should be used as a guide and not as the basis of a strict "pass" or "fail" determination.

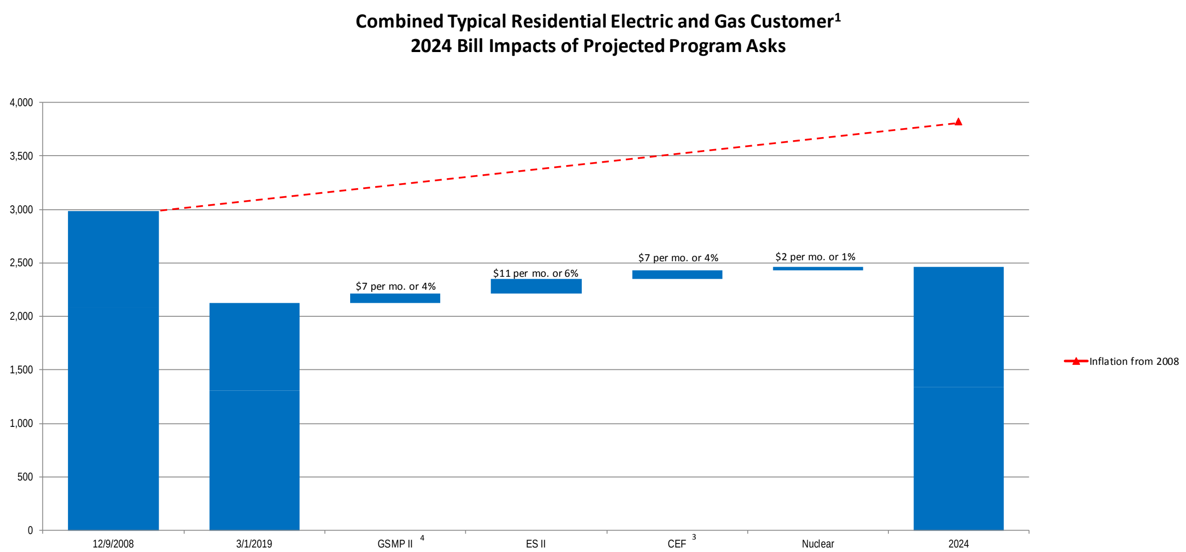
PSE&G acknowledges ES II is not proposed in a Vacuum

Q. On page 12 of Dr. Dismukes' testimony he states that it is important the Board understand that the ESII program is not being proposed in a vacuum and the Board needs to consider the cumulative rate burden of other programs the Company has proposed. Do you have any comment?

A. Yes. I agree with Dr. Dismukes that ES II is not occurring in a vacuum and the Board should consider the total impact to customers of the Company's proposed programs. PSE&G carefully considers the costs to provide safe and reliable utility service to our customers, and takes these customer impacts very seriously. Due to reductions in gas prices and the

Company's cost control efforts, typical residential customers who receive electric and gas service from PSE&G are still paying about 30 percent less than they were a decade ago and about 40 percent less when adjusted for inflation, while maintaining top quartile reliability. The following chart shows the impact in 2024 to a combined typical residential customer if all of the Company's proposed new filings are approved as filed, including ES II, GSMP II, all three of PSE&G's Clean Energy Future filings (Energy Efficiency, Electric Vehicles and Energy Storage, and Energy Cloud), and if the Board awards Zero Emissions Certificates to the nuclear power plants that have applied to receive those certificates. While these proposed programs undoubtedly represent bill increases to customers, it is important to note that they are consistent with State legislation to accelerate investment in infrastructure and provide a meaningful increase in energy efficiency. Further, even if all of the Company's proposed programs are approved as filed, customer bills will still be significantly below where they were approximately 10 years ago in nominal dollars, before even taking inflation into account. See Figure 1.

Figure 1



Note 1: Bill for a typical residential electric customer that uses 6,920 kilowatt-hours per year and a typical residential gas heating customer that uses 1,040 therms per year

Note 2: March 1, 2019 rates reflect June 1, 2019 BGS-RSCP supply charges including PSE&G's January 25, 2019 Transmission NITS filing and the Results of the 2019 BGS-RSCP Statewide Auction

Note 3: The Clean Energy Future program includes 4 components: Energy Efficiency (EE), Electric Vehicle (EV) infrasturcture, Energy Storage, and Energy Cloud (EC).
The overall rate impact of the EE program is fully offset in the aggregate by the benefits provided to participating customers (not reflected above).
The EV and Storage investments support State policy goals.
EC costs over ten years are partially offset by customer benefits that are not reflected above.
All Clean Energy Future Program Revenue Requirements have been updated to reflect PSE&G's Base Rate Case results

Note 4: GSMP II represents investments from the Settlement Approved by the Board on May 22, 2018 in Docket No. GR17070776 updated for the results of the PSE&G Base Rate Case.

Q. Is it possible that the impacts can be lower than shown above?

A. Yes. The chart above assumes March 2019 rates other than for the new programs shown will remain the same in 2024. In the Company's CEF-EE program, its proposal assumes programs currently operated by the New Jersey Office of Clean Energy (OCE) will be transitioned to the Company. If that occurs, current funding for the Clean Energy Program could be reduced substantially from its current budget of approximately $200 million per year. In addition, the Company's Green Program Recovery Charge and Solar Pilot Recovery Charge will continue to decrease as the investments amortize/depreciate.

ES II cannot be supported under a traditional base rate making model

Q. Can you address Ms. Crane's claim that ES II should be rejected?

A. Yes. Ms. Crane proposes rejection of ES II due to the fact that the investment will take place through an infrastructure mechanism rather than through traditional rate making practices (i.e., base rate cases) and that there is a risk shifting to ratepayers from the Company's shareholders under the proposed program.

Q. Do you agree with Ms. Crane's underlying reasons for the program to be rejected?

A. I do not agree with Ms. Crane's two main contentions. First, Ms. Crane's position that ES II can be completed under the traditional base rate case process without harm to shareholders is unsupported and, as I will show below, is incorrect. Second, the proposed cost recovery mechanism does not shift risk to customers but simply allows for more timely recovery of program investments, subject to the same risks associated with base investment, as discussed below.

Q. Could you comment on Rate Counsel's position that ES II should be pursued through a traditional base rate case rather than through an infrastructure investment program?

A. Yes. For Rate Counsel to argue that the Board should simply bypass the IIP regulatory mechanism is directly contrary to the letter and spirit of those regulations, which is intended to promote capital investment by utility companies and, in particular, to support accelerated capital investment for reliability and hardening of utility infrastructure. Acceptance of Rate Counsel's position would have negative ramifications not only for PSE&G but also likely for other utilities operating in the State of New Jersey, which I will discuss later in my testimony. As a preliminary matter, Ms. Crane acknowledges there has been a proliferation in clause, rider and infrastructure recovery mechanisms over the past 15 years in the utility industry. These mechanisms are now more of a commonality than a rarity – with the intent to help rate regulated entities mitigate some of the unregulated macroeconomic conditions that could cause financial hardship if the utility were to pursue a large scale capital investment such as ES II under traditional base rate making. Accordingly, the State of New Jersey, along with many other regulatory jurisdictions, has made progressive steps in the rate making process. To revert to a means of recovery that worked in the past would be regressive in nature for a large-scale capital program and would undermine state policy encouraging the type of infrastructure investment proposed under ES II.

Ms. Crane's rationale for rejecting ES II is inconsistent with the IIP regulations

Q. Would you comment on why Ms. Crane proposes rate case recovery in lieu of accelerated cost recovery?

A. Yes. It's essentially a two-fold stance. Ms. Crane asserts the Company is already meeting its service requirement and thus an accelerated recovery mechanism is not needed, as the Company can complete an accelerated investment program such as ES II under the traditional ratemaking process. Secondly, Rate Counsel is simply not a proponent of the IIP regulations.

Q. Ms. Crane states that it does not appear that the ES II Program is required for the Company to meet its current service requirement. Do you agree that this is a criteria for implementing a program under the IIP regulations?

A. I do not. The purpose of the IIP regulations is to accelerate investment in non-revenue producing utility plant and facilities that enhance safety, reliability, and/or resiliency. I agree with Ms. Crane that the Company has an obligation to provide safe and reliable service. The Company has and will continue to meet this obligation. However, the subprograms proposed for ES II are not designed to ensure the Company meets its current service obligation, which it has done and will continue to do through its base spending. Rather, the purpose of ES II is to add resiliency and hardening, and accelerate replacements to avoid more costly mass failures in the future, which are consistent with the purpose of the IIP regulations.

Q. Can you please comment on the concerns expressed by Ms. Crane relating to those regulations?

A. Yes. Many of Ms. Crane's criticisms stem from her apparent dissatisfaction and general disagreement with the IIP regulations in their entirety. Ms. Crane notes that Rate Counsel has "concerns" about the Board's use of accelerated infrastructure investment recovery mechanisms. Crane Direct, beginning on p. 15. Rate Counsel's position is not surprising given Rate Counsel's criticism of the IIP regulations when they were proposed by the Board.[2] However, while Ms. Crane is critical of the Board's IIP regulations because they allow and encourage use of an accelerated cost recovery mechanism, she readily acknowledges the "proliferation" of utility commission-authorized accelerated cost recovery mechanisms such as the approach specified in the IIP regulations. While Rate Counsel may

[2] *See* Rate Counsel Comments filed on May 12, 2017, and October 6, 2017, in connection with the proposed IIP rule.

not approve of the IIP regulations, it is clear from their adoption that the Board has determined that use of the IIP recovery mechanism to encourage accelerated infrastructure investment is appropriate. Despite the adoption of the IIP, Ms. Crane asserts many of the same unsuccessful arguments that were made in opposition during the rulemaking process. For example, similar to Rate Counsel's positions during the IIP rulemaking process, Ms. Crane argues the use of a clause cost recovery mechanism is a departure from traditional ratemaking and is single-issue ratemaking and "the BPU should move away from single-issue ratemaking and return to base rate cases as the vehicle for establishing rates for New Jersey ratepayers." Crane Direct, p. 25.

Q. Is Mrs. Crane's proposal aligned with the IIP regulations adopted by the BPU?

A. No. The BPU issued those regulations to provide a financial incentive for utilities to invest in necessary accelerated infrastructure replacement programs. Such an incentive – which is simply *an opportunity* (not a guarantee as Ms. Crane suggests) to commence earning a return on investment sooner than the utility's next base rate case – is critical to long-term infrastructure replacement programs such as ES II. Rate Counsel's position flies in the face of State policy. Rate Counsel prefers to treat an accelerated infrastructure program such as ES II, which meets the letter of what the IIP was intended to achieve, through a traditional rate case proceeding. Rather than encouraging infrastructure investment programs as the IIP regulations are expressly intended to do, Rate Counsel's position would harm utilities' financial condition and undermine the purpose of the IIP regulations by, among other things, delaying revenue recognition, reducing the utilities' ROE, excluding necessary program costs from the accelerated recovery mechanism, and changing the earnings test in the regulation. Rate Counsel is effectively proposing to undo the policy the BPU just adopted.

Energy Strong II does not shift risk from shareholders to customers

Q. Do you agree with Ms. Crane's assertion that clause rate recovery mechanisms, such as the mechanism authorized in the IIP regulations, transfer risk from utility shareholders to customers?

A. I do not. The transference of risk would mean the shifting of a quantifiable unknown unto customers, which is neither the intent nor the impact of the IIP regulations. In fact, there is no risk transfer to customers - any recovery on capital investment deemed imprudent in a future rate case would be refunded to customers with interest (i.e., customers would be made whole). Furthermore, PSE&G continues to bear the same construction, financial, operational, and prudency risks, if not more prudency risk, for the work conducted under the ES II Program as it does for work recovered following a base rate case proceeding. Operationally, many of the proposed ES II projects, such as the electric Substation and natural gas Curtailment Resiliency subprograms, are complicated projects that will take several years to complete and can be delayed beyond the five year period for accelerated recovery. Likewise, the complex proposed projects are more susceptible to unforeseen costs than PSE&G's standard base level capital program. In addition, the more focused review through annual or semi-annual filings and reporting requirements increase prudency risk. Further, the rate design for all ES II rate adjustments is the same as approved in the Company's 2018 base rate case, so the recovery risk is the same regardless of the cost recovery mechanism employed. As briefly mentioned, the only benefit of ES II compared to traditional base rates is that it helps reduce regulatory lag on the investments, although not enough for the Company to earn its allowed return on the investments as shown below.

Accelerated recovery is required for implementation of the ES II Program

Q. Ms. Crane states that "to the extent PSE&G accelerates investment related to infrastructure replacement, shareholders can expect higher earnings, even if an accelerated cost recovery mechanism is not adopted." Do you agree?

A. No. If it were true that every dollar spent on infrastructure was a benefit to shareholders regardless of whether recovered through an accelerated cost recovery mechanism or through base rates, every utility in the State would likely invest as much as it prudently could to maximize earnings. Furthermore, even with a cost recovery mechanism, earnings lag investment. In the absence of a cost recovery mechanism, the earnings lag relative to the investment would be even further exacerbated.

The reality is that as investment is placed into service, a utility company will incur depreciation expense and interest expense to fund the investment with zero incremental revenue. There is a disparity between the dollar spent by a utility on investment and rate base, which is the investment that rates are based upon. Once placed in service, investment will decrease earnings until recognized in rates, not increase them.

To evaluate the impact that ES II will have on earnings, I developed an income statement and balance sheet for the Program. The revenues are the cumulative revenue requirement for each rate adjustment, shaped annually based on net kWh/therm sales per month. The expenses are the depreciation expense, interest expense and income taxes incurred as plant is placed into service. The table below shows the earnings impact of the ES II consolidated investment being recovered under the following three scenarios:

1. The Company's position as filed ("Scenario 1");

2. Ms. Crane's recommendation if accelerated recovery is approved ("Scenario 2"); and

3. Ms. Crane's recommendation for recovery of Program costs through base rate cases, assuming a 27 month lag between rates ("Scenario 3").

	Earnings ($000)					
	2019	2020	2021	2022	2023	2024
Cumulative Investment	54,600	581,395	1,380,073	2,015,795	2,410,705	2,502,442
Scenario 1: As-Filed	(20)	4,037	25,687	50,861	76,276	105,292
Scenario 2: Rate Counsel Methodology[1]	(20)	4,037	16,982	24,872	40,931	51,827
Scenario 3: Rate Case recovery[2]	(20)	4,037	20,009	17,746	20,268	71,763

1 Assumes no Cost of Removal and indirect overhead allocations in revenue requirements, assumes annual roll-ins, increased stipulated base, and an 8.5% ROE.

2 Assumes rate case result every 27 months based on rate base as of 24 months, excludes rate case settlement post 2024.

Under each of the scenarios, negative incremental earnings result in the first year as interest costs are incurred to finance the capital expenditures, and as depreciation expense grows as projects are placed in service. At first, the Program will solely earn a de minimis amount of earnings from the Allowance for Funds Used During Construction ("AFUDC") Debt and Equity until PSE&G's earnings increase from the first rate adjustment when the investment satisfies the 10% of the total program investment requirement pursuant to the IIP regulations.

Q. Even in the rate case recovery scenario, the Company is generating positive earnings in total through 2024. Doesn't that mean the Program is beneficial to shareholders regardless of the recovery mechanism as Ms. Crane suggests?

A. Ms. Crane is correct that once recognized in rates, shareholders will see an increase in earnings from the ES II investment. However, she does not consider the level of the rate of return on that investment, which is measured by return on equity ("ROE"). Even as proposed, regulatory lag for recovery of and on investment has a significant impact on the Company's actual ROE. Even with the semi-annual rate adjustments, due to incremental investment between roll-ins, the Company will not achieve its allowed ROE before the conclusion of its next base rate case (to be filed by no later than January 1, 2024), at which time all ES II investment will be reset as part of utility rate base.

Q. What would be the impact on the Company's actual ROE if the Company were to recover its ES II investment with an average regulatory lag of 27 months?

A. Ms. Crane's recommendation to only allow recovery through a base rate case (where she assumes a 27 month lag) would result in an ROE through 2024 materially below the ROE of 8.5% recommended by Rate Counsel's own witness, Kevin O'Donnell. Utilizing the annual rate adjustments she recommends if ES II is approved in some form, the corresponding investments would have a negative ROE for the first year, followed by returns materially under any acceptable level. In each case, the return on the Program does not reach the allowed ROE during these years especially under Rate Counsel's Methodology and under the base rate recovery approach. This is in direct opposition to the BPU's IIP policy goal of creating "a rate recovery mechanism that encourages and supports necessary accelerated construction, installation, and rehabilitation of certain utility plants and equipment."[3] The table below shows a comparison of the annual ROEs through 2024 based upon (1) the cost recovery mechanism proposed by the Company; (2) Ms. Crane's recommendation if accelerated recovery is approved, and (3) base rate recovery as recommended by Ms. Crane.

	2019	2020	2021	2022	2023	2024
Scenario 1: As-Filed	-0.2%	2.2%	4.7%	5.3%	6.2%	7.7%
Scenario 2: Rate Counsel Methodology[1]	-0.2%	2.2%	3.1%	2.6%	3.3%	3.8%
Scenario 3: Rate Case recovery [2]	-0.2%	2.2%	3.6%	1.9%	1.7%	5.3%

1 Assumes no Cost of Removal and indirect overhead allocations in revenue requirements, assumes annual roll-ins, increased stipulated base, and an 8.5% ROE.

[2] Assumes rate case result every 27 months based on rate base as of 24 months, excludes rate case settlement post 2024.

[3] IIP, *N.J.A.C.* 14:3-2A.1(b)

Q. Could implementing the ES II Program as proposed with base rate recovery as Ms. Crane suggests impact the Company's credit metrics and ability to raise debt cost-effectively?

A. Yes. Rating agencies consider both qualitative (business) risk and quantitative (financial) risk in their assessments. Overall, undertaking ES II absent an accelerated cost recovery mechanism would be viewed negatively by the rating agencies. Further, Rate Counsel's proposals to further delay providing revenue for this Program, to lower the Company's ROE on Program investment, and to exclude a portion of the investment from recovery would each exacerbate this impact. Based on a quantitative (financial) risk assessment, the Company would be negatively impacted due to one of the most important credit metrics, Funds from Operations ("FFO") divided by debt. The regulatory lag associated with realizing revenues from these investments would lead to lower FFO (including increased interest expense) and higher debt cost (to finance the capital expenditures).

Perhaps most importantly, the rating agencies would view a decision to undertake ES II without a mechanism to promptly recover the associated revenue requirement of the invested capital as an imprudent financial policy decision by management, increasing the Company's financial risk.

RATE COUNSEL PROPOSED ADJUSTMENTS TO THE RECOVERY MECHANISM SHOULD BE REJECTED

Q. Do Ms. Crane and Dr. Dismukes recommend any adjustments to the Company's proposed cost recovery methodology if an accelerated recovery mechanism is approved?

A. Yes. Ms. Crane and Dr. Dismukes propose several adjustments to our proposed recovery methodology including the following:

a. Imposing a cap on Program expenditures

b. Increasing the Company's baseline capital expenditures and stipulated base;

c. Annual roll-ins instead of the proposed semi-annual roll-ins;

d. Utilizing a lower ROE as proposed by Mr. O'Donnell;

e. Exclusion of return on ES II specific cost of removal expenditures;

f. Exclusion of all indirect overhead costs;

g. Inclusion of an O&M offset as proposed by Dr. Dismukes;

h. Capping rate increases at 1% annually; and

i. Eliminating the 50 basis point buffer on the earnings test included in the IIR.

I address each of these proposals below:

Cap on program expenditures is unneeded

Q. Do you agree with Dr. Dismukes that recovery on and of capital expenditures through the accelerated recovery mechanism should be eliminated?

A. No. The Company is not asking the Board to authorize a "blank check" for ES II. Rather, ES II sets forth an estimated dollar amount of investment and specific types of investments that are to be included in the Program. All the investments made by PSE&G during the Program will be subject to a prudency review by the Board in a future base rate case proceeding. As a result, all the investments made in the Board approved ES II will be subject to careful scrutiny, examination and review by the Board and interested parties.

Proposed Baseline Capital and Stipulated Base levels are appropriate

Q. Do you agree with Ms. Crane that the IIP regulations requires the Company to establish a baseline for capital expenditures and spend 10% on similar work?

A. Yes. The IIP regulations require baseline spending as stated in section 14:3-2A.3(a): "A utility seeking to establish an Infrastructure Investment Program shall, within its petition, propose annual baseline spending levels to be maintained by the utility throughout the length of the proposed Infrastructure Investment Program. These expenditures shall be recovered by the utility in the normal course within the utility's next base rate case." The regulations also requires that base spending include 10% of the accelerated program cost on work similar to the projects proposed for accelerated recovery, in section 14:3-2A.2(c):

> "A utility shall maintain its capital expenditures on projects similar to those proposed within the utility's Infrastructure Investment Program. These capital expenditures shall amount to at least 10 percent of any approved Infrastructure Investment Program. These capital expenditures shall be made in the normal course of business and recovered in a base rate proceeding, and shall not be subject to the recovery mechanism set forth in N.J.A.C. 14:3-2A.6."

We agree with Ms. Crane that these are requirements of the IIP regulations, and our filing addresses these requirements.

Q. Do you agree with the baseline expenditures and stipulated base proposed by Ms. Crane?

A. No, I do not. The Company proposed both baseline spending and 10% stipulated base spending on similar work in Schedules EFG-ESII-2B and WEM-ESII-2B, and in Mr. Gray's and Mr. Miller's direct testimonies. Dissimilar to Rate Counsels' direct testimony position, the IIP regulations do not state that 10% of similar work cannot be part of the baseline capital expenditures. Therefore, the Company's proposed combined baseline capital expenditures, stipulated base of $233 million per year for electric and an annual average of $171 million for gas are appropriate and consistent with the IIP regulations.

Semi-annual rate adjustments are appropriate

Q. Do you agree with Ms. Crane's recommendation that the Board permit annual rate adjustments instead of semi-annual as the Company proposed?

A. I do not agree, for several reasons. The IIP regulations specifically allow for semi-annual roll-ins. As I have discussed at length, the purpose of these regulations is to provide a recovery mechanism to encourage utilities to accelerate infrastructure investment. As shown above, even with semi-annual rate adjustments, the Company never achieves its allowed ROE. Increasing the regulatory lag as Rate Counsel proposes would further reduce the Company's ROE.

Q. Is there precedent for semi-annual rate adjustments?

A. Yes. Beyond the fact that the IIP regulations expressly allow for semi-annual rate adjustments, ES was approved with semi-annual rate adjustments for the electric subprograms. While ES gas subprograms were approved with annual rate adjustments, GSMP II, the Company's first infrastructure program approved since implementation of the

IIP regulations, was approved with semi-annual rate adjustments. Therefore, there is precedent for semi-annual rate adjustments for both electric and gas infrastructure programs.

Q. Do you have any comments on Ms. Crane's concern that there are limited resources for BPU Staff and Rate Counsel to address semi-annual roll-ins?

A. Yes. We understand and appreciate the limited resources of Staff and Rate Counsel to address an increasing number of filings and rate reviews. However, while the Company is proposing semi-annual rate adjustments, it also proposes to adhere to the IIP requirement that at least 10% of the program be in-service to qualify for a roll-in. As a result of this limit and the timing of the proposed projects going into service, the Company is only forecasting seven rate adjustments for electric and three for gas (which is even less than annual rate adjustments). The Energy Strong II Program ROE is appropriate

Mr. O'Donnell's adjustments to the ROE are inappropriate

Q. Do you with Mr. O'Donnell's recommendation that the ROE be set at 8.5% for the Program?

A. No, I do not. As discussed in more detail in the Rebuttal Testimony of Ann Bulkley, Mr. O'Donnell's calculation of a 9.0% ROE is flawed and his 50 basis point reduction for the Energy Strong II Program has no support. With regard to the 9.0% ROE for the utility recommended by Mr. O'Donnell, it is important to note that the Company just settled its 2018 base rate case at 9.60% less than six months ago.

Q. Has there been a significant shift in the markets that warrant reexamining the ROE set in the 2018 base rate case?

A. No. This is evident by Mr. O'Donnell's proposed ROE of 9.0%, which is exactly the same as Rate Counsel's proposal in the 2018 base rate case. There has not been a market shift rendering PSE&G's ROE no longer appropriate. Rate Counsel is simply ignoring the settlement of the 2018 base rate case and reverting back to their 2018 base rate case litigated position.

Q. Is there precedent for utilizing the utility ROE for an infrastructure program?

A. Yes. Mr. O'Donnell is correct that in Energy Strong I, the Company accepted an ROE of 9.75% in settlement, which was below the ROE of 10.3% set at the conclusion of PSE&G's 2009-2010 base rate case. However, ES was approved several years after the conclusion of that base rate case and ROEs around the country had dropped significantly in that time period. In GSMP I, the Company proposed a 9.75% ROE and the parties agreed, "…any WACC authorized by the Board in a subsequent base rate case will be reflected in the subsequent revenue requirement calculations rather than the WACC stated above". (see paragraph 21 of the Board Order approving the Program, Docket No. GR15030272) In GSMP II, the parties agreed that "PSE&G's capital structure and return on equity for GSMP II will be set based on the capital structure and return on equity level established in the Company's most recently approved base rate case" (see paragraph 18 of the Board Order approving the Program). These settlements clearly show that the infrastructure programs were to use the utility's latest approved ROE in a base rate case, without any basis point reduction.

Q. Has similar language been in the settlements for other NJ utility infrastructure programs?

A. Yes. Other infrastructure programs with similar language to use the latest base rate case ROE are South Jersey Gas's Accelerated Infrastructure Replacement Program II[4] approved in 2016, New Jersey Natura Gas's SAFE program approved in 2016[5], and Atlantic City Electric's Power Ahead Program approved in 2017[6].

Cost of Removal Expenditures should not be excluded from accelerated recovery

Q. What is cost of removal expenditures?

A. Cost of removal ("COR") expenditures are the incurred costs associated with the demolishing, dismantling, and removing utility plant, including the cost of transportation and handling incidental to the process. These are necessary expenditures to complete the ES II projects.

[4] In the Matter of the Petition of South Jersey Gas Company to Continue its Accelerated Infrastructure Replacement Program ("AIRP") Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and for Approval of a Base Rate Adjustment to Reflect AIRP Investments in Base Rates, Docket No. GR16020175, Decision and Order Approving Stipulation of Settlement (October 31, 2016), page 6.

[5] In the Matter of the Petition of New Jersey Natural Gas Company for Approval of an Increase in Gas Base Rates and for Changes in its Tariff for Gas Service, Approval of SAFE Program Extension, and Approval of SAFE Extension and NJ RISE Rate Recovery Mechanisms Pursuant to N.J.S.A. 48:2-21, 48:2.21.1 and for Changes to Depreciation Rates for Gas Property Pursuant to N.J.S.A. 48:2-18, Docket No. GR1511304, Decision and Order Approving Stipulation (September 21, 2016), paragraph 27.

[6] In the Matter of the Petition of Atlantic City Electric Company for Approval of Amendments to its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21.1 and for Approval of a Grid Resiliency Initiative and Cost Recovery Related Thereto; and for Other Appropriate Relief (201) – Phase II, Docket No. ER16030252, Order Approving Stipulation (May 31, 2017), paragraph 14.

Q. Why does Ms. Crane recommend the COR expenditures be excluded from accelerated recovery?

A. Rate Counsel's argument as stated in Crane Direct, p. 31 of her testimony is that ratepayers continue to pay a return "on" and a return "of" the investment that is retired between base rate cases, and since the revenue requirement for these retirements continues to be in base rates, ratepayers should not be required to pay a return on the costs of removal between base rate cases.

Q. Do you agree with her recommendation?

A. No. To be clear, the Company is requesting accelerated return "on" the COR expenditures in this Program. These expenditures are incremental to existing rate base currently in rates. The return "on" COR expenditures in accelerated recovery has been included and approved in all of PSE&G's previously approved capital infrastructure programs including those of Capital Infrastructure Program ("CIP"), CIP II, ES I, GSMP, and GSMP II.

Even with the accelerated recovery an infrastructure program in place, the Company still experiences regulatory lag for up to nine months on semi-annual roll-ins and the return on the these COR expenditures go unrecovered until rate roll-ins become effective. As shown in the ROE table above, PSE&G does not earn its allowed rate of return on the Program even under its filed position. Exclusion of these COR expenditures from accelerated recovery will further exacerbate under-earning and work against the goal of the IIP regulations, which is to encourage utilities to invest in their infrastructure.

Q. Is there precedent for recovering the return on program related COR expenditures?

A. Yes. As previously mentioned, the precedent has been to recover the return these COR expenditures in all of its previously approved infrastructure programs.

An adjustment for Operating Expense offsets is not needed at this time

Q. Do you agree with Dr. Dismukes' recommendation that the accelerated recovery mechanism include operating expense offsets?

A. No. First, recovery of operating expenses are excluded from the rate filings, so only including operating offsets within the Program would be asymmetrical in nature. In addition, there are incremental expenses associated with the Grid Modernization subprogram that the Company is not seeking recovery on through the accelerated recovery mechanism. In addition, while the proposed program will result in O&M savings, those savings will be realized as projects are placed in service and will be reflected in the Company's next base rate case and then be returned to customers. Furthermore, any O&M savings that result in the Company earning more than its allowed rate of return would limit the Company's rate adjustment due to the proposed earnings test.

Indirect Overheads should not be excluded from Energy Strong II Program costs

Q. Is Ms. Crane's assertion that indirect overhead costs should be excluded from Energy Strong II program costs based on sound regulatory accounting practices?

A. No it is not a correct assertion. As required in the Code of Federal Regulations' Uniform System of Accounts ("USofA"), Electric Plant Instruction 4, "Overhead Construction Costs" are a **required** component of Construction Costs and **must** be applied in a ratable fashion to all projects so that "each job or unit shall bear its equitable proportion of such cost." This same instruction is required for Gas Construction.

If a single job or unit or a group of jobs or units are excluded from the ratable application of overheads, it will result in the misapplication of those overheads to the remaining pool of jobs, thus misstating the true cost of construction for all jobs. This would be a direct violation of the rules proscribed by both the Federal Energy Regulatory Commission ("FERC") and Generally Accepted Accounting Principles ("GAAP").

Appropriate costing application of direct and indirect costs are a critical component of the Company's accounting policies and procedures and are subject to GAAP as well as FERC practices and relevant instructions contained in the USofA as cited above. The applicability of these rules and the Company's practices in their application was specifically reviewed under ES by the Independent Monitor (IM).

Q. What is the IM's role?

A. As stipulated in the Board's approval of the Company's ES, an Independent Monitor ("IM") was hired to "review and report to Board Staff and Rate Counsel on the impact of ES on overall system performance during severe weather events, cost effectiveness and efficiency; **appropriate cost assignment;** and other information deemed appropriate by the Company, Board Staff and Rate Counsel." (Order Approving Stipulation of Settlement; Docket Nos. EO13020155 and GO13020156 p. 17).

As part of the review of "appropriate cost assignment", the IM performed a detailed review of the Company's policies and procedures with respect to the relevant accounting practices, including Cost Reporting. Please refer to the excerpt from "Energy Strong

Independent Monitor 2014 Annual Report" dated March 24, 2015 by Pegasus Global Holdings, Inc. provided as Exhibit SS-ESII-1R. Section 5.3 of that report includes the review of "Proper Capitalization of Energy Strong Project Costs". The IM's findings and observations included the following relevant comments on the Company's accounting practices, including application of those practices in general, application of those practices to ES in particular, and the allocation of indirect costs:

- *The Company's accounting personnel are experienced and highly knowledgeable with respect to utility accounting in general, and have made specific system modifications to accommodate accounting for the Energy Strong Program.*
- *The Company has a comprehensive set of rules and internal algorithms within [sic] its SAP system to effectively allocate direct and indirect costs, including any costs to be allocated to the Energy Strong projects.*
- *Based on the work to date, the IM observes that the Energy Strong Program should not create any changes to the Company's allocation methodology. In addition, other than direct charges from various supporting organizations, Energy Strong capital projects should not be receiving significant indirect allocations.*
- *The IM has not discovered anything in PSE&G's accounting for Energy Strong projects that is in contravention of any know policy or practice. The Company is subject to a broad array of accounting protocols from both external sources and*

internal controls, and at this stage of the Energy Strong Program appears to be in compliance.

Q. Is there precedent for recovery of indirect costs through an accelerated mechanism?

A. Yes. Indirect costs were included in the accelerated recovery mechanism for all prior infrastructure investment programs, including the CIP, CIP II ES, GSMP, and GSMP II.

An annual rate cap is inappropriate

Q. Ms. Crane and Dr. Dismuke recommend that the Board impose an annual 1% cap on increases under ES II. Can you comment on their recommendation?

A. As stated above, due to reductions in gas prices and the Company's cost control efforts, typical residential customers who receive electric and gas service from PSE&G are still paying about 30 percent less than they were a decade ago, and about 40 percent lower when adjusted for inflation. It is unnecessary to impose the proposed cap given how much energy bills have decreased since 2010. In addition, a percentage cap has the inverse desired effect of reducing investment when bills are lower and increasing investments when bills are higher. Further, there is no basis for the 1% cap determined. In GSMP II, Ms. Crane and Dr. Dismukes made the same recommendation for a rate impact cap, but at 2% rather than 1%.

The earnings test should be consistent with the IIP

Q. Ms. Crane suggests that earnings test exclude the 50 basis point buffer as constructed in the IIP regulations. Can you comment on that recommendation?

A. Yes. First and foremost, this recommendation is inconsistent with the IIP regulations, which specifically state in section 14:3-2A.6(h): "For any Infrastructure Investment Program approved by the Board, if the calculated ROE exceeds the allowed ROE from the utility's last base rate case by 50 basis points or more, accelerated recovery shall not be allowed for the applicable filing period."

Ms. Crane's proposal is a unilateral departure from the already established IIP rules. In addition, the earnings test is already an asymmetrical test that favors customers. There is a cap on the Company's upside but no symmetrical adjustment or floor if the Company is not earnings its allowed return. In addition, the 50 basis point buffer is a means by which to help exclude non-recurring performance. For instance, a mere transient increase in financial performance could prolong an ES II roll-in. In addition, delaying a roll-in for a fleeting moment of financial performance would increase the rate shock to customers as a later roll-in could result in a sizable amount of investment rolled into rates.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

Exhibit SS-ESII-1R

ENERGY STRONG PROGRAM INDEPENDENT MONITOR 2014 ANNUAL REPORT

PREPARED AND SUBMITTED BY

PEGASUS GLOBAL HOLDINGS, INC. ®

24 MARCH 2015

Table of Contents

List of Acronyms and Abbreviations

AACE International, Inc. .... AACE

Advisory Base Flood Elevations .... ABFEs

Allowance for Funds Used During Construction .... AFUDC

Architect/Engineer .... A/E

Base Flood Elevation .... BFE

Best and Final Offer .... BAFO

Capital Review Committee .... CRC

Computerized Maintenance Management System .... CMMS

Construction Management Association of America .... CMAA

Construction Work In Progress .... CWIP

Customer Average Interruption Duration Index .... CAIDI

Delivery Projects and Construction .... DP&C

Distribution Supervisory Control and Data Acquisition .... D-SCADA

Edison Electric Institute .... EEI

Electric Distribution Companies .... EDC

Emergency Preparedness Partnerships .... EPP

Engineer Procure Construct .... EPC

Energy Strong Advanced Technology Program Management Office .... ESAT PMO

Federal Emergency Management Agency .... FEMA

Federal Energy Regulatory Commission .... FERC

Field Quality Assessment .... FQA

Flood Insurance Rate Maps .... FIRMs

Generally Accepted Accounting Principles .... GAAP

Generally Accepted Government Auditing Standards .... GAGAS

Geographic Information System .... GIS

Independent Monitor .... IM

Investment Planning and Resource Development .... IPRD

Investment Request .... IR

Jersey Central Power & Light .... JCP&L

Liquefied Natural Gas .... LNG

Liquefied Petroleum Gas .... LPG

Metering and Regulating .... M&R

National Flood Insurance Program .... NFIP

New Jersey Administrative Code .... N.J.A.C.

New Jersey Board of Public Utilities .... BPU

New Jersey Department of Environmental Protection .... NJDEP

Newark Liberty International Airport .... Newark Airport

National Oceanic and Atmospheric Administration .... NOAA

Office of Emergency Management .... OEM

Operator Qualified .... OQ

Pegasus Global Holdings, Inc. .... Pegasus-Global

Program Management Office .... PMO

Project Execution Plan .... PEP

Project Management Body of Knowledge .... PMBOK

Project Management Institute .... PMI

Public Service Electric & Gas Company .... PSE&G

Quality Assurance/Quality Control .... QA/QC

Responsible/Accountable/Consulted/Support/Informed .... RASCI

Schweitzer Engineering Laboratories, Inc. .... SEL

Security and Exchange Commission .... SEC

Structure Consulting Group, LLC .... Structure

Supervisory Control and Data Acquisition .... SCADA

System Average Interruption Frequency Index .... SAIDI

Transmission Life Cycle .... TLC

Utility Review Board .... URB

Utilization Pressure Cast Iron .... UPCI

Work Breakdown Structure .... WBS

the company's SEC filings, and therefore need to be computationally consistent and explainable. Current month and year-to-date variances greater than $2 million in major income and expense categories are generally to be explained, although for some subsidiary companies, the threshold is $1 million. These thresholds would work out to be considerably lower than that required under the SEC's rules for Management Discussions and Analysis; however, the greater level of granularity would be extremely helpful for internal management usage and cost variance understanding.

Finally, the Stipulation calls for quarterly reports on the Energy Strong Program to be provided to the BPU Staff and Rate Counsel. Among the quantitative information to be included is actual and forecasted Energy Strong costs to-date.

Findings and Observations:

- The cost reporting process and reports generated thereby are as comprehensive as the IM has seen in the utility industry. All elements of project management are examined. The reports generated are in sufficient depth and detail, including a 'lessons learned' discussion required with each project close out.
- The Company has in place sufficient procedures which provide for adequate analytics, exposure, visibility, approval, and on-going monitoring for its major capital investment projects. The requirements for project approval and on-going monitoring and funding are as comprehensive as any seen in the utility industry. Financial analyses encompass the involvement of several areas, require sensitivities, and approvals are to be rigorously documented. The use of a three-tiered (major) approval approach (URB, CRC, and the Board of Directors) is relatively unique and appears at this stage of the Energy Strong Program to be effective.

Recommendations:

- The IPRD Group is an efficient conduit for cost reporting in general, and Energy Strong in particular, as it has knowledgeable staff dedicated to the Energy Strong Program and other reporting. One improvement in the area would be to document its monthly reporting responsibilities and activities in a written procedure document. This is important due to the vital part the group plays in PSE&G cost reporting. The procedure should also cover its specific responsibilities with respect to URB and CRC proceedings, its frequent touch points with the Accounting and Finance areas, the various recipients of its numerous reports, proper thresholds for variance analyses, and the DP&C procedures and Enterprise practices to which it adheres. The IM raised these issues with Company personnel, and they have developed drafts of new procedures covering the activities of the IPRD Group, its reporting responsibilities, and metrics to be used in its variance analyses.

5.3 Accounting

In order to monitor PSE&G's compliance with accounting-related provisions of the Stipulation, the IM reviewed the Company's policies and procedures with respect to the relevant accounting practices. PSE&G's accounting practices as a regulated utility are subject to Generally Accepted Accounting Principles (GAAP), as well as Federal Energy Regulatory Commission practices and relevant instructions as contained in the Uniform Systems of Accounts. In addition, the Company is subject to Financial Accounting Standards Board pronouncements as they relate to rate regulated entities, and practices accepted and/or mandated by the BPU. Finally, the Company is subject to the Sarbanes-Oxley Act of

2002, and specifically here, Section 401, as it relates to accurate recording of fixed asset values. Collectively, these requirements for documentation provide most of the guidance needed to ensure proper accounting treatment.

Through interviews with PSE&G accounting personnel and review of relevant accounting policies, the IM has gained a general understanding of the Company's accounting practices, and more specifically as they relate to the Energy Strong Program. Also reviewed was *Accounting Services Practice 630-4* regarding journal entries. This was done to ensure a procedure exists that supports the accuracy, timeliness and validity of the fundamental accounting information that is entered into the general ledger from which financial, cost and other important business information is ultimately retrieved.

There are three general accounting areas arising from the Stipulation that should be monitored for proper treatment. The IM has reviewed whether these areas are covered by specific policies beyond that which is provided by GAAP and FERC due to the nature of PSE&G's business and/or regulatory instructions. These general areas, along with any subsets, are described below:

5.3.1 Proper Capitalization of Energy Strong Project Costs

This area runs the gamut from initial capitalization of costs to ultimate transfer to plant-in-service for financial accounting and ratemaking purposes. The IM has reviewed the existence of documentation for each separate stage in this process, as itemized below:

- Most projects begin with preliminary investigative work and feasibility studies before presentation to the URB and CRC in the Company's capital approval process. When and under what circumstances these costs are capitalized or expensed is covered by Accounting Practice 650-16, *Practice for Use of Account E183*. To qualify as eligible for capitalization, project costs must, among other things, be approved as potentially part of the Company's long-term plan or mandated by regulators, and proceed along a path in the capital approval process. If the project is denied at any point, costs are expensed. If the project is ultimately approved, costs incurred are journalized over to a capital account, generally within CWIP. The account where pending costs are held is reviewed and approved quarterly for disposition. In interview questions conducted by the IM, Company accounting personnel have indicated that any Energy Strong costs incurred prior to the Stipulation were expensed. In addition, *Accounting Practice 650-3*, *Capitalization Practice*, indicates it is PSE&G's general practice to expense training costs. As such, the IM would expect that the training costs currently being incurred in connection with the Energy Strong new hires would be expensed, instead of being charged to Energy Strong capital projects. This will be audited in the IM's future work.
- Project cost accumulation in CWIP is addressed by *Accounting Practice 650-10*, *In-Service Transfers*. Projects will be charged to or transferred into CWIP if they exceed $5,000 and take in excess of 60 days to complete, among other parameters. This also begins the capitalization of AFUDC.
- Ongoing cost capitalization guidance, in addition to those found in GAAP and FERC regulations, are also covered by Company *Property Record Unit Manual Policies* GI-6, GI-7, and GI-8. These documents provide further guidance on capitalization versus expensing of costs incurred. Additionally, in cases where these policies do not specifically address aspects of a proposed capital project, the Company's *Sarbanes-Oxley Control FA005* requires a written determination from the Utility Property Accounting area.

- The Company's cost allocation (direct and indirects) policies and methodology are contained in its *Cost Accounting Manual*. The Company follows a philosophy of allocating direct and indirect costs, whether at the Service Company or from utility support organizations, to the operating company or unit receiving the benefit, and ultimately, if appropriate, settling costs to individual assets. With respect to the Service Company, services are charged directly to the entity receiving the benefit based on either fully loaded hourly rates multiplied by the number of hours spent, or through a transactional count multiplied by a predetermined unit cost. Where direct charging is not possible, cost allocations from the Service Company to operating companies are described in a BPU-approved schedule. Most department overhead, where not directly charged, is assigned using a multi-part allocation methodology. The methodology generally being used by the Service Company to allocate to utility operating units uses a weighted average of three components: utility net fixed assets, headcount, and O&M. In its next phase of work, the IM will be auditing the allocation of direct and indirect costs from the Service Company and utility support to Energy Strong capital projects.
- Cost allocations are performed automatically at each monthly closing by the algorithms contained in the Company's SAP system.
- Once a project is completed, or energized and carrying load, and/or otherwise considered used and useful, it is transferred out of CWIP to plant-in-service. This procedure is covered by *Accounting Practice 650-10*, *In-Service Transfers*. The responsible operating department notifies the Property Accounting department of the in-service date, and actual costs plus trailing costs are added to plant-in-service. AFUDC also ceases. This is the normal progression for accumulation and disposition of project costs. The IM notes that of the $11.2 million gross plant investment as of November 30, 2014, reflected in the Company's first Energy Strong Program electric roll-in calculation, $10.3 million, or over 90%, represented CWIP transferred into gross plant.

5.3.2 Treatment of Plant Retirements and Costs of Removal

Accounting for retirements of plant arising from the Energy Strong Program will be covered by *Accounting Practice 650-11*, *Retirements and Associated Transfers*. The original cost will be debited to depreciation reserve and credited to depreciable plant. As a result, no gains or losses will be recorded in the retirement of utility plant. This represents no change in the Company's method of accounting for retirements.

The Stipulation prescribes the treatment for recovery through rates of cost of removal. Actual costs of removal will be included only in the $1.22 billion maximum cost. As a result, revenue requirement will not include an expense for recovery of these costs (except as reflected in depreciation rates), but will include a return on the cost of removal investment. As of November 30, 2014, approximately $3 million of costs of removal has been incurred in connection with the Energy Strong Program. The IM will also monitor the expected accounting treatment of any salvage value of assets retired, such that these costs are netted against costs of removal.

5.3.3 Application of AFUDC

The Stipulation permits recovery of AFUDC on Energy Strong projects without regard to the $1.22 billion maximum recoverable investment. In addition, the Stipulation states accrual of AFUDC should be consistent with Company policy, and compounding as permitted by FERC Order 561.

Guidelines for capitalization of AFUDC at the Company are provided by *Accounting Practice 650-9, Allowance for Funds Used during Construction and Rate Calculations*. The procedures therein define eligible projects, the cessation of AFUDC and the rate calculation formulas. Based on these procedures, the IM would not expect significant amounts of AFUDC to be applied to certain Energy Strong projects, such as the UPCI subprogram. The IM will continue monitoring this expectation in its ongoing audit work. Although the rate is determined annually, the Company periodically recalculates and examines the AFUDC rate for material changes. An interim rate adjustment may occur if the recalculated rate deviates from the current rate by more than 25 basis points. The latest recalculation indicated a 6 basis point increase over the existing rate, so no adjustment was made.

Findings and Observations:

- Effective policies exist for proper capitalization of project costs from feasibility studies to project recording of on-going capital costs to CWIP through transfer of project costs from CWIP to plant in-service.
- The Company's accounting personnel are experienced and highly knowledgeable with respect to utility accounting in general, and have made specific system modifications to accommodate accounting for the Energy Strong Program.
- The Company has a comprehensive set of rules and internal algorithms with its SAP system to effectively allocate direct and indirect costs, including any costs to be allocated to the Energy Strong projects.
- *Practice 630-4* covers proper accruals, required journal entry documentation, necessary review and approvals, and timely posting. The practice document appears to be clear and comprehensive.
- Based on work to date, the IM observes that the Energy Strong Program should not create any changes to the Company's allocation methodology. In addition, other than direct charges from various supporting organizations, Energy Strong capital projects should not be receiving significant indirect allocations. This will be tested and validated as the IM begins and continues with its walkthrough audits of project costs.
- The Company's practices with respect to AFUDC appear to be in accordance with Electric (Gas) Plant Instructions 3(17) of the FERC's Uniform Systems of Accounts prescribed for public utilities (formerly FERC Order 561).
- The IM has not discovered anything in PSE&G's accounting for Energy Strong projects that is in contravention of any known policy or practice. The Company is subject to a broad array of accounting protocols from both external sources and internal controls, and at this stage of the Energy Strong Program appears to be in compliance.
- The IM will monitor other accounting related areas mentioned specifically in the Stipulation. One area is treatment of plant retirements and costs of removal (net of any salvage). The IM notes that the Company has supplemental policy statements covering this area and will determine if these areas are being followed as the Program progresses. The other area that the IM will continue to monitor is the proper calculation and application of AFUDC.