Matthew M. Weissman
General Regulatory Counsel - Rates

Law Department
PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
tel : 973-430-7052 fax: 973-430-5983
email: matthew.weissman@pseg.com

June 8, 2018

In The Matter of the Petition of
Public Service Electric and Gas Company
for Approval of The Second Energy Strong Program
(Energy Strong II)

BPU Docket Nos. __________________

VIA E-FILING & OVERNIGHT MAIL

Office of the Secretary
Attn: Aida Camacho-Welch
Board of Public Utilities
44 South Clinton Avenue, 9th Flr.
P.O. Box 350
Trenton, New Jersey 08625-0350

Dear Secretary Camacho-Welch:

Enclosed for filing are the original and two copies of the Verified Petition of Public Service Electric and Gas Company ("PSE&G") in the above-entitled matter. Also attached and filed herewith are the Direct Testimonies and Schedules of the following witnesses in support of the Company's Petition.

Attachment	**Witness**	**Area of Responsibility**
1	Wade E. Miller, Director – Gas Transmission and Distribution Engineering, PSE&G	Gas portion of PSE&G's proposed Energy Strong II Program
2	Edward F. Gray, Director – Electric Transmission and Distribution Engineering, PSE&G	Electric portion of PSE&G's proposed Energy Strong II Program
3	Stephen Swetz, Senior Director – Corporate Rates and Revenue Requirements, PSE&G	Revenue requirements, cost recovery methodology, and rate design

4	William D. Williams, Black & Veatch	Use of a risk-based model in identifying priority investments, and estimating the risk reduction attributable to ES II electric substation projects
5	CBA Electric Panel – Krystal Richart, Craig Preuss and Andrew Trump, Black & Veatch	Cost-benefit analyses of the electric portion of the Energy Strong II Program
6	CBA Gas Panel – Russell Feingold, Michael Nushart, Krystal Richart, and Andrew Trump, Black & Veatch	Cost-benefit analyses of the gas portion of the Energy Strong II Program
7	Legal Notice	

PSE&G is filing this Petition seeking Board approval of its Energy Strong II program by which the Company seeks to invest $2.5 billion, over a five year period, to further strengthen the utility's electric and gas systems to withstand storms, improve reliability and significantly enhance resiliency. This Program builds upon the initial Energy Strong Program, which was approved by a Board order dated May 21, 2014 in BPU Docket Nos. EO13020155 and GO13020156, and complies with the Board's rules on Infrastructure Investment Programs, N.J.A.C. 14:3-2A.

If approved, the proposed program will enable PSE&G to continue its momentum to modernize its infrastructure by launching the second phase of Energy Strong that will:

- Rebuild, raise and/or harden critical electrical equipment, including within flood prone areas,
- install stronger poles and wires to reduce wind and tree damage,
- deploy advanced technology to quicken restoration,
- build backup pipes to distribute natural gas to enhance reliability,
- modernize critical gas equipment within flood prone areas, and
- improve PSE&G's already strong customer service.

Attached to the testimony of Wade Miller (Attachment 1) and Edward Gray (Attachment 2), concerning, respectively, the gas and electric portions of Energy Strong II, are several schedules that contain confidential information. This material will be furnished to the Board of Public Utilities staff and the Division of Rate Counsel upon execution of a Confidentiality Agreement, which is provided herewith for execution. Please note that this Confidentiality Agreement is the version most recently executed by BPU Staff and Rate Counsel in PSE&G's pending 2018 Base Rate Case proceeding.

Copies of the Petition and supporting documentation will be served upon all entities legally required to be noticed.

Very truly yours,

Matthew Weissman

Attachment
C Attached Service List (E-Mail Only)

BPU
Aida Camacho-Welch
Board of Public Utilities
44 South Clinton Avenue, 3rd Floor, Suite 314
Post Office Box 350
Trenton NJ 08625-0350
aida.camacho@bpu.nj.gov

BPU
Joe Costa
Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
P.O. Box 350
Trenton NJ 08625-0350
(609) 984-4558
joe.costa@bpu.nj.gov

BPU
Paul Flanagan
Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
P.O. Box 350
Trenton NJ 08625-2836
paul.flanagan@bpu.nj.gov

BPU
Noreen M. Giblin Esq.
Board of Public Utilities
44 South Clinton Avenue, Suite 314
P.O. Box 350
Trenton NJ 08625-0350
noreen.giblin@bpu.nj.gov

BPU
Son Lin Lai
Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
P.O. Box 350
Trenton NJ 08625-0350
(609) 292-2098
son-lin.lai@bpu.nj.gov

BPU
Christine Lin
Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
P.O. Box 350
Trenton NJ 08625-0350
(609) 292-2956
christine.lin@bpu.nj.gov

BPU
Megan Lupo
Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
P.O. Box 350
Trenton NJ 08625-0350
megan.lupo@bpu.nj.gov

BPU
John Masiello
Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
P.O. Box 350
Trenton NJ 08635-0350
john.masiello@bpu.nj.gov

BPU
Jacqueline O'Grady
Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
P.O. Box 350
Trenton NJ 08625-0350
(609) 292-2947
jackie.ogrady@bpu.nj.gov

BPU
Stacy Peterson
Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
P.O. Box 350
Trenton NJ 08625-0350
(609) 292-4517
stacy.peterson@bpu.nj.gov

BPU
Bethany Rocque-Romaine Esq.
Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
P.O. Box 350
Trenton NJ 08625-0350
(609) 292-1496
bethany.romaine@bpu.nj.gov

BPU
Michael Stonack
Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
P.O. Box 350
Trenton NJ 08625-0350
(609) 777-0192
michael.stonack@bpu.nj.gov

BPU
Scott Sumliner
Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
P.O. Box 350
Trenton NJ 08625-0350
(609) 292-4519
scott.sumliner@bpu.nj.gov

DAG
Jenique Jones
NJ Dept. of Law & Public Safety
Division of Law
124 Halsey Street, 5th Flr.
P.O. Box 45029
Newark NJ 07101
jenique.jones@dol.lps.state.nj.us

DAG
Patricia A. Krogman DAG
NJ Dept of Law & Public Safety
Division of Law
124 Halsey Street, 5th Flr.
P.O. Box 45029
Newark NJ 07101
(973) 648-3441
patricia.krogman@dol.lps.state.nj.us

DAG
Alex Moreau DAG
NJ Dept. of Law & Public Safety
Division of Law
124 Halsey Street, 5th Flr.
P.O. Box 45029
Newark NJ 07101
(973) 648-3762
Alex.Moreau@dol.lps.state.nj.us

DAG
Caroline Vachier DAG
NJ Dept. of Law & Public Safety
Division of Law
124 Halsey Street, 5th Flr.
P.O. Box 45029
Newark NJ 07101
(973) 648-3709
caroline.vachier@dol.lps.state.nj.us

DAG
Emma Xiao DAG
NJ Dept of Law & Public Safety
Division of Law
124 Halsey Street, 2nd Floor
Newark NJ 07101
emma.xiao@law.njoag.gov

PSE&G
Michele Falcao
PSEG Services Corporation
80 Park Plaza, T5
P.O. Box 570
Newark NJ 07102
(973) 430-6119
michele.falcao@pseg.com

PSE&G
Danielle Lopez Esq.
Public Services Corporation
80 Park Plaza, T5
P.O. Box 570
Newark NJ 07102
973-430-6479
danielle.lopez@pseg.com

PSE&G
Martin C. Rothfelder Esq.
Rothfelder Stern, L.L.C.
407 Greenwood Avenue
Suite 301
Trenton NJ 08609-2158
(609) 394-1000
mrothfelder@rothfelderstern.com

PSE&G
Bernard Smalls
PSEG Services Corporation
80 Park Plaza-T5
Newark NJ 07102-4194
(973) 430-5930
bernard.smalls@pseg.com

PSE&G
Matthew M. Weissman Esq.
PSEG Services Corporation
80 Park Plaza, T5
P.O. Box 570
Newark NJ 07102
(973) 430-7052
matthew.weissman@pseg.com

PSE&G
Caitlyn White
PSEG Services Corporation
80 Park Plaza, T-5
P.O. Box 570
Newark NJ 07102
(973)-430-5659
caitlyn.white@pseg.com

Rate Counsel
Stefanie A. Brand
Division of Rate Counsel
140 East Front Street, 4th Flr.
P.O. Box 003
Trenton NJ 08625
(609) 984-1460
sbrand@rpa.state.nj.us

Rate Counsel
Lisa Gurkas
Division of Rate Counsel
140 East Front Street, 4th Flr.
P.O. Box 003
Trenton NJ 08625
(609) 984-1460
lgurkas@rpa.state.nj.us

Rate Counsel
Kurt Lewandowski Esq.
Division of Rate Counsel
140 East Front Street, 4th Flr.
P.O. Box 003
Trenton NJ 08625
(609) 984-1460
klewando@rpa.state.nj.us

Rate Counsel
Brian O. Lipman
Division of Rate Counsel
140 East Front Street, 4th Flr.
P.O. Box 003
Trenton NJ 08625
(609) 984-1460
blipman@rpa.nj.gov

Rate Counsel
Ami Morita
Division of Rate Counsel
140 East Front Street, 4th Flr.
P.O. Box 003
Trenton NJ 08625
(609) 984-1460
amorita@rpa.state.nj.us

Rate Counsel
Diane Schulze Esq.
Division of Rate Counsel
140 East Front Street, 4th Flr.
P.O. Box 003
Trenton NJ 08625
(609) 984-1460
dschulze@rpa.state.nj.us

Rate Counsel
Felicia Thomas-Friel
Division of Rate Counsel
140 East Front Street, 4th Flr.
P.O. Box 003
Trenton NJ 08625
(609) 984-1460
fthomas@rpa.nj.gov

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF THE SECOND ENERGY STRONG PROGRAM (ENERGY STRONG II)	)))))	PETITION BPU DOCKET NOS. EO18______ GO18______

VERIFIED PETITION

Public Service Electric and Gas Company ("PSE&G," "the Company," or "Petitioner"), a corporation of the State of New Jersey, having its principal offices at 80 Park Plaza, Newark, New Jersey, respectfully petitions the New Jersey Board of Public Utilities ("Board" or "BPU") pursuant to *N.J.S.A.* 48: 2-21, or any other statute the Board deems applicable, as follows:

INTRODUCTION AND OVERVIEW OF THE FILING

1. Petitioner is a public utility engaged in the distribution of electricity and the provision of electric Basic Generation Service ("BGS"), and distribution of gas and the provision of Basic Gas Supply Service ("BGSS"), for residential, commercial and industrial customers within the State of New Jersey. PSE&G provides service to approximately 2.2 million electric and 1.8 million gas customers in an area having a population in excess of 6.2 million persons and that extends from the Hudson River opposite New York City, southwest to the Delaware River at Trenton, and south to Camden, New Jersey.

2. Petitioner is subject to Board regulation for the purposes of setting its retail distribution rates and to assure safe, adequate, and reliable electric distribution and natural gas distribution service pursuant to N.J.S.A. 48:2-21 *et seq.*

3. PSE&G is filing this Petition seeking Board approval of the Energy Strong II Program ("ES II" or "Program") and associated cost recovery mechanism for a five-year period. The Program builds upon the Energy Strong Program ("Energy Strong" or "ES I"), which was approved by a Board order dated May 21, 2014 in BPU Docket Nos. EO13020155 and GO13020156 ("Energy Strong Order"). The Program is also designed to comply with the Board's rules on Infrastructure Investment Programs ("IIPs"), N.J.A.C. 14:3-2A.

4. Consistent with the IIP regulations, ES II proposes infrastructure investments to enhance safety, reliability, and/or resiliency through four electric and two gas subprograms. PSE&G anticipates the Program will be conducted over the five-year period on the latter of March 1, 2019 through February 29, 2024, or the 5-year period that starts on the first of the month following the effective date of a Board order of approval, with certain limited close out expenses to follow the five year period. The Program proposes estimated investment of $1.503 billion in electric infrastructure over 5 years and $0.999 billion in gas infrastructure over 5 years, with cost recovery based upon the Board's IIP rules and consistent with the cost recovery for electric investments in ES I.

THE PROGRAM

5. As noted above, this ES II filing has been designed to be consistent with the Board's regulations. Appendix 1 attached to this Petition sets forth the location in this filing of all requirements per the Board's IIP regulations. The Program includes the following proposed electric subprograms, with summaries and investment totals as listed below:

(1) Station Subprogram

This subprogram would provide flood mitigation for 16 stations based on the location of those stations within flood zones as identified by the Federal Emergency Management Agency

(FEMA) 100-year flood zone. Based on that criterion, 16 PSE&G distributions stations require flood mitigation. This subprogram will also provide life cycle replacements for 15 substation facilities that have been selected based on an asset management risk model. Where it is cost effective, stations will be eliminated.

The stations that will be addressed through this subprogram, and the proposed methodology at this time, are reflected in the chart below:

CHART 1 - SUBSTATION PROGRAM				
	Flood Mitigation		**Life Cycle Upgrades**	
	Station	**Anticipated Method**	**Station**	**Anticipated Method**
1	Meadow Road	Raise	Woodbury	Rebuild 4kV
2	Leonia	Raise	Plainfield	Rebuild 4kV
3	Kingsland	Raise	Spring Valley Rd	Rebuild 4kV
4	Ridgefield 13kV	Raise	Mount Holly	Rebuild 4kV
5	Ridgefield 4kV	Eliminate	Mclean Blvd	Rebuild 4kV
6	Hasbrouck Heights	Raise	Paramus	Rebuild 4kV
7	Academy Street	Raise	Warren Point	Rebuild 4kV
8	Woodlynne	Raise	Hamilton	Rebuild 4kV
9	Toney's Brook	Raise	Teaneck	Rebuild 4kV
10	Clay Street	Raise	Front Street	Rebuild 4kV
11	Waverly	Raise	Tonnelle Avenue	Rebuild 4kV
12	State Street	Raise	Great Notch	Rebuild 4kV
13	Orange Valley	Raise	Dumont	Rebuild 4kV
14	Market Street	Eliminate	Fourteenth St	Rebuild 4kV
15	Lakeside Avenue	Raise	Totowa	Rebuild 4kV
16	Constable Hook	Raise		
Total	**$428 million**		**$478 million**	

This subprogram involves estimated investment of $906 million.

(2) Outside Plant Higher Design and Construction Standards Subprogram

This subprogram will involve upgrading circuits with cross-arm open wire construction with a more compact spacer cable configuration to harden those circuits against damage from storms. A spacer cable system is composed of rugged weatherproofed conductors, compacted into a bundle, with a steel cable support. It is resistant to tree and limb damage because of its high strength and smaller profile. PSE&G proposes to address approximately 475 circuit miles; the specific circuits to be addressed will be determined by circuit performance and number of customers served.

This subprogram involves estimated investment of $345 million.

(3) Contingency Reconfiguration Subprogram

The Company proposes to harden the electric system and increase electric system resiliency by investment in contingency reconfiguration strategies. These strategies, which were also a part of ES I, would increase the sections in present loop designs utilizing reclosers, providing alternative circuit feeds or circuit reconfigurations to allow for greater flexibility for switching to alternative sources. Under this proposed subprogram, PSE&G would convert all existing two section overhead 13kV circuits to three section circuits by installing an additional three phase recloser. In addition, overhead 4kV radial circuits would be enhanced with a three phase recloser to create two sections and reduce the number of customers impacted by an outage. In addition, three phase branches with and without fuses will be enhanced with three phase reclosers that will avoid extended interruptions for faults of a transient nature. Finally, three phase reclosers would be used to tie circuits together to create new tie points where service can be restored from an alternative source in the event of an outage.

This proposed subprogram also includes installation of single phase recloser devices on branch lines that currently have only fuses. Those existing fuses require customer calls and/or field inspections to understand if customers are out of power or restored. The devices would be pole-mounted and will trip and reclose in the event of a fault on the branch line. They would also communicate both successful reclosing and power status.

This subprogram involves estimated investment of $145 million.

(4) Grid Modernization Subprogram

The Company proposes to develop an Advanced Distribution Management System ("ADMS") to incorporate data sources such as outage information gained from SCADA, intelligent fault indicators, potential future deployment of Smart Meters and other advanced metering infrastructure ("AMI"), and add-on analysis applications such as load flows and state estimations for data accuracy. ADMS provides tools for dynamic visualization, monitoring and control of the electric distribution network, together with a wide set of power applications for operations analysis, planning, and optimization. The system will replace the existing Outage Management System ("OMS") and assimilate data from Geographic Information System ("GIS") and SCADA systems. ADMS will provide efficient management of faults and voltage improvements; real-time network monitoring and control; incident management to assist in damage location identification; mathematical network modeling and power applications; network analysis; reduction of system losses through Volt/Var controls; integration of Distributed Energy Resources ("DER"s); and improvement of power quality and customer services.

In addition, this investment would associate plant damage with its geographical location and relate it to trouble incidents; enable customers to provide information about damage, including pictures; develop a work plan optimization engine to improve work prioritization and provide predictive estimated time of restoration; develop new and simplified storm management applications for internal mobile crews; develop a mutual aid field application; and enhance storm management analytics, visualization and reporting.

This proposed subprogram also includes installation of a communications network and elimination of the use of dedicated phone lines for remote communication to both PSE&G and customer equipment. The overall network will use wireless and fiber technology to provide coverage for all switching devices on the system to facilitate both system and customer equipment communication moving forward. The system will be private and encrypted to ensure the security of PSE&G's capability to monitor and control the Distribution system.

This subprogram involves estimated investment of $107 million.

6. ES II includes the following two gas subprograms:

(1) Curtailment Resiliency Subprogram

The Curtailment Resiliency Subprogram consists of six discrete projects that will improve the resiliency of PSE&G's gas distribution system to potential interstate gas pipeline supply curtailments. Five proposed distribution facility projects would provide increased resiliency by moving gas supplies across the PSE&G service territory between areas served by the different pipeline systems. An additional Liquefied Natural Gas ("LNG") facility would inject additional gas into the system in a time of curtailment. This subprogram involves estimated investment of $863 million.

The chart below provides additional information on these six projects.

CHART 2 - CURTAILMENT RESILIENCY SUBPROGRAM PROJECTS	
NAME	**DESCRIPTION**
Central – South Plainfield	Modify the Central (Edison) M&R station to add a 600 psi alternate supply line to PSE&G's Woodbridge-Central transmission system and a new 120 psi distribution system.
Hamilton – West Windsor	Extend the existing 150 psi distribution system from Hamilton Township to West Windsor Township.
Mahwah – Paramus – Wanaque	Modify the Mahwah M&R station and Wanaque M&R station and add a new joint 120 psi system that will tie-in to the existing 120 psi system out of the Paramus M&R station to create one interconnected 120 psi system between the Mahwah, Paramus, and Wanaque M&R stations.
Sayreville – Jamesburg	Modify the Sayreville M&R station and add a new 120 psi system between the Sayreville M&R station and the Jamesburg M&R station.
Bernards – Gillette – Parsippany – Chatham – Bridgewater	Modify Bernards, Gillette, Parsippany, Chatham and Bridgewater M&R stations and add new 120 psi distribution systems.
Liquefied Natural Gas Facility	Construct a LNG facility with the ability to deliver 50.0 MDTH/Day in Linden or Edison, NJ.

(2) Metering and Regulation Upgrade Subprogram

The Metering and Regulating ("M&R") Upgrade Subprogram involves rebuilding seven gas M&R stations for needed modernization and, in the case of two of the stations that are in recognized flood zones, storm hardening. The following M&R stations are included in the proposed Subprogram:

- Camden
- East Rutherford
- Central
- Paramus
- Westampton
- Mount Laurel
- Hillsborough

This subprogram involves estimated investment of $136 million.

7. The Company commits to capital expenditures on projects similar to those proposed within the Program in an amount of at least ten (10) percent of the Program. These capital

expenditures shall be recovered in a base rate proceeding, and shall not be subject to the cost recovery mechanism set forth herein. In the gas Curtailment Resiliency Subprogram, the Company will meet this requirement by only seeking 90% of the type of expenditures approved in this proceeding through the cost recovery mechanism set forth herein. In addition, the Company will reduce its program recovery in the M&R Upgrade Subprogram by $2.0 million, the amount not planned to be done in base to meet the 10% requirement.

BENEFITS TO CUSTOMERS AND THE NEW JERSEY ECONOMY

8. This proposed Program, like the prior PSE&G Capital Infrastructure Programs, Energy Strong, GSMP, and GSMP II will produce many benefits for customers served by PSE&G's electric and gas distribution systems, and for the State of New Jersey. Customers will benefit from a safer, more modern system that accommodates new technologies, providing an electric system that can integrate and manage larger quantities of DERs, and other innovations. When catastrophic events occur, the electric and gas systems will have increased ability to withstand and recover from those events with associated lower extraordinary restoration costs, if any, and less disruption, if any, to customers and the New Jersey economy. The Program will provide higher levels of reliability in the PSE&G electric and gas distribution systems.

9. A five year period is necessary for this program because the vast majority of the construction projects proposed in the gas portion of ES II require five years to complete. Various aspects of permitting, planning, and coordinating the projects, cannot be reasonably planned for and executed in less than a five year period. In addition, the multi-year approach provides various efficiencies in planning, staffing, and managing contractors and material procurement.

10. The Cost Benefit Analysis attached to the Prepared Direct Testimony of the Cost-Benefit Analysis Panel – Gas and the Prepared Direct Testimony of the Cost-Benefit Analysis Panel – Electric further supports the approval of the Program.

11. Proceeding with this Program will also continue PSE&G's support of economic development and enhanced employment opportunities in New Jersey. This Program will support additional skilled jobs. The multi-year nature of the Program will provide more stability and permanence in the jobs the Program creates and supports.

COST RECOVERY

12. PSE&G is proposing a cost recovery mechanism for ESII that is consistent with the BPU IIP regulations, as addressed in detail in the attached Direct Testimony of Stephen Swetz. The cost recovery method will involve the potential of semi-annual base rate adjustment filings for electric and gas, consistent with the IIP regulations and the same approach used for PSE&G's Energy Strong program for electric investments. The proposed schedule for these potential filings are shown in the chart below:

CHART 3 - PROPOSED SCHEDULE FOR POTENTIAL FILINGS

Initial Filing	Investment as of	Actual Historical Data Update Filing	Rates Effective
9/30/19	11/30/19	12/15/19	3/1/20
3/31/20	5/31/20	6/15/20	9/1/20
9/30/20	11/30/20	12/15/20	3/1/21
3/31/21	5/31/21	6/15/21	9/1/21
9/30/21	11/30/21	12/15/21	3/1/22
3/31/22	5/31/22	6/15/22	9/1/22
9/30/22	11/30/22	12/15/22	3/1/23
3/31/23	5/31/23	6/15/23	9/1/23
9/30/23	11/30/23	12/15/23	3/1/24
3/31/24	5/31/24	6/15/24	9/1/24

13. Since the IIP rule limits each electric and gas base rate adjustment request to a minimum investment level of 10 percent of each respective electric and gas program, PSE&G projects that its filings for such increases will be less often than the potential semi-annual filings and that the first base rate adjustment filings in the Program will be in September 2020 for electric rates and March 2022 for gas rates.

14. ES II is scheduled to be complete February 29, 2024, except certain close out work that may occur 3 to 6 months following the conclusion of the Program. In addition, trailing charges from contractors may lag further into 2024. Without a firm date for completion of this close out work, the Company is proposing a rate filing no later than September 15, 2024 comprised of all actual (as opposed to projected) cost data for rates effective January 1, 2025.

15. Consistent with the Energy Strong program, GSMP and GSMP II, PSE&G proposes that the costs to be included in rates will include: depreciation/amortization expense providing for the recovery of the invested capital over its useful book life; return on the net investment, where net investment is the capital expenditures less accumulated depreciation/amortization, less associated accumulated deferred income taxes; and the impact of any tax adjustments applicable to the Program. The return on net investment will be based upon a weighted average cost of capital ("WACC"). The Company proposes a WACC for the Program based upon the most recent WACC for base rates approved by the Board. Since the Company has a pending base rate case and anticipates approval before the first ES II rate adjustment filing, the WACC utilized for forecasting purposes is the WACC proposed in the pending base rate case proceeding. PSE&G proposes that any change in the WACC authorized by the Board in the

pending or any subsequent base rate case be reflected in the subsequent revenue requirement calculations.

16. BPU Staff and Rate Counsel will have an opportunity to review each rate adjustment filing to ensure that the revenue requirements and proposed rates are being calculated in accordance with the BPU Order approving the Program and the IIP rules. The changes to base rates made through these rate adjustment filings would be subject to refund based upon a Board finding that PSE&G imprudently incurred capital expenditures in its implementation of the ES II program. The actual prudence of the Company's expenditures in ES II will be reviewed as part of PSE&G's subsequent base rate case(s) following the rate adjustments. This is identical to the approach under the Energy Strong program and GSMP, and the Board's regulation at N.J.A.C. 14:3-2A.6(e). The Company proposes that it will file its subsequent base rate case no later than five years after the commencement of ES II.

17. In addition to limiting the base rate adjustment requests to a minimum investment level of ten (10) percent of the total program investment, PSE&G is also proposing to limit the amount of investment to be included in the rate base adjustments by an earnings test. Consistent with the IIP regulations, if the Company exceeds the allowed ROE from the utility's last base rate case by fifty (50) basis points or more for the most recent twelve (12) month period, the pending base rate adjustment shall not be allowed for the applicable filing period. Details regarding application of the earnings test are set forth in the Direct Testimony of Stephen Swetz, submitted herewith.

18. This Petition does not propose any rate increase and, for that reason, no public comment hearings are required. Nevertheless, PSE&G proposes public comment hearings similar to those that are held when rate increases are proposed. Thus, a proposed form of public

notice of filing and public hearings, including the proposed rates and bill impacts attributable to the proposed implementation of the Program, is attached to this Petition. PSE&G proposes this Form of Notice will be placed in newspapers having a circulation within the Company's electric and gas service territory upon receipt, scheduling and publication of public hearing dates. As with petitions that propose rate increases, PSE&G proposes public hearings will be held in each geographic area within the Company's service territories, *i.e.*, Northern, Central, and Southern. PSE&G also proposes that it provide notice to the County Executives and Clerks of all municipalities within the Company's electric and gas service territories upon receipt of public hearing dates.

19. The typical annual bill impacts for a typical residential customer as well as rate class average customers compared to rates as of June 1, 2018 are set forth in the testimony of Mr. Stephen Swetz. The forecasted cumulative impact (impact from the entire Program) on the typical residential electric customer is an increase of approximately 3.99% on an average annual bill or about a $4.04 increase in their average monthly bill. The forecasted cumulative impact (impact from the entire Program) on the typical residential gas heating customer is an increase of approximately 6.80% on an average annual bill or about a $4.98 increase in their average monthly bill. The total impact for a combined typical electric and gas residential customer would average about 1% per year over the five year period.

ATTACHED DIRECT TESTIMONY AND PROPOSED PROCEDURAL SCHEDULE

20. Given the completion of ES I in 2018, and the importance of maintaining the support for jobs through PSE&G infrastructure programs and continuity in those programs, it is important for PSE&G to receive Board approval before March 2019 to begin planning for, designing and making the capital investments described herein. Therefore, the Company

respectfully requests that the Board retain this matter and utilize a schedule similar to the following procedural schedule:

Petition and Direct Testimony filed	June 8, 2018
Prehearing Conference	July 11, 2018
Discovery/Technical Conferences	July 12 & August 28 & 29, 2018
Non-Petitioner Direct Testimony Due	September 14, 2018
Rebuttal Testimony – All Parties	October 12, 2018
Settlement Conferences	September 7 & 10
	October 1, 3, 23, 25
Hearings	November 1, 2, 7- 9 & 14-15
Initial Briefs	December 10, 2018
Reply Briefs	December 21, 2018
BPU Order	February, 2019

21. PSE&G respectfully requests that the Board issue an order in this matter no later than February 2019.

22. Attached please find the following direct testimony with schedules and other attachments in support of the proposal in this petition:

Appendix 1 - Location of requirements per the IIP regulations at N.J.A.C. 14:3-2A

Non-Disclosure Agreement

Attachment 1 - Prepared Direct Testimony of Wade E. Miller

Attachment 2 - Prepared Direct Testimony of Edward F. Gray

Attachment 3 - Prepared Direct Testimony of Stephen Swetz

Attachment 4 - Prepared Direct Testimony of William A. Williams

Attachment 5 - Prepared Direct Testimony of the Cost-Benefit Analysis Panel – Gas

Attachment 6 - Prepared Direct Testimony of the Cost-Benefit Analysis Panel – Electric

Attachment 7 – Legal Notice

COMMUNICATIONS

23. Communications and correspondence related to the Petition should be sent as follows:

Joseph F. Accardo, Esq.
Deputy General Counsel
PSEG Services Corporation
80 Park Plaza, T5
P. O. Box 570
Newark, New Jersey 07102
Phone: (973) 430-5811
joseph.accardojr@pseg.com

Matthew M. Weissman, Esq.
General Regulatory Counsel-Rates
PSEG Services Corporation
80 Park Plaza, T5
P. O. Box 570
Newark, New Jersey 07102
Phone: (973) 430-7052
matthew.weissman@pseg.com

Hesser G. McBride, Jr.
Associate General Regulatory Counsel
PSEG Services Corporation
80 Park Plaza, T5
P. O. Box 570
Newark, NJ 07102
Phone: (973) 430-5333
Hesser.Mcbride@pseg.com

Martin C. Rothfelder, Esq.
Rothfelder Stern, L.L.C.
407 Greenwood Ave.
Suite #301
Trenton, NJ 08609
Phone: (609) 394-1000
mrothfelder@rothfelderstern.com

Danielle Lopez
Assistant General Regulatory Counsel
PSEG Services Corporation
80 Park Plaza, T5
P.O. Box 570
Newark, New Jersey 07102
Phone: (973) 430-6479
Danielle.Lopez@pseg.com

Michele Falcao
Regulatory Filings Supervisor
PSEG Services Corporation
80 Park Plaza, T5
P.O. Box 570
Newark, New Jersey 07102
Phone: (973) 430-6119
michele.falcao@pseg.com

Caitlyn White
Regulatory Case Coordinator
PSEG Services Corporation
80 Park Plaza, T5
P.O. Box 570
Newark, New Jersey 07102
Phone: (973) 430-5659
caitlyn.white@pseg.com

CONCLUSION AND REQUESTS FOR APPROVAL

For all the foregoing reasons, PSE&G respectfully requests that the Board issue an Order approving this Petition no later than February 2019 and specifically finding that:

1. The Energy Strong II Program is in the public interest;

2. The Energy Strong II Program as described herein is reasonable and prudent;

3. PSE&G is authorized to implement and administer the Program under the terms set forth in this Petition and accompanying Attachments;

4. The cost recovery proposal and mechanism set forth in this Petition will provide for implementation of just and reasonable rates and is approved; and

5. PSE&G may recover all prudently-incurred Program costs, on a full and timely basis, under the cost recovery mechanism set forth herein.

Respectfully submitted,

PUBLIC SERVICE ELECTRIC
AND GAS COMPANY

By: Matthew M. Weissman, Esq.

DATED: June 8, 2018

STATE OF NEW JERSEY)
COUNTY OF ESSEX)

I, Michael P. McFadden, of full age, being duly sworn according to law, on his oath deposes and says:

1. I am Manager of Revenue Requirements of PSEG Services Corporation.

2. I have read the annexed Petition, and the matters contained therein are true to the best of my knowledge and belief.

____
Michael P. McFadden

Sworn to and Subscribed to
Before me this 8th day of
June, 2018

MICHELE D. FALCAO
Notary Public, State of New Jersey
My Commission Expires
November 14, 2021

PUBLIC SERVICE ELECTRIC AND GAS Minimum Filing Requirements – Energy Strong Program II	
Minimum Filing Requirement	**Location in Filing**
14:3-2A.2 Project eligibility	
a) Eligible projects within an Infrastructure Investment Program shall be: 1. Related to safety, reliability, and/or resiliency; 2. Non-revenue producing; 3. Specifically identified by the utility within its petition in support of an Infrastructure Investment Program; and 4. Approved by the Board for inclusion in an Infrastructure Investment Program, in response to the utility's petition.	See Attachment 1, Direct Testimony of Wade E. Miller; See Attachment 2, Direct Testimony of Edward F. Gray
b) Projects within an Infrastructure Investment Program may include: 5. The replacement of gas Utilization Pressure Cast Iron mains with elevated pressure mains and associated services; 6. The replacement of mains and services that are identified as high risk in a gas utility's Distribution Integrity Management Plan; 7. The installation of gas Excess Flow Valves where existing gas service line replacements require them, excluding Excess Flow Valves installed upon customer request pursuant to 49 CFR 192.383; 8. Electric distribution automation investments, including, but not limited to, Supervisory Control and Data Acquisition equipment, cybersecurity investments, relays, reclosers, Voltage and Reactive Power Control, communications networks, and Distribution Management System Integration; 9. The installation of break-predictive water sensors and wastewater sensors to curtail combined sewer overflows; and 10. Other projects deemed appropriate by the Board	See Attachment 1, Direct Testimony of Wade E. Miller; See Attachment 2, Direct Testimony of Edward F. Gray
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 ten (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.	See Attachment 1, Direct Testimony of Wade E. Miller, Schedule WEM-ESII-2B; See Attachment 2, Direct Testimony of Edward F. Gray, Schedule EFG-ESII-2B

14:3-2A.3 Annual baseline spending levels	
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.	See Attachment 1, Direct Testimony of Wade E. Miller, Schedule WEM-ESII-2B; See Attachment 2, Direct Testimony of Edward F. Gray, Schedule EFG-ESII-2B
b) In proposing annual baseline spending levels, the utility shall provide appropriate data to justify the proposed annual baseline spending levels, which may include historical capital expenditure budgets, projected capital expenditure budgets, depreciation expenses, and/or any other data relevant to the utility's proposed baseline spending level	See Attachment 1, Direct Testimony of Wade E. Miller; See Attachment 2, Direct Testimony of Edward F. Gray
14:3-2A.4 Infrastructure Investment Program length and limitations	
a) Allowance for Funds Used During Construction (AFUDC) shall be permitted under an Infrastructure Investment Program, but a utility shall not utilize AFUDC once Infrastructure Investment Program facilities are placed in service.	See Attachment 3, Direct Testimony of Stephen Swetz
14:3-2A.5 Infrastructure Investment Program minimum filing and reporting requirements	
1) Projected annual capital expenditure budgets for a five (5) year period, identified by major categories of expenditures	See Attachment 1, Schedule WEM-ESII-2B, of the Direct Testimony of Wade E. Miller; See Attachment 2, Schedule EFG-ESII-2B, of the Direct Testimony of Edward F. Gray
2) Actual annual capital expenditures for the previous five (5) years, identified by major categories of expenditures	See Attachment 1, Schedule WEM-ESII-2A, of the Direct Testimony of Wade E. Miller; See Attachment 2, Schedule EFG-ESII-2A, of the Direct Testimony of Edward F. Gray
3) An engineering evaluation and report identifying the specific projects to be included in the proposed Infrastructure Investment Program, with descriptions of project objectives, detailed cost estimates, in-service dates, and any applicable cost-benefit analysis for each project	See Attachment 1, Direct Testimony of Wade E. Miller; See Attachment 2, Direct Testimony of Edward F. Gray; See Attachment 4, Direct

	Testimony Of William D. Williams and PSE&G's Substation Asset Risk Model; See Attachment 5, Direct Testimony of the Cost-Benefit Analysis Panel, Energy Strong II Program – Electric and attached Energy Strong II Electric Cost-Benefit Analysis; See Attachment 6, Direct Testimony of the Cost-Benefit Analysis Panel, Energy Strong II Program – Gas and attached Energy Strong II Gas Program Cost-Benefit Analysis
4) An Infrastructure Investment Program budget setting forth annual budget expenditures	See Attachment 1, Schedule WEM-ESII-3, of the Direct Testimony of Wade E. Miller; See Attachment 2, Schedule EFG-ESII-3, of the Direct Testimony of Edward F. Gray
5) A proposal addressing when the utility intends to file its next base rate case, consistent with N.J.A.C. 14:3-2A.6(f)	See Attachment 3, Direct Testimony of Stephen Swetz
6) Proposed annual baseline spending levels, consistent with N.J.A.C. 14:3-2A.3(a) and (b)	See Attachment 1, Schedule WEM-ESII-2B, of the Direct Testimony of Wade E. Miller; See Attachment 2, Schedule EFG-ESII-2B, of the Direct Testimony of Edward F. Gray
7) The maximum dollar amount, in aggregate, the utility seeks to recover through the Infrastructure Investment Program; and	See Attachment 1, Schedule WEM-ESII-3, of the Direct Testimony of Wade E. Miller; See Attachment 2, Schedule EFG-ESII-3, of the Direct Testimony of Edward F. Gray
8) The estimated rate impact of the proposed Infrastructure	See Attachment 3,

	Investment Program on customers	Schedule SS-ESII-8, and Schedule SS-ESII-9 of the Direct testimony of Stephen Swetz
14:3-2A.6	**Infrastructure Investment Program Recovery**	
a)	Each filing made by a utility seeking accelerated recovery under an Infrastructure Investment Program shall seek recovery, at a minimum, of at least ten (10) percent of overall Infrastructure Investment Program expenditures.	See Attachment 3, the Direct testimony of Stephen Swetz
b)	A utility's expenditures made prior to the Board's approval of an Infrastructure Investment Program shall not be eligible for accelerated recovery.	N/A
c)	Rates approved by the Board for recovery of expenditures under an Infrastructure Investment Program shall be accelerated, and recovered through a separate clause of the utility's Board-approved tariff.	See Attachment 3, the Direct testimony of Stephen Swetz
d)	Rates approved by the Board for recovery of expenditures under an Infrastructure Investment Program shall be provisional, subject to refund and interest. Prudence of Infrastructure Investment Program expenditures shall be determined in the utility's next base rate case.	See Attachment 3, the Direct testimony of Stephen Swetz
e)	A utility shall file its next base rate case not later than five (5) years after the Board's approval of the Infrastructure Investment Program, although the Board, in its discretion, may require a utility to file its next base rate case within a shorter period	See Attachment 3, the Direct testimony of Stephen Swetz
f)	An earnings test shall be required, where Return on Equity (ROE) shall be determined based on the actual net income of the utility for the most recent twelve (12) month period divided by the average of the beginning and ending common equity balances for the corresponding period.	See Attachment 3, the Direct testimony of Stephen Swetz
g)	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 fifty (50) basis points or more, accelerated recovery shall not be allowed for the applicable filing period.	See Attachment 3, the Direct testimony of Stephen Swetz

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF THE SECOND ENERGY STRONG PROGRAM (ENERGY STRONG II)	**AGREEMENT OF NON-DISCLOSURE OF INFORMATION CLAIMED TO BE CONFIDENTIAL** **BPU DOCKET NOS. EO18______ GO18______**

It is hereby AGREED, as of the __ day of June 2018, by and among Public Service Electric and Gas Company ("**PETITIONER**")**,** the Staff of the New Jersey Board of Public Utilities ("Board Staff') and the New Jersey Division of the Rate Counsel ("Rate Counsel"), (collectively, the "Parties"), who have agreed to execute this Agreement of Non-Disclosure of Information Claimed to be Confidential ("Agreement"), and to be bound thereby that:

WHEREAS, in connection with the above-captioned proceeding before the Board of Public Utilities (the "Board"), **PETITIONER** and/or another party ("Producing Party") may be requested or required to provide petitions, prefiled testimony, other documents, analyses and/or other data or information regarding the subject matter of this proceeding that the Producing Party may claim constitutes or contains confidential, proprietary or trade secret information, or which otherwise may be claimed by the Producing Party to be of a market-sensitive, competitive, confidential or proprietary nature (hereinafter sometimes referred to as "Confidential Information" or "Information Claimed to be Confidential"); and

WHEREAS, the Parties wish to enter into this Agreement to facilitate the exchange of information while recognizing that under Board regulations at N.J.A.C. 14:1-12 et seq., a request for confidential treatment shall be submitted to the Custodian who is to rule on requests made pursuant to the Open Public Records Act ("OPRA"), N.J.S.A. 47:1A-l et seq., unless such information is to be kept confidential pursuant to court or administrative order (including, but not limited to, an Order by an Administrative Law Judge sealing the record or a portion thereof pursuant to N.J.A.C. 1:1-14.1, and the parties acknowledge that an Order by an Administrative Law Judge to seal the record is subject to modification by the Board), and also recognizing that a request may be made to designate any such purportedly confidential information as public through the course of this administrative proceeding; and

WHEREAS, the Parties acknowledge that unfiled discovery materials are not subject to public access under OPRA; and

WHEREAS, the Parties acknowledge that, despite each Party's best efforts to conduct a thorough pre-production review of all documents and electronically stored information ("ESI"), some work product material and/or privileged material ("protected material") may be inadvertently disclosed to another Party during the course of this proceeding; and

WHEREAS, the undersigned Parties desire to establish a mechanism to avoid waiver of privilege or any other applicable protective evidentiary doctrine as a result of the inadvertent disclosure of protected material;

NOW, THEREFORE, the Parties hereto, intending to be legally bound thereby, DO HEREBY AGREE as follows:

1. The inadvertent disclosure of any document or ESI which is subject to a legitimate claim that the document or ESI should have been withheld from disclosure as protected material shall not waive any privilege or other applicable protective doctrine for that

document or ESI or for the subject matter of the inadvertently disclosed document or ESI if the Producing Party, upon becoming aware of the disclosure, promptly requests its return and takes reasonable precautions to avoid such inadvertent disclosure.

2. Except in the event that the receiving party or parties disputes the claim, any documents or ESI which the Producing Party deems to contain inadvertently disclosed protected material shall be, upon written request, promptly returned to the Producing Party or destroyed at the Producing Party's option. This includes all copies, electronic or otherwise, of any such documents or ESI. In the event that the Producing Party requests destruction, the receiving party shall provide written confirmation of compliance within thirty (30) days of such written request. In the event that the receiving party disputes the Producing Party's claim as to the protected nature of the inadvertently disclosed material, a single set of copies may be sequestered and retained by and under the control of the receiving party until such time as the Producing Party has received final determination of the issue by the Board of Public Utilities or an Administrative Law Judge, provided that the Board has not modified or rejected an order by the Administrative Law Judge.

3. Any such protected material inadvertently disclosed by the Producing Party to the receiving party pursuant to this Agreement shall be and remain the property of the Producing Party.

4. Any Information Claimed to be Confidential that the Producing Party produces to any of the other Parties in connection with the above-captioned proceeding and pursuant to the terms of this Agreement shall be specifically identified and marked by the Producing Party as Confidential Information when provided hereunder. If only portions of a document are claimed

to be confidential, the producing party shall specifically identify which portions of that document are claimed to be confidential. Additionally, any such Information Claimed to be Confidential shall be provided in the form and manner prescribed by the Board's regulations at N.J.A.C. 14:1-12 et seq., unless such information is to be kept confidential pursuant to court or administrative order. However, nothing in this Agreement shall require the Producing Party to file a request with the Board's Custodian of Records for a confidentiality determination under N.J.A.C. 14:1-12 et seq. with respect to any Information Claimed to be Confidential that is provided in discovery and not filed with the Board.

5. With respect to documents identified and marked as Confidential Information, if the Producing Party's intention is that not all of the information contained therein should be given protected status, the Producing Party shall indicate which portions of such documents contain the Confidential Information in accordance with the Board's regulations at N.J.A.C. 14:1-12.2 and 12.3. Additionally, the Producing Party shall provide to all signatories of this Agreement full and complete copies of both the proposed public version and the proposed confidential version of any information for which confidential status is sought.

6. With respect to all Information Claimed to be Confidential, it is further agreed that:

(a) Access to the documents designated as Confidential Information, and to the information contained therein, shall be limited to the Party signatories to this Agreement and their identified attorneys, employees and consultants whose examination of the Information Claimed to be Confidential is required for the conduct of this particular proceeding.

(b) Recipients of Confidential Information shall not disclose the contents of the documents produced pursuant to this Agreement to any person(s) other than their identified employees and any identified experts and consultants whom they may retain in connection with this proceeding, irrespective of whether any such expert is retained specially and is not expected to testify, or is called to testify in this proceeding. All consultants or experts of any Party to this Agreement who are to receive copies of documents produced pursuant to this Agreement shall have previously executed a copy of the Acknowledgement of Agreement attached hereto as "Attachment I," which executed Acknowledgement of Agreement shall be forthwith provided to counsel for the Producing Party, with copies to counsel for Board Staff and Rate Counsel.

(c) No other disclosure of Information Claimed to be Confidential shall be made to any person or entity except with the express written consent of the Producing Party or their counsel, or upon further determination by the Custodian, or order of the Board, the Government Records Council or of any court of competent jurisdiction that may review this matter.

7. The undersigned Parties have executed this Agreement for the exchange of Information Claimed to be Confidential only to the extent that it does not contradict or in any way restrict any applicable Agency Custodian, the Government Records Council, an Administrative Law Judge of the State of New Jersey, the Board, or any court of competent jurisdiction from conducting appropriate analysis and making a determination as to the

confidential nature of said information, where a request is made pursuant to OPRA, N.J.S.A. 47:1A-l et seq. Absent a determination by any applicable Custodian, Government Records Council, an Administrative Law Judge, the Board, or any court of competent jurisdiction that a document is to be made public, the treatment of the documents exchanged during the course of this proceeding and any subsequent appeals is to be governed by the terms of this Agreement.

8. In the absence of a decision by the Custodian, Government Records Council, an Administrative Law Judge, or any court of competent jurisdiction, the acceptance by the undersigned Parties of information which the Producing Party has identified and marked as Confidential Information shall not serve to create a presumption that the material is in fact entitled to any special status in these or any other proceedings. Likewise, the affidavit submitted pursuant to N.J.A.C. 14:1-12.8 shall not alone be presumed to constitute adequate proof that the Producing Party is entitled to a protective order for any of the information provided hereunder.

9. In the event that any Party seeks to use the Information Claimed to be Confidential in the course of any hearings or as part of the record of this proceeding, the Parties shall seek a determination by the trier of fact as to whether the portion of the record containing the Information Claimed to be Confidential should be placed under seal. Furthermore, if any Party wishes to challenge the Producing Party's designation of the material as Confidential Information, such Party shall provide reasonable notice to all other Parties of such challenge and the Producing Party may make a motion seeking a protective order. In the event of such challenge to the designation of material as Confidential Information, the Producing Party, as the provider of the Information Claimed to be Confidential, shall have the burden of proving that the material is entitled to protected status. However, all Parties shall continue to treat the material as

Confidential Information in accordance with the terms of this Agreement, pending resolution of the dispute as to its status by the trier of fact.

10. Confidential Information that is placed on the record of this proceeding under seal pursuant to a protective order issued by the Board, an Administrative Law Judge, provided that the Board has not modified or rejected an order by the Administrative Law Judge, or any court of competent jurisdiction shall remain with the Board under seal after the conclusion of this proceeding. If such Confidential Information is provided to appellate courts for the purposes of an appeal from this proceeding, such information shall be provided, and shall continue to remain, under seal.

11. This Agreement shall not:

(a) Operate as an admission for any purpose that any document or information produced pursuant to this Agreement is admissible or inadmissible in any proceeding;

(b) Prejudice in any way the right of the Parties, at any time, on notice given in accordance with the rules of the Board, to seek appropriate relief in the exercise of discretion by the Board for violation of any provision of this Agreement.

12. Within forty five (45) days of the final Board Order resolving the above-referenced proceeding, all documents, materials and other information designated as "Confidential Information," regardless of format, shall be destroyed or returned to counsel for the Producing Party. In the event that such Board Order is appealed, the documents and materials designated as "Confidential Information" shall be returned to counsel for the Producing Party or

destroyed within forty-five (45) days of the conclusion of the appeal. Notwithstanding the above return requirement, Board Staff and Rate Counsel may maintain in their files copies of all pleadings, briefs, transcripts, discovery and other documents, materials and information designated as "Confidential Information," regardless of format, exchanged or otherwise produced during these proceedings, provided that all such information and/or materials that contain Information Claimed to be Confidential shall remain subject to the terms of this Agreement. The Producing Party may request consultants who received Confidential Information who have not returned such material to counsel for the Producing Party as required above to certify in writing to counsel for the Producing Party that the terms of this Agreement have been met upon resolution of the proceeding.

13. The execution of this Agreement shall not prejudice the rights of any Party to seek relief from discovery under any applicable law providing relief from discovery.

14. The Parties agree that one original of this Agreement shall be created for each of the signatory parties for the convenience of all. The signature pages of each original shall be executed by the recipient and transmitted to counsel of record for PETITIONER, who shall send a copy of the fully executed document to all counsel of record. The multiple signature pages shall be regarded as, and given the same effect as, a single page executed by all Parties.

IN WITNESS THEREOF, the undersigned Parties do HEREBY AGREE to the form and execution of this Agreement.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By:__________________________________
Matthew M. Weissman
General Regulatory Counsel - Rates

GURBIR S. GREWAL
ATTORNEY GENERAL OF THE STATE OF NEW JERSEY, ATTORNEY FOR THE STAFF OF THE BOARD OF PUBLIC UTILITIES

By:__________________________________
Patricia A. Krogman
Deputy Attorney General

STEFANIE A. BRAND
DIRECTOR, DIVISION OF RATE COUNSEL

By: ________________________________
Brian O. Lipman
Litigation Manager

DATED: June __ , 2018

ATTACHMENT I

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF THE SECOND ENERGY STRONG PROGRAM (ENERGY STRONG II))	PETITION BPU DOCKET NOS. EO17______ GO17______

ACKNOWLEDGEMENT OF AGREEMENT

The undersigned is an attorney, employee, consultant and/or expert witness for Division of the Rate Counsel, Board Staff, or an intervenor, who has received, or is expected to receive, Confidential Information provided by PSE&G or by another party (Producing Party) which has been identified and marked by the Producing Party as "Confidential Information." The undersigned acknowledges receipt of the Agreement of Non-Disclosure of Information Claimed to be Confidential and agrees to be bound by the terms of the Agreement.

Dated: __________________ By: ________________________________

(Name, Title and Affiliation)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
WADE E. MILLER
DIRECTOR – GAS TRANSMISSION AND DISTRIBUTION ENGINEERING
ENERGY STRONG II PROGRAM - GAS

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

A. My name is Wade E. Miller, and I am Director - Gas Transmission and Distribution (T&D) Engineering of Public Service Electric and Gas Company (PSE&G, or the Company), the Petitioner in this matter.

Q. Please describe your responsibilities as Director of Gas Transmission and Distribution Engineering.

A. As the Director of Gas T&D Engineering, I have the responsibility and accountability for three core functions of PSE&G's gas business. The first core function is delivering the natural gas. This includes gas control and system reliability for over 1.8 million customers. Delivering the gas also includes the operation and maintenance of 58 metering and regulating stations, one Liquefied Natural Gas (LNG) plant, three Liquid Propane Air (LPA) plants, and one Liquid Propane (LP) storage facility. The second core function is gas asset management. This includes the safe and efficient engineering and design of PSE&G's gas transmission and distribution assets, capacity planning, corrosion control, replacement facility identification and prioritization, transmission pipeline maintenance, and the management of the Transmission and Distribution Integrity Management Programs. The third core function is business support and technical services. This includes the development of operating standards and procedures, material evaluation and specification, operator qualification and other programs.

Q. Please describe your educational and professional background and qualifications.

A. That information is provided in Schedule WEM-ESII-1, which is attached hereto.

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

A. My testimony supports the gas portion of PSE&G's proposed Energy Strong II Program (the Program or ES II Program) as it relates to the natural gas delivery system. The gas portion of the ES II Program includes two subprograms. The first subprogram, the Curtailment Resiliency Subprogram, consists of six discrete projects that will improve the resiliency of PSE&G's gas distribution system to potential interstate gas pipeline supply curtailments. The second subprogram, the Metering and Regulating (M&R) Upgrade Subprogram, involves rebuilding seven gas M&R stations for needed modernization. In the case of two of the stations that are in recognized flood zones, there will also be storm hardening.

Q. Are there other witnesses supporting these proposed ES II Gas Subprograms?

A. The benefits associated with the Curtailment Resiliency Subprogram and the M&R Upgrade Subprogram are addressed in a cost benefit analysis being submitted on behalf of PSE&G by a group from Black & Veatch.

Q. Please provide an overview of PSE&G gas operations.

A. PSE&G provides gas distribution service and Basic Gas Supply Service (BGSS), and provides these services under regulation by the New Jersey Board of Public Utilities (Board or BPU). PSE&G serves approximately 1.8 million gas customers in an area that extends from the Hudson River opposite New York City, southwest to the Delaware River at Trenton and south to Camden, New Jersey.

Q. Please provide an overview of the proposed investments.

A. In the Curtailment Resiliency Subprogram, the Company has identified projects that can be constructed as an integral part of PSE&G's gas distribution system and that can help mitigate the impact of potential interstate gas pipeline curtailments. Five proposed distribution facility projects would provide increased resiliency by moving gas supplies across the PSE&G service territory between areas served by the different pipeline systems. An additional LNG facility would inject additional gas into the system in a time of curtailment. These six projects are designed to continue gas service to the extent possible for those areas of the service territory that could be most affected by curtailment.

In the M&R Upgrade Subprogram PSE&G seeks to modernize certain of its M&R stations by phasing out outdated designs and replacing aging facilities as well as hardening facilities located in flood zones against severe flooding events. Two of the seven stations in the subprogram are in recognized flood zones.

Both of the proposed gas Energy Strong II subprograms are consistent with the BPU's IIP rules.

Q. Why is PSE&G recommending the proposed investments now?

A. Recent events have heightened awareness of the risks of interstate gas pipeline curtailments. For example, PSE&G experienced an interstate gas pipeline curtailment due to a rupture of a Texas Eastern gas transmission pipeline in the vicinity of Delmont, Pennsylvania on April 29, 2016. As a result, four parallel gas transmission pipelines in the vicinity were shut down within one hour. Texas Eastern declared a "Force Majeure" related to the unplanned outage. Due to this incident, Texas Eastern reduced system operating pressures on all pipelines from the Armagh, Pennsylvania compressor station downstream of the rupture, east to Lambertville, New Jersey. The initial supply reduction was estimated to be approximately 78% for a period of eleven days, at which time the curtailment was reduced to approximately 39% for a period of 5-1/2 months as Texas Eastern replaced the damaged segment, verified the integrity of the pipelines and made other required repairs. All work was completed on the Texas Eastern system by October 30, 2016 and all lines were returned to full capacity on November 6, 2016. Overall, there was some level of curtailment on the Texas Eastern system for more than 6 months.

PSE&G was able to operate its gas system for the duration of this interstate pipeline curtailment without an impact to its firm customers due to the relatively low gas demand during the time of year (April through October) that the curtailment occurred. However, if the curtailment had occurred in mid-winter, PSE&G may have initially interrupted service to more than 250,000 firm customers (on a 5° F average temperature day) and potentially more than 400,000 firm customers as the initial curtailment continued and locally-held peak shaving supplies were depleted.

With regard to the M&R Upgrade Subprogram, the life cycle upgrades are being proposed to modernize the operation of M&R stations placed in service decades ago. These proposed M&R projects will maintain service reliability, harden stations against flooding where applicable, and reduce the potential for a large volume release of methane, a potent greenhouse gas. The asset lifecycle approach to upgrading facilities, and the severe weather events in recent years that supported the original Energy Strong program, all support proceeding with the M&R Upgrade Subprogram at this time.

With regard to both subprograms, the current relatively low gas commodity costs also support proceeding with the Energy Strong II program at this time. Current bills for a typical gas residential customer are approximately half of what they were in 2009.

Q. In addition to the curtailment described above, what has been the national experience on interstate gas pipeline curtailments and related issues?

A. There have been curtailments around the country for a variety of reasons. In December 2016 and again in January 2017, Southern California Gas Company (SoCalGas), faced with diminished gas storage options, called for its customers to "immediately" reduce their gas use to help "lower the risk of possible gas and electricity shortages." SoCalGas urged customers to lower thermostats, delay using gas appliances, and wash clothes in cold water. SoCalGas also issued a system-wide “curtailment watch” for noncore customers (large commercial and industrial customers, including electric generation plants), due to forecasted cold weather conditions throughout the SoCalGas service territory, and a potential for supply shortfall. Customers were advised that they may be receiving a notice to curtail service.

SoCalGas is currently dealing with a reduction of gas supply due to a recent pipeline explosion. On October 1, 2017, a 30-inch natural gas pipeline exploded in Newberry Springs, California. This pipeline rupture also damaged an adjacent gas pipeline. Together these two pipelines typically account for about one-fifth or approximately 800 million cubic feet per day of the natural gas flowing into the region. The adjacent pipeline was returned to service by the end of December, 2017, but was again removed from service on January 17, 2018, due to a new unplanned remediation event and returned to service on January 29, 2018.

After the October incident, the CPUC described the reduction in gas supplies as "unprecedented". In response, the CPUC urged people to conserve gas and electricity this past winter. They asked customers to opt into "demand response" programs that can lower wi-fi connected thermostats when there is a potential shortage. The Chairman of the CPUC also proposed that power utilities that burn gas from SoCalGas shift their power generation outside the region or use other fuel sources. The Chairman also called on Los Angeles County to issue an emergency halt to all permitting for new customer gas connections for business, industry and residential development over the 2017-18 winter.

The SoCalGas system continues to operate at less than full capacity due to a significant number of pipeline outages and continuing restrictions on use of the Aliso Canyon natural gas storage facility. According to a report by the California Public Utilities Commission and other agencies, this reduction in capacity creates a moderate threat to electric reliability this summer. The concerns stem primarily from continuing outages on four key natural gas pipelines as well as other pipelines operating at reduced pressure.

Another gas curtailment example occurred when an arctic cold front impacted the Southwest portion of the United States during the first week of February 2011. The weather was unusually severe in terms of temperature, wind, and overall duration, but was not without precedent. This extreme weather caused complications in obtaining power and natural gas for the region. The Electric Reliability Council of Texas (ERCOT) had a cumulative loss of 29,729 MW of generating capacity during the event. Twelve (12) percent of this loss was due to natural gas curtailments to gas-fired generators and difficulties in fuel switching. Natural gas problems largely resulted from production declines in the region. For the period of February 1st – February 5th, an estimated 13.8 billion cubic feet of production was lost. These declines propagated downstream through the rest of the gas delivery chain, ultimately resulting in natural gas curtailments to over 50,000 gas utility customers in New Mexico, Arizona, and Texas.

Q. What steps has PSE&G taken to improve preparedness and response following the 2016 Texas Eastern curtailment?

A. In addition to preparing this filing, including the analysis of various curtailment events, PSE&G performed a complete reevaluation of its Gas Curtailment Plan. This is a comprehensive plan to be implemented whenever it is necessary to reduce gas consumption due to supply difficulties, and is required by Chapter 29 of Title 14 of the New Jersey Administrative Code (N.J.A.C.). In addition, PSE&G revised its procedures for restoration following curtailment of retail service.

Q. Is the BPU concerned with the resiliency of the natural gas system in New Jersey to gas supply shortages or outages?

A. It appears that the BPU is concerned. The BPU Division of Reliability and Security sponsored an exercise named NJ Pilot Light in June 2017, in which representatives of PSE&G participated as well as representatives from the New Jersey Office of Homeland Security and Preparedness, New Jersey Natural Gas Company, Elizabethtown Gas Company, South Jersey Gas Company, and Texas Eastern Gas Transmission Company. The exercise simulated a major interstate pipeline rupture within New Jersey and the consequent loss of gas supplies in mid-winter in an effort to evaluate gas system resiliency, company preparedness, and emergency response. While the exercise focused on response to an immediate incident, it showed that a major interstate pipeline curtailment during cold winter weather could have widespread and prolonged consequences and cause significant harm to customers and the New Jersey economy. Overall, the exercise highlighted the importance of improving gas system resilience to mitigate the impact of such an interstate pipeline curtailment event.

Q. Please summarize your conclusions and recommendations.

A. PSE&G's natural gas delivery system operates twenty-four hours per day, seven days a week. It delivers, on average, 400 billion cubic feet of natural gas to customers each year. It is a highly elastic system, with the proven capability to deliver up to 3.0 billion cubic feet in a single day.

The redundancy and interconnectedness currently present in PSE&G's natural gas system provides some consumers with alternate sources and routes for natural gas supply. However, PSE&G's natural gas network is still vulnerable to significant supplier curtailment during periods of high gas demand.

The rules in Chapter 29 of Title 14 of the N.J.A.C. contain specific requirements for retail gas load curtailment during an energy emergency. The actions provided for in these rules range from least intrusive to more severe, ranging from a public appeal to conserve, to required reductions in usage, to actual curtailment of retail service in a specified priority. PSE&G's pipeline supply resiliency projects proposed in this ES II filing directly address the need to further strengthen the resiliency of its gas system to mitigate the expected impact of these severe consequences and the need to implement the procedures required by the rules.

Any substantial prolonged curtailment would have severe economic impact to the New Jersey economy since interruptible, large industrial and commercial loads would be curtailed first, effectively shutting down many of these businesses.

Any curtailment of interstate pipeline supply that results in loss of gas service to

PSE&G's firm retail customers (i.e., residential customers), even of limited duration (i.e., several hours) could involve additional days without gas service after the interstate curtailment is addressed. In order to safely re-establish gas service to a customer, the system must first be secured by isolating the main and service lines from the parts of the system still in operation. This is typically done using main and service valves but in cases where building access is not available and no outside service valve exists, the service must be excavated and physically separated. Excavations and pipe separations are also required for isolation of mains in legacy low pressure systems where valves do not exist.

As sections of the curtailed area are re-pressurized, PSE&G personnel would survey the areas and assist customers with turning appliances back on to ensure gas appliances are returned to safe operation. This process would continue until all customers have been restored. This is a time consuming process that can take days or weeks depending on the number of customers affected. PSE&G experienced these time-consuming restoration processes during the recovery from Superstorm Sandy and other flood events. Following Hurricane Irene in 2011, the Company required 10 days to restore gas service to over 10,180 customers. In the aftermath of Superstorm Sandy in 2012, the Company required 12 days to restore gas service to over 6,250 customers. In both cases many more customers remained shut off due to significant foundation damage, premise review by local building inspectors, or replacement of customer equipment.

To address these issues, PSE&G is requesting the Board approve the proposed Curtailment Resiliency Subprogram, which involves an investment of approximately $863 million in gas distribution assets, including a Liquefied Natural Gas (LNG) plant. Construction of these ES II Curtailment Resiliency projects will enable PSE&G to move large volumes of gas across areas of its service territory to ensure the continuation of firm gas service to areas currently served solely by one interstate pipeline. Maintaining a supplemental supply of LNG on PSE&G's system provides additional support when no more supply can be obtained on the interstate systems. These projects will provide supply resiliency to PSE&G's gas distribution system at times of high customer demand.

For reasons noted above, PSE&G is also requesting that the Board approve the M&R Upgrade Subprogram. This subprogram involves an investment of approximately $136 million. The M&R components of PSE&G's initial Energy Strong filing were important investments to harden its M&R stations against storm surge and severe flooding, and there is hardening associated with two of the ES II M&R stations that are in recognized flood zones. Beyond that, analogous to the PSE&G Gas System Modernization program for our infrastructure of main and services, it is important to modernize the designs of M&R stations, which are the critical sources of gas supply into PSE&G's distribution system. The modernization enhances the safety, reliability and resiliency of the system and delivers many specific benefits, including the replacement of aging equipment, reducing the likelihood and consequence of equipment failure, implementing modern design practices to reduce the potential for methane emissions, and noise abatement.

Lastly, as each project is completed there are benefits. Thus, customers do not need to wait for the conclusion of the subprogram to receive benefits of the subprogram.

Q. How is the remainder of your testimony organized?

A. My testimony is organized into six sections: (1) the alignment of ES II with the Board's IIP rules; (2) a more detailed explanation of the Curtailment Resiliency Subprogram projects; (3) a more detailed explanation of the M&R Upgrade Subprogram projects; (4) identification of the cost-benefit analysis submitted with this filing; (5) the significant benefits to New Jersey created by PSE&G's gas distribution system ES II Program; and (6) reporting requirements.

I. INFRASTRUCTURE INVESTMENT PROGRAM

Q. Please describe the BPU's IIP rules.

A. The IIP rules were recently adopted by the BPU "to provide a rate recovery mechanism that encourages and supports necessary accelerated construction, installation, and rehabilitation of certain utility plants and equipment."

Q. Are the projects in the Gas ES II Program eligible under the IIP rules?

A. Yes. The IIP rules include projects that are related to safety, reliability, and/or resiliency, and that are non-revenue producing. The ES II gas projects that my testimony addresses all satisfy this requirement.

Q. Are there filing requirements associated with seeking accelerated rate recovery of infrastructure investments under the IIP rules?

A. Yes. The location of all requirements under the IIP rules in the ES II filing is provided in Appendix 1 to the Petition. I will address the requirements related to program eligibility, capital expenditures, selection criteria, and reporting. Mr. Swetz will address requirements associated with cost recovery. A panel of witnesses from Black & Veatch will address the benefits of the Program.

Q. Is the Company proposing base capital expenditures on similar gas distribution projects as proposed for the ES II Program?

A. Yes. Consistent with the IIP rules, the Company commits to base rate treatment of investments in an amount at least 10 percent of the capital expenditures recovered through the recovery mechanism proposed for the gas ES II Program. These capital expenditures will be for work similar to that proposed to be recovered under the ES II recovery mechanism. This is shown on Schedule WEM-ESII-2B.

Q. Is the Company proposing annual baseline spending levels over the life of the Program?

A. Yes. Please see Schedule WEM-ESII-2B for the annual baseline spending levels for gas delivery projects over the ES II period.

Q. What is the justification for the annual baseline budget spending levels?

A. The annual baseline spending levels proposed in Schedule WEM-ESII-2B are the Company's projected capital budget as recently approved in the Company's Gas System Modernization Program Extension (GSMP II).

Q. Is the Company proposing any limit to variations in annual spending?

A. Yes. Consistent with the IIP regulations, the Company proposes that it be allowed annual variations in its capital expenditures up to 10 percent so long as the expenditures do not exceed the overall approved budget for the Program. The Company will seek Board approval for any year-to-year variances from the BPU approved annual expenditure level that are expected to be greater than 10 percent.

Q. Have you included the Company's actual gas delivery capital expenditures over the past five years and projected capital expenditures over the next five years by major category?

A. Yes. Please see Schedule WEM-ESII-2A for the actual capital expenditures by major category from 2012-2017, and Schedule WEM-ESII-2B for the projected gas delivery capital expenditures by major category from 2019 through 2023.

Q. Has an engineering evaluation been done to determine the projects, in-service dates, costs and benefits of the proposed ES II Program?

A. Yes. PSE&G has conducted engineering evaluations of the various projects that comprise the M&R Upgrade and Curtailment Resiliency Subprograms. These analyses have helped determine specific projects, in service dates, and costs. Furthermore, Black & Veatch has prepared a cost–benefit analysis for these subprograms.

Q. Have you developed an annual budget for the gas portion of the ES II Program?

A. Yes. Please see Schedule WEM-ESII-3 for the monthly and annual capital expenditures for the Program. As shown in Schedule WEM-ESII-3, the estimated capital expenditure dollar amount is approximately $1.0 billion.

Q. Is the Company proposing any reporting requirements associated with its ES II Program?

A. Yes. Consistent with the IIP rules, the Company is proposing semi-annual status reports on the ES II Program. The reporting requirements are detailed later in my testimony.

II. CURTAILMENT RESILIENCY SUBPROGRAM PROJECTS

Q. Please provide an overview of PSE&G's gas supply acquired from interstate gas pipelines and other sources and describe how it relates to the proposed ES II projects.

A. PSE&G's system is supplied by five interstate pipeline systems, one LNG peak shaving plant owned and operated by an interstate pipeline, three LPA peak shaving plants, and one LNG peak shaving plant owned and operated by PSE&G, through fifty-eight (58) M&R stations. PSE&G has the advantage of being connected to multiple gas pipelines and to gas storage facilities to provide some supply flexibility and supply redundancy when curtailed by one pipeline.

The attached confidential map (see Schedule WEM-ESII-4) shows the interstate pipelines that supply the PSE&G system. Table 1 below shows the PSE&G gas supply by pipeline for analysis of their potential curtailment impact on PSE&G and its customers.

Table 1: Interstate Pipeline Systems Supplying PSE&G

PIPELINE	% OF GAS SUPPLY*
Enbridge (Texas Eastern & Algonquin gas transmission systems)	32%
Transcontinental (Transco) Gulf	17%
Transco Leidy	28%
Tennessee	5%
Columbia	1%
TOTAL	83%**

* Note: Percentages listed include Third Party Supplier (TPS) deliveries.
** Note: The remainder of the PSE&G distribution system supply (17%) is provided by peak shaving facilities of Transco (LNG) and PSE&G (LNG and LPA), all of which are located within PSE&G's service territory.

In Table 1 and the analysis that follows, the Transco system was treated as two separate delivery systems due to the separate geography of the Leidy and Gulf systems from the gas producing areas into the New Jersey market. The Transco Leidy system is sourced from the Pennsylvania area and the Transco Gulf system is sourced from the Gulf of Mexico area, coming into the PSE&G system at different locations.

In general, each of the five proposed distribution projects in the Curtailment Resiliency Subprogram are designed to address an area served primarily by one pipeline by enabling the transportation of gas from another pipeline to that area. PSE&G currently has limited capability to accomplish this.

Q. Have you conducted an analysis of the impact of potential gas pipeline curtailments on PSE&G's system?

A. Yes. PSE&G conducted a vulnerability analysis to understand, in an order of magnitude way, the number of firm customers that would lose gas service if there were a gas supply curtailment. We evaluated the impact if the pipeline systems supplying PSE&G each individually experienced a 100% curtailment during the winter months. In Table 2, the customer outage estimates are based on a single day gas outage event and are rounded to reflect an average therm/day usage for all classes of Firm customers. In this vulnerability analysis, all interruptible customers are 100% curtailed during the gas outage event. No additional steps or actions such as those addressed in PSE&G's Gas Emergency Procedures and NJAC Title 14, Chapter 29, were considered for this assessment. The results of this analysis are summarized in Table 2.

Table 2: Gas Supply Curtailment Vulnerability

POTENTIAL # of FIRM CUSTOMERS WITHOUT GAS SERVICE

	Daily Average Temperature			
Interstate System Curtailed	5° F	10° F	20° F	30° F
Enbridge (Texas Eastern & Algonquin Pipelines)	407,000	292,000	197,000	140,000
Transco Gulf Pipelines	94,000	0	0	0
Transco Leidy Pipelines	332,000	215,000	0	0
Tennessee Pipeline	50,000	49,000	43,000	37,000

Based on these outcomes and additional analysis PSE&G has developed the resiliency solutions proposed under ES II to maximize the number of firm customer outages that could be avoided.

Q. What objectives did PSE&G seek to achieve with the Curtailment Resiliency Subprogram?

A. Recognizing the inherent resiliency in the current distribution system, there were certain objectives that were considered when evaluating options. These objectives include:

- Achieving quantifiable reductions in the potential number of retail customer curtailments;
- Leveraging existing supply contracts, or providing alternative supply to the existing portfolio;
- Developing projects with a high degree of constructability (sub transmission assets);
- Developing projects that are consistent with PSE&G's existing distribution system, such as consistent type of materials and design pressures;

- Enhancing the resiliency, reliability and safety of PSE&G's gas distribution system.

Q. Please provide an overview of PSE&G's proposed Curtailment Resiliency Subprogram.

A. The Company has identified five supply resiliency projects and one supplemental LNG Plant that will improve the resiliency of PSE&G's gas distribution system to mitigate the impact of potential interstate pipeline supply curtailments. PSE&G evaluated these projects based on the total project resiliency potential over multiple gas outage scenarios. All of these projects provide measurably improved gas system resiliency during a single day outage event occurring at temperatures down to 20° F, and one of the projects provides these benefits for 50,000 customers at temperatures down to 5° F. The impact of the resiliency projects is summarized in Table 3.

Table 3: Enhanced System Resiliency

Estimated Number of Gas Outages Avoided by Firm Customers

			Daily Average Temperature			
Project	Name	Curtailed Pipeline System	5° F	10° F	20° F	30° F
1	Central - South Plainfield	Enbridge	0	0	54,000	40,000
2	Hamilton - West Windsor	Enbridge	0	0	35,000	38,000
3	Mahwah-Paramus-Wanaque	Enbridge	0	0	49,000	55,000
		Tennessee	50,000	49,000	43,000	37,000
4	Sayreville - Jamesburg	Enbridge	0	0	32,000	0
5	Bernards-Gillette-Parsippany-Chatham-Bridgewater	Enbridge	0	0	24,000	18,000

In order to prioritize projects, PSE&G used the estimated number of firm customer outages avoided from Table 3, multiplied by the average number of days where temperatures are at the levels shown (30 degrees Fahrenheit, 20 degrees Fahrenheit, and below) under a

November 15 to March 31 curtailment, to derive a measure of total customer outage days avoided by a project for an average winter period. If a project supported curtailment resiliency on two pipeline systems, the results were additive for purposes of prioritization. The total estimated project cost was then divided by the total cumulative customer outage days avoided to estimate the cost per customer outage day avoided. Table 4 below summarizes the proposed projects, their estimated costs and projected impacts. The projects are listed in priority order based on the lowest cost per customer outage day avoided for an average winter.

Table 4: Curtailment Resiliency Distribution Projects

Project	Name	Estimated Cost $M	Cumulative Winter Customer Outage Days Avoided	$/Customer Outage Day Avoided
1	Central - South Plainfield	$61.7	2,002,000	$30.80
2	Hamilton - West Windsor	$81.9	1,690,000	$48.50
3	Mahwah-Paramus-Wanaque	$271.0	4,383,000	$61.80
4	Sayreville - Jamesburg	$59.7	416,000	$143.50
5	Bernards-Gillette-Parsippany-Chatham-Bridgewater	$230.0	897,000	$256.40

Q. Why were the proposed ES II projects chosen over other potential projects?

A. One goal was to maximize the use of PSE&G's available firm supplies under its existing pipeline contracts and its existing peaking facilities. This is particularly important because at winter temperatures between 20° F and 30° F there is available contracted supply that could be used to address a pipeline system curtailment, but PSE&G is unable to move this gas within the service territory. For this reason PSE&G chose these five distribution projects, which would extend our high pressure distribution systems to achieve the goal of moving large volumes of gas across the service territory from areas with adequate supply to areas served by the curtailed pipeline.

At temperatures below 20° F, this contracted supply is needed to serve firm customers and is no longer available. In order to provide resiliency at these colder temperatures, additional supply is necessary. We recognize the importance of increasing the diversity of supplies in order to provide a level of independence from any one supplier. For this reason, we chose to support these projects with a supplemental supply of LNG that would be located in our service territory and be available to extend the ability of the distribution system to avoid firm customer outages. The LNG solutions were evaluated at eight (8) potential locations and we are proposing to pursue an LNG project in the Linden or Edison, New Jersey areas, which are critical locations to achieving the resiliency objectives of ES II. Collectively, with the five distribution projects and the LNG facility, we will have enhanced our ability to serve customers at temperatures below 20° F.

Additionally, PSE&G is aware of costs of recent firm supply acquisitions and offers made by pipeline suppliers. When using this data and comparing to the proposed LNG plant, the plant represents a lower total cost over the life of the facility. Furthermore, there are many unknowns related to the actual cost, timeframe, and likelihood of completing gas transmission projects. Additional firm pipeline supply has the advantage of being available year round, but requires supply to be added on more than one pipeline system to achieve resiliency against significant outage events.

Q. What is the advantage of including an LNG project in PSE&G's proposed Curtailment Resiliency Subprogram?

A. LNG is a gas supply on hand that can be utilized to address curtailments that may occur on one or more of the pipeline systems serving PSE&G. The LNG plant provides supplemental supply as a specific solution to a variety of potential gas pipeline curtailments.

Q. When would this additional amount of LNG be utilized by PSE&G?

A. The additional LNG supplies proposed under ES II would be utilized if a pipeline curtailment occurs at a time when PSE&G's firm pipeline supplies and peak shaving supplies are inadequate to offset the curtailment. Another example would be a colder than design day when demand exceeds all planned and available gas supplies.

Q. Please describe in detail each of PSE&G's proposed distribution projects under its Curtailment Resiliency Subprogram

A. **Project 1: Central - South Plainfield:** See confidential Schedule WEM-ESII-5, page 1, for a map of the proposed project. PSE&G proposes to modify the Central (Edison) M&R station to add a 600 psi alternate supply line to PSE&G's Woodbridge-Central transmission system and a new 120 psi distribution system. Under this proposal, this new 24" 120 psi system would extend 5.4 miles from Central M&R station towards the South Plainfield M&R station. A new 120psi/60psi regulator station would be installed in the vicinity of Stelton Road and New Brunswick Avenue in South Plainfield.

This project would provide the ability to move Transco gas from the Central M&R station (Location A on Schedule WEM-ESII-5, page 1) into an area supplied by Texas Eastern from the South Plainfield M&R station (Location 1 on Schedule WEM-ESII-5, page 1). Additionally, through the connection to PSE&G's Woodbridge-Central transmission system, the project enables the movement of Transco gas into another area supplied by Texas Eastern at PSE&G's Sayreville regulating station (Location 2 on Schedule WEM-ESII-5, page 1).

This project uses available pipeline capacity and existing peak shaving gas to offset a supply curtailment on the Enbridge system. The project provides the ability to retain up to approximately 40,000 customers during a 30° F curtailment event, and to retain approximately 54,000 customers during a 20° F curtailment event. The number of avoided customer outages increases as temperatures get colder as the increased demand for Transco gas in other parts of the system creates an increased demand for flow of gas into the system through this project. The estimated cost of this project is $61.7 million, and a $/Customer Outage Day Avoided of $30.80.

Project 2: Hamilton - West Windsor: See confidential Schedule WEM-ESII-5, page 2, for a map of the proposed project. PSE&G proposes to extend its existing 150 psi distribution line 11.5 miles from Hamilton Township to West Windsor Township. The project would consist of 1.5 miles of 24" diameter pipe and 10 miles of 20" diameter pipe. Two new 150psi/60psi regulator stations would be installed off this new 150 psi system in the vicinity of White Horse Avenue & Kuser Road, Hamilton Township, and US Route 1 & Alexander Road, West Windsor Township.

This project would provide the ability to move Transco gas from the Hamilton M&R station (Location A on Schedule WEM-ESII-5, page 2) into an area supplied by Texas Eastern from the Hillsborough M&R station (Location 1 on Schedule WEM-ESII-5, page 2) and from the Jamesburg M&R station (Location 2 on Schedule WEM-ESII-5, page 2).

This project uses available pipeline capacity and existing peak shaving gas to offset a supply curtailment on the Enbridge system. The project provides the ability to retain up to approximately 38,000 customers on a 30° F curtailment and 35,000 on a 20° F curtailment. The number of avoided customer outages declines slightly as temperatures get colder as the influence of Project 4 (discussed below) is seen in the area served by the Jamesburg M&R station. The estimated cost of this project is $81.9 million, with a $/Customer Outage Day Avoided of $48.50.

Project 3: Mahwah-Paramus-Wanaque: See confidential Schedule WEM-ESII-5, page 3, for a map of the proposed project. PSE&G proposes to modify the Mahwah M&R station and Wanaque M&R station. PSE&G also proposes to add a new joint 120 psi system that will tie-in to the existing 120 psi system out of the Paramus M&R station to create one interconnected 120 psi system between the Mahwah, Paramus, and Wanaque M&R stations. In order to accomplish this, PSE&G would need to construct large diameter 120 psi distribution main across its northern territory to connect the stations. In addition, PSE&G proposes extending the existing Hanover Roseland 120 psi system. The following would be included under this project:

- 11.1 miles of 24" main would be installed from Mahwah M&R station to PSE&G's existing Glen Rock 120psi/15psi regulator stations off the existing Paramus 120 psi line. Three new regulator stations would also be installed off this new 120 psi line. Two would feed into PSE&G's Northern 60 psi system in the vicinity of Hillside Avenue and Forest Road in Allendale, and North Central Avenue and Swan Street in Ramsey. The third new regulator station would feed into PSE&G's Northern 15 psi system in the vicinity of Goffle Road and Goffle Hill Road in Hawthorne.

- 10.2 miles of 24" main would be installed from Wanaque M&R station to the Glen Rock psi/psi regulator stations off the existing Paramus 120 psi line. One new 120 psi/60 psi regulator station would be installed in the vicinity of Willard Street and Ringwood Avenue in Pompton Lakes.
- 4.1 miles of 24" main would be installed from Wanaque M&R station going west towards Kinnelon. A new 120psi/60psi regulator station would be installed in the vicinity of Keil Ave & Route 23, Kinnelon. The main would then be reduced in size to 12" steel and continue 7.2 miles towards PSE&G's West Milford system. A new 120psi/60psi regulator station will be installed in the vicinity of La Rue Road & Union Valley Road, West Milford.
- 4.5 miles of 12" main would be installed from Wanaque M&R station towards Ringwood M&R. A new 120psi/60psi regulator station would be installed in the vicinity of Greenwood Lake Turnpike & Skyline Lake Drive, Ringwood.
- 0.7 Miles of 24" main would be installed from Paramus M&R station going north from the station. A new 120psi/15psi regulator station would be installed in the vicinity of Spring Valley Road & Forest Avenue, Paramus.
- In addition, PSE&G would extend its existing Hanover-Roseland 120psi system by installing 5.1 miles of 20" main north towards Little Falls. A new 120psi/15psi regulator station would be installed in the vicinity of Furler Street & Union Boulevard, Totowa.

This project would provide the ability to move Transco gas from the Paramus M&R station (Location A on Schedule WEM-ESII-5, page 3) and/or Texas Eastern gas from the Wanaque M&R station (Location 4 on Schedule WEM-ESII-5, page 3) into an area supplied by Tennessee from the West Milford M&R station (Location 1 on Schedule WEM-ESII-5, page 3), Ringwood M&R station (Location 2 on Schedule WEM-ESII-5, page 3) and the Mahwah M&R station (Location 3 on Schedule WEM-ESII-5, page 3). This project would also provide the ability to move Transco gas from the Paramus M&R station (Location A on Schedule WEM-ESII-5, page 3) and the Roseland M&R station (Location B on Schedule WEM-ESII-5, page 3) and/or Tennessee gas from the Mahwah M&R station (Location 3 on Schedule WEM-ESII-5, page 3) into an area supplied by Texas Eastern from the Wanaque M&R station (Location 4 on Schedule WEM-ESII-5, page 3). Finally, this project would provide the ability to move Texas Eastern gas from the Wanaque M&R station (Location 4 on Schedule WEM-ESII-5, page 3) and/or Tennessee gas from the Mahwah M&R station (Location 3 on Schedule WEM-ESII-5, page 3) into an area supplied by Transco from the Paramus M&R station (Location A on Schedule WEM-ESII-5, page 3) and will mitigate a supply curtailment on any of these pipeline systems.

The project provides the ability to retain up to approximately 55,000 customers on a 30°F curtailment and 49,000 customers on a 20° F curtailment on the Enbridge system. If the curtailment was on the Tennessee system the project provides the ability to retain up to approximately 37,000 customers on a 30° F curtailment, 43,000 on a 20° F curtailment, 49,000 on a 10° F curtailment, and 50,000 customers on a 5° F curtailment. The estimated number of avoided customer outages varies as temperatures get colder due to the influence of adjacent

M&R stations in the system as attempts are made to maximize available supplies across the system. The estimated cost of this project is $271.0 million, with a $/Customer Outage Day Avoided of $61.80.

Project 4: Sayreville - Jamesburg: See confidential Schedule WEM-ESII-5, page 4, for a map of the proposed project. PSE&G would modify the Sayreville M&R station and add a new 20" 120 psi system that would extend 10.3 miles between the Sayreville M&R station and the Jamesburg M&R station. In addition, a new 120psi/60psi regulator station would be installed in the vicinity of Ridge Road and Cranbury South River Road in South Brunswick Township.

This project would provide the ability to move Transco gas from the Sayreville M&R station (Location A on Schedule WEM-ESII-5, page 4) into an area normally supplied by Texas Eastern from the Jamesburg M&R station (Location 1 on Schedule WEM-ESII-5, page 4).

This project uses available pipeline capacity and existing peak shaving gas including supplemental LNG to offset a supply curtailment on the Enbridge system. This project provides the ability to retain up to approximately 32,000 customers on a 20° F curtailment. The estimated cost of this project is $59.7 million, with a $/Customer Outage Day Avoided of $143.50.

Project 5: Bernards-Gillette-Parsippany-Chatham-Bridgewater: See confidential Schedule WEM-ESII-5, page 5, for a map of the proposed project. The Bernards, Gillette, Parsippany, Chatham and Bridgewater M&R stations would be modified and new 120 psi distribution systems would be added. PSE&G would need to construct large diameter 120 psi distribution mains across its northern territory from these stations. The following would be included:

- 7.3 miles of 12" main would be installed from Parsippany M&R station going southwest towards the Bernards/Gillette 60 psi system. One new 120psi/60psi regulator would also be installed off this new 120 psi line. It would feed into PSE&G's Bernards/Gillette 60 psi system in the vicinity of US-24 & Glen Gary Drive in Mendham Township.
- 3.5 miles of 12" main would be installed from Chatham M&R station going west. One new 120psi/15psi regulator would also be installed off this new 120 psi line. It would feed into PSE&G's Northern 15 psi system in the vicinity of Blue Mill Road & Spring Valley Road, Chatham Township.
- 7.2 miles of 24" main would be installed between the Bernards and Gillette M&R stations. Two new 120psi/60psi regulators would be installed near each station, feeding into the Bernards/Gillette 60 psi system. The 120psi/60psi regulators would be installed in the vicinity of US-202 and Childs Road, Bernardsville and Morristown Road & Valley Road, Long Hill Township.
- 3.2 miles of 12" main would branch off the 24" installed between Bernards and Gillette M&R stations and proceed southwest to an additional 120psi/60psi regulator feeding into the Bernards/Gillette 60psi system. This 120psi/60psi regulator would be installed in the vicinity of Lyons Road & Church Street, Bernards Township.

- 6.6 miles of 12” main would be installed from Bridgewater M&R stations going north. One new 120psi/60psi regulator would also be installed off this new 120 psi line. It would feed into the Bernards/Gillette 60 psi system in the vicinity of US-206 & Hills Drive, Bedminster Township.

This project would provide the ability to move Transco gas from the Gillette M&R station (Location A on Schedule WEM-ESII-5, page 5), Chatham M&R station (Location B on Schedule WEM-ESII-5, page 5), and Bridgewater M&R station (Location C on Schedule WEM-ESII-5, page 5) and Columbia gas from the Parsippany M&R station (Location D on Schedule WEM-ESII-5, page 5) into an area supplied by the Algonquin Gas Transmission pipeline from the Bernards M&R station (Location 1 on Schedule WEM-ESII-5, page 5) and the Morris M&R station (Location 2 on Schedule WEM-ESII-5, page 5). This project would also provide the ability to move Algonquin gas from the Bernards M&R station (Location 1 on Schedule WEM-ESII-5, page 5) into an area supplied by Transco from the Gillette M&R station (Location A on Schedule WEM-ESII-5, page 5).

This project provides the ability to move Transco and Columbia gas into an area supplied by the Algonquin Gas transmission pipeline. This project uses available pipeline capacity and existing peak shaving gas including supplemental LNG to offset a supply curtailment on the Enbridge system. This project provides the ability to retain up to approximately 18,000 customers on a 30° F curtailment and 24,000 customers on a 20° F curtailment. The estimated number of avoided customer outages increase as temperatures get colder because of the dynamics of the system gas flows. The estimated project cost is $230.0 million, and the $/Customer Outage Day Avoided is $256.40.

Q. Please describe in detail PSE&G's proposed LNG project under its Curtailment Resiliency Subprogram.

A. An LNG facility with the ability to deliver 50.0 MDTH/Day would be constructed at PSE&G's property in Linden, NJ or PSE&G's property in Edison, NJ. This facility can supplement 50.0 MDTH/Day during either an Enbridge or Transco curtailment and has the ability to retain up to approximately 35,000 customers during a 5° F curtailment event, 38,000 customers during a 10° F curtailment event, and ensures no customers are lost on a 20° F curtailment event when used in conjunction with the other proposed Curtailment Resiliency projects. The estimated cost of this facility is $158.9 million over a 5-year planning and construction period, with a $/Customer Outage Day Avoided of $353.00.

Q. You provided cost estimates for each of the ES II projects listed above. Please explain how you have prepared those cost estimates.

A. These cost estimates have been developed using actual cost and construction experience from Energy Strong and other PSE&G construction projects. The LNG plant estimate was included in a feasibility study performed by Black & Veatch, a consulting engineering firm familiar with this type of facility.

Q. What resources are required to complete the ES II Curtailment Resiliency Subprogram?

A. The ES II Curtailment Resiliency Subprogram requires an investment of $863 million over 5 years for full implementation. The IIP regulations require base capital expenditures on projects similar to those proposed within the Program in an amount of at least 10 percent of the Program. In the gas Curtailment Resiliency Subprogram, the Company will meet this requirement by only seeking 90% of those type of expenditures approved in the subprogram through the cost recovery mechanism proposed for ES II set forth herein. See Schedule WEM-ESII-3.

III. M&R UPGRADE SUBPROGRAM

Q. Please provide an overview of PSE&G's proposed M&R Upgrade Subprogram.

A. PSE&G is proposing to implement a program to systematically upgrade seven M&R stations. The purpose is to modernize M&R Station designs, reduce the likelihood and consequence of equipment failure, and, in two of the seven stations, harden against flooding events. PSE&G has analyzed asset demographics, failure curves, and risk scoring for all its M&R assets, similar to its efforts regarding PSE&G's electric distribution assets.

Q. Which of PSE&G's M&R stations are included in this subprogram?

A. The Camden, East Rutherford, Central, Paramus, Westampton, Mount Laurel, and Hillsborough M&R stations are included in the proposed subprogram.

Q. Why have these M&R stations been chosen for inclusion in this subprogram?

A. These M&R stations were chosen for several reasons. All of these stations have an outdated design with upstream relief valves and single regulation runs. This arrangement can lead to a methane emission release through the relief valves in the event of a single regulator failure.

In addition, all of these stations have a number of aging components, which in some cases contain parts that are unavailable or are no longer supported by the manufacturer.

Two stations, Camden and East Rutherford, are located within the 100 year flood zone. Additionally, the Camden regulation building is over 100 years old. The East

Rutherford, Hillsborough, Mount Laurel and Westampton buildings are not large enough to accommodate a modern design. The Central location has three separate stations approximately 600 feet apart. Two are located outdoors subject to the elements, and the third is in a building that is not large enough to accommodate a modern design. The Paramus station is in a residential neighborhood directly across the street from the Paramus public high school. A release of gas from a relief valve at this location would result in a significant disruption to the community given the sensitive surroundings. Upgrading to a modern design will greatly reduce the likelihood of a relief valve event.

These stations were prioritized considering flood hazard exposure and using the PSE&G Asset Management Risk model. This model prioritizes stations using a risk matrix. The two main components of the matrix are consequence of failure and likelihood of failure. Consequence of failure is comprised of the following factors: safety impact, customer impact, asset reliability impact, and environmental impact. Each factor has specific criteria to calculate station consequence of failure, with examples such as stations located in proximity to populated areas, replacement part availability, and redundancy. Likelihood of failure is based upon equipment age, structural integrity, and station design. Equipment age and maintenance practices are used to plot assets along depreciation curves in order to calculate the likelihood of failure. The stations are organized in the risk matrix based upon their calculated consequence and likelihood of failure.

Q. Are there other M&R stations that have the same outdated design as the ones included in the ES II Program?

A. Yes. There are two stations with the same outdated design and that have been prioritized for future modernization upgrades.

Q. What advantage does the new design offer?

A. The new design eliminates relief valves and installs two regulators in series as the primary means of overpressure protection, thereby greatly reducing the likelihood of a gas release due to a regulator failure. The new design also replaces aging equipment and facilities, provides noise abatement, locates pressure regulation within a controlled environment, and provides greater working access to equipment. Taken together, these characteristics ultimately result in improved reliability, enhanced safety, and improved environmental performance.

Q. Please describe the proposed M&R life cycle projects in prioritized order.

A. **Camden** – The proposed new station would be constructed adjacent to the existing station where buildings and critical components would be at an elevation a minimum of one foot above the FEMA 100 year flood elevation. New underground piping rated for the full pipeline company maximum allowable operating pressure (MAOP) would be installed, eliminating the need for high pressure relief valves, thus enhancing safety and environmental performance. Series regulators with a working regulator and a monitor regulator for overpressure protection would be the new standard design. Downstream distribution system relief valves would also be installed as a third line of overpressure protection, also enhancing safety and environmental performance. Major equipment that is not near end of life condition and operationally can be relocated would be relocated to the appropriate elevation at the new station location.

East Rutherford – The proposed new station would be constructed adjacent to the existing station where buildings and critical components would be at an elevation a minimum of one foot above the FEMA 100 year flood elevation. New underground piping rated for the full pipeline company MAOP would be installed, eliminating the need for high pressure relief valves, thus enhancing safety and environmental performance. Series regulators with a working regulator and a monitor regulator for overpressure protection would be the new standard design. Downstream distribution system relief valves would also be installed as a third line of overpressure protection, enhancing safety and environmental performance. Major equipment that is not near end of life condition and operationally can be relocated would be relocated to the appropriate elevation at the new station location.

Central – The existing stations would be consolidated into a new building. New underground piping rated for the full pipeline company MAOP would be installed, eliminating the need for high pressure relief valves, thus enhancing safety and environmental performance. Series regulators with a working regulator and a monitor regulator for overpressure protection would be the new standard design. Downstream distribution system relief valves would also be installed as a third line of overpressure protection, enhancing safety and environmental performance. Major equipment that is not near end of life condition and operationally can be relocated would be relocated to the new station location.

Paramus – New piping rated for the full pipeline company MAOP would be installed, eliminating the need for high pressure relief valves, thus enhancing safety and environmental performance. Series regulators with a working regulator and a monitor regulator for overpressure protection would be the new standard design. Downstream distribution system relief valves would also be installed as a third line of overpressure protection, enhancing safety and environmental performance. Major equipment that is not near end of life condition and operationally can remain in service would not be replaced.

Westampton – New piping rated for the full pipeline company MAOP would be installed, eliminating the need for high pressure relief valves, thus enhancing safety and environmental performance. Series regulators with a working regulator and a monitor regulator for overpressure protection would be the new standard design. Downstream distribution system relief valves would also be installed as a third line of overpressure protection, enhancing safety and environmental performance. Major equipment that is not near end of life condition and operationally can remain in service would not be replaced.

Mount Laurel – New piping rated for the full pipeline company MAOP would be installed, eliminating the need for high pressure relief valves, thus enhancing safety and environmental performance. Series regulators with a working regulator and a monitor regulator for overpressure protection would be the new standard design. Downstream distribution system relief valves would also be installed as a third line of overpressure protection, enhancing safety and environmental performance. Major equipment that is not near end of life condition and operationally can remain in service would not be replaced.

Hillsborough – New piping rated for the full pipeline company MAOP would be installed, eliminating the need for high pressure relief valves, thus enhancing safety and environmental performance. Series regulators with a working regulator and a monitor regulator for overpressure protection would be the new standard design. Downstream distribution system relief valves would also be installed as a third line of overpressure protection, enhancing safety and environmental performance. Major equipment that is not near end of life condition and operationally can remain in service would not be replaced.

Q. Have you prepared cost estimates for these proposed projects?

A. Yes, we have prepared class 5 level estimates for each project. These costs have been developed using the actual cost and construction experience from Energy Strong and other PSE&G construction projects of this type and are considered office estimates. They are attached in Schedule WEM-ESII-3.

Q. What resources are required to complete the ES II M&R Upgrade Subprogram?

A. The proposed M&R Upgrade Subprogram requires $136 million over 5 years for full implementation. The IIP regulations require capital expenditures on projects similar to those proposed within the Program in an amount of at least 10 percent of the Program. In the gas M&R Upgrade Subprogram, the Company will meet the 10 percent requirement primarily through its base expenditures ($11.6 million). The Company will meet the remaining $2 million requirement by not seeking recovery through the Program rate adjustments.

IV. COST-BENEFIT ANALYSIS

Q Did the Company prepare a cost-benefit analysis of this gas portion of ES II?

A. Yes. Black & Veatch has completed a cost-benefit analysis for PSE&G of the proposed Gas Energy Strong II program. The Black & Veatch report is a result of analysis of both quantifiable and unquantifiable benefits of the two sub-programs that form the gas portion of ES II. Their report is being filed in this matter.

V. BENEFITS TO NEW JERSEY'S ECONOMY

Q. How will the infrastructure investments proposed herein benefit New Jersey's economy?

A. The gas portion of the ES II Program will provide benefits to both PSE&G's customers and New Jersey's economy. This component of the proposed ES II Program will result in additional skilled jobs. Using the methodology for job creation from the introductory materials to the Board's August 7, 2017 proposal for the IIP regulations, this portion of the proposed program would create an estimated 1,200 fulltime jobs per year for the duration of the Program.

Q. Please elaborate on the labor and other resources required to successfully complete this Program.

A. The Company anticipates an increase in staffing for engineering, construction and construction management, and records management in order to carry out the Program each year. As we have for the Energy Strong and GSMP Programs, PSE&G will continue to utilize a combination of internal labor and outside contractors for the Program. The Program will support employment opportunities for suppliers as well.

Q. How does a multi-year program affect the work effort involved with the ES II Program?

A. The vast majority of the construction projects proposed in the gas portion of ES II require five years to complete. Various aspects of permitting, planning, and coordinating the projects, cannot be reasonably planned for and executed in less than a five year period. In addition, the multi-year approach provides various efficiencies in planning, staffing, and managing contractors and material procurement.

VI. PROGRAM REPORTING

Q. Does the Company intend to provide regular reporting on its progress?

A. Yes. PSE&G proposes to provide semi-annual reports consistent with the requirements of the IIP rule. The rule requires the following:

1. Forecasted and actual costs of the Infrastructure Investment Program for the applicable reporting period, and for the Program to date, where Program projects are identified by major category;
2. The estimated total quantity of work completed under the Program identified by major category. In the event that the work cannot be quantified, major tasks completed shall be provided;
3. Estimated completion dates for the Infrastructure Investment Program as a whole, and estimated completion dates for each major Program category;
4. Anticipated changes to Infrastructure Investment Program projects, if any;
5. Actual capital expenditures made by the utility in the normal course of business on similar projects, identified by major category; and
6. Any other performance metrics concerning the Infrastructure Investment Program required by the Board.

Q. Is it correct that PSE&G is proposing a cost recovery mechanism for the ES II Program, including the gas portions of the Program that you are supporting?

A. Yes. The Direct Testimony of Stephen Swetz explains the cost recovery mechanism proposed by the Company.

Q. Please summarize your recommendations.

A. Even as PSE&G continues to provide safe and reliable service to customers, I recommend approval of the proposed ES II Curtailment Resiliency Subprogram to provide system resilience from pipeline supplier curtailments, and to make PSE&G's gas distribution system more resilient to upstream supply reliability issues. The projects proposed in that Subprogram will, if implemented, reduce the potential for customer outages, especially in the winter months if PSE&G were to experience supplier curtailment due to pipeline failures, periods of extreme cold and supply shortage, or for any other reason.

I also recommend approval of the proposed M&R Upgrade Subprogram to rebuild the seven specified M&R stations to modern design practices, greatly reducing the potential for gas release; maintaining the reliability and enhancing the safety of operation; and providing storm hardening for the two M&R stations that are in recognized flood areas.

Q. Does this conclude your prepared direct testimony?

A. Yes.

CREDENTIALS
OF
WADE E. MILLER
DIRECTOR – GAS TRANSMISSION &
DISTRIBUTION ENGINEERING

I received a Bachelor of Science Degree in Mechanical Engineering from The College of New Jersey in 2000. I also received my Engineer-In-Training certification in 2000. I became licensed as a Professional Engineer with the State of New Jersey in 2006. I also received my certification as a Project Management Professional with the Project Management Institute in 2006. In 2007, I earned the designation of Registered Gas Distribution Professional from the Gas Technology Institute.

I was employed by PSE&G in June 2000 as an Associate Engineer in the Trenton Gas Distribution District where I began my training program and was mentored under a senior engineer. In 2001, I was relocated from Trenton District to Burlington District where I acted as the sole engineer. In 2003, I was promoted to the position of Lead Engineer. During my first four years, I provided engineering and managerial support for all phases of planning, design, construction, and maintenance of the gas distribution system while adhering to the established capital and O&M budgets.

In 2004, I was promoted to the position of Supervising Engineer in the Asset Management department and given the responsibility for the approval of all engineering designs associated with new and replacement main requisitions, district and pound to pound regulator installations, large volume meter sets, higher than normal delivery pressure requests, gas load increase submittals, and written gas out procedures covering six of the twelve gas districts. In addition, I was also responsible for developing the replacement main plans for these same six districts including identification and prioritization.

In 2007, I was promoted to the position of Planning & Design Manager in the Asset Management department overseeing a team of engineers and given the responsibility for developing and maintaining Company design standards for the Gas system, maintaining system integrity, and providing technical support to gas field operations. I was also responsible for developing the annual replacement main, regulator, and system reinforcement programs for the Company.

In April 2014, I assumed my current position, which involves overall responsibility for system planning and reliability as well as the safe and efficient engineering, design, and operating procedures of PSE&G's gas transmission and distribution assets. I am also responsible for the management of the Transmission and Distribution Integrity Management Programs, operation and maintenance of 48 city gate stations, four gas plants, and gas control to over 1.8 million customers.

I am the Committee sponsor for PSE&G's Gas Engineering Committee which is responsible for approval of action items due to regulatory changes and changes to Company technical manuals, the Operator Qualification program, Integrity Management programs, and new technology and materials.

I am a member of the Operations Safety Regulatory Action committee and the Engineering committee of the American Gas Association.

Attachment 1

Gas Delivery Capital Summary (2012 - 2017)

Schedule WEM-ESII-2A

Capital Category ($M)	2012 Full Year Actual	2013 Full Year Actual	2014 Full Year Actual	2015 Full Year Actual	2016 Full Year Actual	2017 Full Year Actual
Total Base	**145**	**117**	**138**	**174**	**210**	**352**
New Business	52	68	63	73	79	74
GSMP I						
Recovery Mechanism					159	245
Stipulated Base					95	100
Energy Strong			95	225	70	5
CIP II	54	5				
Total Capital $	**$ 251**	**$ 189**	**$ 296**	**$ 472**	**$ 613**	**$ 774**

Base Breakdown by Major Category

Replace Facilities	$ 63	$ 42	$ 44	$ 72	$ 77	$ 174
System Reinforcement	$ 28	$ 31	$ 48	$ 51	$ 60	$ 71
Environmental Regulatory	$ 23	$ 26	$ 28	$ 26	$ 27	$ 36
Replace Meters	$ 27	$ 15	$ 14	$ 19	$ 37	$ 57
Support Facilities	$ 5	$ 3	$ 4	$ 5	$ 9	$ 13
Total Base $	**$ 145**	**$ 117**	**$ 138**	**$ 174**	**$ 210**	**$ 352**

Attachment 1

Schedule WEM-ESII-2B

Gas Delivery Capital Summary (2019 - 2023)

Capital Category ($M)	2019 Full Year Plan	2020 Full Year Plan	2021 Full Year Plan	2022 Full Year Plan	2023 Full Year Plan
Base (Energy Strong II-Like Work)	2	2	2	2	2
Base (All Other)	153	153	153	153	153
Total Base	**155**	**155**	**155**	**155**	**155**
New Business	81	83	85	86	86
GSMP I					
Recovery Mechanism	32				
Stipulated Base	-	-	-	-	-
GSMP II					
Recovery Mechanism	226	338	339	339	334
Average Projected Stipulated Base	60	60	60	60	60
Energy Strong II					
Recovery Mechanism	12	165	221	262	174
Projected Stipulated Base	1	16	21	25	17
Total Capital $	**$ 566**	**$ 817**	**$ 880**	**$ 927**	**$ 826**

Base Breakdown by Major Category

Replace Facilities	$ 33	$ 33	$ 40	$ 38	$ 36
System Reinforcement	$ 33	$ 32	$ 55	$ 56	$ 57
Environmental Regulatory	$ 28	$ 28	$ 28	$ 28	$ 28
Replace Meters	$ 60	$ 60	$ 30	$ 31	$ 32
Support Facilities	$ 1	$ 1	$ 2	$ 2	$ 2
Total Base $*	**$ 155**	**$ 155**	**$ 155**	**$ 155**	**$ 155**

*The Company proposes to maintain base level spending from 2019-2023 at the projections shown above

Stipulated Base Requirement						**Trailing**	**Total**
ESII-Like Work in Total Base	2	2	2	2	2		
ESII Projected Stipulated Base	1	16	21	25	17	8	
Energy Strong II Total Stipulated Base	3	18	23	28	19	8	100
Energy Strong II Recovery Mechanism	$ 12	$ 165	$ 221	$ 262	$ 174	$ 78	$ 911
% Stipulated Base							**11%**

PSE&G Energy Strong Program II
Gas Summary Cash Flows

Cash Flows ($000s)	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Program Year - 2019													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ -	$ -	$ 125	$ 250	$ 375	$ 375	$ 749	$ 999	$ 1,249	$ 1,874	$ 2,748	$ 3,756	$ 12,499
COR	$ -	$ -	$ 1	$ 2	$ 3	$ 3	$ 6	$ 8	$ 10	$ 16	$ 23	$ 31	$ 105
Total	**$ -**	**$ -**	**$ 126**	**$ 252**	**$ 378**	**$ 378**	**$ 756**	**$ 1,008**	**$ 1,260**	**$ 1,889**	**$ 2,771**	**$ 3,788**	**$ 12,604**
Program Year - 2020													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 14,988	$ 14,988	$ 14,988	$ 14,988	$ 14,988	$ 14,988	$ 14,988	$ 14,988	$ 14,988	$ 14,988	$ 14,988	$ 14,988	$ 179,856
COR	$ 81	$ 81	$ 81	$ 81	$ 81	$ 81	$ 81	$ 81	$ 81	$ 81	$ 81	$ 81	$ 970
Total	**$ 15,069**	**$ 15,069**	**$ 15,069**	**$ 15,069**	**$ 15,069**	**$ 15,069**	**$ 15,069**	**$ 15,069**	**$ 15,069**	**$ 15,069**	**$ 15,069**	**$ 15,069**	**$ 180,827**
Program Year - 2021													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 20,023	$ 20,023	$ 20,023	$ 20,023	$ 20,023	$ 20,023	$ 20,023	$ 20,023	$ 20,023	$ 20,023	$ 20,023	$ 20,023	$ 240,281
COR	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 1,326
Total	**$ 20,134**	**$ 20,134**	**$ 20,134**	**$ 20,134**	**$ 20,134**	**$ 20,134**	**$ 20,134**	**$ 20,134**	**$ 20,134**	**$ 20,134**	**$ 20,134**	**$ 20,134**	**$ 241,607**
Program Year - 2022													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 26,495	$ 26,495	$ 26,495	$ 26,495	$ 26,495	$ 21,843	$ 21,843	$ 21,843	$ 21,843	$ 21,843	$ 21,843	$ 21,843	$ 285,376
COR	$ 146	$ 146	$ 146	$ 146	$ 146	$ 141	$ 141	$ 141	$ 141	$ 141	$ 141	$ 141	$ 1,716
Total	**$ 26,641**	**$ 26,641**	**$ 26,641**	**$ 26,641**	**$ 26,641**	**$ 21,984**	**$ 21,984**	**$ 21,984**	**$ 21,984**	**$ 21,984**	**$ 21,984**	**$ 21,984**	**$ 287,092**
Program Year - 2023													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 17,847	$ 17,847	$ 17,847	$ 17,847	$ 17,847	$ 14,368	$ 14,368	$ 14,368	$ 14,368	$ 14,368	$ 14,368	$ 14,368	$ 189,813
COR	$ 112	$ 112	$ 112	$ 112	$ 112	$ 80	$ 80	$ 80	$ 80	$ 80	$ 80	$ 80	$ 1,121
Total	**$ 17,959**	**$ 17,959**	**$ 17,959**	**$ 17,959**	**$ 17,959**	**$ 14,449**	**$ 14,449**	**$ 14,449**	**$ 14,449**	**$ 14,449**	**$ 14,449**	**$ 14,449**	**$ 190,935**
Program Year - 2024													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 42,728	$ 42,728	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 85,456
COR	$ 330	$ 330	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 661
Total	**$ 43,058**	**$ 43,058**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 86,117**
Totals													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 122,082	$ 122,082	$ 79,479	$ 79,604	$ 79,729	$ 71,597	$ 71,972	$ 72,222	$ 72,471	$ 73,096	$ 73,970	$ 74,979	$ 993,282
COR	$ 779	$ 779	$ 450	$ 451	$ 452	$ 416	$ 419	$ 421	$ 423	$ 428	$ 436	$ 444	$ 5,899
Total	**$ 122,861**	**$ 122,861**	**$ 79,929**	**$ 80,055**	**$ 80,180**	**$ 72,013**	**$ 72,391**	**$ 72,643**	**$ 72,895**	**$ 73,524**	**$ 74,406**	**$ 75,423**	**$ 999,180**

* The Overall Summary of the Subprograms' Cash Flow reflects 100% of the program's cash flow, some of which will be invested in base capital - pursuant to the BPU's regulations entitled Infrastructure Investment And Recovery

PSE&G Energy Strong Program II
Gas Curtailment Resiliency Subprogram Cash Flows

Cash Flows ($000s)	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Program Year - 2019													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ -	$ -	$ 109	$ 217	$ 326	$ 326	$ 651	$ 868	$ 1,086	$ 1,628	$ 2,388	$ 3,266	$ 10,864
COR	$ -	$ -	$ 1	$ 1	$ 2	$ 2	$ 4	$ 6	$ 7	$ 11	$ 16	$ 21	$ 72
Total	**$ -**	**$ -**	**$ 109**	**$ 219**	**$ 328**	**$ 328**	**$ 656**	**$ 874**	**$ 1,093**	**$ 1,639**	**$ 2,404**	**$ 3,287**	**$ 10,936**
Program Year - 2020													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 12,972	$ 12,972	$ 12,972	$ 12,972	$ 12,972	$ 12,972	$ 12,972	$ 12,972	$ 12,972	$ 12,972	$ 12,972	$ 12,972	$ 155,667
COR	$ 40	$ 40	$ 40	$ 40	$ 40	$ 40	$ 40	$ 40	$ 40	$ 40	$ 40	$ 40	$ 477
Total	**$ 13,012**	**$ 13,012**	**$ 13,012**	**$ 13,012**	**$ 13,012**	**$ 13,012**	**$ 13,012**	**$ 13,012**	**$ 13,012**	**$ 13,012**	**$ 13,012**	**$ 13,012**	**$ 156,144**
Program Year - 2021													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 16,555	$ 16,555	$ 16,555	$ 16,555	$ 16,555	$ 16,555	$ 16,555	$ 16,555	$ 16,555	$ 16,555	$ 16,555	$ 16,555	$ 198,665
COR	$ 40	$ 40	$ 40	$ 40	$ 40	$ 40	$ 40	$ 40	$ 40	$ 40	$ 40	$ 40	$ 477
Total	**$ 16,595**	**$ 16,595**	**$ 16,595**	**$ 16,595**	**$ 16,595**	**$ 16,595**	**$ 16,595**	**$ 16,595**	**$ 16,595**	**$ 16,595**	**$ 16,595**	**$ 16,595**	**$ 199,142**
Program Year - 2022													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 23,248	$ 23,248	$ 23,248	$ 23,248	$ 23,248	$ 18,827	$ 18,827	$ 18,827	$ 18,827	$ 18,827	$ 18,827	$ 18,827	$ 248,028
COR	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 953
Total	**$ 23,327**	**$ 23,327**	**$ 23,327**	**$ 23,327**	**$ 23,327**	**$ 18,907**	**$ 18,907**	**$ 18,907**	**$ 18,907**	**$ 18,907**	**$ 18,907**	**$ 18,907**	**$ 248,981**
Program Year - 2023													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 14,969	$ 14,969	$ 14,969	$ 14,969	$ 14,969	$ 13,026	$ 13,026	$ 13,026	$ 13,026	$ 13,026	$ 13,026	$ 13,026	$ 166,028
COR	$ 53	$ 53	$ 53	$ 53	$ 53	$ 53	$ 53	$ 53	$ 53	$ 53	$ 53	$ 53	$ 636
Total	**$ 15,022**	**$ 15,022**	**$ 15,022**	**$ 15,022**	**$ 15,022**	**$ 13,079**	**$ 13,079**	**$ 13,079**	**$ 13,079**	**$ 13,079**	**$ 13,079**	**$ 13,079**	**$ 166,663**
Program Year - 2024													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 40,360	$ 40,360	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 80,721
COR	$ 282	$ 282	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 564
Total	**$ 40,642**	**$ 40,642**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 81,285**
Totals													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 108,105	$ 108,105	$ 67,853	$ 67,962	$ 68,070	$ 61,706	$ 62,032	$ 62,249	$ 62,466	$ 63,009	$ 63,769	$ 64,646	$ 859,972
COR	$ 494	$ 494	$ 213	$ 213	$ 214	$ 214	$ 216	$ 218	$ 219	$ 223	$ 228	$ 233	$ 3,178
Total	**$ 108,599**	**$ 108,599**	**$ 68,066**	**$ 68,175**	**$ 68,284**	**$ 61,920**	**$ 62,248**	**$ 62,466**	**$ 62,685**	**$ 63,231**	**$ 63,996**	**$ 64,879**	**$ 863,150**

* The Gas Curtailment Resiliency Subprogram Cash Flow reflects 100% of the program's cash flow, some of which will be invested in base capital - pursuant to the BPU's regulations entitled Infrastructure Investment And Recovery

PSE&G Energy Strong Program II
Gas Metering and Regulating (M&R) Upgrade Subprogram Cash Flows

Cash Flows ($000s)	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Program Year - 2019													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ -	$ -	$ 16	$ 33	$ 49	$ 49	$ 98	$ 131	$ 164	$ 245	$ 360	$ 491	$ 1,635
COR	$ -	$ -	$ 0	$ 1	$ 1	$ 1	$ 2	$ 3	$ 3	$ 5	$ 7	$ 10	$ 33
Total	**$ -**	**$ -**	**$ 17**	**$ 33**	**$ 50**	**$ 50**	**$ 100**	**$ 133**	**$ 167**	**$ 250**	**$ 367**	**$ 501**	**$ 1,669**
Program Year - 2020													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 2,016	$ 2,016	$ 2,016	$ 2,016	$ 2,016	$ 2,016	$ 2,016	$ 2,016	$ 2,016	$ 2,016	$ 2,016	$ 2,016	$ 24,189
COR	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 494
Total	**$ 2,057**	**$ 2,057**	**$ 2,057**	**$ 2,057**	**$ 2,057**	**$ 2,057**	**$ 2,057**	**$ 2,057**	**$ 2,057**	**$ 2,057**	**$ 2,057**	**$ 2,057**	**$ 24,683**
Program Year - 2021													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 3,468	$ 3,468	$ 3,468	$ 3,468	$ 3,468	$ 3,468	$ 3,468	$ 3,468	$ 3,468	$ 3,468	$ 3,468	$ 3,468	$ 41,616
COR	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 849
Total	**$ 3,539**	**$ 3,539**	**$ 3,539**	**$ 3,539**	**$ 3,539**	**$ 3,539**	**$ 3,539**	**$ 3,539**	**$ 3,539**	**$ 3,539**	**$ 3,539**	**$ 3,539**	**$ 42,465**
Program Year - 2022													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 3,248	$ 3,248	$ 3,248	$ 3,248	$ 3,248	$ 3,016	$ 3,016	$ 3,016	$ 3,016	$ 3,016	$ 3,016	$ 3,016	$ 37,348
COR	$ 66	$ 66	$ 66	$ 66	$ 66	$ 62	$ 62	$ 62	$ 62	$ 62	$ 62	$ 62	$ 762
Total	**$ 3,314**	**$ 3,314**	**$ 3,314**	**$ 3,314**	**$ 3,314**	**$ 3,077**	**$ 3,077**	**$ 3,077**	**$ 3,077**	**$ 3,077**	**$ 3,077**	**$ 3,077**	**$ 38,111**
Program Year - 2023													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 2,878	$ 2,878	$ 2,878	$ 2,878	$ 2,878	$ 1,342	$ 1,342	$ 1,342	$ 1,342	$ 1,342	$ 1,342	$ 1,342	$ 23,786
COR	$ 59	$ 59	$ 59	$ 59	$ 59	$ 27	$ 27	$ 27	$ 27	$ 27	$ 27	$ 27	$ 485
Total	**$ 2,936**	**$ 2,936**	**$ 2,936**	**$ 2,936**	**$ 2,936**	**$ 1,370**	**$ 1,370**	**$ 1,370**	**$ 1,370**	**$ 1,370**	**$ 1,370**	**$ 1,370**	**$ 24,271**
Program Year - 2024													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 2,368	$ 2,368	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,735
COR	$ 48	$ 48	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 97
Total	**$ 2,416**	**$ 2,416**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 4,832**
Totals													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 13,977	$ 13,977	$ 11,625	$ 11,642	$ 11,658	$ 9,891	$ 9,940	$ 9,973	$ 10,005	$ 10,087	$ 10,202	$ 10,333	$ 133,309
COR	$ 285	$ 285	$ 237	$ 238	$ 238	$ 202	$ 203	$ 204	$ 204	$ 206	$ 208	$ 211	$ 2,721
Total	**$ 14,262**	**$ 14,262**	**$ 11,863**	**$ 11,879**	**$ 11,896**	**$ 10,093**	**$ 10,143**	**$ 10,176**	**$ 10,210**	**$ 10,293**	**$ 10,410**	**$ 10,543**	**$ 136,030**

* The M&R Subprogram Cash Flow reflects 100% of the program's cash flow, some of which will be invested in base capital - pursuant to the BPU's regulations entitled Infrastructure Investment And Recovery

Attachment 1

Miller-Schedule-WEM-ESII-4

Confidential

Attachment 1

Miller-Schedule-WEM-ESII-5

Confidential

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
EDWARD F. GRAY
DIRECTOR – TRANSMISSION AND DISTRIBUTION ENGINEERING
ENERGY STRONG II PROGRAM - ELECTRIC

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

A. My name is Edward F. Gray, and I am the Director of Transmission and Distribution Engineering for Public Service Electric and Gas Company (PSE&G, or the Company), the Petitioner in this matter. My educational and professional background and experience are set forth in the attached Schedule EFG-ESII-1.

Q. Please describe your responsibilities as Director of Transmission and Distribution Engineering as it relates to electric delivery.

A. I am responsible for the plant design, reliability, and asset life cycles for PSE&G's electric distribution and transmission system, serving 2.2 million electric customers. I am responsible for ensuring the reliability of PSE&G's electric delivery assets and overseeing various functions that support the provision of safe, adequate, proper, and reliable electric delivery service.

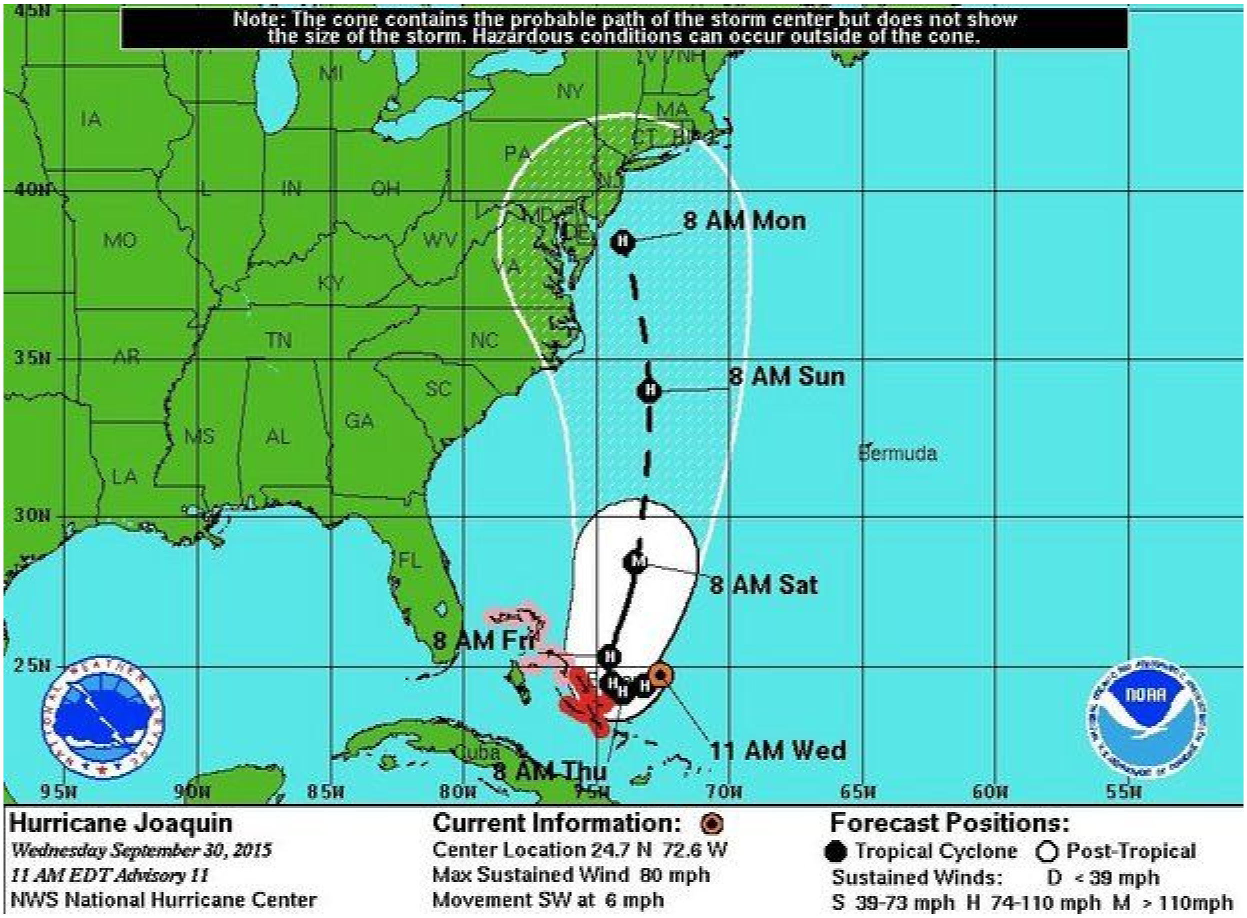
Q. What is the purpose of your testimony in this proceeding?

A. My testimony will support the electric portion of PSE&G's proposed Energy Strong II Program (the Program or the ES II Program). PSE&G seeks Board approval for an infrastructure program that will harden the electric infrastructure from the effects of major storm events, improve resiliency by allowing for faster restoration of outages, and ensure safe and reliable service by replacing facilities at the end-of-life. The electric hardening and resiliency investments represent an extension of PSE&G's Energy Strong program for areas where additional investments are warranted. The resiliency work includes technology investments that will ensure field communication to devices, make the system smarter and improve customer communication, and support future grid needs. Finally, the proposal includes an asset life cycle component utilizing a risk based model to prioritize the replacement of facilities that have reached end-of-life.

Q. Why is PSE&G recommending the proposed investments now?

A. In alignment with the Board's Infrastructure Investment Program (IIP) regulations, this program provides for investments related to reliability, resiliency, and/or safety to provide safe and adequate service. Since 2010 PSE&G has experienced the four most impactful storms in terms of customers interrupted in its operating history. These include the 2010 Nor'easter, Hurricane Irene, the October 2011 snow storm, and Superstorm Sandy in 2012. Each of these storms caused significant damage across the state, including damage to electric infrastructure. While no hurricanes have affected the service territory since Superstorm Sandy, 2016 was the most active Atlantic Hurricane season since 2012 with 15 named storms, including a category 5 hurricane (Matthew) that paralleled the Atlantic coast.[1] Furthermore, in 2015 Hurricane Juaquin was modelled to directly hit New Jersey and storm preparations were underway before the storm eventually turned east.

[1] National Hurricane Center Annual Summary, http://www.nhc.noaa.gov/data/tcr/summary_atlc_2016.pdf.



In 2017, hurricane activity in the Atlantic basin was well above average, and this season was the 5th most active on record to date, behind only 1893, 1926, 1933 and 2005.[2] This season included Hurricane Irma, which had outage impacts similar to Sandy with approximately 8.2 million outages (Sandy's total was 8.7 million), including 1.5 million outages in Puerto Rico alone.[3] As noted, the hardening and resiliency work planned under Energy Strong II would continue PSE&G's efforts to make its distribution systems harder and more resilient, begun under Energy Strong, for areas where additional investments are warranted.

[2] http://www.nhc.noaa.gov/text/MIATWSAT.shtml.

[3] http://www.wlky.com/article/update-on-power-outages-from-harvey-irma-and-maria/12445723.

In addition, PSE&G service territory experienced significant storms and outages in March 2018 that were comparable to the major events prior to the initial Energy Strong program. The effect of the storm events on March 2nd and March 7th resulted in the highest outage totals since Hurricane Sandy (476,880) and a higher number of primary circuit damage locations (1,537) than Hurricane Irene (1,462), the 2011 Wet Snow Storm (1,440) or the 2010 Nor'easter (1,205).

The life cycle aspect of this subprogram is being proposed to maintain service reliability, resiliency and safety through planned replacements, and to reduce service interruptions and emergency replacements generally. PSE&G has one of the older electric infrastructures in the United States. As an example, PSE&G has 95 stations with Distribution equipment with an average age of 73 years, where the majority of Distribution station equipment is original. These facilities have provided decades of safe, reliable, and -- having been in service well beyond the current book life of approximately 40 years -- low cost service to customers. Comparing the age of these facilities to industry average lives, PSE&G anticipates that failures will increase as the facilities continue to age. The costs associated with the scale of the investments and the urgency to move these projects forward requires a program that can be efficiently planned and executed while avoiding unplanned or emergency repairs.

The life cycle aspect of this subprogram if continued beyond the initial 5 years would upgrade these facilities over approximately 20 years through an organized, staffed and planned replacement program while reducing risk associated with an increasing rate of equipment failures, outages and worker safety. The current five-year base capital plan for Replace Facilities is approximately $620 million. In contrast to the $478 million pro-active life cycle aspects of ES II, the base capital plan addresses the entire electric distribution system and is primarily for replacement of specific components that fail in service or are actually expected to fail, and are replaced to maintain continuity of service.

Q. How have the programs implemented during the Energy Strong program improved preparedness and response for major events?

A. The Energy Strong program, which is nearing completion, provides significant benefits to all customers by avoiding outages related to flooding and enabling faster restoration for customers impacted by damaged circuits. Some specific examples include the following:

- PSE&G has hardened 26 stations by either raising or replacing them so that they will not be impacted by flood waters similar to those during Hurricane Irene or Superstorm Sandy. Approximately 490,000 customers will directly benefit from the flood protection provided by this project.
- PSE&G has improved resiliency through a new supervisory control and data acquisition ("SCADA") system that incorporates the entire Distribution system model and provides enhanced visibility of the system to operators managing storm restoration.
- PSE&G has improved resiliency by installing new communications and microprocessor relays at 111 stations serving 1,418,820 customers, to enable remote detection of circuit outages and significantly improving resiliency by enabling remote implementation of work safety settings.

- PSE&G has improved resiliency by providing additional supply options, re-routing circuits, and reducing circuit exposure to 260 critical facilities identified through outreach to County Offices of Emergency Management in its service territory. The work focused on these critical facilities also benefits 413,000 customers on the same circuits that can be supplied by these additional sources.

Q. What other actions has PSE&G taken to improve storm restoration since the original Energy Strong filing?

A. In addition to the Energy Strong Program, PSE&G has implemented and/or defined several new processes in support of major storm restoration as part of its base capital and O&M spending. Some specific examples include:

- Damage Assessment – The Company reviewed processes and developed new training material, including an on-line course that is required to be completed by all associates annually. This training allows for associates not normally involved with Division operations to assess damage to facilities to support the prioritization and effective restoration of service. Based on on-line access, this training will also be performed immediately prior to major events. In addition, process improvements were identified and implemented to standardize and enhance productivity and information collected during the damage assessment process.
- Staging Areas – To support material needed by mutual aid crews, staging areas are required to store and issue material from temporary locations that can support high truck volumes and efficiently supply crews the material they need. PSE&G performed a thorough review and improvement of existing processes, developed and

conducted training for individuals identified to staff these locations in a major event, built four new mobile incident command centers, and identified and secured over 20 sites for staging areas throughout the State.

- Storm/Outage Response Roles – The Company inventoried the skills and capabilities of all Electric Delivery personnel, and assigned all PSE&G personnel Storm/Outage roles and locations and identified training needs for all individuals.
- Securing Line Contractors – PSE&G has developed and signed contracts with 12 utility line contractors with first option clause to support PSE&G in the event of a storm situation.
- Customer Communications – PSE&G has implemented an improvement initiative related to customer communication on estimated time to restoration (ETR) that is measured and managed on a daily basis.

Q. Please summarize your conclusions and recommendations.

A. PSE&G has continued to invest in its delivery system over its 115-year history. Those investments have allowed PSE&G to meet its obligations as well as win numerous awards for reliability.[4] PSE&G is proud of the system it has built and the decisions made over the years to invest in the current system. PSE&G also believes that it is at a critical point where choices need to be made. PSE&G can continue to invest prudently in the existing electric system and

[4] PSE&G has consistently been ranked as the most reliable electric utility in the mid-Atlantic region, as well as the most reliable utility the United States. PA Consulting, the industry's benchmarking group, has awarded PSE&G the most reliable electric utility in America five times, most recently winning the award in November 2012 as the most reliable electric utility in America in 2011. In addition, PSE&G has been named by PA Consulting as the most reliable electric utility in the mid-Atlantic region for the last 16 years (2001-2016). PSE&G also won PA Consulting's 2011 Outstanding Response to a Major Outage Event award for its performance during Hurricane Irene and the October 2011 snowstorm.

current designs, providing service to its customers with incremental improvements and repairs being made as necessary and appropriate, and thereby continue to provide safe and adequate service, though maintenance costs would increase and more equipment would run to failure due to age, with the associated emergency repairs, outages, and potential safety issues. Alternatively, PSE&G can take more comprehensive action and proactively make investments in the delivery systems in alignment with the Board's proposed IIP regulatory initiative. Through the ES II Program, PSE&G proposes to make infrastructure investments that will have the greatest impact for system-wide hardening and resiliency, anticipating equipment issues rather than waiting for them to occur, while looking towards the future needs of an evolving grid.

The programs approved as part of the initial Energy Strong filing were important investments in the system and will provide benefits in a flood event, support maintaining service to critical infrastructure, and enable improved crew productivity through SCADA. That program, however, did not address all the areas in need of attention. The initial program did not address 21 stations that are below the local flood elevations as defined by FEMA, leaving those stations vulnerable to storm events with flood impacts. As part of its base capital program, PSE&G has raised or is in the process of raising five of these stations to a minimum of one foot above the flood elevations published by the Federal Emergency Management Agency (FEMA). Energy Strong did not include direct hardening of distribution circuits that would help reduce overall outages. Looking forward, PSE&G believes that programs that, for example, upgrade circuits for improved performance when they are struck by trees and that sectionalize circuits to limit customers impacted in the event of a fault should be expanded beyond the critical facilities covered in Energy Strong to a more wide-spread application across the entire distribution area to reduce outages and improve resiliency. In addition, new technology applications for reclosing devices located on fused branches will reduce outages, increasing system hardening and allow PSE&G to understand the status of these segments without customer phone calls.

PSE&G also proposes to make additional investments in grid modernization to improve storm response, maintain communication and situational awareness, and support the evolving utility of the future. The proposed Advanced Distribution Management System (ADMS) and Communication Network that are part of this Energy Strong II filing will provide the tools for dynamic visualization, monitoring, and control of the electric distribution system built off the SCADA system implemented as part of Energy Strong.

The need for improved communication is even more urgent than it was in 2012. Specifically, all of PSE&G's reclosers currently utilize plain old telephone service (POTS) provided predominately by copper wire for communication. Based on business trends, the telecommunications industry is phasing this technology out with implications for both storm response and day-to-day operations. PSE&G understands that the transition away from copper wire will take about 10 years across the PSE&G territory. PSE&G expects its largest telecommunications provider's level of support for the existing infrastructure would be affected by this decision. Given the criticality of these communications, the reliance on a technology being removed from service with another communication system from a third party will not meet the future needs of the grid where the importance of secure, high speed and reliable communications to a significantly higher number of devices will be required. PSE&G believes that for both improved communication in storm events and to support the future grid with distributed energy resources (DERs),[5] a significantly more robust, secure, and efficient communication system is needed to control devices on circuits and ensure service reliability and quality (i.e., voltage) to customers. The ES II program will result in a company-owned, operated, and maintained communications infrastructure to achieve these ends.

Finally, the Life Cycle investments for substations are being proposed to address assets that have reached or are near end-of-life, where the primary mode of failure is the result of age. These facilities are typically not impacted by storms or external factors (i.e., vegetation, animal contacts) and have high replacement costs. PSE&G has significant numbers of assets in these categories, where an ongoing program of replacement well beyond historical investment can help ensure and enhance the provision of safe and reliable service that the BPU and PSE&G's customers currently receive and expect from PSE&G. These assets have performed well, as demonstrated by PSE&G's sustained reliability performance, and keeping them in service for long durations have helped keep customer rates down. The average age of these PSE&G facilities is typically higher than the industry average, which reflects the age of PSE&G's service territory. In most circumstances, this equipment has exceeded its book depreciation life. The substation examples that I will describe later include two groups of stations with average ages of 92 years and 62 years. PSE&G currently spends approximately $19 million annually on substation equipment replacements and upgrades as part of its base capital program.

[5] For this testimony, I define distributed energy resources, or DERs, as any resource capable of providing electricity services that is located in the distribution system.

PSE&G is requesting the Board approve the proposed Energy Strong II investment program for a five year (60 month) term, permitting investment of approximately $1.5 billion for electric delivery.

Q. How is the remainder of your testimony organized?

A. My testimony is organized into seven main sections: (1) the alignment of Energy Strong II with the Board's Infrastructure Investment Program regulations; (2) Electric Substation Subprogram; (3) Higher Outside Plant Design Standards Subprogram; (4) Contingency Reconfiguration Subprogram; (5) Grid Modernization Subprogram; (6) benefits to New Jersey created by PSE&G's ES II; and (7) Program reporting. Within the Substation Subprogram I discuss the Station Flood and Storm Surge Mitigation investments and Substation Life Cycle investments. In the Contingency Reconfiguration Subprogram I discuss the increased sectionalization and installation of reclosing devices. In the Grid Modernization Subprogram I discuss the Company's proposed Advanced Distribution Management System and Communications system.

I. <u>INFRASTRUCTURE INVESTMENT PROGRAM REGULATIONS</u>

Q. What are the Infrastructure Investment Program ("IIP") regulations?

A. They are regulations recently adopted by the BPU "to provide a rate recovery mechanism that encourages and supports necessary accelerated construction, installation, and rehabilitation of certain utility plants and equipment."

Q. Are the projects in the Energy Strong II Program eligible under the IIP proposal?

A. Yes. As stated in the IIP regulations, specifically in N.J.A.C. 14:3-2A.2(a):

(a) Eligible projects within an Infrastructure Investment Program shall be:

1. Related to safety, reliability, and/or resiliency;
2. Non-revenue producing;
3. Specifically identified by the utility within its petition in support of an Infrastructure Investment Program; and
4. Approved by the Board for inclusion in an Infrastructure Investment Program, in response to the utility's petition.

The ES II subprograms all meet these criteria. PSE&G is requesting Board approval to implement this program as consistent with the IIP policy and in the best interests of PSE&G's customers.

Q. Are there minimum filing requirements associated with seeking accelerated recovery of infrastructure investments under the IIP regulations?

A. Yes. The location of all requirements under the IIP regulations in the ES II filing is provided in Appendix 1 to the Petition. I will address the requirements related to program eligibility, capital expenditures, selection criteria, and reporting for the proposed electric investments. Mr. Swetz will address requirements associated with cost recovery. A cost benefit analysis is also being submitted on behalf of PSE&G by a group from Black & Veatch.

Q. Is the Company proposing base capital expenditures on similar electric distribution projects as proposed for the ES II Program?

A. Yes. Consistent with the IIP rules, the Company commits to base rate treatment of investments in an amount at least 10 percent of the capital expenditures recovered through the recovery mechanism proposed for the electric ES II Program. These capital expenditures will be on work similar to that proposed to be recovered under the ES II recovery mechanism. This is shown on Schedule EFG-ESII-2B.

Q. Is the Company proposing annual baseline spending levels over the life of the Program?

A. Yes. Please see Schedule EFG-ESII-2B for the annual baseline spending levels for electric projects over the ES II period.

Q. What is the justification for the annual baseline budget spending levels?

A. The annual baseline spending levels proposed in Schedule EFG-ESII-2B are the Company's projected baseline capital budget, along with an amount of proposed base rate recovery spending on work that is similar to that which is being proposed for the ES II cost recovery mechanism. The annual base line spend total plus the proposed additional "similar work" provides for the capital expenditures required to satisfy PSE&G's obligation to provide safe and adequate utility service.

Q. Is the Company proposing any limit to variations in annual spending?

A. Yes. Consistent with the IIP regulations, the Company proposes that it be allowed annual variations in its capital expenditures up to 10 percent so long as the expenditures do not exceed the overall approved budget for the Program. The Company will seek Board approval for any year-to-year variances that are expected to be greater than 10 percent.

Q. Have you included the Company's actual capital expenditures over the past five years and projected capital expenditures over the next five years by major category?

A. Yes. Please see Schedule EFG-ESII-2A for the actual capital expenditures by major category from 2012-2017, and Schedule EFG-ESII-2B for the projected gas delivery capital expenditures by major category from 2019 through 2023.

Q. Has an engineering evaluation been done to determine the projects, in-service dates, costs and benefits of the proposed Program?

A. Yes. My testimony below details the projects proposed for the Program, how and why they were selected, the monthly forecasted capital expenditures and the cost estimates, including how those cost estimates were developed. A cost benefit analysis of the subprogram is being provided in testimony provided by Black & Veatch.

Q. Have you developed an annual budget for the ES II Electric Program?

A. Yes. Please see Schedule EFG-ESII-3 for the monthly and annual capital expenditures for the Program. As shown in Schedule EFG-ESII-3, the maximum capital expenditure dollar amount the Company seeks to recover through the Program is $1.5 billion.

Q. Is the Company proposing any reporting requirements associated with ES II?

A. Yes. Consistent with the IIP, the Company is proposing semi-annual status reports on the Program. The reporting requirements are detailed later in my testimony.

II. SUBSTATION SUBPROGRAM

Q. Please provide an overview of PSE&G's proposed Substation Subprogram.

A. The Company proposes to rebuild assets at thirty-one (31) distribution stations that have components that are below the local flood elevations as defined by FEMA or reaching end of life. Sixteen (16) of the stations identified as being below established flood elevations will be eliminated or raised up to FEMA elevation plus one foot. This portion of the Substation Subprogram aligns with the station flood mitigation subprogram in the original

Energy Strong Program with the only exception being these stations were not impacted by the major storm events but are at risk under the flood elevations currently defined by FEMA.

The life cycle aspect of the proposed Substation Subprogram provides a programmatic replacement of aged substation facilities, prioritizing fifteen (15) distribution stations in the highest risk category. The risk model utilized for this risk scoring is defined in the testimony of William D. Williams. The life cycle aspect of the Substation Subprogram would be the start of a 15-20 year program to upgrade these facilities in a programmatic fashion to modernize PSE&G substation infrastructure and avoid the safety, reliability, and ongoing costs of operating facilities near end of life. Replacement of these facilities will enhance PSE&G's continued provision of safe and reliable service.

Of the 16 stations identified for flood mitigation, 11 would also be due for life cycle replacement due to the age of the facilities; these stations are thus a high priority.

1. Station Flood and Storm Surge Mitigation

Q. Please provide an overview of PSE&G's proposal with respect to Station Flood and Storm Surge Mitigation.

A. The original Energy Strong filing and approval was limited to stations that had experienced water intrusion in the past. It was noted in the original filing that the Company would also review and identify other substations that could benefit from flood and/or storm surge mitigation, utilizing the FEMA preliminary flood elevations.[6] The flood mitigation aspect of this subprogram is the result of those studies and confirmations of impact on critical station facilities. The studies included topographic field surveys, site inspections to confirm

[6] Information about the advisory based flood elevations and maps are available on the FEMA website at www.region2coastal.com/sandy/abfe .

critical equipment, and development of office level estimates including risk and contingency. This portion of the Substation Subprogram is in compliance with the advised FEMA post-Sandy flood elevations and the flood elevation requirements established by the NJ Department of Environmental Protection (NJDEP) Flood Hazard Rules, codified at N.J.A.C. 7:13. The Company has identified 21 stations that have equipment below the base flood elevations plus 1 foot. Five of these stations (Homestead, North Avenue, North Bergen, Penhorn, and Newport) are being raised as part of PSE&G's base capital program.

Consistent with its experience in the implementation of Energy Strong, PSE&G has compared the alternatives to raise or eliminate stations based on the cost effectiveness of the solutions. In general, 4kV stations with low customer counts and/or peak loads are the best candidates to eliminate, generally with a 13kV circuit upgrade as done with three stations (Garfield Place, River Edge and Bayway 4kV) during Energy Strong. The chart below provides the recommended mitigation for each of the 16 stations recommended for flood mitigation in ES II.

Q. What resources are required to complete the storm surge/ flood mitigation portion of the Substation Subprogram?

A. The Station Flood and Storm Surge Mitigation portion of the Substations Subprogram requires $428 million over 5 years for full implementation. These costs have been developed through a feasibility analysis of each station including construction sequencing using the actual cost and construction experience from Energy Strong. The estimates are considered office level estimates. The benefits of this subprogram will be incremental as phases of the subprogram are executed. Engineering evaluations and estimates for each station are included in confidential Schedule EFG-ESII-4 of this testimony.[7] A cost-benefit analysis of the subprogram is being provided in testimony provided by Black & Veatch.

Station Name	Station Class	Recommendation	Customers Served
Academy Street Substation	C	Raise	9,298
Clay Street	A	Raise	8,492
Constable Hook Substation	Unit	Raise	1,612
Hasbrouck Heights Substation	C	Raise	2,326
Kingsland Substation	H	Raise	21,289
Lakeside Avenue Substation	A	Raise	10,583
Leonia Substation	H	Raise	33,021
Market Street Substation	A	Eliminate	3,770
Meadow Road	H	Raise	13,704
Orange Valley Substation	C	Raise	8,961
Ridgefield 13kV	H	Raise	33,339
Ridgefield 4kV	C	Eliminate	1,084
State Street Substation	A	Raise	3,312
Toney's Brook Substation	C	Raise	9,595
Waverly Substation	A	Raise	3,955
Woodlynne Substation	C	Raise	10,935
		Totals	165,978

2. Life Cycle Station Replacement

Q. Please provide an overview of PSE&G's proposal with respect to Life Cycle replacements.

A. The Substation Subprogram also includes a proposal to systematically replace assets that are near end of life. PSE&G has performed a study of asset demographics, failure curves, and risk scoring for all its Distribution Assets. The parameters of this effort are outlined in testimony by William D. Williams. PSE&G is proposing to replace equipment in

[7] Confidential Schedule EFG-ESII-4 consists of 16 separate Energy Strong II Flood Mitigation Project, Feasibility Analysis Reports ("Reports") for substations identified through site history or FEMA mapping and surveys as having the potential for flooding. The reports outline the scope of work for the 16 locations and provide cost estimates. Additionally, Schedule EFG-ESII-4 includes a spreadsheet summarizing cost estimates and number of customers served for each of the locations.

identified substations. The purpose of these replacements is to avoid a future large scale volume of assets reaching end of life and creating significant reliability and/or safety concerns. The safety concerns for substations are mostly related to workers operating this equipment. Beyond the personnel safety issues, failure to proactively address these facility needs as proposed herein will translate into operational changes requiring increased customer outages to perform work as it becomes necessary.

Q. Please describe PSE&G's proposal for life cycle replacement of equipment in Distribution Substations.

A. The Company proposes to replace or retire substations with 4kV assets that are either at or close to end-of-life. PSE&G has approximately 96 stations with these assets, with Class A and B station designs including 4kV facilities in a masonry building and Class C station designs having all facilities outdoors with 4kV equipment in metal-clad switchgear. Class A and B stations were constructed from PSE&G's inception in 1903 until approximately 1952. The first Class C station was constructed in 1938 and phased out as a standard for new stations in 1970. Excluding the 11 stations that are a part of the flood mitigation aspect of this subprogram, a breakdown of the stations that are considered candidates for life cycle replacement or retirement are listed below:

Class A and B substations

- Number of stations - 34
- Average age - 92
- Total Customers Served: 269,622

Class C substations

- Number of stations - 50
- Average age – 62
- Total Customers Served: 234,001

The majority of the 4kV equipment in these facilities is the original equipment installed at the time the station was in service. PSE&G will evaluate each station to determine if the station is still required or if its circuits can be cost effectively converted to 13kV operation. Based on risk scoring, the stations that supply 13kV circuits have 90% lower risk scores than 4kV stations due to the station design, configuration, and age. Aligned with the analysis performed on three stations in the Energy Strong program (Garfield Place, River Edge and Bayway), 4kV stations with low customer counts and/or peak loads are the best candidates to eliminate with a 13kV circuit upgrade. For stations that must remain, PSE&G will prioritize Class C stations for replacement; these stations have significantly higher risk scores than the Class A and B stations in part due to the fact that the 4kV equipment is in outdoor switchgear and is exposed to the elements. Due to the outdated (circa 1940) design and condition of the 4kV equipment in the Class C stations, PSE&G is proposing that this equipment be completely replaced with modern insulation, equipment, and protection schemes. PSE&G has prioritized work at existing 4kV stations based on the rationale outlined below.

1. Class C stations that are located where 69kV upgrades are completed or are in progress. These facilities are necessary to supply customers and are not anticipated to be eliminated in the future, so the upgrade of the 4kV will provide long term risk reduction. (15 Stations)
2. Class C stations identified for elimination and where there is capacity available for 13kV conversion. While these stations also provide long term risk reduction at a lower cost, they are given a lower priority due to resource constraints caused by the high level of Outside Plant work proposed in the other parts of the ES II proposal. (13 Stations)
3. Class C stations where a full station upgrade is required. These projects will be higher costs than the earlier priorities. (10 Stations)
4. Class A and B stations where 69kV upgrades are completed or are in progress or 26kV upgrades are planned. These facilities are necessary to supply customers and are not anticipated to be eliminated in the future, so the upgrade of the 4kV will provide long term risk reduction. (26 Stations)
5. The remaining Class A, B and C stations are not candidates to be completed within the proposed 5 year subprogram. (21 Stations)

Based on the priority above PSE&G is proposing the upgrading of the fifteen stations that fall into the top priority group listed below:

Station Name	Station Class	Recommendation	Customers Served
DUMONT	C	Rebuild 4kV	5,515
FOURTIETH ST	C	Rebuild 4kV	6,590
FRONT STREET	C	Rebuild 4kV	5,529
GREAT NOTCH	C	Rebuild 4kV	3,889
HAMILTON	C	Rebuild 4kV	1,650
MCLEAN BLVD	C	Rebuild 4kV	11,359
MOUNT HOLLY	C	Rebuild 4kV	4,127
PARAMUS	C	Rebuild 4kV	1,592
PLAINFIELD	C	Rebuild 4kV	6,885
SPRING VALLEY RD	C	Rebuild 4kV	962
TEANECK	C	Rebuild 4kV	4,658
TONNELLE AVENUE	C	Rebuild 4kV	3,681
TOTOWA	C	Rebuild 4kV	1,464
WARREN POINT	C	Rebuild 4kV	5,687
WOODBURY	C	Rebuild 4kV	4,663
		Totals	68,251

Q. What resources are required to complete the life cycle aspects of the Substation subprogram?

A. PSE&G estimates the lifecycle aspects of this subprogram will take 20 years for full implementation with an estimated investment of approximately $2.4 billion. PSE&G is requesting approval of $478 million for the first 5 years for the lifecycle aspect of this subprogram. An outline of the project scope and cost estimate is included in Schedule EFG—ESII-5.[8] There are incremental benefits as substations in the subprogram are executed.

[8] Confidential Schedule EFG-ESII-5 is a feasibility analysis report that outlines the design, construction and cost estimates for the replacement and upgrading of existing 4kV feeder rows with 4kV two story over-under sheltered aisle switchgear for Class C Stations. Additionally, Schedule EFG-ESII-5 includes a spreadsheet summarizing the design recommendations, customers served and cost estimates for upgrades to 15 Class C stations.

III. OUTSIDE PLANT HIGHER DESIGN STANDARD AND CONSTRUCTION STANDARDS SUBPROGRAM

Q. Please provide an overview of PSE&G's proposal with respect to Outside Plant Spacer Cable.

A. The Company proposes to convert existing open wire construction 13kV and 4kV circuits to spacer cable on circuits with poor storm performance. The construction change consists of replacement of cross-arm open wire construction with a more compact spacer cable configuration. Approximately 47% of PSE&G's overhead 13kV and 4kV mainline electrical system is composed of wires installed on cross-arms. A picture of typical cross arm construction is shown in picture #1 below.

A spacer cable system is composed of rugged weatherproofed wire, compacted into a bundle with a steel cable support. It is resistant to tree and limb damage because of its high strength and smaller profile. A picture of a typical spacer cable system is shown in picture #2 below.

On cross-arm construction, approximately 8 feet of 13kV open wire is placed on cross arms and is exposed to harm from tree limbs and other debris compared to approximately 18 inches on spacer cable. PSE&G has analyzed the performance of spacer cable in major events and has found that on a per mile basis spacer cable had 60% to 500% fewer damage locations attributed to tree contacts that caused customer interruptions, compared with cross arm construction. Fewer damage locations will result in fewer outages and faster restoration of service. This is due to the smaller profile and the presence of a steel supporting wire that supplies additional strength and protects the conductors from tree contacts. As vegetation related damage accounts for up to 80% of damage during a storm event, this reduction in damage will have significant hardening benefits for customers for all types of storm events. Better overvoltage protection is also obtained by the installation of supporting wire, offering protection from lightning strikes that are also more prevalent during storm conditions. The subprogram proposed will upgrade approximately 450 miles of circuits during the first 5 years with the possibility of continuing this program if approved beyond five years. As part of this subprogram PSE&G also proposes the replacement of approximately 7,100 poles on these circuits along with additional storm guying along these circuits. The pole replacements will target smaller diameter poles that are greater than 30 years of age. Due to the age of the existing poles the spacer cable upgrades require the pole to be replaced where pole tops cannot support spacer construction. In addition, by replacing the existing poles with larger diameter (Class 2) poles the strength of the pole will be increased significantly. A structural analysis of typical pole configurations, along with the age of the pole, shows the replacement of a typical 40 foot Class 4 (smaller diameter) pole with a Class 2 pole results in an overall strength gain of 53%. PSE&G will also enhance storm guying for the poles along these circuits. Pole guying refers to the use of cables and earth embedded anchors to strengthen poles and support the overhead electrical distribution system. The tension on guy wires from wind forces and tree impact will significantly reduce the shear and bending forces on pole lines. Appropriate placement of additional pole guys would reduce overall storm damage significantly by increasing pole strength and reducing cascading pole failures. This is required where spacer cable is being installed, as the additional strength of the conductor construction (steel support cable) will typically hold up large trees provided the supporting poles are of sufficient strength. The additional strength provided by pole upgrades and storm guying aligns with the need for upgrading to spacer cable.

Picture #1 - Open Wire Construction – Phases Spread over Wood Cross Arms

Picture #2 - Spacer Cable – Phases across spacer supported by steel cable with metal bracket at pole.

Q. Is PSE&G already performing this type of work?

A. PSE&G has done this work selectively for poor performing circuits during normal weather conditions as part of its base spending programs. PSE&G is in the process of upgrading approximately 11 circuits with a total of approximately 50 circuit miles with spacer cable.

Q. Are there any other benefits of converting open wire construction to spacer cable?

A. This subprogram provides the added benefit of replacing aged circuit facilities with new construction. While not the primary driver for the subprogram, it also aligns with PSE&G's life cycle replacement proposal by replacing facilities where performance can be expected to degrade due to the age. The wood cross-arms, insulators and wire ties are all examples of aged facilities that support open wire conductors that will be replaced. Where pole replacements are performed, aged facilities such as pole top transformers, will be replaced as part of the work.

Q. What resources are required to complete this subprogram?

A. PSE&G estimates this subprogram will take five years to implement with an investment of $345 million. There will be incremental benefits as circuit miles are energized with spacer cable throughout the subprogram. A list of the circuits proposed for this subprogram with associated mileage is shown in Schedule EFG-ESII-6. A cost-benefit analysis of the subprogram is being provided in testimony provided by Black & Veatch.

IV. CONTINGENCY RECONFIGURATION STRATEGIES SUBPROGRAM

Q. Please provide an overview of PSE&G's proposal with respect to implementing Contingency Reconfiguration Strategies.

A. The Company proposes to increase electric system resiliency and hardening by implementing circuit improvements, including increasing the number of sections in present loop designs utilizing reclosers, providing alternative circuit feeds or circuit reconfigurations to allow for greater flexibility for switching to alternative sources, and placing new devices on the system that will provide reclosing where it previously did not exist and allow for PSE&G to receive outage notifications without customer calls. In the approved Energy Strong program, contingency reconfiguration focused primarily on 260 critical facilities identified through communication with County Offices of Emergency Management in PSE&G's service territory, with benefits to approximately 413,000 customers in proximity to these facilities. The proposed subprogram will expand the benefits of these strategies to additional customers. PSE&G estimates that over 900,000 customers will benefit directly from this subprogram.

Q. Please describe the Company's proposal with respect to increased sectionalization.

A. PSE&G is proposing add an additional three-phase recloser to convert all existing two section overhead 13kV circuits to three section circuits. Through these automated recloser devices, the number of customers impacted by any type of damage to overhead circuits will be reduced on average by 17% per event. In addition, overhead 4kV radial circuits would be enhanced by a recloser to create two sections and reduce the number of customers impacted by an outage. For circuits where this is implemented, the number of customers impacted by an outage would be reduced by 25%. In addition, three phase branches with and without fuses will be enhanced with reclosers that will avoid extended interruptions for faults of a transient nature. On average, 50% of the events that occur will be reduced from extended outages to momentary outages of a minute or less. Finally, reclosers will be used to tie circuits together to create new tie points where service can be restored from an alternative source in the event of an outage.

Q. What resources are required to implement the proposal?

A. PSE&G estimates this portion of the subprogram will take five years for full implementation with an investment of $100 million. There will be incremental benefits as phases of the subprogram are executed. Schedule EFG-ESII-7 shows a list of circuits where reclosers are being proposed as part of this subprogram, but the exact circuits that will be addressed may differ somewhat from that list based on field conditions and other variables. A cost-benefit analysis of the subprogram is being provided in testimony provided by Black & Veatch.

Q. Please provide an overview of PSE&G's proposal with respect to single phase reclosing devices.

A. PSE&G proposes to install single phase devices on branch lines that currently have only fuses and require customer calls and/or field inspections to understand if customers are out of power or restored. The devices will be pole-mounted and will trip and reclose in the event of a fault on the branch line. They will also communicate both successful reclosing and power status at their location. These devices will provide both hardening and resiliency benefits.

Hardening

Based on PSE&G's experience with reclosers, it is estimated that over 60% of the time the device will successfully reclose and restore customer service. In these cases, customers only experience a momentary interruption of under a minute while in the past, these outages could range from over an hour to significantly longer in the case of a storm event with wide scale outages.

Resiliency

The devices provide a resiliency benefit by communicating power status through the communication network and SCADA to the ADMS system to indicate customer outages without phone calls and confirmation of customer restoration when circuits are returned to service. When damage occurs on a branch line and the branch trips out, PSE&G would receive electronic indication that repairs need to be made on the branch line even if an upstream protective device (i.e. station breaker or mainline recloser) later trips out. The current outage management system estimates all these outages are related to the same mainline event and these branch-line damage locations are lost until a customer calls back after the mainline event is repaired or the location is visited by a damage assessor or crew. Another resiliency benefit is the identification of branch-line outages after a circuit is restored. In major events, storm periods can extend well beyond the time when the initial circuit trips out of service and damage on branches can occur while the circuit is de-energized. Currently on circuit restoration, the only mechanism to confirm branch restoration is customer calls and/or circuit patrols. These reclosing devices would provide electronic indication of branch line outages that remain, and PSE&G can streamline the process of restoration by having confirmation where outages still exist.

Q. How will PSE&G identify and prioritize the location of these devices on the PSE&G system?

A. PSE&G will identify all locations where customers are served from overhead facilities on a branch-line. Priority will be given to locations with the most events over the past several years and the greatest number of customers served on the branch-line. The proposed list of locations is identified in Schedule EFG-ESII–8.

Q. What resources are required to implement the proposal?

A. PSE&G estimates this portion of the subprogram will take five years for full implementation with an investment of $45 million. However, there are incremental benefits as individual units are installed and are communicating. The subprogram will be coordinated with the communication network expansion and ADMS implementation. The communication network infrastructure is required to allow PSE&G to accurately report momentary outages and to take advantage of the resiliency benefits. A cost-benefit analysis of the subprogram is being provided in testimony provided by Black & Veatch.

V. <u>GRID MODERNIZATION SUBPROGRAM</u>

Q. Please provide an overview of PSE&G's proposal with respect to implementing grid modernization.

A. PSE&G proposes to build onto the new SCADA system that was part of Energy Strong to implement an ADMS and Communication Network to improve resiliency in storm events, and to enable PSE&G to meet future grid needs. Resiliency will be enhanced through greatly improved visibility of current system conditions, situational awareness, and enhanced remote communications. All these tools will enable PSE&G to better prioritize and perform restoration activities in a more efficient manner. Satisfaction of future grid needs will be enabled by providing for greatly improved modelling and system control to integrate DERs and also providing for secure and reliable communications to both PSE&G and customer equipment for monitoring and control.

Q. Please describe the capabilities of the proposed Advanced Distribution Management System (ADMS).

A. The Company proposes to develop an ADMS to incorporate data sources such as outage information gained from SCADA, intelligent fault indicators, potential future deployment of Smart Meters and AMI, and add-on analysis applications such as load flows and state estimations for data accuracy. ADMS provides tools for dynamic visualization, monitoring and control of the electric distribution network, together with a wide set of power applications for operations analysis, planning, and optimization. The system replaces the existing Outage Management System (OMS) and assimilates data from Geographic Information System (GIS) and SCADA systems. ADMS will provide efficient management of faults and voltage improvements; real-time network monitoring and control; incident management to assist in damage location identification; mathematical network modeling and power applications; network analysis; reduction of system losses through Volt/Var controls, which control and coordinate substation and pole mounted capacitors to optimize circuit voltages; and improvement of power quality and customer services.

In addition, enhancements to the OMS and GIS systems are proposed that would associate plant damage to its geographical location and relate it with trouble incidents;

enable customers to provide information about damage, including pictures; develop a work plan optimization engine to improve work prioritization and Estimated Time of Restoration; develop new and simplified storm management applications for internal mobile crews; develop a mutual aid field application; and enhance storm management analytics, visualization and reporting.

By enhancing and improving these storm management systems, PSE&G would be able to improve customer communications and satisfaction, and shorten customer outage durations. The system proposed would geographically display confirmed damage locations, current status (confirmed, assigned, etc.) and relate the damage locations to groups of outage incidents. This geographic view of outages and damage locations is not currently available in the existing OMS or GIS system. Providing this information will significantly improve damage assessment time by eliminating duplicate assignments and increase the speed of restoration. This would allow for efficient use of mutual aid workers, which is critical for minimizing cost of restoration work during major events, as the number of crews is typically substantially more than the existing workforce, and efficient work identification, prioritization and assignment to crews requires additional tools for storm restoration.

Q. What resources are required to implement ADMS?

A. PSE&G estimates this portion of the Grid Modernization subprogram will take five years for full implementation with an investment of $35 million. An outline of the project scope and estimate are included in Schedule EFG-ESII-9.

Q. Please provide an overview of PSE&G's proposal with respect to improving its communication network.

A. The Company proposes to install a wireless mesh network (which includes wireless and fiber components) and eliminate the use of copper wire telecommunication lines and dedicated phone lines for remote communication to both PSE&G and customer equipment. The overall mesh network will be designed to provide coverage for all switching devices on the system to facilitate both system and customer equipment communication moving forward. The system will be private and encrypted to ensure the security of PSE&G's capability to monitor and control the Distribution system. Once devices are connected to the system, the monitoring and control functions will be routed through PSE&G's new SCADA system installed during Energy Strong. This information will allow PSE&G to continue to use the SCADA system as designed for storm response but also allow for easy integration of new devices that can support further reliability enhancements as well as DER, demand response, electric vehicles and/or energy efficiency in the future.

Q. Please describe the communication infrastructure that is necessary to support electric system visibility efforts.

A. The subprogram will involve the installation of fiber to distribution substations not currently on the PSE&G transmission fiber system to provide the backbone communication system for this network. The transmission fiber system is already constructed and will provide the backbone for the majority of customers, and provides significant storm hardening benefits by being installed on transmission right-of-way steel towers cleared of vegetation. PSE&G substations will be the connection points for the high-speed pole mounted wireless mesh network that will be installed for communication to PSE&G and customer equipment.

For this subprogram, communication for existing PSE&G reclosers will be converted to this system, as these are the critical devices for PSE&G's existing and future circuit automation system and the existing copper wire communication system is being phased out by Verizon. The additional reclosers and reclosing devices proposed in this Program will also utilize this communication system. The exact number of mesh nodes will be dependent on the vendor, who will be selected through a competitive bidding process. The major work efforts related to the communication infrastructure include the following:

- Installation of wireless mesh network to cover the entire service territory and provide communications to all existing reclosers ($48 million)
- Installation of fiber to approximately 31 stations where it does not already exist to provide data back-hall for the wireless infrastructure ($14 million)
- Cut-over of 133 stations with existing fiber at the station ($7 million)
- Third communications feed to each electric operations center ($3M)

Q. What resources are required to complete this subprogram?

A. PSE&G estimates this portion of the Grid Modernization subprogram will take 3-5 years for full implementation with an investment of $72 million. However, there are incremental benefits as phases of the subprogram are executed. An outline of the project scope and estimate are included in Schedule EFG-ESII-10. A cost-benefit analysis of the subprogram is being provided in testimony provided by Black & Veatch.

VI. BENEFITS TO NEW JERSEY'S ECONOMY

Q. How will the infrastructure investments proposed herein benefit New Jersey's economy?

A. The electric portion of the ES II Program will provide benefits to both PSE&G's customers and New Jersey's economy. This component of the proposed ES II Program will result in additional skilled jobs. Using the methodology from the introductory material to the Board's IIP proposal for job creation in New Jersey, this portion of the proposed program would create an estimated 1,950 fulltime jobs per year for the duration of the Program.

Q. Please elaborate on the labor and other resources required to successfully complete this Program.

A. The Company anticipates an increase in staffing for engineering, construction and construction management, and records management in order to carry out the Program each year. PSE&G will continue to utilize a combination of internal labor and outside contractors for the Program. The Program will support employment opportunities for suppliers as well.

Q. How does a multi-year program affect the work effort involved with the ES II Program?

A. First and foremost, the vast majority of the construction projects proposed in ES II require five years to complete. Various aspects of permitting, planning, and coordinating the projects, many of which are interdependent, cannot be reasonably planned for and executed in less than a five year period. In addition, the multi-year approach provides various efficiencies in planning, staffing, and managing contractors and material procurement.

VII. PROGRAM REPORTING

Q. Does the Company intend to provide regular reporting on its progress?

A. Yes. Consistent with the IPP regulations, the Company proposes to submit semi-annual status reports to Board Staff and the Division of Rate Counsel that contain the following information:

1. Forecasted and actual costs of the Infrastructure Investment Program for the applicable reporting period, and for the Program to date, where Program projects are identified by major category;
2. The estimated total quantity of work completed under the Program identified by major category. In the event that the work cannot be quantified, major tasks completed shall be provided;
3. Estimated completion dates for the Infrastructure Investment Program as a whole, and estimated completion dates for each major Program category;
4. Anticipated changes to Infrastructure Investment Program projects, if any; and
5. Actual capital expenditures made by the utility in the normal course of business on similar projects, identified by major category.

Q. Does this conclude your testimony?

A. Yes.

CREDENTIALS OF EDWARD F GRAY DIRECTOR-TRANSMISSION AND DISTRIBUTION ENGINEERING

My name is Edward F. Gray and I am employed by Public Service Electric and Gas. I am the Director – Transmission and Distribution Engineering where I am responsible for engineering standards, reliability and maintenance programs for Electric Transmission and Distribution.

EDUCATIONAL BACKGROUND

I graduated from Rensselaer Polytechnic Institute with a Bachelor of Science degree in Civil Engineering. I also earned a Master's in Civil Engineering from Rutgers University and a Master's in Management from New Jersey Institute of Technology. I am a Licensed Professional Engineer in the State of New Jersey.

WORK EXPERIENCE

I have over 29 years' experience in Engineering and Asset Management at PSE&G. I have had various positions at PSE&G in Substation Engineering, System development for Electric and Gas work management, New Business Policy, Solar Interconnections, Resource Planning and Financial Management. I am presently the Director – Transmission and Distribution Engineering with oversight of electric engineering standards, reliability and maintenance programs.

I have been actively involved in Electric programs implemented since 2009. I was the program lead for Electric Distribution for both Capital Economic Stimulus Infrastructure Investment Programs responsible for the project implementation including cost and scheduling for each sub-program. For both programs developed discovery responses and was involved in various settlement and review meetings with BPU Staff and Rate Council. I was directly involved in my current position in the development of the Energy Strong program. I was actively involved in the preparation of testimony, project estimates, discovery responses and settlement meetings during the project approval. After approval was directly involved with project implementation on engineering and design of projects as well as working with the Independent Monitor on various process and data requests.

In addition to these programs I have been involved with various items with Board Staff including storm cost recovery filings and the PVSC substation petition as well as other items related to Smart Growth and solar policy.

Attachment 2

Electric Delivery Capital Summary (2012 - 2017)

Schedule EFG-ESII-2A

($ in millions)

Capital Category	2012 Full Year Actual	2013 Full Year Actual	2014 Full Year Actual	2015 Full Year Actual	2016 Full Year Actual	2017 Full Year Actual
New Business	$ 58.7	$ 110.6	$ 102.6	$ 113.4	$ 119.3	$ 124.9
Base	**$ 211.4**	**$ 181.1**	**$ 164.6**	**$ 188.8**	**$ 226.1**	**$ 357.5**
Energy Strong			$ 54.1	$ 181.7	$ 252.0	$ 108.9
CIP II	$ 140.5	$ 21.1				
Total Capital $	**$ 410.7**	**$ 312.8**	**$ 321.3**	**$ 484.0**	**$ 597.4**	**$ 591.4**

Base Breakdown by Major Category

Replace Facilities	$ 162.6	$ 113.1	$ 104.0	$ 101.0	$ 123.0	$ 172.0
System Reinforcement	$ 38.0	$ 43.6	$ 34.6	$ 55.5	$ 74.3	$ 146.8
Environmental Regulatory	$ (6.8)	$ 9.7	$ 9.2	$ 9.4	$ 8.4	$ 7.5
Replace Meters	$ 13.3	$ 13.3	$ 11.8	$ 15.2	$ 14.9	$ 16.4
Support Facilities	$ 4.3	$ 1.5	$ 5.0	$ 7.7	$ 5.5	$ 14.8
Base Total $	**$ 211.4**	**$ 181.1**	**$ 164.6**	**$ 188.8**	**$ 226.1**	**$ 357.5**

Electric Delivery Capital Summary (2019 - 2023)

Capital Category ($M)	2019 Full Year Plan	2020 Full Year Plan	2021 Full Year Plan	2022 Full Year Plan	2023 Full Year Plan
Base (Energy Strong II-Like Work)	51	40	20	19	20
Base (All Other)	182	193	213	214	213
Total Base	**233**	**233**	**233**	**233**	**233**
New Business	114	113	116	118	118
Energy Strong II - Recovery Mechanism	42	346	557	348	204
Total Capital $	**$ 389**	**$ 692**	**$ 906**	**$ 699**	**$ 555**

Base Breakdown by Major Category

Replace Facilities	$ 121	$ 117	$ 133	$ 125	$ 125
System Reinforcement	$ 85	$ 91	$ 64	$ 68	$ 68
Environmental Regulatory	$ 5	$ 5	$ 6	$ 12	$ 12
Replace Meters	$ 18	$ 18	$ 18	$ 18	$ 18
Support Facilities	$ 3	$ 2	$ 12	$ 10	$ 10
Base Total $*	**$ 233**	**$ 233**	**$ 233**	**$ 233**	**$ 233**

*The Company proposes to maintain base level spending from 2019-2023 at the projections shown above

Stipulated Base Requirement						Trailing	Total
ESII-Like Work in Total Base	51	40	20	19	20		$ 150
Energy Strong II Program Expenditures	42	346	557	348	204	6	$ 1,503
% Stipulated base							**10%**

PSE&G Energy Strong Program II
Electric Summary Cash Flows

Cash Flows ($000s)	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Program Year - 2019													
Direct In-Service	$ -	$ -	$ 999	$ 999	$ 999	$ 1,998	$ 1,998	$ 1,998	$ 1,998	$ 2,996	$ 2,996	$ 2,996	$ 19,976
CWIP Spending	$ -	$ -	$ 904	$ 904	$ 904	$ 1,808	$ 1,808	$ 1,808	$ 1,808	$ 2,711	$ 2,711	$ 2,711	$ 18,075
COR	$ -	$ -	$ 198	$ 198	$ 198	$ 395	$ 395	$ 395	$ 395	$ 593	$ 593	$ 593	$ 3,954
Total	**$ -**	**$ -**	**$ 2,100**	**$ 2,100**	**$ 2,100**	**$ 4,201**	**$ 4,201**	**$ 4,201**	**$ 4,201**	**$ 6,301**	**$ 6,301**	**$ 6,301**	**$ 42,005**
Program Year - 2020													
Direct In-Service	$ 8,323	$ 8,323	$ 8,323	$ 8,323	$ 8,323	$ 8,323	$ 8,323	$ 8,323	$ 8,323	$ 8,323	$ 8,323	$ 8,323	$ 99,880
CWIP Spending	$ 17,954	$ 17,954	$ 17,954	$ 17,954	$ 17,954	$ 17,954	$ 17,954	$ 17,954	$ 17,954	$ 17,954	$ 17,954	$ 17,954	$ 215,442
COR	$ 2,554	$ 2,554	$ 2,554	$ 2,554	$ 2,554	$ 2,554	$ 2,554	$ 2,554	$ 2,554	$ 2,554	$ 2,554	$ 2,554	$ 30,645
Total	**$ 28,831**	**$ 28,831**	**$ 28,831**	**$ 28,831**	**$ 28,831**	**$ 28,831**	**$ 28,831**	**$ 28,831**	**$ 28,831**	**$ 28,831**	**$ 28,831**	**$ 28,831**	**$ 345,968**
Program Year - 2021													
Direct In-Service	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 124,850
CWIP Spending	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 383,946
COR	$ 4,023	$ 4,023	$ 4,023	$ 4,023	$ 4,023	$ 4,023	$ 4,023	$ 4,023	$ 4,023	$ 4,023	$ 4,023	$ 4,023	$ 48,276
Total	**$ 46,423**	**$ 46,423**	**$ 46,423**	**$ 46,423**	**$ 46,423**	**$ 46,423**	**$ 46,423**	**$ 46,423**	**$ 46,423**	**$ 46,423**	**$ 46,423**	**$ 46,423**	**$ 557,072**
Program Year - 2022													
Direct In-Service	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 124,850
CWIP Spending	$ 16,015	$ 16,015	$ 16,015	$ 16,015	$ 16,015	$ 16,015	$ 16,015	$ 16,015	$ 16,015	$ 16,015	$ 16,015	$ 16,015	$ 192,179
COR	$ 2,633	$ 2,633	$ 2,633	$ 2,633	$ 2,633	$ 2,633	$ 2,633	$ 2,633	$ 2,633	$ 2,633	$ 2,633	$ 2,633	$ 31,600
Total	**$ 29,052**	**$ 29,052**	**$ 29,052**	**$ 29,052**	**$ 29,052**	**$ 29,052**	**$ 29,052**	**$ 29,052**	**$ 29,052**	**$ 29,052**	**$ 29,052**	**$ 29,052**	**$ 348,630**
Program Year - 2023													
Direct In-Service	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 10,404	$ 124,850
CWIP Spending	$ 5,375	$ 5,375	$ 5,375	$ 5,375	$ 5,375	$ 5,375	$ 5,375	$ 5,375	$ 5,375	$ 5,375	$ 5,375	$ -	$ 59,126
COR	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,304	$ 20,000
Total	**$ 17,479**	**$ 17,479**	**$ 17,479**	**$ 17,479**	**$ 17,479**	**$ 17,479**	**$ 17,479**	**$ 17,479**	**$ 17,479**	**$ 17,479**	**$ 17,479**	**$ 11,708**	**$ 203,976**
Program Year - 2024													
Direct In-Service	$ 2,497	$ 2,497	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,994
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 313	$ 313	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 626
Total	**$ 2,810**	**$ 2,810**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5,620**
Totals													
Direct In-Service	$ 42,033	$ 42,033	$ 40,535	$ 40,535	$ 40,535	$ 41,533	$ 41,533	$ 41,533	$ 41,533	$ 42,532	$ 42,532	$ 42,532	$ 499,400
CWIP Spending	$ 71,339	$ 71,339	$ 72,243	$ 72,243	$ 72,243	$ 73,147	$ 73,147	$ 73,147	$ 73,147	$ 74,050	$ 74,050	$ 68,675	$ 868,769
COR	$ 11,223	$ 11,223	$ 11,107	$ 11,107	$ 11,107	$ 11,305	$ 11,305	$ 11,305	$ 11,305	$ 11,503	$ 11,503	$ 11,107	$ 135,102
Total	**$ 124,595**	**$ 124,595**	**$ 123,885**	**$ 123,885**	**$ 123,885**	**$ 125,985**	**$ 125,985**	**$ 125,985**	**$ 125,985**	**$ 128,085**	**$ 128,085**	**$ 122,315**	**$ 1,503,271**

PSE&G Energy Strong Program II
Electric Substation Subprogram Cash Flows

Cash Flows ($000s)	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Program Year - 2019													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ -	$ -	$ 834	$ 834	$ 834	$ 1,668	$ 1,668	$ 1,668	$ 1,668	$ 2,501	$ 2,501	$ 2,501	$ 16,675
COR	$ -	$ -	$ 73	$ 73	$ 73	$ 145	$ 145	$ 145	$ 145	$ 218	$ 218	$ 218	$ 1,450
Total	**$ -**	**$ -**	**$ 906**	**$ 906**	**$ 906**	**$ 1,813**	**$ 1,813**	**$ 1,813**	**$ 1,813**	**$ 2,719**	**$ 2,719**	**$ 2,719**	**$ 18,125**
Program Year - 2020													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 17,370	$ 17,370	$ 17,370	$ 17,370	$ 17,370	$ 17,370	$ 17,370	$ 17,370	$ 17,370	$ 17,370	$ 17,370	$ 17,370	$ 208,442
COR	$ 1,510	$ 1,510	$ 1,510	$ 1,510	$ 1,510	$ 1,510	$ 1,510	$ 1,510	$ 1,510	$ 1,510	$ 1,510	$ 1,510	$ 18,125
Total	**$ 18,881**	**$ 18,881**	**$ 18,881**	**$ 18,881**	**$ 18,881**	**$ 18,881**	**$ 18,881**	**$ 18,881**	**$ 18,881**	**$ 18,881**	**$ 18,881**	**$ 18,881**	**$ 226,568**
Program Year - 2021													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 31,266	$ 31,266	$ 31,266	$ 31,266	$ 31,266	$ 31,266	$ 31,266	$ 31,266	$ 31,266	$ 31,266	$ 31,266	$ 31,266	$ 375,196
COR	$ 2,719	$ 2,719	$ 2,719	$ 2,719	$ 2,719	$ 2,719	$ 2,719	$ 2,719	$ 2,719	$ 2,719	$ 2,719	$ 2,719	$ 32,626
Total	**$ 33,985**	**$ 33,985**	**$ 33,985**	**$ 33,985**	**$ 33,985**	**$ 33,985**	**$ 33,985**	**$ 33,985**	**$ 33,985**	**$ 33,985**	**$ 33,985**	**$ 33,985**	**$ 407,822**
Program Year - 2022													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 15,286	$ 15,286	$ 15,286	$ 15,286	$ 15,286	$ 15,286	$ 15,286	$ 15,286	$ 15,286	$ 15,286	$ 15,286	$ 15,286	$ 183,429
COR	$ 1,329	$ 1,329	$ 1,329	$ 1,329	$ 1,329	$ 1,329	$ 1,329	$ 1,329	$ 1,329	$ 1,329	$ 1,329	$ 1,329	$ 15,950
Total	**$ 16,615**	**$ 16,615**	**$ 16,615**	**$ 16,615**	**$ 16,615**	**$ 16,615**	**$ 16,615**	**$ 16,615**	**$ 16,615**	**$ 16,615**	**$ 16,615**	**$ 16,615**	**$ 199,380**
Program Year - 2023													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 4,548	$ 4,548	$ 4,548	$ 4,548	$ 4,548	$ 4,548	$ 4,548	$ 4,548	$ 4,548	$ 4,548	$ 4,548	$ -	$ 50,026
COR	$ 395	$ 395	$ 395	$ 395	$ 395	$ 395	$ 395	$ 395	$ 395	$ 395	$ 395	$ -	$ 4,350
Total	**$ 4,943**	**$ 4,943**	**$ 4,943**	**$ 4,943**	**$ 4,943**	**$ 4,943**	**$ 4,943**	**$ 4,943**	**$ 4,943**	**$ 4,943**	**$ 4,943**	**$ -**	**$ 54,376**
Totals													
Direct In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWIP Spending	$ 68,470	$ 68,470	$ 69,304	$ 69,304	$ 69,304	$ 70,138	$ 70,138	$ 70,138	$ 70,138	$ 70,971	$ 70,971	$ 66,424	$ 833,769
COR	$ 5,954	$ 5,954	$ 6,026	$ 6,026	$ 6,026	$ 6,099	$ 6,099	$ 6,099	$ 6,099	$ 6,171	$ 6,171	$ 5,776	$ 72,502
Total	**$ 74,424**	**$ 74,424**	**$ 75,330**	**$ 75,330**	**$ 75,330**	**$ 76,237**	**$ 76,237**	**$ 76,237**	**$ 76,237**	**$ 77,143**	**$ 77,143**	**$ 72,200**	**$ 906,271**

PSE&G Energy Strong Program II
Electric Higher Outside Plant Design Standards Subprogram Cash Flows

Cash Flows ($000s)	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Program Year - 2019													
Direct In-Service	$ -	$ -	$ 587	$ 587	$ 587	$ 1,173	$ 1,173	$ 1,173	$ 1,173	$ 1,760	$ 1,760	$ 1,760	$ 11,730
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ -	$ -	$ 104	$ 104	$ 104	$ 207	$ 207	$ 207	$ 207	$ 311	$ 311	$ 311	$ 2,070
Total	**$ -**	**$ -**	**$ 690**	**$ 690**	**$ 690**	**$ 1,380**	**$ 1,380**	**$ 1,380**	**$ 1,380**	**$ 2,070**	**$ 2,070**	**$ 2,070**	**$ 13,800**
Program Year - 2020													
Direct In-Service	$ 4,888	$ 4,888	$ 4,888	$ 4,888	$ 4,888	$ 4,888	$ 4,888	$ 4,888	$ 4,888	$ 4,888	$ 4,888	$ 4,888	$ 58,650
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 10,350
Total	**$ 5,750**	**$ 5,750**	**$ 5,750**	**$ 5,750**	**$ 5,750**	**$ 5,750**	**$ 5,750**	**$ 5,750**	**$ 5,750**	**$ 5,750**	**$ 5,750**	**$ 5,750**	**$ 69,000**
Program Year - 2021													
Direct In-Service	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 73,313
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 12,938
Total	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 86,250**
Program Year - 2022													
Direct In-Service	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 73,313
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 12,938
Total	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 86,250**
Program Year - 2023													
Direct In-Service	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 6,109	$ 73,313
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 1,078	$ 12,938
Total	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 7,188**	**$ 86,250**
Program Year - 2024													
Direct In-Service	$ 1,466	$ 1,466	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,933
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 259	$ 259	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 518
Total	**$ 1,725**	**$ 1,725**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,450**
Totals													
Direct In-Service	$ 24,682	$ 24,682	$ 23,802	$ 23,802	$ 23,802	$ 24,389	$ 24,389	$ 24,389	$ 24,389	$ 24,975	$ 24,975	$ 24,975	$ 293,250
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 4,356	$ 4,356	$ 4,200	$ 4,200	$ 4,200	$ 4,304	$ 4,304	$ 4,304	$ 4,304	$ 4,407	$ 4,407	$ 4,407	$ 51,750
Total	**$ 29,038**	**$ 29,038**	**$ 28,003**	**$ 28,003**	**$ 28,003**	**$ 28,693**	**$ 28,693**	**$ 28,693**	**$ 28,693**	**$ 29,383**	**$ 29,383**	**$ 29,383**	**$ 345,000**

PSE&G Energy Strong Program II

Electric Contingency Reconfiguration Subprogram Cash Flows

Cash Flows ($000s)	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Program Year - 2019													
Direct In-Service	$ -	$ -	$ 276	$ 276	$ 276	$ 551	$ 551	$ 551	$ 551	$ 827	$ 827	$ 827	$ 5,510
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ -	$ -	$ 15	$ 15	$ 15	$ 29	$ 29	$ 29	$ 29	$ 44	$ 44	$ 44	$ 290
Total	**$ -**	**$ -**	**$ 290**	**$ 290**	**$ 290**	**$ 580**	**$ 580**	**$ 580**	**$ 580**	**$ 870**	**$ 870**	**$ 870**	**$ 5,800**
Program Year - 2020													
Direct In-Service	$ 2,296	$ 2,296	$ 2,296	$ 2,296	$ 2,296	$ 2,296	$ 2,296	$ 2,296	$ 2,296	$ 2,296	$ 2,296	$ 2,296	$ 27,550
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 121	$ 121	$ 121	$ 121	$ 121	$ 121	$ 121	$ 121	$ 121	$ 121	$ 121	$ 121	$ 1,450
Total	**$ 2,417**	**$ 2,417**	**$ 2,417**	**$ 2,417**	**$ 2,417**	**$ 2,417**	**$ 2,417**	**$ 2,417**	**$ 2,417**	**$ 2,417**	**$ 2,417**	**$ 2,417**	**$ 29,000**
Program Year - 2021													
Direct In-Service	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 34,438
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 1,813
Total	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 36,250**
Program Year - 2022													
Direct In-Service	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 34,438
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 1,813
Total	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 36,250**
Program Year - 2023													
Direct In-Service	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 2,870	$ 34,438
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 151	$ 1,813
Total	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 3,021**	**$ 36,250**
Program Year - 2024													
Direct In-Service	$ 689	$ 689	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,378
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 36	$ 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 73
Total	**$ 725**	**$ 725**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,450**
Totals													
Direct In-Service	$ 11,594	$ 11,594	$ 11,181	$ 11,181	$ 11,181	$ 11,456	$ 11,456	$ 11,456	$ 11,456	$ 11,732	$ 11,732	$ 11,732	$ 137,750
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 610	$ 610	$ 588	$ 588	$ 588	$ 603	$ 603	$ 603	$ 603	$ 617	$ 617	$ 617	$ 7,250
Total	**$ 12,204**	**$ 12,204**	**$ 11,769**	**$ 11,769**	**$ 11,769**	**$ 12,059**	**$ 12,059**	**$ 12,059**	**$ 12,059**	**$ 12,349**	**$ 12,349**	**$ 12,349**	**$ 145,000**

PSE&G Energy Strong Program II
Electric Grid Modernization Subprogram Cash Flows

Cash Flows ($000s)	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Program Year - 2019													
Direct In-Service	$ -	$ -	$ 137	$ 137	$ 137	$ 274	$ 274	$ 274	$ 274	$ 410	$ 410	$ 410	$ 2,736
CWIP Spending	$ -	$ -	$ 70	$ 70	$ 70	$ 140	$ 140	$ 140	$ 140	$ 210	$ 210	$ 210	$ 1,400
COR	$ -	$ -	$ 7	$ 7	$ 7	$ 14	$ 14	$ 14	$ 14	$ 22	$ 22	$ 22	$ 144
Total	**$ -**	**$ -**	**$ 214**	**$ 214**	**$ 214**	**$ 428**	**$ 428**	**$ 428**	**$ 428**	**$ 642**	**$ 642**	**$ 642**	**$ 4,280**
Program Year - 2020													
Direct In-Service	$ 1,140	$ 1,140	$ 1,140	$ 1,140	$ 1,140	$ 1,140	$ 1,140	$ 1,140	$ 1,140	$ 1,140	$ 1,140	$ 1,140	$ 13,680
CWIP Spending	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 7,000
COR	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 720
Total	**$ 1,783**	**$ 1,783**	**$ 1,783**	**$ 1,783**	**$ 1,783**	**$ 1,783**	**$ 1,783**	**$ 1,783**	**$ 1,783**	**$ 1,783**	**$ 1,783**	**$ 1,783**	**$ 21,400**
Program Year - 2021													
Direct In-Service	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 17,100
CWIP Spending	$ 729	$ 729	$ 729	$ 729	$ 729	$ 729	$ 729	$ 729	$ 729	$ 729	$ 729	$ 729	$ 8,750
COR	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 900
Total	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 26,750**
Program Year - 2022													
Direct In-Service	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 17,100
CWIP Spending	$ 729	$ 729	$ 729	$ 729	$ 729	$ 729	$ 729	$ 729	$ 729	$ 729	$ 729	$ 729	$ 8,750
COR	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 900
Total	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 2,229**	**$ 26,750**
Program Year - 2023													
Direct In-Service	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 17,100
CWIP Spending	$ 827	$ 827	$ 827	$ 827	$ 827	$ 827	$ 827	$ 827	$ 827	$ 827	$ 827	$ -	$ 9,100
COR	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 900
Total	**$ 2,327**	**$ 2,327**	**$ 2,327**	**$ 2,327**	**$ 2,327**	**$ 2,327**	**$ 2,327**	**$ 2,327**	**$ 2,327**	**$ 2,327**	**$ 2,327**	**$ 1,500**	**$ 27,100**
Program Year - 2024													
Direct In-Service	$ 342	$ 342	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 684
CWIP Spending	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COR	$ 18	$ 18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 36
Total	**$ 360**	**$ 360**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 720**
Totals													
Direct In-Service	$ 5,757	$ 5,757	$ 5,552	$ 5,552	$ 5,552	$ 5,689	$ 5,689	$ 5,689	$ 5,689	$ 5,825	$ 5,825	$ 5,825	$ 68,400
CWIP Spending	$ 2,869	$ 2,869	$ 2,939	$ 2,939	$ 2,939	$ 3,009	$ 3,009	$ 3,009	$ 3,009	$ 3,079	$ 3,079	$ 2,252	$ 35,000
COR	$ 303	$ 303	$ 292	$ 292	$ 292	$ 299	$ 299	$ 299	$ 299	$ 307	$ 307	$ 307	$ 3,600
Total	**$ 8,929**	**$ 8,929**	**$ 8,783**	**$ 8,783**	**$ 8,783**	**$ 8,997**	**$ 8,997**	**$ 8,997**	**$ 8,997**	**$ 9,211**	**$ 9,211**	**$ 8,384**	**$ 107,000**

Substation Subprogram - Station Flood and Storm Surge Mitigation Estimate Summary				
Station Name	**Station Class**	**Recommendation**	**Customer Served**	**Estimate (1,000's)**
Academy Street Substation	C	Raise	9,298	$18,906
Clay Street	A	Raise	8,492	$50,000
Constable Hook Substation	Unit	Raise	1,612	$5,884
Hasbrouck Heights Substation	C	Raise	2,326	$22,400
Kingsland Substation	H	Raise	21,289	$18,403
Lakeside Avenue Substation	A	Raise	10,583	$40,147
Leonia Substation	H	Raise	33,021	$25,649
Market Street Substation	A	Eliminate	3,770	$11,508
Meadow Road	H	Raise	13,704	$29,500
Orange Valley Substation	C	Raise	8,961	$28,194
Ridgefield 13kV	H	Raise	33,339	$18,588
Ridgefield 4kV	C	Eliminate	1,084	$31,145
State Street Substation	A	Raise	3,312	$17,889
Toney's Brook Substation	C	Raise	9,595	$31,803
Waverly Substation	A	Raise	3,955	$42,900
Woodlynne Substation	C	Raise	10,935	$35,000
		Totals	165,978	$427,916

FEMA Flood and Station Equipment Elevations for Substation Flood and Surge Mitigation Program

					Elevations from survey								
Station Name	**Town**	**Station Class**	**Controlling FEMA Elev.**	**FEMA + 1**	**Site**	**Control House Floor**	**Transformer Pad**	**XFMR Control Cab. Height**	**XFMR Control Cabinet Elev**	**Switchgear Pad**	**Swgr. Base Height**	**Swgr. Base Elevation**	**Distribution Equipment Impacted**
Academy Street Substation	Jersey City	C	AE 11	12	8.5	12.05	11	1	12.00*	10-11	0.25	10.25	4kV switchgear
Clay Street Substation	Newark	A	AE 10	11	9	10.4	9	0.708	9.7*				4kV Regulators
Constable Hook Substation	Bayonne	Unit	AE 12	13	9.5		10.17/9.83	2/4.83	9.4/10.5	9.92	1	9.4/10.5	Unit Substations
Hasbrouck Heights Substation	Hasbrouck Heights	C	AE 8	9	8	8.15	8.2	See notes below		7.8	0.17	7.97	4kV switchgear
Kingsland Substation	North Arlington	H	AE 9	10	8	10.75	10.28	3.75/1.67	14.03/11.95	8.4	0.5	8.9	13kV Switchgear
Lakeside Avenue Substation	Orange	A	AE 158	159	153	153.9/ 154.5	152	1.75	153.75**				26 and 4kV Breakers, 4kV Regulators and Voltage Regulators, Control House, Transformers
Leonia Substation	Leonia	H	AE 8	9	7	9	7.5			7.5	0.17	7.67	13kV Switchgear
Market Street Substation	Gloucester	A	AE 10	11		8.3	8.5	3	11.5				4kV Regulators and Reactors
Meadow Road	Edison	H	A (54)	55	51	51	51						13kV Switchgear
Orange Valley Substation	Orange	C	A0 2	172.5	169.5		170	0.79	170.8*	170	0.375	170.375	4kV switchgear
Ridgefield Substation 13kV	Ridgefield	H	AE 8	9	7	8.36	8.65	See notes below		8.2	0.17	8.37	13kV Switchgear
Ridgefield Substation 4kv	Ridgefield	C	AE 8	9	7	8.36	8.65	See notes below		8.2	0.17	8.37	4kV switchgear
State Street Substation	Camden	A	AE 9	10	8	7.94	8	1.17	9.2*	8	0.75	8.75	4kV Regulators, Reactors and Switchgear
Toney’s Brook Substation	Bloomfield	C	AE 128	129	124	124.8	124	0.33	124.33*	124.2	0.42	124.62	Control House, Transformers, Switchgear
Waverly Substation	Newark	A	AE 11	12	11	9.8	12.97	1.25	14.22				4kV Regulators and Reactors
Woodlynne Substation	Camden	C	AE 9	10	8-9	9.49	9.5	1	9.4*	9	0.42	9.42	4kV Switchgear

* No transformer control cabinet. Transformer sits on steel beam. Elevation shown is at the base of the transformer
** T1 and T3 are old units without cabinets. T2 cabinet is 1'-9" above the foundation.

Hasbrouck Heights		Pad Elev	**XFMR Control Cab. Height**	**XFMR Control Cabinet Elev**	
	T1	8.2	1	9.2	No Control Cabinet
	T2	8.2	1	9.2	No Control Cabinet
	T3	8.2	2.22	10.42	
	T4	8.2	1.55	9.75	

Ridgefield		Pad Elev	**XFMR Control Cab. Height**	**XFMR Control Cabinet Elev**	
	T1	8.65	1	9.65	No Control Cabinet
	T2	8.65	3.83	12.48	
	T10	8.65	3.17	11.82	
	T30	8.65	2.75	11.4	

Attachment 2

Gray-Schedule-EFG-ESII-4

Confidential

Substation Subprogram - Life Cycle Program Estimate Summary				
Station Name	**Station Class**	**Recommendation**	**Customer Served**	**Estimate (1,000's)**
DUMONT	C	Rebuild 4kV	5,515	$29,500
FOURTIETH ST	C	Rebuild 4kV	6,590	$29,375
FRONT STREET	C	Rebuild 4kV	5,529	$29,625
GREAT NOTCH	C	Rebuild 4kV	3,889	$30,300
HAMILTON	C	Rebuild 4kV	1,650	$29,625
MCLEAN BLVD	C	Rebuild 4kV	11,359	$34,875
MOUNT HOLLY	C	Rebuild 4kV	4,127	$34,875
PARAMUS	C	Rebuild 4kV	1,592	$36,200
PLAINFIELD	C	Rebuild 4kV	6,885	$35,125
SPRING VALLEY RD	C	Rebuild 4kV	962	$35,125
TEANECK	C	Rebuild 4kV	4,658	$29,750
TONNELLE AVENUE	C	Rebuild 4kV	3,681	$29,500
TOTOWA	C	Rebuild 4kV	1,464	$29,500
WARREN POINT	C	Rebuild 4kV	5,687	$29,750
WOODBURY	C	Rebuild 4kV	4,663	$35,250
		Totals	68,251	$478,375

Attachment 2

Gray-Schedule-EFG-ESII-5

Confidential

EFG-ESII-6: Proposed Circuits for Open Wire Replacement with Spacer Cable

Station	Circuit	Voltage	Miles
Academy Street	ACA 4003	4	1.33
Adams	ADA 8023	13	1.03
Aldene Sub	ALD 8014	13	0.78
Arcola	ARC 4001	4	1.26
Beaver Brook	BEA 8002	13	3.20
Beaver Brook	BEA 8005	13	4.28
Beaver Brook	BEA 8009	13	8.25
Bloomfield	BLO 4014	4	1.30
Bordentown	BOR 4007	4	1.59
Branchbrook	BRA 8011	13	2.54
Bustleton	BUS 8014	13	8.94
Chauncey Street	CHA 4015	4	0.42
Cherry Hill	CHE 4008	4	0.97
Cinnaminson	CIN 8006	13	1.32
Cinnaminson	CIN 8011	13	2.84
Clarksville	CLK 8015	13	3.35
Clarksville	CLK 8025	13	2.15
Cook Rd	COR 8033	13	2.91
Crosswicks	CRX 8004	13	4.83
Crosswicks	CRX 8006	13	13.67
Cuthbert Blvd	CUT 8032	13	5.79
Cuthbert Blvd	CUT 8043	13	2.40
Coxs Corner Sub	CXC 8022	13	4.48
Deptford	DFD 8033	13	4.98
Doremus Place	DOR 8014	13	1.23
Doremus Place	DOR 8024	13	1.29
Doremus Place	DOR 8045	13	0.42
East Orange Sub	EAO 4012	4	0.61
East Rutherford Sub	EAT 8011	13	3.30
East Rutherford Sub	EAT 8022	13	1.00
Edison	EDI 4008	4	0.86
Englewood	ENG 4006	4	0.72
Englewood	ENG 4017	4	0.73
Fanwood	FAW 8024	13	0.84
Federal Square	FED 4004	4	2.42
Fernwood Unit 8051	FEN 8051	13	5.36
Fort Lee	FOR 4013	4	0.41
Garfield Avenue	GAE 4003	4	1.64
Garfield Avenue	GAE 4006	4	1.45
Green Brook	GBK 8012	13	3.94
Green Brook	GBK 8025	13	2.78
Haddon Heights	HAD 4002	4	1.47
Haledon	HAL 4002	4	2.08
Hillsdale	HID 8025	13	4.12
Hillsdale	HID 8032	13	0.41
Hillsdale	HID 8033	13	4.98
Homestead	HOM 8014	13	2.17

EFG-ESII-6: Proposed Circuits for Open Wire Replacement with Spacer Cable

Station	Circuit	Voltage	Miles
Homestead	HOM 8023	13	3.12
Hudson Terrace	HUD 4002	4	0.91
Kingsland	KIN 8025	13	3.09
Kuser Rd	KUS 8001	13	5.03
Kuser Rd	KUS 8002	13	2.59
Kuser Rd	KUS 8006	13	2.42
Kuser Rd	KUS 8008	13	1.16
Kuser Rd	KUS 8031	13	4.56
Kuser Rd	KUS 8033	13	3.96
Kuser Rd	KUS 8041	13	5.46
Kuser Rd	KUS 8045	13	5.64
Lawnside	LAW 8016	13	1.94
Lawnside	LAW 8018	13	4.26
Lawnside	LAW 8019	13	3.82
Lawnside	LAW 8025	13	5.31
Lawnside	LAW 8026	13	5.01
Lawrence Sub	LCE 8034	13	4.15
Lawrence Unit Sub	LCU 8051	13	2.11
Leonia	LEO 8002	13	2.05
Leonia	LEO 8003	13	3.09
Leonia	LEO 8004	13	2.04
Leonia	LEO 8008	13	0.41
Leonia	LEO 8033	13	1.01
Leonia	LEO 8035	13	3.55
Leonia	LEO 8041	13	2.72
Leonia	LEO 8043	13	2.71
Leonia	LEO 8044	13	3.54
Levittown	LEV 8003	13	5.07
Levittown	LEV 8004	13	1.82
Levittown	LEV 8005	13	3.35
Levittown	LEV 8008	13	11.17
Levittown	LEV 8015	13	3.55
Lumberton	LUM 8011	13	9.59
Maple Shade	MAD 8017	13	1.39
Maple Shade	MAD 8018	13	4.55
Maple Shade	MAD 8022	13	2.47
Maple Shade	MAD 8032	13	3.17
Maple Shade	MAD 8033	13	4.13
Marlton	MAR 8015	13	4.13
Marlton	MAR 8018	13	4.01
Marlton	MAR 8020	13	3.97
Maywood	MAY 8012	13	3.50
Maywood	MAY 8015	13	2.01
Maywood	MAY 8022	13	1.53
Maywood	MAY 8023	13	1.48
McLean Blvd	MCL 4008	4	1.78
Medford	MDF 8013	13	7.08

EFG-ESII-6: Proposed Circuits for Open Wire Replacement with Spacer Cable

Station	Circuit	Voltage	Miles
Medford	MDF 8014	13	4.72
Medford	MDF 8022	13	4.68
Mechanic Street	MEC 4007	4	1.24
Montclair	MNT 4012	4	1.23
Mount Rose	MRO 8012	13	1.17
Mount Rose	MRO 8022	13	3.37
Mount Rose	MRO 8023	13	2.05
Mount Rose	MRO 8024	13	1.84
Mount Laurel	MTL 8021	13	4.54
New Dover	NED 8016	13	1.38
New Milford	NEW 8013	13	3.75
New Milford	NEW 8015	13	0.80
New Milford	NEW 8022	13	4.43
New Milford	NEW 8024	13	2.22
New Milford	NEW 8031	13	6.71
New Milford	NEW 8032	13	2.68
New Milford	NEW 8033	13	3.12
New Milford	NEW 8035	13	1.50
New Milford	NEW 8042	13	5.41
New Milford	NEW 8044	13	3.77
Oak St	OAK 4008	4	1.84
Penns Neck	PEK 8013	13	3.83
Penns Neck	PEK 8022	13	2.49
Penns Neck	PEK 8023	13	2.12
Penns Neck	PEK 8026	13	0.45
Penns Neck	PEK 8036	13	3.41
Pierson Avenue	PIE 8023	13	2.42
Pine Street	PIN 4001	4	0.69
Plainsboro	PLI 8003	13	2.68
Plainsboro	PLI 8004	13	6.35
Rahway	RAH 4007	4	0.43
Ridgefield	RFD 4006	4	0.67
Ridgefield	RFL 8012	13	2.09
Ridgewood	RGW 4012	4	0.71
Runnemede	RUN 8001	13	1.35
River Road Sub	RVR 8031	13	2.20
Sand Hills	SDH 8025	13	6.38
Sand Hills	SDH 8032	13	3.05
So Orange	SOO 4004	4	1.52
State Street	STS 4010	4	1.27
Sunnymeade	SUN 8012	13	4.51
Teaneck	TEA 4003	4	1.88
Thorofare	THO 8021	13	7.40
Thirty Second Street	THY 4006	4	0.54
Thirty Second Street	THY 4007	4	0.28
Thirty Second Street	THY 4010	4	1.18
Turnpike	TUR 8025	13	1.52

EFG-ESII-6: Proposed Circuits for Open Wire Replacement with Spacer Cable

Station	Circuit	Voltage	Miles
Union	UN 4001	4	0.73
Union	UN 4011	4	1.23
Waldwick	WAD 8021	13	2.20
Waldwick	WAD 8023	13	4.06
Waldwick	WAD 8024	13	2.96
Waldwick	WAD 8025	13	1.45
Westmont	WMT 4007	4	0.43
West New York	WNY 4007	4	0.20
Woodlynne	WYN 4003	4	2.18

EFG-ESII-7: Proposed Circuits to Add a Recloser

13kV Sectionalizing Reclosers	
Station	Circuit
Adams	ADA 8011
Adams	ADA 8012
Adams	ADA 8013
Adams	ADA 8015
Adams	ADA 8016
Adams	ADA 8021
Adams	ADA 8023
Adams	ADA 8024
Adams	ADA 8025
Adams	ADA 8026
Aldene Sub	ALD 8014
Aldene Sub	ALD 8015
Aldene Sub	ALD 8016
Aldene Sub	ALD 8022
Aldene Sub	ALD 8023
Aldene Sub	ALD 8024
Aldene Sub	ALD 8025
Aldene Sub	ALD 8026
Bayonne Sub	BAO 8003
Bayonne Sub	BAO 8006
Bayonne Sub	BAO 8008
Bayonne Sub	BAO 8014
Bayonne Sub	BAO 8015
Bayonne Sub	BAO 8022
Bayonne Sub	BAO 8025
Bayonne Sub	BAO 8033
Beaver Brook	BEA 8002
Beaver Brook	BEA 8003
Beaver Brook	BEA 8004
Beaver Brook	BEA 8010
Bergenfield	BEF 8012
Bergenfield	BEF 8013
Bergenfield	BEF 8015
Bergenfield	BEF 8016
Bergenfield	BEF 8021
Bergenfield	BEF 8022
Bergenfield	BEF 8023
Bergenfield	BEF 8024
Belmont	BEM 8001
Bennetts Lane	BEN 8011
Bennetts Lane	BEN 8012
Bennetts Lane	BEN 8014
Bennetts Lane	BEN 8015
Bennetts Lane	BEN 8016
Bennetts Lane	BEN 8021
Bennetts Lane	BEN 8022
Bennetts Lane	BEN 8023
Bennetts Lane	BEN 8025
Bennetts Lane	BEN 8026
Brunswick Sub	BRU 8011
Brunswick Sub	BRU 8012
Brunswick Sub	BRU 8013

4kV Sectionalizing Reclosers	
Station	Circuit
Academy Street	ACA 4003
Academy Street	ACA 4008
Allwood	ALL 4002
Allwood	ALL 4006
Arcola	ARC 4001
Arcola	ARC 4003
Audubon	AUD 4001
Audubon	AUD 4004
Audubon	AUD 4008
Avenel	AVE 4001
Avenel	AVE 4003
Belleville	BEE 4008
Bergen Point	BER 4008
Bergen Point	BER 4011
Bergen Point	BER 4013
Bergen Point	BER 4014
Bergen Point	BER 4015
Bergen Point	BER 4018
Bloomfield	BLO 4002
Bloomfield	BLO 4004
Bloomfield	BLO 4007
Bloomfield	BLO 4009
Bloomfield	BLO 4012
Bloomfield	BLO 4014
Bloomfield	BLO 4015
Bloomfield	BLO 4016
Bloomfield	BLO 4017
Bloomfield	BLO 4018
Bordentown	BOR 4001
Bordentown	BOR 4002
Bordentown	BOR 4007
Bound Brook	BOU 4009
Bound Brook	BOU 4010
Carteret	CAT 4005
Carteret	CAT 4006
Carteret	CAT 4008
Carteret	CAT 4009
Central Ave	CET 4012
Chauncey Street	CHA 4001
Chauncey Street	CHA 4002
Chauncey Street	CHA 4004
Chauncey Street	CHA 4005
Chauncey Street	CHA 4012
Chauncey Street	CHA 4013
Chauncey Street	CHA 4014
Chauncey Street	CHA 4015
Cherry Hill	CHE 4008
Chester	CHS 4001
Chester	CHS 4006
Chester	CHS 4007
Chester	CHS 4008
Clark	CLA 4006

13kV Branch Reclosers	
Station	Circuit
Adams	ADA 8012
Aldene Sub	ALD 8016
Aldene Sub	ALD 8022
Aldene Sub	ALD 8026
Bergenfield	BEF 8023
Brunswick Sub	BRU 8013
Bustleton	BUS 8023
Cedar Grove	CED 8011
Cedar Grove	CED 8021
Cedar Grove	CED 8021
Cinnaminson	CIN 8033
Crosswicks	CRX 8005
Cuthbert Blvd	CUT 8001
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8006
Cuthbert Blvd	CUT 8007
Dayton Unit	DAY 8001
Deptford	DFD 8007
Deptford	DFD 8008
Deptford	DFD 8009
Doremus Place	DOR 8022
Doremus Place	DOR 8045
East Rutherford Sub	EAT 8011
Hoboken	HOE 8044
Hoboken	HOE 8044
Homestead	HOM 8012
Homestead	HOM 8014
Homestead	HOM 8041
Kingsland	KIN 8023
Kingsland	KIN 8025
Kuser Rd	KUS 8004
Kuser Rd	KUS 8010
Kuser Rd	KUS 8042
Lafayette Road	LAF 8013
Lawnside	LAW 8025
Lawnside	LAW 8033
Lawrence Sub	LCE 8005
Lawrence Sub	LCE 8032
Lawrence Unit Sub	LCU 8051
Leonia	LEO 8001
Leonia	LEO 8034
Levittown	LEV 8004
Levittown	LEV 8005
Levittown	LEV 8008
Levittown	LEV 8010
Levittown	LEV 8015
Levittown	LEV 8015
Little Ferry	LIT 8001
Lumberton	LUM 8011
Lumberton	LUM 8015
Lyndhurst	LYN 8001
Maple Shade	MAD 8018

4kV Branch Reclosers	
Station	Circuit
Central Ave	CET 4019
Chauncey Street	CHA 4012
East Orange Sub	EAO 4019
East Orange Sub	EAO 4023
Haledon	HAL 4005
Irvington	IRV 4002
Irvington	IRV 4002
Liberty Street	LIB 4009
Montclair	MNT 4009
Montclair	MNT 4012
So Orange	SOO 4003
So Orange	SOO 4003
Toneys Brook	TNY 4008
Toneys Brook	TNY 4010
Woodlynne	WYN 4003
Woodlynne	WYN 4003

EFG-ESII-7: Proposed Circuits to Add a Recloser

13kV Sectionalizing Reclosers	
Brunswick Sub	BRU 8021
Brunswick Sub	BRU 8022
Brunswick Sub	BRU 8023
Bustleton	BUS 8011
Bustleton	BUS 8012
Bustleton	BUS 8013
Bustleton	BUS 8015
Bustleton	BUS 8023
Carlstadt	CAR 8003
Carlstadt	CAR 8006
Camden Sub	CAS 8001
Camden Sub	CAS 8002
Cedar Grove	CED 8012
Cedar Grove	CED 8013
Cedar Grove	CED 8014
Cedar Grove	CED 8015
Cedar Grove	CED 8016
Cedar Grove	CED 8021
Cedar Grove	CED 8022
Cedar Grove	CED 8025
Cedar Grove	CED 8026
Cinnaminson	CIN 8001
Cinnaminson	CIN 8002
Cinnaminson	CIN 8004
Cinnaminson	CIN 8005
Cinnaminson	CIN 8006
Cinnaminson	CIN 8031
Cinnaminson	CIN 8032
Cinnaminson	CIN 8033
Cinnaminson	CIN 8034
Cinnaminson	CIN 8043
Clifton	CLF 8012
Clifton	CLF 8013
Clifton	CLF 8014
Clifton	CLF 8023
Clifton	CLF 8024
Clifton	CLF 8025
Clarksville	CLK 8012
Clarksville	CLK 8013
Clarksville	CLK 8014
Clarksville	CLK 8022
Clarksville	CLK 8023
Clarksville	CLK 8024
Clarksville	CLK 8025
Clarksville	CLK 8034
Clarksville	CLK 8041
Constable Hook	CON 8001
Constable Hook2	CON 8002
Cook Rd	COR 8012
Cook Rd	COR 8013
Cook Rd	COR 8014
Cook Rd	COR 8015
Cook Rd	COR 8025

4kV Sectionalizing Reclosers	
Clay St	CLE 4001
Clay St	CLE 4002
Clay St	CLE 4008
Clay St	CLE 4011
Clay St	CLE 4016
Clinton Avenue	CLN 4006
Cranford	CRA 4003
Cranford	CRA 4004
Cranford	CRA 4009
Cranford	CRA 4010
Cranford	CRA 4011
Cranford	CRA 4012
Cranford	CRA 4016
Culver Avenue	CUL 4001
Culver Avenue	CUL 4012
Delair	DEA 4001
Delair	DEA 4009
Dumont	DUM 4001
Dumont	DUM 4002
Dumont	DUM 4003
Dumont	DUM 4004
Dumont	DUM 4005
Dumont	DUM 4006
Dumont	DUM 4007
East Orange Sub	EAO 4006
East Orange Sub	EAO 4008
East Orange Sub	EAO 4013
East Orange Sub	EAO 4023
East Orange Sub	EAO 4024
Edison	EDI 4003
Edison	EDI 4006
Edison	EDI 4007
Edison	EDI 4008
Edison	EDI 4009
Elizabeth	ELI 4002
Elizabeth	ELI 4016
Englewood	ENG 4004
Englewood	ENG 4006
Englewood	ENG 4016
Englewood	ENG 4017
Ewing	EWI 4002
Ewing	EWI 4003
Ewing	EWI 4004
Ewing	EWI 4006
Ewing	EWI 4007
Ewing	EWI 4008
Fairlawn	FAR 4002
Fairlawn	FAR 4004
Fairlawn	FAR 4005
Fairlawn	FAR 4006
Fairview	FAV 4001
Fairview	FAV 4003
Fairview	FAV 4005

13kV Branch Reclosers	
Maple Shade	MAD 8031
Marion Drive	MAI 8022
Maywood	MAY 8015
Maywood	MAY 8023
Maywood	MAY 8034
Maywood	MAY 8034
Maywood	MAY 8044
Meadow Road	MEA 8013
Meadow Road	MEA 8024
Mountain Avenue	MON 8002
Mount Rose	MRO 8022
Mount Rose	MRO 8023
Mount Rose	MRO 8024
Nevins Road	NEV 8001
New Milford	NEW 8044
Plainsboro	PLI 8003
Ridgefield	RFL 8024
Riverside - 13KV	RIV 8006
River Road Substation	RVR 8012
Saddle Brook	SAD 8007
Saddle Brook	SAD 8044
Sand Hills	SDH 8024
South Second Street	SOS 8016
Springfield Road	SPF 8022
St Pauls	STP 8001
Sunnymeade	SUN 8043
Turnpike	TUR 8004
Turnpike	TUR 8015
Turnpike	TUR 8015
Waldwick	WAD 8014
Waldwick	WAD 8031
Westfield	WFL 8032
Woodbridge	WOR 8013
Woodbridge	WOR 8022

EFG-ESII-7: Proposed Circuits to Add a Recloser

13kV Sectionalizing Reclosers	
Cook Rd	COR 8033
Cook Rd	COR 8034
Cook Rd	COR 8035
Cook Rd	COR 8041
Cook Rd	COR 8042
Cook Rd	COR 8044
Crosswicks	CRX 8001
Crosswicks	CRX 8003
Crosswicks	CRX 8004
Crosswicks	CRX 8005
Crosswicks	CRX 8008
Cuthbert Blvd	CUT 8002
Cuthbert Blvd	CUT 8005
Cuthbert Blvd	CUT 8006
Cuthbert Blvd	CUT 8007
Cuthbert Blvd	CUT 8008
Cuthbert Blvd	CUT 8010
Cuthbert Blvd	CUT 8031
Cuthbert Blvd	CUT 8032
Cuthbert Blvd	CUT 8033
Cuthbert Blvd	CUT 8041
Cuthbert Blvd	CUT 8042
Cuthbert Blvd	CUT 8044
Coxs Corner Sub	CXC 8011
Coxs Corner Sub	CXC 8012
Coxs Corner Sub	CXC 8022
Dayton Unit	DAY 8001
Dayton Unit2	DAY 8002
Deptford	DFD 8007
Deptford	DFD 8009
Deptford	DFD 8032
Deptford	DFD 8035
Deptford	DFD 8041
Deptford	DFD 8042
Doremus Place	DOR 8012
Doremus Place	DOR 8013
Doremus Place	DOR 8015
Doremus Place	DOR 8023
Doremus Place	DOR 8025
Doremus Place	DOR 8033
Doremus Place	DOR 8035
Doremus Place	DOR 8043
Doremus Place	DOR 8044
Devils Brook	DVB 8011
Devils Brook	DVB 8012
Devils Brook	DVB 8013
Devils Brook	DVB 8014
Devils Brook	DVB 8015
Devils Brook	DVB 8021
Devils Brook	DVB 8022
Devils Brook	DVB 8023
Devils Brook	DVB 8024
Devils Brook	DVB 8025

4kV Sectionalizing Reclosers	
Fairview	FAV 4007
Fairview	FAV 4008
Federal Square	FED 4004
Federal Square	FED 4010
Federal Square	FED 4018
Federal Square	FED 4021
Federal Square	FED 4022
Federal Square	FED 4030
Fifteenth St	FIF 4002
First Street	FIR 4002
First Street	FIR 4003
First Street	FIR 4004
First Street	FIR 4006
Fourtieth St	FOH 4002
Fourtieth St	FOH 4003
Fourtieth St	FOH 4004
Fourtieth St	FOH 4006
Fourtieth St	FOH 4007
Fourtieth St	FOH 4008
Fort Lee	FOR 4001
Fort Lee	FOR 4003
Fort Lee	FOR 4008
Fort Lee	FOR 4009
Fort Lee	FOR 4010
Fort Lee	FOR 4013
Front Street	FRO 4006
Front Street	FRO 4007
Front Street	FRO 4008
Front Street	FRO 4009
Garfield Avenue	GAE 4001
Garfield Avenue	GAE 4003
Garfield Avenue	GAE 4006
Garfield Avenue	GAE 4014
Getty Ave	GET 4003
Getty Ave	GET 4007
Getty Ave	GET 4008
Getty Ave	GET 4009
Great Notch	GRE 4002
Great Notch	GRE 4003
Great Notch	GRE 4004
Great Notch	GRE 4007
Greenville	GRN 4001
Greenville	GRN 4008
Greenville	GRN 4009
Hackensack	HAC 4005
Hackensack	HAC 4006
Hackensack	HAC 4007
Hackensack	HAC 4009
Hackensack	HAC 4010
Hackensack	HAC 4011
Hackensack	HAC 4012
Hackensack	HAC 4013
Hackensack	HAC 4016

EFG-ESII-7: Proposed Circuits to Add a Recloser

13kV Sectionalizing Reclosers	
East Rutherford Sub	EAT 8011
East Rutherford Sub	EAT 8013
East Rutherford Sub	EAT 8014
East Rutherford Sub	EAT 8021
East Rutherford Sub	EAT 8022
East Rutherford Sub	EAT 8023
East Rutherford Sub	EAT 8025
East Riverton	ERT 8003
Fanwood	FAW 8011
Fanwood	FAW 8012
Fanwood	FAW 8014
Fanwood	FAW 8015
Fanwood	FAW 8016
Fanwood	FAW 8021
Fanwood	FAW 8022
Fanwood	FAW 8023
Fanwood	FAW 8026
Fernwood	FEN 8041
Fifteenth St Unit	FIT 8003
Fort Lee	FOT 8004
Foundry St	FOU 8014
Foundry St	FOU 8022
Foundry St	FOU 8024
Franklin	FRA 8011
Franklin	FRA 8012
Franklin	FRA 8013
Franklin	FRA 8021
Franklin	FRA 8023
Green Brook	GBK 8011
Green Brook	GBK 8012
Green Brook	GBK 8013
Green Brook	GBK 8014
Green Brook	GBK 8021
Green Brook	GBK 8022
Green Brook	GBK 8023
Green Brook	GBK 8024
Green Brook	GBK 8025
Harts Lane	HAT 8011
Harts Lane	HAT 8012
Harts Lane	HAT 8013
Harts Lane	HAT 8014
Harts Lane	HAT 8015
Harts Lane	HAT 8021
Harts Lane	HAT 8022
Harts Lane	HAT 8023
Harts Lane	HAT 8027
Harts Lane	HAT 8034
Harts Lane	HAT 8035
Harts Lane	HAT 8036
Harts Lane	HAT 8037
Hawthorne	HAW 8032
Hawthorne	HAW 8034
Hawthorne	HAW 8041

4kV Sectionalizing Reclosers	
Haddon Heights	HAD 4002
Haddon Heights	HAD 4003
Haddon Heights	HAD 4005
Haddon Heights	HAD 4008
Haddon Heights	HAD 4009
Haddon Heights	HAD 4010
Haledon	HAL 4004
Haledon	HAL 4005
Haledon	HAL 4008
Hamilton	HAM 4007
Hamilton	HAM 4008
Hancock Street	HAN 4001
Hancock Street	HAN 4005
Harrison	HAR 4014
Harrison	HAR 4015
Hasbrouck Heights	HBG 4007
Henry Street	HEN 4004
Henry Street	HEN 4007
Hudson Terrace	HUD 4002
Ironbound	IRO 4001
Ironbound	IRO 4002
Ironbound	IRO 4003
Ironbound	IRO 4005
Ironbound	IRO 4011
Ironbound	IRO 4012
Ironbound	IRO 4014
Irvington	IRV 4004
Irvington	IRV 4013
Irvington	IRV 4019
Irvington	IRV 4021
Irvington	IRV 4022
Keasbey	KEA 4001
Keasbey	KEA 4003
Keasbey	KEA 4005
Kenilworth	KEN 4002
Kenilworth	KEN 4003
Kenilworth	KEN 4005
Kenilworth	KEN 4006
Lakeside	LAS 4009
Lehigh Avenue	LEH 4002
Lehigh Avenue	LEH 4003
Lehigh Avenue	LEH 4004
Lehigh Avenue	LEH 4006
Lehigh Avenue	LEH 4007
Liberty Street	LIB 4003
Liberty Street	LIB 4004
Liberty Street	LIB 4005
Liberty Street	LIB 4007
Liberty Street	LIB 4009
Locust Street	LLO 4003
Market Street	MAK 4002
Market Street	MAK 4005
Market Street	MAK 4006

EFG-ESII-7: Proposed Circuits to Add a Recloser

13kV Sectionalizing Reclosers	
Hillsdale	HID 8011
Hillsdale	HID 8013
Hillsdale	HID 8034
Hillsdale	HID 8035
Hillsdale	HID 8041
Hillsdale	HID 8042
Hillsdale	HID 8043
Hillsdale	HID 8044
Hillsdale	HID 8045
Hinchmans	HNC 8012
Hinchmans	HNC 8015
Hinchmans	HNC 8021
Hinchmans	HNC 8022
Hinchmans	HNC 8023
Hinchmans	HNC 8024
Hinchmans	HNC 8025
Hoboken	HOE 8032
Hoboken	HOE 8038
Hoboken	HOE 8047
Hoboken	HOE 8048
Homestead	HOM 8001
Homestead	HOM 8002
Homestead	HOM 8003
Homestead	HOM 8014
Homestead	HOM 8021
Homestead	HOM 8025
Homestead	HOM 8041
Homestead	HOM 8042
Homestead	HOM 8044
Jackson Rd	JAC 8011
Jackson Rd	JAC 8012
Jackson Rd	JAC 8015
Jackson Rd	JAC 8021
Jackson Rd	JAC 8022
Jackson Rd	JAC 8023
Jackson Rd	JAC 8024
Jackson Rd	JAC 8025
Jackson Rd	JAC 8033
Jackson Rd	JAC 8043
Kilmer	KIL 8012
Kilmer	KIL 8013
Kilmer	KIL 8014
Kilmer	KIL 8015
Kilmer	KIL 8016
Kilmer	KIL 8022
Kilmer	KIL 8023
Kilmer	KIL 8024
Kilmer	KIL 8025
Kilmer	KIL 8031
Kilmer	KIL 8033
Kilmer	KIL 8034
Kilmer	KIL 8035
Kilmer	KIL 8041

4kV Sectionalizing Reclosers	
Marshall Street	MAS 4003
Marshall Street	MAS 4005
Marshall Street	MAS 4007
McLean Blvd	MCL 4001
McLean Blvd	MCL 4002
McLean Blvd	MCL 4003
McLean Blvd	MCL 4004
McLean Blvd	MCL 4006
McLean Blvd	MCL 4007
McLean Blvd	MCL 4008
McLean Blvd	MCL 4009
Madison Street	MDS 4002
Madison Street	MDS 4003
Madison Street	MDS 4012
Mechanic Street	MEC 4001
Mechanic Street	MEC 4003
Mechanic Street	MEC 4008
Mechanic Street	MEC 4011
Mechanic Street	MEC 4013
Montclair	MNT 4004
Montclair	MNT 4005
Montclair	MNT 4010
Montclair	MNT 4015
Morgan Street	MOG 4001
Morgan Street	MOG 4002
Morgan Street	MOG 4003
Morgan Street	MOG 4005
Morgan Street	MOG 4007
Morgan Street	MOG 4011
Morgan Street	MOG 4013
Mount Holly	MOY 4002
Mount Holly	MOY 4005
Mount Holly	MOY 4009
Nineteenth Ave	NIN 4001
Nineteenth Ave	NIN 4002
Nineteenth Ave	NIN 4003
Nineteenth Ave	NIN 4004
Nineteenth Ave	NIN 4005
Nineteenth Ave	NIN 4006
Norfolk St	NOF 4003
Norfolk St	NOF 4004
Norfolk St	NOF 4010
North Paterson	NRP 4001
North Paterson	NRP 4002
North Paterson	NRP 4003
North Paterson	NRP 4004
North Paterson	NRP 4007
North Paterson	NRP 4009
North Paterson	NRP 4010
North Paterson	NRP 4014
North Paterson	NRP 4015
Nutley	NUT 4006
Oak St	OAK 4001

EFG-ESII-7: Proposed Circuits to Add a Recloser

13kV Sectionalizing Reclosers	
Kilmer	KIL 8042
Kilmer	KIL 8043
Kilmer	KIL 8044
Kingsland	KIN 8011
Kingsland	KIN 8012
Kingsland	KIN 8013
Kingsland	KIN 8014
Kingsland	KIN 8015
Kingsland	KIN 8022
Kingsland	KIN 8023
Kuller Road	KUL 8012
Kuller Road	KUL 8013
Kuller Road	KUL 8021
Kuller Road	KUL 8022
Kuller Road	KUL 8023
Kuser Rd	KUS 8003
Kuser Rd	KUS 8004
Kuser Rd	KUS 8008
Kuser Rd	KUS 8010
Kuser Rd	KUS 8034
Kuser Rd	KUS 8042
Kuser Rd	KUS 8043
Kuser Rd	KUS 8044
Kuser Rd	KUS 8045
Lafayette Road	LAF 8013
Lafayette Road	LAF 8014
Lafayette Road	LAF 8015
Lafayette Road	LAF 8021
Lafayette Road	LAF 8022
Lafayette Road	LAF 8023
Lafayette Road	LAF 8025
Lafayette Road	LAF 8026
Lake Nelson	LAK 8011
Lake Nelson	LAK 8012
Lake Nelson	LAK 8013
Lake Nelson	LAK 8015
Lake Nelson	LAK 8021
Lake Nelson	LAK 8022
Lake Nelson	LAK 8023
Lake Nelson	LAK 8024
Lake Nelson	LAK 8025
Laurel Ave	LAU 8011
Laurel Ave	LAU 8012
Laurel Ave	LAU 8013
Laurel Ave	LAU 8014
Laurel Ave	LAU 8021
Laurel Ave	LAU 8023
Laurel Ave	LAU 8024
Laurel Ave	LAU 8025
Laurel Ave	LAU 8034
Laurel Ave	LAU 8035
Laurel Ave	LAU 8036
Laurel Ave	LAU 8044

4kV Sectionalizing Reclosers	
Oak St	OAK 4003
Oak St	OAK 4004
Oak St	OAK 4006
Oak St	OAK 4008
Orange Valley	ORA 4001
Orange Valley	ORA 4002
Orange Valley	ORA 4003
Orange Valley	ORA 4007
Paramus	PAR 4002
Paramus	PAR 4003
Paramus	PAR 4006
Passaic	PAS 4003
Passaic	PAS 4007
Passaic	PAS 4011
Passaic	PAS 4016
Passaic	PAS 4020
Paterson	PAT 4003
Paterson	PAT 4008
Paterson	PAT 4010
Paterson	PAT 4011
Paterson	PAT 4012
Paterson	PAT 4016
Pine Street	PIN 4001
Pine Street	PIN 4002
Plainfield	PLA 4004
Plainfield	PLA 4007
Plainfield	PLA 4008
Plainfield	PLA 4010
Plainfield	PLA 4012
Plainfield	PLA 4013
Plauderville	PLR 4002
Plauderville	PLR 4004
Plauderville	PLR 4006
Plauderville	PLR 4007
Pleasant Street	PLS 4001
Pleasant Street	PLS 4004
Pleasant Street	PLS 4007
Polk Street	POL 4003
Polk Street	POL 4004
Polk Street	POL 4005
Polk Street	POL 4006
Polk Street	POL 4012
Rahway	RAH 4006
Rahway	RAH 4010
Raritan Valley	RAR 4003
Ridgewood	RGW 4004
Ridgewood	RGW 4005
Ridgewood	RGW 4006
Ridgewood	RGW 4007
Ridgewood	RGW 4009
Ridgewood	RGW 4012
Ridgewood	RGW 4014
Riverside - 4KV	RIS 4004

EFG-ESII-7: Proposed Circuits to Add a Recloser

13kV Sectionalizing Reclosers	
Laurel Ave	LAU 8046
Lawnside	LAW 8014
Lawnside	LAW 8015
Lawnside	LAW 8016
Lawnside	LAW 8019
Lawnside	LAW 8023
Lawnside	LAW 8024
Lawnside	LAW 8025
Lawnside	LAW 8033
Lawnside	LAW 8038
Lawnside	LAW 8039
Lawrence Sub	LCE 8003
Lawrence Sub	LCE 8009
Lawrence Sub	LCE 8010
Lawrence Sub	LCE 8032
Lawrence Sub	LCE 8033
Lawrence Sub	LCE 8043
Lawrence Sub	LCE 8044
Lawrence Sub	LCE 8045
Lawrence Sub	LCE 8046
Leonia	LEO 8003
Leonia	LEO 8005
Leonia	LEO 8006
Leonia	LEO 8008
Leonia	LEO 8009
Leonia	LEO 8032
Leonia	LEO 8033
Leonia	LEO 8035
Leonia	LEO 8041
Leonia	LEO 8042
Leonia	LEO 8043
Leonia	LEO 8044
Leonia	LEO 8045
Levittown	LEV 8002
Levittown	LEV 8003
Levittown	LEV 8005
Levittown	LEV 8006
Levittown	LEV 8011
Levittown	LEV 8012
Levittown	LEV 8013
Levittown	LEV 8015
Levittown	LEV 8016
Levittown	LEV 8017
Little Ferry	LIT 8001
Little Ferry	LIT 8004
Locust Street	LOC 8001
Locust Street	LOC 8004
Locust Street	LOC 8005
Lodi	LOI 8001
Lumberton	LUM 8014
Lumberton	LUM 8021
Lumberton	LUM 8022
Lumberton	LUM 8024

4kV Sectionalizing Reclosers	
Riverside - 4KV	RIS 4005
Roselle	RSL 4003
Roselle	RSL 4006
Roselle	RSL 4007
Roselle	RSL 4008
Scotch Plains	SCO 4001
Scotch Plains	SCO 4004
So Orange	SOO 4002
So Orange	SOO 4004
So Orange	SOO 4010
So Orange	SOO 4011
So Orange	SOO 4012
So Orange	SOO 4013
So Orange	SOO 4014
So Paterson	SOP 4004
So Paterson	SOP 4007
So Paterson	SOP 4008
So Paterson	SOP 4010
Spring Valley Rd	SPR 4005
State Street	STS 4003
State Street	STS 4005
State Street	STS 4010
Teaneck	TEA 4001
Teaneck	TEA 4002
Teaneck	TEA 4003
Teaneck	TEA 4004
Teaneck	TEA 4006
Teaneck	TEA 4007
Teaneck	TEA 4009
Third Street	THR 4006
Thirty Second Street	THY 4003
Thirty Second Street	THY 4004
Thirty Second Street	THY 4005
Thirty Second Street	THY 4006
Thirty Second Street	THY 4007
Thirty Second Street	THY 4008
Thirty Second Street	THY 4009
Thirty Second Street	THY 4010
Thirty Second Street	THY 4012
Thirty Second Street	THY 4013
Thirty Second Street	THY 4014
Toneys Brook	TNY 4001
Toneys Brook	TNY 4002
Toneys Brook	TNY 4003
Toneys Brook	TNY 4008
Toneys Brook	TNY 4010
Tonnelle Avenue	TON 4003
Tonnelle Avenue	TON 4006
Tonnelle Avenue	TON 4007
Totowa	TOT 4002
Union	UN 4001
Union	UN 4004
Union	UN 4006

EFG-ESII-7: Proposed Circuits to Add a Recloser

13kV Sectionalizing Reclosers	
Lumberton	LUM 8025
Maple Shade	MAD 8014
Maple Shade	MAD 8015
Maple Shade	MAD 8016
Maple Shade	MAD 8021
Maple Shade	MAD 8022
Maple Shade	MAD 8023
Maple Shade	MAD 8024
Maple Shade	MAD 8025
Maple Shade	MAD 8026
Maple Shade	MAD 8031
Maple Shade	MAD 8032
Maple Shade	MAD 8033
Maple Shade	MAD 8037
Marion Drive	MAI 8011
Marion Drive	MAI 8013
Marion Drive	MAI 8022
Marion Drive	MAI 8024
Marlton	MAR 8001
Marlton	MAR 8002
Marlton	MAR 8004
Marlton	MAR 8005
Marlton	MAR 8006
Marlton	MAR 8007
Marlton	MAR 8008
Marlton	MAR 8009
Marlton	MAR 8010
Marlton	MAR 8011
Marlton	MAR 8012
Marlton	MAR 8013
Marlton	MAR 8014
Marlton	MAR 8016
Marlton	MAR 8017
Marlton	MAR 8018
Maywood	MAY 8013
Maywood	MAY 8014
Maywood	MAY 8015
Maywood	MAY 8022
Maywood	MAY 8023
Maywood	MAY 8024
Maywood	MAY 8025
Maywood	MAY 8044
Maywood	MAY 8046
Medford	MDF 8012
Medford	MDF 8014
Medford	MDF 8021
Medford	MDF 8023
Medford	MDF 8024
Meadow Road	MEA 8011
Meadow Road	MEA 8012
Meadow Road	MEA 8013
Meadow Road	MEA 8015
Meadow Road	MEA 8016

4kV Sectionalizing Reclosers	
Union	UN 4010
Union	UN 4011
Union City	UNC 4001
Union City	UNC 4006
Union City	UNC 4009
Union City	UNC 4012
Van Houten Ave	VNH 4004
Van Houten Ave	VNH 4005
Van Houten Ave	VNH 4006
Van Winkle Street	VNK 4003
Van Winkle Street	VNK 4006
Van Winkle Street	VNK 4010
Van Winkle Street	VNK 4012
Van Winkle Street	VNK 4013
Van Winkle Street	VNK 4015
Warren Point	WAR 4001
Warren Point	WAR 4002
Warren Point	WAR 4003
Warren Point	WAR 4004
Warren Point	WAR 4005
Warren Point	WAR 4006
Warren Point	WAR 4007
Warren Point	WAR 4008
Warren Point	WAR 4009
Waverly	WAV 4001
Waverly	WAV 4004
Waverly	WAV 4015
Waverly	WAV 4016
Waverly	WAV 4018
Westmont	WMT 4001
Westmont	WMT 4002
Westmont	WMT 4004
Westmont	WMT 4005
Westmont	WMT 4006
Westmont	WMT 4007
West New York	WNY 4004
West New York	WNY 4005
West New York	WNY 4007
West New York	WNY 4011
West New York	WNY 4013
West Orange Sub	WOA 4003
West Orange Sub	WOA 4010
Westwood	WOD 4001
Westwood	WOD 4004
Westwood	WOD 4005
Westwood	WOD 4006
Westwood	WOD 4007
Westwood	WOD 4008
Westwood	WOD 4010
Woodbury	WRY 4005
Woodbury	WRY 4008
Woodbury	WRY 4010
Woodbury	WRY 4011

EFG-ESII-7: Proposed Circuits to Add a Recloser

13kV Sectionalizing Reclosers	
Meadow Road	MEA 8023
Meadow Road	MEA 8024
Meadow Road	MEA 8025
Mechanic Street	MEC 8004
Minue Street	MIN 8011
Minue Street	MIN 8013
Minue Street	MIN 8015
Minue Street	MIN 8021
Minue Street	MIN 8022
Minue Street	MIN 8023
Minue Street	MIN 8024
Minue Street	MIN 8025
Minue Street	MIN 8026
Mountain Avenue	MON 8002
Mountain Avenue	MON 8003
Mountain Avenue	MON 8004
Montgomery Sub	MOT 8001
Montgomery Sub	MOT 8002
Montgomery Sub	MOT 8003
Mountain View	MOU 8001
Mount Rose	MRO 8013
Moutainside Unit	MSD 8001
Mount Laurel	MTL 8013
Mount Laurel	MTL 8014
Mount Laurel	MTL 8015
Mount Laurel	MTL 8021
Mount Laurel	MTL 8022
Mount Laurel	MTL 8024
North Bridge Street	NBS 8011
North Bridge Street	NBS 8012
North Bridge Street	NBS 8013
North Bridge Street	NBS 8021
North Bridge Street	NBS 8022
North Bridge Street	NBS 8023
New Dover	NED 8013
New Dover	NED 8014
New Dover	NED 8015
New Dover	NED 8016
New Dover	NED 8022
New Dover	NED 8023
New Dover	NED 8024
New Dover	NED 8025
New Dover	NED 8026
Nevins Road	NEV 8001
New Milford	NEW 8013
New Milford	NEW 8014
New Milford	NEW 8022
New Milford	NEW 8024
New Milford	NEW 8025
New Milford	NEW 8031
New Milford	NEW 8032
New Milford	NEW 8033
New Milford	NEW 8034

4kV Sectionalizing Reclosers	
Woodlynne	WYN 4001
Woodlynne	WYN 4002
Woodlynne	WYN 4003
Woodlynne	WYN 4004
Woodlynne	WYN 4005
Woodlynne	WYN 4006
Woodlynne	WYN 4007
Woodlynne	WYN 4009
Woodlynne	WYN 4010
Academy Street	ACA 4006
Avenel	AVE 4002
Avenel	AVE 4004
Avenel	AVE 4007
Bergen Point	BER 4005
Bound Brook	BOU 4002
Chauncey Street	CHA 4008
Chester	CHS 4003
Clark	CLA 4005
Clark	CLA 4008
Cranford	CRA 4001
Cranford	CRA 4007
Culver Avenue	CUL 4002
East Riverton 2	EAR 4001
Elizabeth	ELI 4015
Englewood	ENG 4005
Englewood	ENG 4009
Englewood	ENG 4012
Ewing	EWI 4001
Fairlawn	FAR 4009
Fairview	FAV 4002
Finderne	FIN 4003
Fort Lee	FOR 4002
Fort Lee	FOR 4012
Front Street	FRO 4003
Getty Ave	GET 4004
Great Notch	GRE 4005
Great Notch	GRE 4006
Greenville	GRN 4003
Hackensack	HAC 4018
Haledon	HAL 4006
Hamilton	HAM 4009
Hasbrouck Heights	HBG 4009
Henry Street	HEN 4003
Hudson Terrace	HUD 4001
Ironbound	IRO 4009
Irvington	IRV 4006
Irvington	IRV 4011
Kenilworth	KEN 4001
Kenilworth	KEN 4004
Marshall Street	MAS 4006
Marshall Street	MAS 4008
Morgan Street	MOG 4006
Morgan Street	MOG 4014

EFG-ESII-7: Proposed Circuits to Add a Recloser

13kV Sectionalizing Reclosers	
New Milford	NEW 8035
New Milford	NEW 8041
New Milford	NEW 8042
New Milford	NEW 8044
Nineteenth Ave Unit	NIT 8007
North Avenue	NOT 8011
North Avenue	NOT 8012
North Avenue	NOT 8013
North Avenue	NOT 8014
Mobile North Avenue	NOT 8016
North Avenue	NOT 8021
North Avenue	NOT 8022
North Avenue	NOT 8023
North Avenue	NOT 8024
North Avenue	NOT 8025
North Bergen	NRB 8011
North Bergen	NRB 8012
North Bergen	NRB 8013
North Bergen	NRB 8014
North Bergen	NRB 8015
North Bergen	NRB 8021
North Bergen	NRB 8022
North Bergen	NRB 8023
North Bergen	NRB 8024
North Bergen	NRB 8025
Penhorn	PEH 8001
Penhorn	PEH 8004
Penhorn	PEH 8007
Penhorn	PEH 8008
Penhorn	PEH 8013
Penhorn	PEH 8014
Penhorn	PEH 8022
Penhorn	PEH 8025
Penns Neck	PEK 8011
Penns Neck	PEK 8012
Penns Neck	PEK 8018
Penns Neck	PEK 8021
Penns Neck	PEK 8022
Penns Neck	PEK 8023
Penns Neck	PEK 8024
Penns Neck	PEK 8026
Penns Neck	PEK 8034
Penns Neck	PEK 8036
Pierson Avenue	PIE 8011
Pierson Avenue	PIE 8012
Pierson Avenue	PIE 8013
Pierson Avenue	PIE 8014
Pierson Avenue	PIE 8015
Pierson Avenue	PIE 8021
Pierson Avenue	PIE 8022
Pierson Avenue	PIE 8023
Plainsboro	PLI 8003
Plainsboro	PLI 8005

4kV Sectionalizing Reclosers	
Mount Holly	MOY 4003
Norfolk St	NOF 4016
North Paterson	NRP 4012
Nutley	NUT 4003
Passaic	PAS 4008
Pleasant Street	PLS 4003
Polk Street	POL 4010
Princeton	PRI 4001
Princeton	PRI 4002
Rahway	RAH 4005
Rahway	RAH 4008
Spring Valley Rd	SPR 4006
Spring Valley Rd	SPR 4012
So Orange Unit Sub	SUS 4041
Thirty Second Street	THY 4011
Totowa	TOT 4001
Totowa	TOT 4007
Union City	UNC 4010
Van Houten Ave	VNH 4008
Van Winkle Street	VNK 4014
Westwood	WOD 4009
Woodbury	WRY 4001
Woodbury	WRY 4006
Woodlynne	WYN 4008

EFG-ESII-7: Proposed Circuits to Add a Recloser

13kV Sectionalizing Reclosers	
Plainsboro	PLI 8006
Plainsboro	PLI 8007
Plainsboro	PLI 8008
Plainsboro	PLI 8010
Plainsboro	PLI 8011
Plainsboro	PLI 8012
Polhemus Lane	POH 8012
Polhemus Lane	POH 8013
Polhemus Lane	POH 8015
Polhemus Lane	POH 8021
Polhemus Lane	POH 8022
Polhemus Lane	POH 8024
Polhemus Lane	POH 8025
Polhemus Lane	POH 8026
Port St	POR 8003
Raritan Valley	RAV 8003
Ridgefield	RFL 8011
Ridgefield	RFL 8013
Ridgefield	RFL 8014
Ridgefield	RFL 8015
Ridgefield	RFL 8021
Ridgefield	RFL 8022
Ridgefield	RFL 8023
Ridgefield	RFL 8024
Ridgefield	RFL 8025
Ridgefield	RFL 8032
Ridgefield	RFL 8034
Ridgefield	RFL 8035
Ridgefield	RFL 8042
Ridgefield	RFL 8044
Ridgefield	RFL 8045
Riverside - 13KV	RIV 8006
Runnemede	RUN 8001
Runnemede	RUN 8002
Runnemede	RUN 8003
Runnemede	RUN 8004
Runnemede	RUN 8006
River Road Sub	RVR 8011
River Road Sub	RVR 8012
River Road Sub	RVR 8022
River Road Sub	RVR 8031
Saddle Brook	SAD 8002
Saddle Brook	SAD 8003
Saddle Brook	SAD 8004
Saddle Brook	SAD 8005
Saddle Brook	SAD 8006
Saddle Brook	SAD 8008
Saddle Brook	SAD 8032
Saddle Brook	SAD 8033
Saddle Brook	SAD 8034
Saddle Brook	SAD 8035
Saddle Brook	SAD 8043
Saddle Brook	SAD 8044

EFG-ESII-7: Proposed Circuits to Add a Recloser

13kV Sectionalizing Reclosers	
Saddle Brook	SAD 8045
Sand Hills	SDH 8021
Sand Hills	SDH 8023
Sand Hills	SDH 8024
Sand Hills	SDH 8025
Sand Hills	SDH 8026
Sand Hills	SDH 8031
Sand Hills	SDH 8033
Sand Hills	SDH 8034
Sand Hills	SDH 8035
Somerville	SMV 8011
Somerville	SMV 8012
Somerville	SMV 8013
Somerville	SMV 8014
Somerville	SMV 8021
Somerville	SMV 8022
Somerville	SMV 8023
Somerville	SMV 8024
Somerville	SMV 8025
Southampton	SOH 8022
Southampton	SOH 8031
South Second Street	SOS 8016
Springfield Road	SPF 8012
Springfield Road	SPF 8013
Springfield Road	SPF 8014
Springfield Road	SPF 8015
Springfield Road	SPF 8016
Springfield Road	SPF 8022
Springfield Road	SPF 8023
Springfield Road	SPF 8024
Springfield Road	SPF 8025
Springfield Road	SPF 8026
Sunnymeade	SUN 8011
Sunnymeade	SUN 8012
Sunnymeade	SUN 8013
Sunnymeade	SUN 8021
Sunnymeade	SUN 8022
Sunnymeade	SUN 8024
Sunnymeade	SUN 8033
Sunnymeade	SUN 8034
Sunnymeade	SUN 8035
Sunnymeade	SUN 8043
Sunnymeade	SUN 8044
Sunnymeade	SUN 8045
South Waterfront	SWT 8001
South Waterfront	SWT 8002
Thorofare	THO 8011
Thorofare	THO 8012
Thorofare	THO 8014
Thorofare	THO 8022
Thorofare	THO 8023
Thorofare	THO 8024
Turnpike	TUR 8001

EFG-ESII-7: Proposed Circuits to Add a Recloser

13kV Sectionalizing Reclosers	
Turnpike	TUR 8002
Turnpike	TUR 8003
Turnpike	TUR 8025
Village Rd	VIL 8001
Waldwick	WAD 8011
Waldwick	WAD 8014
Waldwick	WAD 8015
Waldwick	WAD 8023
Waldwick	WAD 8041
Warinanco	WAN 8011
Warinanco	WAN 8012
Warinanco	WAN 8013
Warinanco	WAN 8014
Warinanco	WAN 8015
Warinanco	WAN 8022
Warinanco	WAN 8024
Warinanco	WAN 8025
West Caldwell	WEW 8011
West Caldwell	WEW 8014
West Caldwell	WEW 8015
West Caldwell	WEW 8021
West Caldwell	WEW 8023
West Caldwell	WEW 8025
West Caldwell	WEW 8031
West Caldwell	WEW 8032
West Caldwell	WEW 8033
West Caldwell	WEW 8034
West Caldwell	WEW 8041
West Caldwell	WEW 8042
West Caldwell	WEW 8044
Westfield	WFL 8011
Westfield	WFL 8012
Westfield	WFL 8021
Westfield	WFL 8032
Westfield	WFL 8034
Westfield	WFL 8041
Woodbridge	WOR 8011
Woodbridge	WOR 8013
Woodbridge	WOR 8017
Woodbridge	WOR 8018
Woodbridge	WOR 8019
Woodbridge	WOR 8021
Woodbridge	WOR 8022
Woodbridge	WOR 8024
Woodbridge	WOR 8025
Woodbridge	WOR 8034
Woodbridge	WOR 8035
Woodbridge	WOR 8037
Woodbridge	WOR 8039
Yardville	YRD 8011
Yardville	YRD 8012
Yardville	YRD 8014
Yardville	YRD 8021

EFG-ESII-7: Proposed Circuits to Add a Recloser

13kV Sectionalizing Reclosers	
Yardville	YRD 8023
Yardville	YRD 8024

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Academy Street	ACA 4011
Academy Street	ACA 4001
Adams	ADA 8022
Adams	ADA 8024
Adams	ADA 8013
Adams	ADA 8016
Adams	ADA 8016
Adams	ADA 8021
Adams	ADA 8016
Adams	ADA 8016
Adams	ADA 8025
Adams	ADA 8023
Adams	ADA 8012
Adams	ADA 8012
Adams	ADA 8012
Adams	ADA 8022
Adams	ADA 8021
Adams	ADA 8013
Adams	ADA 8023
Adams	ADA 8011
Adams	ADA 8023
Adams	ADA 8023
Adams	ADA 8011
Adams	ADA 8025
Adams	ADA 8023
Adams	ADA 8023
Adams	ADA 8015
Adams	ADA 8012
Adams	ADA 8022
Aldene Sub	ALD 8026
Aldene Sub	ALD 8022
Aldene Sub	ALD 8023
Aldene Sub	ALD 8023
Aldene Sub	ALD 8012
Aldene Sub	ALD 8022
Aldene Sub	ALD 8023
Aldene Sub	ALD 8013
Aldene Sub	ALD 8023
Aldene Sub	ALD 8016
Aldene Sub	ALD 8022
Aldene Sub	ALD 8026
Aldene Sub	ALD 8013
Aldene Sub	ALD 8015
Aldene Sub	ALD 8016
Aldene Sub	ALD 8023
Aldene Sub	ALD 8012

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Aldene Sub	ALD 8014
Aldene Sub	ALD 8026
Aldene Sub	ALD 8012
Aldene Sub	ALD 8013
Aldene Sub	ALD 8022
Aldene Sub	ALD 8026
Aldene Sub	ALD 8012
Aldene Sub	ALD 8023
Aldene Sub	ALD 8023
Aldene Sub	ALD 8026
Aldene Sub	ALD 8012
Aldene Sub	ALD 8013
Aldene Sub	ALD 8023
Aldene Sub	ALD 8014
Aldene Sub	ALD 8013
Aldene Sub	ALD 8026
Aldene Sub	ALD 8025
Aldene Sub	ALD 8025
Aldene Sub	ALD 8022
Aldene Sub	ALD 8015
Aldene Sub	ALD 8023
Aldene Sub	ALD 8015
Aldene Sub	ALD 8013
Arcola	ARC 4003
Arcola	ARC 4001
Avenel	AVE 4003
Avenel	AVE 4003
Bayonne Sub	BAO 8025
Bayonne Sub	BAO 8011
Bayonne Sub	BAO 8034
Bayonne Sub	BAO 8044
Bayonne Sub	BAO 8006
Bayonne Sub	BAO 8023
Bayonne Sub	BAO 8011
Bayonne Sub	BAO 8034
Bayonne Sub	BAO 8044
Bayonne Sub	BAO 8044
Bayonne Sub	BAO 8023
Bayonne Sub	BAO 8043
Bayonne Sub	BAO 8043
Bayonne Sub	BAO 8013
Bayonne Sub	BAO 8023
Bayonne Sub	BAO 8033
Bayonne Sub	BAO 8011
Bayonne Sub	BAO 8011
Bayonne Sub	BAO 8034

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Bayonne Sub	BAO 8003
Bayonne Sub	BAO 8022
Bayonne Sub	BAO 8003
Bayonne Sub	BAO 8023
Bayonne Sub	BAO 8011
Bayonne Sub	BAO 8011
Bayonne Sub	BAO 8044
Bayonne Sub	BAO 8023
Bayonne Sub	BAO 8022
Bayonne Sub	BAO 8022
Bayonne Sub	BAO 8003
Bayonne Sub	BAO 8033
Bayonne Sub	BAO 8044
Bayonne Sub	BAO 8034
Bayonne Sub	BAO 8033
Bayonne Sub	BAO 8011
Bayonne Sub	BAO 8043
Bayonne Sub	BAO 8015
Bayonne Sub	BAO 8003
Bayonne Sub	BAO 8023
Bayonne Sub	BAO 8044
Bayonne Sub	BAO 8013
Bayonne Sub	BAO 8013
Bayonne Sub	BAO 8013
Bayonne Sub	BAO 8013
Bayonne Sub	BAO 8025
Bayonne Sub	BAO 8043
Bayonne Sub	BAO 8043
Bayonne Sub	BAO 8043
Bayonne Sub	BAO 8006
Bayonne Sub	BAO 8034
Bayonne Sub	BAO 8013
Bayonne Sub	BAO 8043
Bayonne Sub	BAO 8043
Bayonne Sub	BAO 8025
Bayonne Sub	BAO 8043
Bayonne Sub	BAO 8013
Bayonne Sub	BAO 8043
Bayonne Sub	BAO 8044
Bayonne Sub	BAO 8013
Bayonne Sub	BAO 8023
Bayonne Sub	BAO 8034
Bayonne Sub	BAO 8043
Bayonne Sub	BAO 8043
Beaver Brook	BEA 8006
Beaver Brook	BEA 8010

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Beaver Brook	BEA 8002
Beaver Brook	BEA 8001
Beaver Brook	BEA 8002
Beaver Brook	BEA 8010
Beaver Brook	BEA 8002
Beaver Brook	BEA 8005
Beaver Brook	BEA 8010
Beaver Brook	BEA 8001
Beaver Brook	BEA 8005
Beaver Brook	BEA 8006
Beaver Brook	BEA 8002
Beaver Brook	BEA 8005
Beaver Brook	BEA 8002
Beaver Brook	BEA 8007
Beaver Brook	BEA 8010
Beaver Brook	BEA 8005
Beaver Brook	BEA 8008
Beaver Brook	BEA 8006
Beaver Brook	BEA 8010
Beaver Brook	BEA 8003
Beaver Brook	BEA 8005
Beaver Brook	BEA 8007
Beaver Brook	BEA 8008
Beaver Brook	BEA 8002
Beaver Brook	BEA 8006
Beaver Brook	BEA 8010
Beaver Brook	BEA 8004
Beaver Brook	BEA 8002
Beaver Brook	BEA 8002
Beaver Brook	BEA 8002
Beaver Brook	BEA 8005
Beaver Brook	BEA 8001
Beaver Brook	BEA 8005
Beaver Brook	BEA 8006
Beaver Brook	BEA 8005
Beaver Brook	BEA 8005
Beaver Brook	BEA 8002
Belleville	BEE 4004
Belmont	BEM 8001
Belmont	BEM 8001
Belmont	BEM 8001
Belmont	BEM 8001
Belmont	BEM 8001
Belmont	BEM 8001
Bennetts Lane	BEN 8022
Bennetts Lane	BEN 8012

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Bennetts Lane	BEN 8016
Bennetts Lane	BEN 8025
Bennetts Lane	BEN 8012
Bennetts Lane	BEN 8023
Bennetts Lane	BEN 8025
Bennetts Lane	BEN 8023
Bennetts Lane	BEN 8021
Bennetts Lane	BEN 8021
Bennetts Lane	BEN 8014
Bennetts Lane	BEN 8012
Bennetts Lane	BEN 8026
Bennetts Lane	BEN 8025
Bennetts Lane	BEN 8026
Bennetts Lane	BEN 8016
Bennetts Lane	BEN 8016
Bennetts Lane	BEN 8011
Bennetts Lane	BEN 8021
Bennetts Lane	BEN 8021
Bennetts Lane	BEN 8015
Bennetts Lane	BEN 8012
Bennetts Lane	BEN 8022
Bennetts Lane	BEN 8022
Bennetts Lane	BEN 8024
Bennetts Lane	BEN 8016
Bennetts Lane	BEN 8022
Bennetts Lane	BEN 8025
Bennetts Lane	BEN 8022
Bennetts Lane	BEN 8022
Bennetts Lane	BEN 8011
Bennetts Lane	BEN 8024
Bennetts Lane	BEN 8021
Bennetts Lane	BEN 8011
Bennetts Lane	BEN 8011
Bennetts Lane	BEN 8011
Bennetts Lane	BEN 8014
Bergen Point	BER 4013
Bergen Point	BER 4013
Bergen Point	BER 4013
Bergen Point	BER 4006
Bergenfield	BEF 8016
Bergenfield	BEF 8012
Bergenfield	BEF 8022
Bergenfield	BEF 8015
Bergenfield	BEF 8016
Bergenfield	BEF 8024
Bergenfield	BEF 8015

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Bergenfield	BEF 8023
Bergenfield	BEF 8012
Bergenfield	BEF 8022
Bergenfield	BEF 8016
Bergenfield	BEF 8023
Bergenfield	BEF 8023
Bergenfield	BEF 8024
Bergenfield	BEF 8012
Bergenfield	BEF 8024
Bergenfield	BEF 8015
Bergenfield	BEF 8014
Bergenfield	BEF 8014
Bergenfield	BEF 8021
Bergenfield	BEF 8024
Bergenfield	BEF 8024
Bergenfield	BEF 8024
Bergenfield	BEF 8014
Bergenfield	BEF 8022
Bergenfield	BEF 8016
Bergenfield	BEF 8015
Bergenfield	BEF 8022
Bergenfield	BEF 8013
Bergenfield	BEF 8022
Bergenfield	BEF 8014
Bergenfield	BEF 8014
Bergenfield	BEF 8025
Bergenfield	BEF 8011
Bergenfield	BEF 8024
Bergenfield	BEF 8011
Bergenfield	BEF 8023
Bloomfield	BLO 4002
Bloomfield	BLO 4002
Bloomfield	BLO 4007
Bloomfield	BLO 4017
Bloomfield	BLO 4006
Bloomfield	BLO 4008
Bloomfield	BLO 4019
Bloomfield	BLO 4006
Bloomfield	BLO 4006
Bloomfield	BLO 4006
Bloomfield	BLO 4006
Bloomfield	BLO 4006
Bloomfield	BLO 4006
Bloomfield	BLO 4018
Bloomfield	BLO 4018
Bloomfield	BLO 4017

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Bloomfield	BLO 4002
Bloomfield	BLO 4002
Bloomfield	BLO 4002
Bloomfield	BLO 4016
Bloomfield	BLO 4016
Bloomfield	BLO 4018
Bloomfield	BLO 4015
Bloomfield	BLO 4014
Bloomfield	BLO 4017
Bloomfield	BLO 4007
Bloomfield	BLO 4018
Bloomfield	BLO 4007
Bloomfield	BLO 4015
Bloomfield	BLO 4007
Bloomfield	BLO 4004
Bloomfield	BLO 4007
Bloomfield	BLO 4004
Branchbrook	BRA 8012
Branchbrook	BRA 8011
Branchbrook	BRA 8011
Branchbrook	BRA 8011
Branchbrook	BRA 8011
Branchbrook	BRA 8011
Branchbrook	BRA 8012
Branchbrook	BRA 8012
Branchbrook	BRA 8011
Branchbrook	BRA 8012
Brunswick Sub	BRU 8022
Brunswick Sub	BRU 8012
Brunswick Sub	BRU 8011
Brunswick Sub	BRU 8012
Brunswick Sub	BRU 8011
Brunswick Sub	BRU 8022
Brunswick Sub	BRU 8023
Brunswick Sub	BRU 8011
Brunswick Sub	BRU 8013
Brunswick Sub	BRU 8023
Brunswick Sub	BRU 8021
Brunswick Sub	BRU 8021
Brunswick Sub	BRU 8021
Brunswick Sub	BRU 8021
Brunswick Sub	BRU 8012
Brunswick Sub	BRU 8013
Bustleton	BUS 8021
Bustleton	BUS 8012
Bustleton	BUS 8025

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Bustleton	BUS 8021
Bustleton	BUS 8023
Bustleton	BUS 8012
Bustleton	BUS 8012
Bustleton	BUS 8012
Bustleton	BUS 8021
Bustleton	BUS 8014
Bustleton	BUS 8011
Bustleton	BUS 8011
Bustleton	BUS 8014
Bustleton	BUS 8025
Bustleton	BUS 8024
Bustleton	BUS 8012
Bustleton	BUS 8021
Camden Sub	CAS 8001
Camden Sub	CAS 8002
Camden Sub	CAS 8001
Camden Sub	CAS 8001
Camden Sub	CAS 8001
Camden Sub	CAS 8001
Camden Sub	CAS 8001
Camden Sub	CAS 8001
Camden Sub	CAS 8001
Camden Sub	CAS 8001
Camden Sub	CAS 8001
Camden Sub	CAS 8001
Carlstadt	CAR 8004
Carteret	CAT 4009
Cedar Grove	CED 8011
Cedar Grove	CED 8021
Cedar Grove	CED 8011
Cedar Grove	CED 8011
Cedar Grove	CED 8011
Cedar Grove	CED 8016
Cedar Grove	CED 8023
Cedar Grove	CED 8022
Cedar Grove	CED 8021
Cedar Grove	CED 8022
Cedar Grove	CED 8023
Cedar Grove	CED 8011
Cedar Grove	CED 8016
Cedar Grove	CED 8022
Cedar Grove	CED 8022
Cedar Grove	CED 8024
Cedar Grove	CED 8013
Cedar Grove	CED 8022

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Cedar Grove	CED 8016
Cedar Grove	CED 8016
Cedar Grove	CED 8023
Cedar Grove	CED 8021
Cedar Grove	CED 8021
Central Ave	CET 4004
Central Ave	CET 4012
Central Ave	CET 4012
Central Ave	CET 4012
Central Ave	CET 4012
Central Ave	CET 4012
Central Ave	CET 4012
Central Ave	CET 4019
Chauncey Street	CHA 4009
Chauncey Street	CHA 4012
Chauncey Street	CHA 4012
Chauncey Street	CHA 4012
Chauncey Street	CHA 4012
Chauncey Street	CHA 4004
Chauncey Street	CHA 4005
Chauncey Street	CHA 4013
Chauncey Street	CHA 4012
Chester	CHS 4001
Cinnaminson	CIN 8034
Cinnaminson	CIN 8011
Cinnaminson	CIN 8043
Cinnaminson	CIN 8043
Cinnaminson	CIN 8043
Cinnaminson	CIN 8006
Cinnaminson	CIN 8006
Cinnaminson	CIN 8032
Cinnaminson	CIN 8011
Cinnaminson	CIN 8043
Cinnaminson	CIN 8007
Cinnaminson	CIN 8034
Cinnaminson	CIN 8011
Cinnaminson	CIN 8001
Cinnaminson	CIN 8011
Cinnaminson	CIN 8042
Cinnaminson	CIN 8032
Cinnaminson	CIN 8002
Cinnaminson	CIN 8043
Cinnaminson	CIN 8034
Cinnaminson	CIN 8001
Cinnaminson	CIN 8034
Cinnaminson	CIN 8034

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Cinnaminson	CIN 8007
Cinnaminson	CIN 8034
Cinnaminson	CIN 8043
Cinnaminson	CIN 8043
Cinnaminson	CIN 8034
Cinnaminson	CIN 8002
Cinnaminson	CIN 8011
Cinnaminson	CIN 8033
Cinnaminson	CIN 8043
Cinnaminson	CIN 8043
Cinnaminson	CIN 8011
Cinnaminson	CIN 8043
Cinnaminson	CIN 8007
Cinnaminson	CIN 8001
Cinnaminson	CIN 8001
Cinnaminson	CIN 8007
Cinnaminson	CIN 8007
Cinnaminson	CIN 8007
Cinnaminson	CIN 8033
Cinnaminson	CIN 8033
Cinnaminson	CIN 8043
Cinnaminson	CIN 8007
Cinnaminson	CIN 8033
Cinnaminson	CIN 8033
Cinnaminson	CIN 8001
Cinnaminson	CIN 8033
Cinnaminson	CIN 8007
Cinnaminson	CIN 8012
Cinnaminson	CIN 8043
Cinnaminson	CIN 8007
Cinnaminson	CIN 8001
Clark	CLA 4008
Clark	CLA 4004
Clark	CLA 4005
Clarksville	CLK 8025
Clarksville	CLK 8025
Clarksville	CLK 8025
Clarksville	CLK 8015
Clarksville	CLK 8034
Clarksville	CLK 8043
Clarksville	CLK 8034
Clarksville	CLK 8022
Clarksville	CLK 8012
Clarksville	CLK 8016
Clarksville	CLK 8016
Clarksville	CLK 8025

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Clarksville	CLK 8022
Clarksville	CLK 8034
Clifton	CLF 8015
Clifton	CLF 8022
Clifton	CLF 8012
Clifton	CLF 8022
Clifton	CLF 8022
Clifton	CLF 8016
Clifton	CLF 8024
Clifton	CLF 8023
Clifton	CLF 8022
Clifton	CLF 8022
Clifton	CLF 8012
Clifton	CLF 8023
Clifton	CLF 8014
Clifton	CLF 8015
Clifton	CLF 8013
Clifton	CLF 8013
Clifton	CLF 8022
Clifton	CLF 8022
Clifton	CLF 8023
Clifton	CLF 8022
Clifton	CLF 8022
Clifton	CLF 8016
Clifton	CLF 8025
Clifton	CLF 8015
Clifton	CLF 8022
Clifton	CLF 8015
Clifton	CLF 8013
Clifton	CLF 8026
Clifton	CLF 8015
Clifton	CLF 8025
Clifton	CLF 8024
Clifton	CLF 8015
Clifton	CLF 8015
Clifton	CLF 8016
Clifton	CLF 8015
Clifton	CLF 8016
Clifton	CLF 8023
Clifton	CLF 8012
Clifton	CLF 8024
Clifton	CLF 8022
Clifton	CLF 8014
Clinton Avenue	CLN 4006
Clinton Avenue	CLN 4006
Clinton Avenue	CLN 4006

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Constable Hook	CON 8001
Constable Hook	CON 8001
Constable Hook	CON 8001
Constable Hook2	CON 8002
Cook Rd	COR 8042
Cook Rd	COR 8034
Cook Rd	COR 8015
Cook Rd	COR 8043
Cook Rd	COR 8033
Cook Rd	COR 8043
Cook Rd	COR 8043
Cook Rd	COR 8042
Cook Rd	COR 8021
Cook Rd	COR 8012
Cook Rd	COR 8012
Cook Rd	COR 8011
Cook Rd	COR 8044
Cook Rd	COR 8042
Cook Rd	COR 8024
Cook Rd	COR 8034
Cook Rd	COR 8032
Cook Rd	COR 8031
Cook Rd	COR 8043
Cook Rd	COR 8014
Cook Rd	COR 8023
Cook Rd	COR 8012
Cook Rd	COR 8024
Cook Rd	COR 8033
Cook Rd	COR 8042
Cook Rd	COR 8023
Cook Rd	COR 8014
Cook Rd	COR 8021
Cook Rd	COR 8043
Cook Rd	COR 8044
Cook Rd	COR 8042
Cook Rd	COR 8043
Cook Rd	COR 8031
Cook Rd	COR 8033
Cook Rd	COR 8043
Cook Rd	COR 8021
Cook Rd	COR 8044
Cook Rd	COR 8043
Cook Rd	COR 8014
Cook Rd	COR 8024
Cook Rd	COR 8014
Cook Rd	COR 8042

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Cook Rd	COR 8013
Cook Rd	COR 8043
Cook Rd	COR 8013
Cook Rd	COR 8013
Cook Rd	COR 8044
Cook Rd	COR 8033
Cook Rd	COR 8044
Cook Rd	COR 8033
Cook Rd	COR 8023
Cook Rd	COR 8042
Cook Rd	COR 8043
Cook Rd	COR 8042
Cook Rd	COR 8034
Cook Rd	COR 8021
Cook Rd	COR 8014
Cook Rd	COR 8011
Cook Rd	COR 8023
Cook Rd	COR 8041
Cook Rd	COR 8035
Cook Rd	COR 8013
Cook Rd	COR 8024
Cook Rd	COR 8015
Cook Rd	COR 8034
Cook Rd	COR 8023
Cook Rd	COR 8033
Cook Rd	COR 8043
Cook Rd	COR 8012
Cook Rd	COR 8023
Cook Rd	COR 8022
Cook Rd	COR 8041
Cook Rd	COR 8044
Cook Rd	COR 8013
Cook Rd	COR 8015
Cook Rd	COR 8044
Coxs Corner Sub	CXC 8022
Coxs Corner Sub	CXC 8022
Coxs Corner Sub	CXC 8021
Coxs Corner Sub	CXC 8021
Cranford	CRA 4016
Cranford	CRA 4010
Cranford	CRA 4009
Cranford	CRA 4004
Cranford	CRA 4009
Crosswicks	CRX 8003
Crosswicks	CRX 8004
Crosswicks	CRX 8003

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Crosswicks	CRX 8005
Crosswicks	CRX 8007
Crosswicks	CRX 8002
Crosswicks	CRX 8004
Crosswicks	CRX 8004
Crosswicks	CRX 8007
Crosswicks	CRX 8007
Crosswicks	CRX 8003
Crosswicks	CRX 8004
Crosswicks	CRX 8004
Crosswicks	CRX 8004
Crosswicks	CRX 8006
Crosswicks	CRX 8003
Crosswicks	CRX 8004
Crosswicks	CRX 8006
Crosswicks	CRX 8005
Crosswicks	CRX 8004
Crosswicks	CRX 8004
Crosswicks	CRX 8001
Crosswicks	CRX 8006
Crosswicks	CRX 8004
Crosswicks	CRX 8004
Crosswicks	CRX 8005
Crosswicks	CRX 8006
Culver Avenue	CUL 4002
Culver Avenue	CUL 4002
Cuthbert Blvd	CUT 8033
Cuthbert Blvd	CUT 8034
Cuthbert Blvd	CUT 8034
Cuthbert Blvd	CUT 8043
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8043
Cuthbert Blvd	CUT 8043
Cuthbert Blvd	CUT 8043
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8007
Cuthbert Blvd	CUT 8034
Cuthbert Blvd	CUT 8043
Cuthbert Blvd	CUT 8009
Cuthbert Blvd	CUT 8032
Cuthbert Blvd	CUT 8034
Cuthbert Blvd	CUT 8004
Cuthbert Blvd	CUT 8007
Cuthbert Blvd	CUT 8035
Cuthbert Blvd	CUT 8042
Cuthbert Blvd	CUT 8005

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8010
Cuthbert Blvd	CUT 8001
Cuthbert Blvd	CUT 8042
Cuthbert Blvd	CUT 8032
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8032
Cuthbert Blvd	CUT 8004
Cuthbert Blvd	CUT 8004
Cuthbert Blvd	CUT 8034
Cuthbert Blvd	CUT 8043
Cuthbert Blvd	CUT 8043
Cuthbert Blvd	CUT 8033
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8032
Cuthbert Blvd	CUT 8007
Cuthbert Blvd	CUT 8043
Cuthbert Blvd	CUT 8032
Cuthbert Blvd	CUT 8005
Cuthbert Blvd	CUT 8043
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8034
Cuthbert Blvd	CUT 8034
Cuthbert Blvd	CUT 8043
Cuthbert Blvd	CUT 8010
Cuthbert Blvd	CUT 8005
Cuthbert Blvd	CUT 8042
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8034
Cuthbert Blvd	CUT 8004
Cuthbert Blvd	CUT 8042
Cuthbert Blvd	CUT 8009
Cuthbert Blvd	CUT 8043
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8041
Cuthbert Blvd	CUT 8006
Cuthbert Blvd	CUT 8004
Cuthbert Blvd	CUT 8004
Cuthbert Blvd	CUT 8005
Cuthbert Blvd	CUT 8004
Cuthbert Blvd	CUT 8042

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Cuthbert Blvd	CUT 8032
Cuthbert Blvd	CUT 8001
Cuthbert Blvd	CUT 8001
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8043
Cuthbert Blvd	CUT 8043
Cuthbert Blvd	CUT 8003
Cuthbert Blvd	CUT 8043
Cuthbert Blvd	CUT 8032
Cuthbert Blvd	CUT 8044
Cuthbert Blvd	CUT 8033
Cuthbert Blvd	CUT 8009
Cuthbert Blvd	CUT 8043
Cuthbert Blvd	CUT 8042
Dayton Unit	DAY 8001
Dayton Unit	DAY 8001
Deptford	DFD 8031
Deptford	DFD 8034
Deptford	DFD 8008
Deptford	DFD 8007
Deptford	DFD 8007
Deptford	DFD 8010
Deptford	DFD 8008
Deptford	DFD 8009
Deptford	DFD 8035
Deptford	DFD 8009
Deptford	DFD 8034
Deptford	DFD 8010
Deptford	DFD 8031
Deptford	DFD 8031
Deptford	DFD 8008
Deptford	DFD 8031
Deptford	DFD 8010
Deptford	DFD 8033
Deptford	DFD 8035
Deptford	DFD 8031
Deptford	DFD 8009
Deptford	DFD 8034
Deptford	DFD 8034
Deptford	DFD 8042
Deptford	DFD 8035
Deptford	DFD 8031
Deptford	DFD 8008
Deptford	DFD 8007

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Deptford	DFD 8007
Deptford	DFD 8035
Deptford	DFD 8010
Deptford	DFD 8034
Deptford	DFD 8007
Deptford	DFD 8042
Deptford	DFD 8042
Deptford	DFD 8042
Deptford	DFD 8042
Deptford	DFD 8008
Deptford	DFD 8042
Deptford	DFD 8007
Deptford	DFD 8008
Deptford	DFD 8007
Deptford	DFD 8009
Deptford	DFD 8010
Deptford	DFD 8031
Devils Brook	DVB 8011
Devils Brook	DVB 8023
Devils Brook	DVB 8012
Devils Brook	DVB 8012
Devils Brook	DVB 8023
Devils Brook	DVB 8023
Devils Brook	DVB 8013
Doremus Place	DOR 8042
Doremus Place	DOR 8044
Doremus Place	DOR 8042
Doremus Place	DOR 8042
Doremus Place	DOR 8035
Doremus Place	DOR 8035
Doremus Place	DOR 8023
Doremus Place	DOR 8042
Doremus Place	DOR 8042
Doremus Place	DOR 8042
Doremus Place	DOR 8032
Doremus Place	DOR 8023
Doremus Place	DOR 8032
Doremus Place	DOR 8042
Doremus Place	DOR 8043
Doremus Place	DOR 8035
Doremus Place	DOR 8014
Doremus Place	DOR 8042
Doremus Place	DOR 8013
Doremus Place	DOR 8045
Doremus Place	DOR 8025
Doremus Place	DOR 8015

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Doremus Place	DOR 8013
Doremus Place	DOR 8022
Doremus Place	DOR 8042
Doremus Place	DOR 8034
Doremus Place	DOR 8035
Doremus Place	DOR 8013
Doremus Place	DOR 8012
Doremus Place	DOR 8042
Doremus Place	DOR 8045
Doremus Place	DOR 8035
Doremus Place	DOR 8043
Doremus Place	DOR 8043
Doremus Place	DOR 8044
Doremus Place	DOR 8035
Doremus Place	DOR 8035
Doremus Place	DOR 8013
Doremus Place	DOR 8032
Doremus Place	DOR 8015
Doremus Place	DOR 8032
Doremus Place	DOR 8032
Doremus Place	DOR 8025
Doremus Place	DOR 8034
Doremus Place	DOR 8044
Doremus Place	DOR 8035
Doremus Place	DOR 8032
Doremus Place	DOR 8012
Doremus Place	DOR 8042
Doremus Place	DOR 8044
Doremus Place	DOR 8043
Doremus Place	DOR 8032
Doremus Place	DOR 8012
Doremus Place	DOR 8023
Doremus Place	DOR 8042
Doremus Place	DOR 8043
Doremus Place	DOR 8045
Doremus Place	DOR 8012
Doremus Place	DOR 8045
Doremus Place	DOR 8035
Doremus Place	DOR 8032
Doremus Place	DOR 8022
Doremus Place	DOR 8035
Doremus Place	DOR 8044
Doremus Place	DOR 8032
Doremus Place	DOR 8034
Doremus Place	DOR 8012
Doremus Place	DOR 8012

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Doremus Place	DOR 8032
Doremus Place	DOR 8043
Doremus Place	DOR 8043
Doremus Place	DOR 8024
Doremus Place	DOR 8033
Doremus Place	DOR 8024
Doremus Place	DOR 8014
Doremus Place	DOR 8034
Doremus Place	DOR 8033
Doremus Place	DOR 8032
Doremus Place	DOR 8023
Doremus Place	DOR 8022
Doremus Place	DOR 8033
Doremus Place	DOR 8022
Doremus Place	DOR 8042
Doremus Place	DOR 8042
Doremus Place	DOR 8022
Dumont	DUM 4002
Dumont	DUM 4003
East Orange Sub	EAO 4006
East Orange Sub	EAO 4012
East Orange Sub	EAO 4012
East Orange Sub	EAO 4003
East Orange Sub	EAO 4023
East Orange Sub	EAO 4012
East Orange Sub	EAO 4012
East Orange Sub	EAO 4008
East Orange Sub	EAO 4003
East Orange Sub	EAO 4008
East Orange Sub	EAO 4012
East Orange Sub	EAO 4006
East Orange Sub	EAO 4019
East Orange Sub	EAO 4008
East Orange Sub	EAO 4023
East Orange Sub	EAO 4024
East Orange Sub	EAO 4003
East Orange Sub	EAO 4019
East Orange Sub	EAO 4012
East Orange Sub	EAO 4012
East Orange Sub	EAO 4006
East Orange Sub	EAO 4019
East Orange Sub	EAO 4019
East Orange Sub	EAO 4019
East Orange Sub	EAO 4019
East Orange Sub	EAO 4023
East Orange Sub	EAO 4006

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
East Orange Sub	EAO 4006
East Orange Sub	EAO 4013
East Orange Sub	EAO 4006
East Orange Sub	EAO 4006
East Orange Sub	EAO 4008
East Orange Sub	EAO 4019
East Orange Sub	EAO 4023
East Orange Sub	EAO 4013
East Orange Sub	EAO 4003
East Orange Sub	EAO 4023
East Orange Sub	EAO 4024
East Riverton	ERT 8003
East Riverton 2	EAR 4001
East Riverton 2	EAR 4002
East Rutherford Sub	EAT 8021
East Rutherford Sub	EAT 8021
East Rutherford Sub	EAT 8011
East Rutherford Sub	EAT 8024
East Rutherford Sub	EAT 8012
East Rutherford Sub	EAT 8011
East Rutherford Sub	EAT 8013
East Rutherford Sub	EAT 8021
East Rutherford Sub	EAT 8024
East Rutherford Sub	EAT 8021
East Rutherford Sub	EAT 8024
East Rutherford Sub	EAT 8013
East Rutherford Sub	EAT 8024
East Rutherford Sub	EAT 8024
East Rutherford Sub	EAT 8024
East Rutherford Sub	EAT 8012
East Rutherford Sub	EAT 8012
East Rutherford Sub	EAT 8024
East Rutherford Sub	EAT 8013
East Rutherford Sub	EAT 8013
East Rutherford Sub	EAT 8024
East Rutherford Sub	EAT 8012
East Rutherford Sub	EAT 8024
East Rutherford Sub	EAT 8024
East Rutherford Sub	EAT 8024
East Rutherford Sub	EAT 8022
East Rutherford Sub	EAT 8022
East Rutherford Sub	EAT 8022
East Rutherford Sub	EAT 8011
Edison	EDI 4007
Edison	EDI 4007
Edison	EDI 4006

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Edison	EDI 4006
Edison	EDI 4008
Elizabeth	ELI 4008
Ewing	EWI 4006
Ewing	EWI 4004
Ewing	EWI 4004
Ewing	EWI 4006
Ewing	EWI 4004
Fairlawn	FAR 4005
Fairlawn	FAR 4006
Fairlawn	FAR 4006
Fanwood	FAW 8016
Fanwood	FAW 8021
Fanwood	FAW 8024
Fanwood	FAW 8024
Fanwood	FAW 8024
Fanwood	FAW 8025
Fanwood	FAW 8012
Fanwood	FAW 8024
Fanwood	FAW 8016
Fanwood	FAW 8023
Fanwood	FAW 8025
Fanwood	FAW 8021
Fanwood	FAW 8021
Fanwood	FAW 8012
Fanwood	FAW 8021
Fanwood	FAW 8022
Fanwood	FAW 8021
Fanwood	FAW 8013
Fanwood	FAW 8025
Fanwood	FAW 8023
Fanwood	FAW 8025
Fanwood	FAW 8015
Fanwood	FAW 8021
Fanwood	FAW 8011
Fanwood	FAW 8011
Fanwood	FAW 8012
Fanwood	FAW 8022
Fanwood	FAW 8014
Fanwood	FAW 8014
Fanwood	FAW 8011
Fanwood	FAW 8024
Fanwood	FAW 8021
Fanwood	FAW 8024
Fanwood	FAW 8011
Fanwood	FAW 8025

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Fanwood	FAW 8023
Fanwood	FAW 8013
Fanwood	FAW 8024
Fanwood	FAW 8021
Fanwood	FAW 8022
Fanwood	FAW 8022
Fanwood	FAW 8014
Fanwood	FAW 8021
Fanwood	FAW 8024
Fanwood	FAW 8016
Fanwood	FAW 8014
Fanwood	FAW 8022
Fanwood	FAW 8014
Fanwood	FAW 8011
Fanwood	FAW 8011
Federal Square	FED 4018
Federal Square	FED 4004
Federal Square	FED 4004
Federal Square	FED 4021
Federal Square	FED 4010
Federal Square	FED 4018
Federal Square	FED 4030
Federal Square	FED 4004
Federal Square	FED 4010
Fernwood	FEN 8041
Fernwood Unit 8051	FEN 8051
Fernwood Unit 8051	FEN 8051
Fernwood Unit 8051	FEN 8051
Fernwood Unit 8051	FEN 8051
Fernwood Unit 8051	FEN 8051
Fernwood Unit 8051	FEN 8051
Fifteenth St	FIF 4002
Fifteenth St	FIF 4002
Fifteenth St	FIF 4002
Fifteenth St Unit	FIT 8003
Finderne	FIN 4006
First Street	FIR 4006
First Street	FIR 4004
First Street	FIR 4006
First Street	FIR 4003
First Street	FIR 4006
Foundry St	FOU 8021
Foundry St	FOU 8021
Foundry St	FOU 8012
Foundry St	FOU 8012
Foundry St	FOU 8013

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Foundry St	FOU 8012
Foundry St	FOU 8021
Foundry St	FOU 8013
Foundry St	FOU 8012
Foundry St	FOU 8012
Foundry St	FOU 8012
Foundry St	FOU 8021
Foundry St	FOU 8012
Foundry St	FOU 8021
Foundry St	FOU 8012
Foundry St	FOU 8012
Foundry St	FOU 8013
Fourtieth St	FOH 4007
Fourtieth St	FOH 4007
Fourtieth St	FOH 4007
Fourtieth St	FOH 4007
Fourtieth St	FOH 4006
Franklin	FRA 8022
Franklin	FRA 8022
Franklin	FRA 8023
Front Street	FRO 4009
Front Street	FRO 4007
Front Street	FRO 4008
Garfield Avenue	GAE 4001
Garfield Avenue	GAE 4003
Getty Ave	GET 4008
Getty Ave	GET 4008
Getty Ave	GET 4008
Green Brook	GBK 8023
Green Brook	GBK 8014
Green Brook	GBK 8011
Green Brook	GBK 8014
Green Brook	GBK 8013
Green Brook	GBK 8024
Green Brook	GBK 8021
Green Brook	GBK 8011
Green Brook	GBK 8025
Green Brook	GBK 8013
Green Brook	GBK 8011
Green Brook	GBK 8022
Green Brook	GBK 8012
Green Brook	GBK 8024
Green Brook	GBK 8021
Green Brook	GBK 8024
Green Brook	GBK 8024
Green Brook	GBK 8013

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Green Brook	GBK 8025
Green Brook	GBK 8013
Green Brook	GBK 8012
Green Brook	GBK 8025
Green Brook	GBK 8025
Green Brook	GBK 8014
Green Brook	GBK 8013
Green Brook	GBK 8022
Green Brook	GBK 8022
Green Brook	GBK 8022
Green Brook	GBK 8011
Green Brook	GBK 8013
Green Brook	GBK 8013
Green Brook	GBK 8025
Greenville	GRN 4008
Greenville	GRN 4009
Greenville	GRN 4001
Hackensack	HAC 4007
Haddon Heights	HAD 4005
Haddon Heights	HAD 4010
Haddon Heights	HAD 4009
Haddon Heights	HAD 4005
Haledon	HAL 4001
Haledon	HAL 4006
Haledon	HAL 4002
Haledon	HAL 4007
Haledon	HAL 4004
Haledon	HAL 4002
Haledon	HAL 4002
Haledon	HAL 4002
Haledon	HAL 4005
Hamilton	HAM 4009
Hancock Street	HAN 4001
Hancock Street	HAN 4001
Hancock Street	HAN 4001
Hancock Street	HAN 4006
Harrison	HAR 4006
Harrison	HAR 4006
Harrison	HAR 4006
Harts Lane	HAT 8023
Harts Lane	HAT 8014
Harts Lane	HAT 8014
Harts Lane	HAT 8037
Harts Lane	HAT 8015
Harts Lane	HAT 8022
Harts Lane	HAT 8012

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Harts Lane	HAT 8037
Harts Lane	HAT 8013
Harts Lane	HAT 8011
Harts Lane	HAT 8013
Harts Lane	HAT 8037
Harts Lane	HAT 8021
Harts Lane	HAT 8011
Harts Lane	HAT 8012
Harts Lane	HAT 8014
Harts Lane	HAT 8014
Harts Lane	HAT 8012
Harts Lane	HAT 8037
Harts Lane	HAT 8013
Harts Lane	HAT 8013
Harts Lane	HAT 8037
Harts Lane	HAT 8037
Harts Lane	HAT 8035
Harts Lane	HAT 8014
Harts Lane	HAT 8014
Harts Lane	HAT 8014
Harts Lane	HAT 8013
Hawthorne	HAW 8041
Hawthorne	HAW 8035
Hawthorne	HAW 8032
Hawthorne	HAW 8044
Hawthorne	HAW 8032
Hawthorne	HAW 8032
Hawthorne	HAW 8041
Hawthorne	HAW 8044
Hawthorne	HAW 8044
Hawthorne	HAW 8032
Hawthorne	HAW 8042
Hawthorne	HAW 8044
Hawthorne	HAW 8041
Hawthorne	HAW 8044
Hawthorne	HAW 8035
Hawthorne	HAW 8032
Hawthorne	HAW 8032
Hawthorne	HAW 8044
Hawthorne	HAW 8042
Hawthorne	HAW 8044
Hawthorne	HAW 8044
Hawthorne	HAW 8035
Hawthorne	HAW 8035
Hawthorne	HAW 8032
Hawthorne	HAW 8032

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Hawthorne	HAW 8041
Henry Street	HEN 4007
Henry Street	HEN 4006
Hillsdale	HID 8033
Hillsdale	HID 8032
Hillsdale	HID 8042
Hillsdale	HID 8044
Hillsdale	HID 8041
Hillsdale	HID 8031
Hillsdale	HID 8043
Hillsdale	HID 8031
Hillsdale	HID 8011
Hillsdale	HID 8035
Hillsdale	HID 8033
Hillsdale	HID 8031
Hillsdale	HID 8031
Hillsdale	HID 8032
Hillsdale	HID 8044
Hillsdale	HID 8025
Hillsdale	HID 8041
Hillsdale	HID 8025
Hillsdale	HID 8042
Hillsdale	HID 8011
Hillsdale	HID 8045
Hillsdale	HID 8044
Hillsdale	HID 8033
Hillsdale	HID 8032
Hillsdale	HID 8041
Hillsdale	HID 8045
Hillsdale	HID 8044
Hillsdale	HID 8045
Hillsdale	HID 8025
Hillsdale	HID 8034
Hillsdale	HID 8045
Hillsdale	HID 8033
Hillsdale	HID 8032
Hinchmans	HNC 8022
Hinchmans	HNC 8024
Hinchmans	HNC 8023
Hinchmans	HNC 8021
Hinchmans	HNC 8021
Hinchmans	HNC 8021
Hinchmans	HNC 8023
Hinchmans	HNC 8012
Hinchmans	HNC 8021
Hinchmans	HNC 8023

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Hinchmans	HNC 8025
Hinchmans	HNC 8013
Hinchmans	HNC 8021
Hinchmans	HNC 8023
Hinchmans	HNC 8012
Hinchmans	HNC 8012
Hinchmans	HNC 8021
Hinchmans	HNC 8022
Hinchmans	HNC 8012
Hoboken	HOE 8044
Hoboken	HOE 8044
Hoboken	HOE 8044
Hoboken	HOE 8044
Hoboken	HOE 8044
Hoboken	HOE 8038
Hoboken	HOE 8047
Hoboken	HOE 8038
Hoboken	HOE 8038
Hoboken	HOE 8044
Hoboken	HOE 8044
Homestead	HOM 8021
Homestead	HOM 8001
Homestead	HOM 8032
Homestead	HOM 8033
Homestead	HOM 8012
Homestead	HOM 8001
Homestead	HOM 8032
Homestead	HOM 8033
Homestead	HOM 8001
Homestead	HOM 8032
Homestead	HOM 8032
Homestead	HOM 8034
Homestead	HOM 8025
Homestead	HOM 8034
Homestead	HOM 8033
Homestead	HOM 8033
Homestead	HOM 8034
Homestead	HOM 8021
Homestead	HOM 8012
Homestead	HOM 8032
Homestead	HOM 8001
Homestead	HOM 8032
Homestead	HOM 8012
Homestead	HOM 8033
Homestead	HOM 8033
Homestead	HOM 8012

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Homestead	HOM 8034
Homestead	HOM 8034
Homestead	HOM 8034
Homestead	HOM 8012
Homestead	HOM 8001
Homestead	HOM 8001
Homestead	HOM 8033
Homestead	HOM 8033
Homestead	HOM 8033
Homestead	HOM 8033
Homestead	HOM 8033
Homestead	HOM 8033
Homestead	HOM 8012
Homestead	HOM 8033
Homestead	HOM 8012
Homestead	HOM 8033
Homestead	HOM 8012
Irvington	IRV 4019
Irvington	IRV 4013
Irvington	IRV 4006
Irvington	IRV 4019
Irvington	IRV 4004
Irvington	IRV 4002
Irvington	IRV 4017
Irvington	IRV 4002
Irvington	IRV 4021
Irvington	IRV 4022
Irvington	IRV 4022
Irvington	IRV 4004
Irvington	IRV 4004
Irvington	IRV 4013
Irvington	IRV 4017
Irvington	IRV 4017
Irvington	IRV 4013
Irvington	IRV 4022
Irvington	IRV 4002
Irvington	IRV 4011
Irvington	IRV 4011
Irvington	IRV 4002
Irvington	IRV 4013
Irvington	IRV 4019
Jackson Rd	JAC 8025
Jackson Rd	JAC 8043
Jackson Rd	JAC 8013
Jackson Rd	JAC 8023
Jackson Rd	JAC 8024

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Jackson Rd	JAC 8024
Jackson Rd	JAC 8043
Jackson Rd	JAC 8023
Jackson Rd	JAC 8013
Jackson Rd	JAC 8023
Jackson Rd	JAC 8023
Jackson Rd	JAC 8013
Jackson Rd	JAC 8032
Jackson Rd	JAC 8024
Jackson Rd	JAC 8032
Jackson Rd	JAC 8043
Jackson Rd	JAC 8033
Jackson Rd	JAC 8032
Jackson Rd	JAC 8013
Jackson Rd	JAC 8013
Jackson Rd	JAC 8013
Jackson Rd	JAC 8013
Jackson Rd	JAC 8013
Keasbey	KEA 4003
Kenilworth	KEN 4001
Kilmer	KIL 8022
Kilmer	KIL 8015
Kilmer	KIL 8041
Kilmer	KIL 8022
Kilmer	KIL 8034
Kilmer	KIL 8042
Kilmer	KIL 8012
Kilmer	KIL 8024
Kilmer	KIL 8044
Kilmer	KIL 8012
Kilmer	KIL 8041
Kilmer	KIL 8035
Kilmer	KIL 8024
Kilmer	KIL 8042
Kilmer	KIL 8024
Kilmer	KIL 8042
Kilmer	KIL 8012
Kilmer	KIL 8025
Kilmer	KIL 8025
Kilmer	KIL 8024
Kilmer	KIL 8035
Kilmer	KIL 8034
Kilmer	KIL 8014
Kilmer	KIL 8024
Kilmer	KIL 8042
Kilmer	KIL 8044

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Kilmer	KIL 8043
Kilmer	KIL 8042
Kilmer	KIL 8041
Kilmer	KIL 8044
Kilmer	KIL 8014
Kilmer	KIL 8014
Kilmer	KIL 8015
Kilmer	KIL 8015
Kilmer	KIL 8044
Kilmer	KIL 8016
Kilmer	KIL 8016
Kilmer	KIL 8016
Kilmer	KIL 8014
Kilmer	KIL 8014
Kilmer	KIL 8014
Kilmer	KIL 8034
Kilmer	KIL 8014
Kilmer	KIL 8023
Kilmer	KIL 8015
Kilmer	KIL 8041
Kilmer	KIL 8034
Kilmer	KIL 8035
Kilmer	KIL 8034
Kilmer	KIL 8022
Kilmer	KIL 8034
Kilmer	KIL 8035
Kilmer	KIL 8035
Kilmer	KIL 8016
Kilmer	KIL 8016
Kilmer	KIL 8033
Kilmer	KIL 8033
Kilmer	KIL 8023
Kilmer	KIL 8025
Kilmer	KIL 8023
Kilmer	KIL 8023
Kilmer	KIL 8023
Kilmer	KIL 8016
Kingsland	KIN 8021
Kingsland	KIN 8021
Kingsland	KIN 8023
Kingsland	KIN 8025
Kingsland	KIN 8021
Kingsland	KIN 8025
Kingsland	KIN 8021
Kingsland	KIN 8025
Kingsland	KIN 8023

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Kingsland	KIN 8022
Kingsland	KIN 8015
Kingsland	KIN 8015
Kingsland	KIN 8021
Kingsland	KIN 8022
Kingsland	KIN 8022
Kingsland	KIN 8023
Kingsland	KIN 8022
Kingsland	KIN 8025
Kingsland	KIN 8022
Kingsland	KIN 8021
Kingsland	KIN 8023
Kingsland	KIN 8015
Kingsland	KIN 8022
Kingsland	KIN 8022
Kingsland	KIN 8023
Kingsland	KIN 8015
Kingsland	KIN 8015
Kingsland	KIN 8015
Kingsland	KIN 8021
Kingsland	KIN 8015
Kingsland	KIN 8021
Kingsland	KIN 8024
Kingsland	KIN 8022
Kingsland	KIN 8022
Kingsland	KIN 8023
Kingsland	KIN 8023
Kingsland	KIN 8023
Kingsland	KIN 8025
Kingsland	KIN 8023
Kingsland	KIN 8023
Kingsland	KIN 8015
Kingsland	KIN 8015
Kingsland	KIN 8025
Kingsland	KIN 8022
Kingsland	KIN 8023
Kingsland	KIN 8025
Kingsland	KIN 8025
Kingsland	KIN 8025
Kingsland	KIN 8023
Kingsland	KIN 8015
Kingsland	KIN 8024
Kingsland	KIN 8014
Kingsland	KIN 8021
Kingsland	KIN 8022
Kingsland	KIN 8021

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Kuller Road	KUL 8014
Kuller Road	KUL 8023
Kuller Road	KUL 8014
Kuller Road	KUL 8013
Kuller Road	KUL 8022
Kuller Road	KUL 8022
Kuller Road	KUL 8023
Kuller Road	KUL 8014
Kuller Road	KUL 8014
Kuller Road	KUL 8011
Kuller Road	KUL 8021
Kuller Road	KUL 8014
Kuller Road	KUL 8014
Kuller Road	KUL 8013
Kuller Road	KUL 8014
Kuller Road	KUL 8014
Kuller Road	KUL 8013
Kuller Road	KUL 8012
Kuller Road	KUL 8012
Kuller Road	KUL 8014
Kuller Road	KUL 8023
Kuller Road	KUL 8014
Kuller Road	KUL 8013
Kuller Road	KUL 8014
Kuller Road	KUL 8014
Kuller Road	KUL 8021
Kuller Road	KUL 8024
Kuller Road	KUL 8011
Kuller Road	KUL 8022
Kuller Road	KUL 8013
Kuller Road	KUL 8011
Kuller Road	KUL 8021
Kuller Road	KUL 8012
Kuller Road	KUL 8012
Kuller Road	KUL 8012
Kuller Road	KUL 8013
Kuser Rd	KUS 8031
Kuser Rd	KUS 8009
Kuser Rd	KUS 8041
Kuser Rd	KUS 8008
Kuser Rd	KUS 8002
Kuser Rd	KUS 8041
Kuser Rd	KUS 8010
Kuser Rd	KUS 8044
Kuser Rd	KUS 8009
Kuser Rd	KUS 8009

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Kuser Rd	KUS 8004
Kuser Rd	KUS 8009
Kuser Rd	KUS 8031
Kuser Rd	KUS 8008
Kuser Rd	KUS 8003
Kuser Rd	KUS 8032
Kuser Rd	KUS 8033
Kuser Rd	KUS 8004
Kuser Rd	KUS 8006
Kuser Rd	KUS 8042
Kuser Rd	KUS 8041
Kuser Rd	KUS 8002
Kuser Rd	KUS 8041
Kuser Rd	KUS 8009
Kuser Rd	KUS 8007
Kuser Rd	KUS 8002
Kuser Rd	KUS 8007
Kuser Rd	KUS 8002
Kuser Rd	KUS 8003
Kuser Rd	KUS 8045
Kuser Rd	KUS 8045
Kuser Rd	KUS 8031
Kuser Rd	KUS 8032
Kuser Rd	KUS 8031
Kuser Rd	KUS 8009
Kuser Rd	KUS 8031
Kuser Rd	KUS 8041
Kuser Rd	KUS 8002
Kuser Rd	KUS 8003
Kuser Rd	KUS 8002
Kuser Rd	KUS 8004
Kuser Rd	KUS 8004
Kuser Rd	KUS 8045
Kuser Rd	KUS 8002
Kuser Rd	KUS 8002
Kuser Rd	KUS 8010
Kuser Rd	KUS 8032
Kuser Rd	KUS 8009
Kuser Rd	KUS 8042
Kuser Rd	KUS 8002
Kuser Rd	KUS 8031
Kuser Rd	KUS 8031
Kuser Rd	KUS 8042
Kuser Rd	KUS 8002
Kuser Rd	KUS 8031
Kuser Rd	KUS 8033

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Kuser Rd	KUS 8002
Kuser Rd	KUS 8009
Kuser Rd	KUS 8032
Kuser Rd	KUS 8003
Kuser Rd	KUS 8010
Kuser Rd	KUS 8043
Kuser Rd	KUS 8042
Kuser Rd	KUS 8031
Kuser Rd	KUS 8003
Kuser Rd	KUS 8031
Kuser Rd	KUS 8033
Kuser Rd	KUS 8033
Kuser Rd	KUS 8007
Kuser Rd	KUS 8004
Kuser Rd	KUS 8002
Kuser Rd	KUS 8008
Kuser Rd	KUS 8008
Kuser Rd	KUS 8045
Kuser Rd	KUS 8002
Kuser Rd	KUS 8007
Lafayette Road	LAF 8026
Lafayette Road	LAF 8026
Lafayette Road	LAF 8022
Lafayette Road	LAF 8015
Lafayette Road	LAF 8026
Lafayette Road	LAF 8022
Lafayette Road	LAF 8011
Lafayette Road	LAF 8026
Lafayette Road	LAF 8022
Lafayette Road	LAF 8015
Lafayette Road	LAF 8011
Lafayette Road	LAF 8011
Lafayette Road	LAF 8023
Lafayette Road	LAF 8012
Lafayette Road	LAF 8012
Lafayette Road	LAF 8012
Lafayette Road	LAF 8011
Lafayette Road	LAF 8012
Lafayette Road	LAF 8011
Lafayette Road	LAF 8022
Lafayette Road	LAF 8011
Lafayette Road	LAF 8011
Lafayette Road	LAF 8011
Lafayette Road	LAF 8011
Lafayette Road	LAF 8015
Lake Nelson	LAK 8014

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Lake Nelson	LAK 8013
Lake Nelson	LAK 8024
Lake Nelson	LAK 8014
Lake Nelson	LAK 8014
Lake Nelson	LAK 8014
Lake Nelson	LAK 8013
Lake Nelson	LAK 8024
Lake Nelson	LAK 8024
Lake Nelson	LAK 8012
Lake Nelson	LAK 8024
Lake Nelson	LAK 8024
Lake Nelson	LAK 8024
Lake Nelson	LAK 8014
Lake Nelson	LAK 8014
Lakeside	LAS 4019
Lakeside	LAS 4010
Lakeside	LAS 4019
Lakeside	LAS 4019
Laurel Ave	LAU 8011
Laurel Ave	LAU 8012
Laurel Ave	LAU 8021
Laurel Ave	LAU 8011
Laurel Ave	LAU 8012
Laurel Ave	LAU 8035
Laurel Ave	LAU 8046
Laurel Ave	LAU 8023
Laurel Ave	LAU 8036
Laurel Ave	LAU 8011
Laurel Ave	LAU 8012
Laurel Ave	LAU 8012
Laurel Ave	LAU 8015
Laurel Ave	LAU 8011
Laurel Ave	LAU 8021
Laurel Ave	LAU 8021
Laurel Ave	LAU 8035
Laurel Ave	LAU 8011
Laurel Ave	LAU 8014
Laurel Ave	LAU 8012
Laurel Ave	LAU 8036
Laurel Ave	LAU 8035
Laurel Ave	LAU 8011
Laurel Ave	LAU 8036
Laurel Ave	LAU 8034
Laurel Ave	LAU 8046
Laurel Ave	LAU 8046
Laurel Ave	LAU 8046

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Lawnside	LAW 8025
Lawnside	LAW 8032
Lawnside	LAW 8032
Lawnside	LAW 8023
Lawnside	LAW 8023
Lawnside	LAW 8033
Lawnside	LAW 8024
Lawnside	LAW 8032
Lawnside	LAW 8019
Lawnside	LAW 8033
Lawnside	LAW 8033
Lawnside	LAW 8023
Lawnside	LAW 8032
Lawnside	LAW 8033
Lawnside	LAW 8033
Lawnside	LAW 8023
Lawnside	LAW 8033
Lawnside	LAW 8025
Lawnside	LAW 8024
Lawnside	LAW 8023
Lawnside	LAW 8015
Lawnside	LAW 8033
Lawnside	LAW 8022
Lawnside	LAW 8032
Lawnside	LAW 8026
Lawnside	LAW 8018
Lawnside	LAW 8025
Lawnside	LAW 8022
Lawnside	LAW 8024
Lawnside	LAW 8025
Lawnside	LAW 8031
Lawnside	LAW 8033
Lawnside	LAW 8033
Lawnside	LAW 8033
Lawnside	LAW 8022
Lawnside	LAW 8022
Lawnside	LAW 8018
Lawnside	LAW 8018
Lawrence Sub	LCE 8010
Lawrence Sub	LCE 8003
Lawrence Sub	LCE 8006
Lawrence Sub	LCE 8032
Lawrence Sub	LCE 8036
Lawrence Sub	LCE 8033
Lawrence Sub	LCE 8035
Lawrence Sub	LCE 8032

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Lawrence Sub	LCE 8003
Lawrence Sub	LCE 8043
Lawrence Sub	LCE 8032
Lawrence Sub	LCE 8045
Lawrence Sub	LCE 8045
Lawrence Sub	LCE 8046
Lawrence Sub	LCE 8010
Lawrence Sub	LCE 8045
Lawrence Sub	LCE 8003
Lawrence Sub	LCE 8044
Lawrence Sub	LCE 8042
Lawrence Sub	LCE 8032
Lawrence Sub	LCE 8042
Lawrence Sub	LCE 8032
Lawrence Sub	LCE 8033
Lawrence Sub	LCE 8044
Lawrence Sub	LCE 8032
Lawrence Sub	LCE 8006
Lawrence Sub	LCE 8009
Lawrence Sub	LCE 8004
Lawrence Sub	LCE 8003
Lawrence Sub	LCE 8010
Lawrence Sub	LCE 8003
Lawrence Sub	LCE 8033
Lawrence Sub	LCE 8034
Lawrence Sub	LCE 8046
Lawrence Sub	LCE 8008
Lawrence Sub	LCE 8046
Lawrence Sub	LCE 8042
Lawrence Sub	LCE 8032
Lawrence Sub	LCE 8033
Lawrence Sub	LCE 8008
Lawrence Sub	LCE 8008
Lawrence Sub	LCE 8008
Lawrence Sub	LCE 8032
Lawrence Sub	LCE 8036
Lawrence Sub	LCE 8046
Lawrence Sub	LCE 8046
Lawrence Unit Sub	LCU 8051
Lehigh Avenue	LEH 4002
Lehigh Avenue	LEH 4009
Leonia	LEO 8035
Leonia	LEO 8031
Leonia	LEO 8008
Leonia	LEO 8009
Leonia	LEO 8005

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Leonia	LEO 8005
Leonia	LEO 8001
Leonia	LEO 8003
Leonia	LEO 8007
Leonia	LEO 8032
Leonia	LEO 8041
Leonia	LEO 8034
Leonia	LEO 8035
Leonia	LEO 8005
Leonia	LEO 8034
Leonia	LEO 8008
Leonia	LEO 8003
Leonia	LEO 8007
Leonia	LEO 8034
Leonia	LEO 8008
Leonia	LEO 8041
Leonia	LEO 8001
Leonia	LEO 8031
Leonia	LEO 8041
Leonia	LEO 8004
Leonia	LEO 8001
Leonia	LEO 8041
Leonia	LEO 8041
Leonia	LEO 8034
Leonia	LEO 8043
Leonia	LEO 8007
Leonia	LEO 8041
Leonia	LEO 8001
Leonia	LEO 8041
Leonia	LEO 8004
Leonia	LEO 8001
Leonia	LEO 8041
Leonia	LEO 8005
Leonia	LEO 8004
Leonia	LEO 8031
Leonia	LEO 8003
Levittown	LEV 8003
Levittown	LEV 8014
Levittown	LEV 8007
Levittown	LEV 8001
Levittown	LEV 8012
Levittown	LEV 8010
Levittown	LEV 8014
Levittown	LEV 8010
Levittown	LEV 8006
Levittown	LEV 8004

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Levittown	LEV 8009
Levittown	LEV 8003
Levittown	LEV 8005
Levittown	LEV 8005
Levittown	LEV 8007
Levittown	LEV 8012
Levittown	LEV 8008
Levittown	LEV 8004
Levittown	LEV 8004
Levittown	LEV 8003
Levittown	LEV 8007
Levittown	LEV 8005
Levittown	LEV 8007
Levittown	LEV 8010
Levittown	LEV 8010
Levittown	LEV 8003
Levittown	LEV 8009
Levittown	LEV 8005
Levittown	LEV 8015
Levittown	LEV 8005
Levittown	LEV 8012
Levittown	LEV 8004
Levittown	LEV 8010
Levittown	LEV 8010
Levittown	LEV 8002
Levittown	LEV 8010
Levittown	LEV 8010
Levittown	LEV 8005
Levittown	LEV 8006
Levittown	LEV 8017
Levittown	LEV 8005
Levittown	LEV 8015
Levittown	LEV 8008
Levittown	LEV 8005
Levittown	LEV 8001
Levittown	LEV 8004
Levittown	LEV 8006
Levittown	LEV 8017
Levittown	LEV 8012
Levittown	LEV 8010
Levittown	LEV 8001
Levittown	LEV 8015
Levittown	LEV 8009
Levittown	LEV 8004
Levittown	LEV 8009
Levittown	LEV 8005

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Levittown	LEV 8001
Levittown	LEV 8001
Levittown	LEV 8003
Levittown	LEV 8015
Levittown	LEV 8003
Levittown	LEV 8005
Levittown	LEV 8001
Levittown	LEV 8015
Levittown	LEV 8010
Levittown	LEV 8017
Levittown	LEV 8004
Levittown	LEV 8001
Levittown	LEV 8003
Levittown	LEV 8005
Levittown	LEV 8008
Levittown	LEV 8003
Levittown	LEV 8010
Levittown	LEV 8005
Levittown	LEV 8018
Levittown	LEV 8005
Levittown	LEV 8005
Levittown	LEV 8008
Levittown	LEV 8010
Levittown	LEV 8001
Levittown	LEV 8010
Levittown	LEV 8018
Levittown	LEV 8010
Levittown	LEV 8006
Levittown	LEV 8005
Levittown	LEV 8008
Levittown	LEV 8005
Levittown	LEV 8017
Levittown	LEV 8017
Levittown	LEV 8017
Levittown	LEV 8017
Levittown	LEV 8017
Levittown	LEV 8005
Levittown	LEV 8005
Levittown	LEV 8005
Levittown	LEV 8017
Levittown	LEV 8001
Levittown	LEV 8001
Levittown	LEV 8008
Levittown	LEV 8001
Levittown	LEV 8008
Levittown	LEV 8008

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Levittown	LEV 8008
Levittown	LEV 8003
Levittown	LEV 8018
Levittown	LEV 8017
Levittown	LEV 8001
Levittown	LEV 8004
Levittown	LEV 8016
Levittown	LEV 8017
Levittown	LEV 8005
Levittown	LEV 8005
Liberty Street	LIB 4009
Liberty Street	LIB 4003
Liberty Street	LIB 4003
Liberty Street	LIB 4003
Liberty Street	LIB 4005
Liberty Street	LIB 4003
Liberty Street	LIB 4009
Little Ferry	LIT 8001
Little Ferry	LIT 8001
Locust Street	LOC 8005
Locust Street	LOC 8005
Locust Street	LOC 8005
Locust Street	LOC 8005
Locust Street	LOC 8004
Locust Street	LOC 8004
Locust Street	LOC 8005
Lodi	LOI 8001
Lumberton	LUM 8013
Lumberton	LUM 8013
Lumberton	LUM 8012
Lumberton	LUM 8012
Lumberton	LUM 8012
Lumberton	LUM 8015
Lumberton	LUM 8015
Lumberton	LUM 8013
Lumberton	LUM 8012
Lumberton	LUM 8012
Lumberton	LUM 8013
Lumberton	LUM 8021
Lumberton	LUM 8024
Lumberton	LUM 8011
Lumberton	LUM 8011
Lumberton	LUM 8011
Lumberton	LUM 8012
Lumberton	LUM 8012
Lumberton	LUM 8021

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Lumberton	LUM 8021
Lumberton	LUM 8021
Lumberton	LUM 8014
Lumberton	LUM 8015
Lumberton	LUM 8012
Lumberton	LUM 8011
Lumberton	LUM 8011
Lumberton	LUM 8011
Lyndhurst	LYN 8001
Lyndhurst	LYN 8001
Lyndhurst	LYN 8001
Maple Shade	MAD 8023
Maple Shade	MAD 8032
Maple Shade	MAD 8033
Maple Shade	MAD 8018
Maple Shade	MAD 8031
Maple Shade	MAD 8018
Maple Shade	MAD 8018
Maple Shade	MAD 8032
Maple Shade	MAD 8032
Maple Shade	MAD 8032
Maple Shade	MAD 8031
Maple Shade	MAD 8037
Maple Shade	MAD 8037
Maple Shade	MAD 8018
Maple Shade	MAD 8033
Maple Shade	MAD 8018
Maple Shade	MAD 8033
Maple Shade	MAD 8023
Maple Shade	MAD 8021
Maple Shade	MAD 8018
Maple Shade	MAD 8031
Maple Shade	MAD 8017
Maple Shade	MAD 8018
Maple Shade	MAD 8018
Maple Shade	MAD 8037
Maple Shade	MAD 8016
Maple Shade	MAD 8033
Maple Shade	MAD 8022
Maple Shade	MAD 8032
Maple Shade	MAD 8037
Maple Shade	MAD 8038
Maple Shade	MAD 8017
Maple Shade	MAD 8022
Maple Shade	MAD 8022
Maple Shade	MAD 8022

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Maple Shade	MAD 8022
Maple Shade	MAD 8031
Maple Shade	MAD 8031
Maple Shade	MAD 8017
Maple Shade	MAD 8016
Maple Shade	MAD 8032
Maple Shade	MAD 8032
Marion Drive	MAI 8013
Marion Drive	MAI 8021
Marion Drive	MAI 8011
Marion Drive	MAI 8022
Marion Drive	MAI 8012
Marion Drive	MAI 8011
Marion Drive	MAI 8014
Marion Drive	MAI 8013
Marion Drive	MAI 8012
Marion Drive	MAI 8012
Marion Drive	MAI 8014
Marion Drive	MAI 8021
Marion Drive	MAI 8021
Marion Drive	MAI 8021
Marion Drive	MAI 8011
Marion Drive	MAI 8012
Marion Drive	MAI 8012
Marion Drive	MAI 8024
Marion Drive	MAI 8021
Marion Drive	MAI 8024
Marion Drive	MAI 8012
Marion Drive	MAI 8014
Marion Drive	MAI 8014
Marlton	Mar-14
Marlton	Mar-19
Marlton	Mar-14
Marlton	Mar-16
Marlton	Mar-16
Marlton	Mar-19
Marlton	Mar-12
Marlton	Mar-02
Marlton	Mar-16
Marlton	Mar-10
Marlton	Mar-15
Marlton	Mar-15
Marlton	Mar-13
Marlton	Mar-12
Marlton	Mar-03
Marlton	Mar-19

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Marlton	Mar-15
Marlton	Mar-14
Marlton	Mar-19
Marlton	Mar-08
Marlton	Mar-19
Marlton	Mar-20
Marlton	Mar-10
Marlton	Mar-19
Marlton	Mar-16
Marlton	Mar-16
Marlton	Mar-15
Marlton	Mar-15
Marlton	Mar-19
Marlton	Mar-12
Marlton	Mar-16
Marlton	Mar-12
Marlton	Mar-10
Marlton	Mar-08
Marlton	Mar-08
Marlton	Mar-07
Marlton	Mar-08
Marlton	Mar-08
Marlton	Mar-02
Marlton	Mar-15
Maywood	MAY 8035
Maywood	May-46
Maywood	May-33
Maywood	May-43
Maywood	May-13
Maywood	May-23
Maywood	May-23
Maywood	May-44
Maywood	May-33
Maywood	May-44
Maywood	May-23
Maywood	May-15
Maywood	May-12
Maywood	May-44
Maywood	May-12
Maywood	May-14
Maywood	May-44
Maywood	May-23
Maywood	May-12
Maywood	May-12
Maywood	May-15
Maywood	May-22

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Maywood	May-33
Maywood	May-24
Maywood	May-34
Maywood	May-35
Maywood	May-34
Maywood	May-33
Maywood	May-33
Maywood	May-46
Maywood	May-43
Maywood	May-44
Maywood	May-15
Maywood	May-24
McLean Blvd	MCL 4009
McLean Blvd	MCL 4007
McLean Blvd	MCL 4009
Meadow Road	MEA 8026
Meadow Road	MEA 8013
Meadow Road	MEA 8024
Meadow Road	MEA 8026
Meadow Road	MEA 8014
Meadow Road	MEA 8021
Meadow Road	MEA 8013
Meadow Road	MEA 8021
Meadow Road	MEA 8026
Meadow Road	MEA 8026
Meadow Road	MEA 8021
Meadow Road	MEA 8025
Meadow Road	MEA 8013
Meadow Road	MEA 8013
Meadow Road	MEA 8026
Meadow Road	MEA 8024
Meadow Road	MEA 8013
Meadow Road	MEA 8025
Meadow Road	MEA 8025
Meadow Road	MEA 8026
Meadow Road	MEA 8013
Meadow Road	MEA 8025
Meadow Road	MEA 8023
Meadow Road	MEA 8023
Meadow Road	MEA 8026
Meadow Road	MEA 8021
Meadow Road	MEA 8026
Meadow Road	MEA 8024
Meadow Road	MEA 8024
Meadow Road	MEA 8024
Meadow Road	MEA 8023

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Meadow Road	MEA 8021
Meadow Road	MEA 8026
Meadow Road	MEA 8026
Meadow Road	MEA 8023
Mechanic Street	MEC 4001
Mechanic Street	MEC 4011
Mechanic Street	MEC 4001
Mechanic Street	MEC 4001
Medford	MDF 8024
Medford	MDF 8013
Medford	MDF 8013
Medford	MDF 8013
Medford	MDF 8013
Medford	MDF 8013
Medford	MDF 8022
Medford	MDF 8013
Medford	MDF 8022
Medford	MDF 8013
Medford	MDF 8013
Medford	MDF 8011
Medford	MDF 8022
Medford	MDF 8023
Medford	MDF 8023
Medford	MDF 8011
Medford	MDF 8011
Medford	MDF 8022
Medford	MDF 8022
Minue Street	MIN 8025
Minue Street	MIN 8014
Minue Street	MIN 8025
Minue Street	MIN 8022
Minue Street	MIN 8022
Minue Street	MIN 8026
Minue Street	MIN 8012
Minue Street	MIN 8015
Minue Street	MIN 8013
Minue Street	MIN 8025
Minue Street	MIN 8013
Minue Street	MIN 8023
Minue Street	MIN 8013
Minue Street	MIN 8015
Minue Street	MIN 8024
Minue Street	MIN 8025
Minue Street	MIN 8025
Minue Street	MIN 8015
Minue Street	MIN 8025

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Minue Street	MIN 8012
Minue Street	MIN 8013
Minue Street	MIN 8013
Minue Street	MIN 8025
Minue Street	MIN 8022
Minue Street	MIN 8025
Minue Street	MIN 8011
Minue Street	MIN 8025
Minue Street	MIN 8025
Mobile North Avenue	NOT 8016
Montclair	MNT 4009
Montclair	MNT 4004
Montclair	MNT 4010
Montclair	MNT 4006
Montclair	MNT 4004
Montclair	MNT 4001
Montclair	MNT 4015
Montclair	MNT 4015
Montclair	MNT 4015
Montclair	MNT 4004
Montclair	MNT 4010
Montclair	MNT 4012
Montgomery Substation	MOT 8002
Montgomery Substation	MOT 8001
Montgomery Substation	MOT 8001
Montgomery Substation	MOT 8001
Montgomery Substation	MOT 8002
Morgan Street	MOG 4002
Mount Holly	MOY 4007
Mount Holly	MOY 4009
Mount Holly	MOY 4002
Mount Holly	MOY 4007
Mount Holly	MOY 4002
Mount Holly	MOY 4002
Mount Laurel	MTL 8012
Mount Laurel	MTL 8013
Mount Laurel	MTL 8025
Mount Laurel	MTL 8023
Mount Laurel	MTL 8012
Mount Laurel	MTL 8013

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Mount Laurel	MTL 8011
Mount Laurel	MTL 8011
Mount Rose	MRO 8021
Mount Rose	MRO 8021
Mount Rose	MRO 8022
Mount Rose	MRO 8011
Mount Rose	MRO 8012
Mount Rose	MRO 8023
Mount Rose	MRO 8023
Mount Rose	MRO 8012
Mount Rose	MRO 8023
Mount Rose	MRO 8024
Mount Rose	MRO 8013
Mount Rose	MRO 8021
Mount Rose	MRO 8011
Mount Rose	MRO 8011
Mount Rose	MRO 8022
Mount Rose	MRO 8013
Mount Rose	MRO 8012
Mount Rose	MRO 8023
Mount Rose	MRO 8012
Mount Rose	MRO 8012
Mount Rose	MRO 8023
Mount Rose	MRO 8022
Mount Rose	MRO 8011
Mount Rose	MRO 8023
Mount Rose	MRO 8022
Mount Rose	MRO 8022
Mount Rose	MRO 8024
Mount Rose	MRO 8011
Mount Rose	MRO 8021
Mountain Avenue	MON 8004
Mountain Avenue	MON 8003
Mountain Avenue	MON 8002
Mountain Avenue	MON 8004
Mountain Avenue	MON 8002
Mountain Avenue	MON 8002
Mountain Avenue	MON 8003
Mountain Avenue	MON 8004
Mountain Avenue	MON 8002
Mountain Avenue	MON 8003
Mountain Avenue	MON 8002
Mountain Avenue	MON 8002
Mountain Avenue	MON 8003
Mountain Avenue	MON 8003
Mountain Avenue	MON 8002

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Mountain Avenue	MON 8002
Mountain View	MOU 8001
Moutainside Unit	MSD 8001
Moutainside Unit	MSD 8001
Moutainside Unit	MSD 8001
Moutainside Unit	MSD 8001
Nevins Road	NEV 8001
Nevins Road	NEV 8001
Nevins Road	NEV 8001
New Dover	NED 8015
New Dover	NED 8024
New Dover	NED 8026
New Dover	NED 8016
New Dover	NED 8014
New Dover	NED 8016
New Dover	NED 8024
New Dover	NED 8022
New Dover	NED 8025
New Dover	NED 8026
New Dover	NED 8015
New Dover	NED 8022
New Dover	NED 8015
New Dover	NED 8016
New Dover	NED 8016
New Dover	NED 8016
New Dover	NED 8016
New Dover	NED 8024
New Dover	NED 8025
New Dover	NED 8016
New Dover	NED 8023
New Dover	NED 8012
New Dover	NED 8026
New Dover	NED 8024
New Dover	NED 8016
New Dover	NED 8015
New Dover	NED 8015
New Dover	NED 8023
New Dover	NED 8022
New Dover	NED 8015
New Dover	NED 8025
New Dover	NED 8026
New Dover	NED 8014
New Dover	NED 8025
New Dover	NED 8023
New Dover	NED 8023
New Dover	NED 8016

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
New Dover	NED 8025
New Dover	NED 8025
New Dover	NED 8025
New Dover	NED 8023
New Dover	NED 8023
New Dover	NED 8013
New Dover	NED 8022
New Dover	NED 8016
New Dover	NED 8014
New Dover	NED 8014
New Dover	NED 8014
New Dover	NED 8012
New Dover	NED 8023
New Dover	NED 8015
New Milford	NEW 8024
New Milford	NEW 8012
New Milford	NEW 8024
New Milford	NEW 8033
New Milford	NEW 8013
New Milford	NEW 8035
New Milford	NEW 8033
New Milford	NEW 8035
New Milford	NEW 8031
New Milford	NEW 8015
New Milford	NEW 8012
New Milford	NEW 8024
New Milford	NEW 8012
New Milford	NEW 8024
New Milford	NEW 8041
New Milford	NEW 8014
New Milford	NEW 8013
New Milford	NEW 8015
New Milford	NEW 8034
New Milford	NEW 8044
New Milford	NEW 8044
New Milford	NEW 8033
New Milford	NEW 8041
New Milford	NEW 8013
New Milford	NEW 8013
New Milford	NEW 8034
New Milford	NEW 8013
New Milford	NEW 8013
New Milford	NEW 8041
New Milford	NEW 8025
New Milford	NEW 8011
New Milford	NEW 8015

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
New Milford	NEW 8024
New Milford	NEW 8012
New Milford	NEW 8034
New Milford	NEW 8034
New Milford	NEW 8024
New Milford	NEW 8041
New Milford	NEW 8011
New Milford	NEW 8031
New Milford	NEW 8034
New Milford	NEW 8031
New Milford	NEW 8044
New Milford	NEW 8031
New Milford	NEW 8022
New Milford	NEW 8015
New Milford	NEW 8014
New Milford	NEW 8015
New Milford	NEW 8015
New Milford	NEW 8013
New Milford	NEW 8022
New Milford	NEW 8022
New Milford	NEW 8031
New Milford	NEW 8034
New Milford	NEW 8041
New Milford	NEW 8013
New Milford	NEW 8041
New Milford	NEW 8034
New Milford	NEW 8035
New Milford	NEW 8035
New Milford	NEW 8015
New Milford	NEW 8041
New Milford	NEW 8022
New Milford	NEW 8044
New Milford	NEW 8034
New Milford	NEW 8015
New Milford	NEW 8044
New Milford	NEW 8033
Nineteenth Ave	NIN 4001
Nineteenth Ave	NIN 4004
Nineteenth Ave	NIN 4001
Nineteenth Ave	NIN 4006
Nineteenth Ave	NIN 4006
Nineteenth Ave	NIN 4004
Nineteenth Ave	NIN 4006
Nineteenth Ave	NIN 4006
Nineteenth Ave	NIN 4001
Nineteenth Ave	NIN 4001

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Nineteenth Ave	NIN 4001
Nineteenth Ave	NIN 4006
Nineteenth Ave	NIN 4006
Nineteenth Ave	NIN 4006
Nineteenth Ave	NIN 4005
Nineteenth Ave	NIN 4005
Nineteenth Ave	NIN 4006
Nineteenth Ave	NIN 4005
Nineteenth Ave	NIN 4006
Nineteenth Ave	NIN 4005
Nineteenth Ave	NIN 4003
Nineteenth Ave	NIN 4002
Nineteenth Ave	NIN 4005
Nineteenth Ave	NIN 4005
Nineteenth Ave	NIN 4004
Nineteenth Ave	NIN 4001
Nineteenth Ave	NIN 4004
Nineteenth Ave	NIN 4001
Nineteenth Ave	NIN 4001
Nineteenth Ave	NIN 4005
Nineteenth Ave	NIN 4004
Nineteenth Ave	NIN 4005
Nineteenth Ave	NIN 4004
Nineteenth Ave	NIN 4005
Nineteenth Ave	NIN 4005
Nineteenth Ave	NIN 4004
Nineteenth Ave	NIN 4002
Nineteenth Ave	NIN 4004
Nineteenth Ave	NIN 4006
Nineteenth Ave	NIN 4005
Nineteenth Ave	NIN 4003
Nineteenth Ave	NIN 4003
Nineteenth Ave	NIN 4006
Nineteenth Ave	NIN 4003
Nineteenth Ave	NIN 4002
Nineteenth Ave	NIN 4004
Nineteenth Ave Unit	NIT 8007
Nineteenth Ave Unit	NIT 8007
Nineteenth Ave Unit	NIT 8007
Nineteenth Ave Unit	NIT 8007
Nineteenth Ave Unit	NIT 8007
Nineteenth Ave Unit	NIT 8007
Norfolk St	NOF 4003
North Avenue	NOT 8024
North Avenue	NOT 8024
North Avenue	NOT 8014

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
North Avenue	NOT 8022
North Avenue	NOT 8014
North Avenue	NOT 8021
North Avenue	NOT 8021
North Avenue	NOT 8022
North Avenue	NOT 8022
North Avenue	NOT 8021
North Avenue	NOT 8022
North Avenue	NOT 8021
North Avenue	NOT 8014
North Avenue	NOT 8022
North Avenue	NOT 8014
North Bergen	NRB 8015
North Bergen	NRB 8015
North Bergen	NRB 8022
North Bergen	NRB 8021
North Bergen	NRB 8013
North Bergen	NRB 8015
North Bergen	NRB 8014
North Bergen	NRB 8012
North Bergen	NRB 8014
North Bergen	NRB 8015
North Bergen	NRB 8015
North Bergen	NRB 8021
North Bergen	NRB 8014
North Bridge Street	NBS 8011
North Bridge Street	NBS 8011
North Bridge Street	NBS 8013
North Bridge Street	NBS 8012
North Bridge Street	NBS 8012
North Bridge Street	NBS 8012
North Bridge Street	NBS 8012
North Bridge Street	NBS 8013
North Paterson	NRP 4007
North Paterson	NRP 4010
North Paterson	NRP 4007
North Paterson	NRP 4003
North Paterson	NRP 4007
North Paterson	NRP 4004
North Paterson	NRP 4009
North Paterson	NRP 4010
North Paterson	NRP 4002
North Paterson	NRP 4002
North Paterson	NRP 4010
Nutley	NUT 4006
Nutley	NUT 4002

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Nutley	NUT 4002
Nutley	NUT 4006
Nutley	NUT 4004
Nutley	NUT 4004
Oak St	OAK 4006
Oak St	OAK 4003
Oak St	OAK 4006
Oak St	OAK 4001
Oak St	OAK 4006
Oak St	OAK 4008
Oak St	OAK 4006
Oak St	OAK 4004
Orange Valley	ORA 4002
Orange Valley	ORA 4001
Orange Valley	ORA 4005
Orange Valley	ORA 4001
Orange Valley	ORA 4001
Orange Valley	ORA 4002
Orange Valley	ORA 4003
Orange Valley	ORA 4005
Passaic	PAS 4011
Passaic	PAS 4003
Paterson	PAT 4017
Paterson	PAT 4008
Paterson	PAT 4003
Paterson	PAT 4016
Paterson	PAT 4017
Paterson	PAT 4011
Paterson	PAT 4011
Paterson	PAT 4008
Penhorn	PEH 8013
Penhorn	PEH 8015
Penhorn	PEH 8022
Penhorn	PEH 8015
Penhorn	PEH 8015
Penhorn	PEH 8014
Penhorn	PEH 8014
Penhorn	PEH 8014
Penhorn	PEH 8015
Penhorn	PEH 8024
Penhorn	PEH 8015
Penhorn	PEH 8024
Penhorn	PEH 8024
Penhorn	PEH 8015
Penhorn	PEH 8015
Penhorn	PEH 8015

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Penhorn	PEH 8024
Penhorn	PEH 8013
Penhorn	PEH 8013
Penhorn	PEH 8015
Penhorn	PEH 8015
Penhorn	PEH 8015
Penhorn	PEH 8015
Penhorn	PEH 8014
Penhorn	PEH 8013
Penhorn	PEH 8013
Penhorn	PEH 8015
Penhorn	PEH 8015
Penhorn	PEH 8024
Penhorn	PEH 8014
Penns Neck	PEK 8022
Penns Neck	PEK 8023
Penns Neck	PEK 8022
Penns Neck	PEK 8036
Penns Neck	PEK 8013
Penns Neck	PEK 8036
Penns Neck	PEK 8023
Penns Neck	PEK 8022
Penns Neck	PEK 8035
Penns Neck	PEK 8036
Penns Neck	PEK 8023
Penns Neck	PEK 8036
Penns Neck	PEK 8023
Penns Neck	PEK 8023
Penns Neck	PEK 8035
Penns Neck	PEK 8023
Penns Neck	PEK 8023
Penns Neck	PEK 8023
Penns Neck	PEK 8022
Penns Neck	PEK 8023
Penns Neck	PEK 8035
Penns Neck	PEK 8023
Penns Neck	PEK 8021
Penns Neck	PEK 8023
Pierson Avenue	PIE 8014
Pierson Avenue	PIE 8014
Pierson Avenue	PIE 8013
Pierson Avenue	PIE 8024
Pierson Avenue	PIE 8024
Pierson Avenue	PIE 8012
Pierson Avenue	PIE 8015
Pierson Avenue	PIE 8012

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Pierson Avenue	PIE 8012
Pierson Avenue	PIE 8015
Pierson Avenue	PIE 8021
Pierson Avenue	PIE 8021
Pierson Avenue	PIE 8013
Pierson Avenue	PIE 8021
Pierson Avenue	PIE 8015
Pierson Avenue	PIE 8013
Pierson Avenue	PIE 8014
Pierson Avenue	PIE 8012
Pierson Avenue	PIE 8024
Pierson Avenue	PIE 8021
Pierson Avenue	PIE 8014
Pierson Avenue	PIE 8013
Pierson Avenue	PIE 8024
Pierson Avenue	PIE 8021
Pierson Avenue	PIE 8012
Pierson Avenue	PIE 8012
Pierson Avenue	PIE 8015
Pierson Avenue	PIE 8012
Pierson Avenue	PIE 8024
Pine Street	PIN 4001
Plainfield	PLA 4007
Plainfield	PLA 4008
Plainfield	PLA 4013
Plainfield	PLA 4008
Plainsboro	PLI 8009
Plainsboro	PLI 8009
Plainsboro	PLI 8006
Plainsboro	PLI 8006
Plainsboro	PLI 8004
Plainsboro	PLI 8007
Plainsboro	PLI 8006
Plank Rd	PLN 4003
Plank Rd	PLN 4003
Plank Rd	PLN 4003
Plauderville	PLR 4007
Plauderville	PLR 4006
Plauderville	PLR 4007
Plauderville	PLR 4007
Plauderville	PLR 4007
Plauderville	PLR 4003
Pleasant Street	PLS 4003
Polhemus Lane	POH 8024
Polhemus Lane	POH 8022
Polhemus Lane	POH 8016

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Polhemus Lane	POH 8013
Polhemus Lane	POH 8022
Polhemus Lane	POH 8011
Polhemus Lane	POH 8011
Polhemus Lane	POH 8024
Polhemus Lane	POH 8013
Polhemus Lane	POH 8024
Polhemus Lane	POH 8023
Polhemus Lane	POH 8023
Polhemus Lane	POH 8011
Polhemus Lane	POH 8023
Polhemus Lane	POH 8022
Polhemus Lane	POH 8023
Polhemus Lane	POH 8026
Polhemus Lane	POH 8022
Polhemus Lane	POH 8023
Polhemus Lane	POH 8016
Polhemus Lane	POH 8013
Polhemus Lane	POH 8016
Polhemus Lane	POH 8023
Polhemus Lane	POH 8013
Polhemus Lane	POH 8011
Polhemus Lane	POH 8023
Polhemus Lane	POH 8023
Polk Street	POL 4010
Polk Street	POL 4010
Rahway	RAH 4008
Rahway	RAH 4010
Rahway	RAH 4007
Rahway	RAH 4004
Rahway	RAH 4006
Rahway	RAH 4010
Rahway	RAH 4010
Rahway	RAH 4007
Raritan Valley	RAV 8003
Raritan Valley	RAV 8003
Ridgefield	RFL 8033
Ridgefield	RFL 8013
Ridgefield	RFL 8034
Ridgefield	RFL 8034
Ridgefield	RFL 8013
Ridgefield	RFL 8033
Ridgefield	RFL 8014
Ridgefield	RFL 8013
Ridgefield	RFL 8012
Ridgefield	RFL 8043

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Ridgefield	RFL 8012
Ridgefield	RFL 8013
Ridgefield	RFL 8034
Ridgefield	RFL 8034
Ridgefield	RFL 8043
Ridgefield	RFL 8014
Ridgefield	RFL 8023
Ridgefield	RFL 8043
Ridgefield	RFL 8042
Ridgefield	RFL 8014
Ridgefield	RFL 8033
Ridgefield	RFL 8033
Ridgefield	RFL 8011
Ridgefield	RFL 8011
Ridgefield	RFL 8012
Ridgefield	RFL 8033
Ridgefield	RFL 8014
Ridgefield	RFL 8013
Ridgefield	RFL 8024
Ridgefield	RFL 8011
Ridgefield	RFL 8013
Ridgefield	RFL 8024
Ridgefield	RFL 8034
Ridgefield	RFL 8034
Ridgefield	RFL 8043
Ridgefield	RFL 8035
Ridgefield	RFL 8043
Ridgefield	RFL 8035
Ridgefield	RFL 8045
Ridgefield	RFL 8013
Ridgefield	RFL 8032
Ridgefield	RFL 8012
Ridgefield	RFL 8012
Ridgefield	RFL 8034
Ridgefield	RFL 8024
Ridgefield	RFL 8043
Ridgefield	RFL 8012
Ridgefield	RFL 8012
Ridgefield	RFL 8014
Ridgefield	RFL 8034
Ridgefield	RFL 8034
Ridgewood	RGW 4006
Ridgewood	RGW 4014
Ridgewood	RGW 4012
Ridgewood	RGW 4014
River Road Substation	RVR 8022

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
River Road Substation	RVR 8022
Riverside - 13KV	RIV 8006
Riverside - 13KV	RIV 8006
Riverside - 13KV	RIV 8006
Riverside - 13KV	RIV 8006
Riverside - 13KV	RIV 8006
Riverside - 13KV	RIV 8006
Roselle	RSL 4003
Roselle	RSL 4008
Roselle	RSL 4008
Roselle	RSL 4003
Roselle	RSL 4008
Roselle	RSL 4006
Roselle	RSL 4003
Runnemede	RUN 8004
Runnemede	RUN 8001
Runnemede	RUN 8002
Runnemede	RUN 8002
Runnemede	RUN 8001
Runnemede	RUN 8003
Runnemede	RUN 8001
Runnemede	RUN 8005
Runnemede	RUN 8005
Runnemede	RUN 8005
Runnemede	RUN 8002
Runnemede	RUN 8006
Runnemede	RUN 8004
Runnemede	RUN 8002
Runnemede	RUN 8006
Runnemede	RUN 8003
Runnemede	RUN 8001
Runnemede	RUN 8004
Runnemede	RUN 8003
Runnemede	RUN 8006
Saddle Brook	SAD 8031
Saddle Brook	SAD 8007
Saddle Brook	SAD 8034
Saddle Brook	SAD 8032
Saddle Brook	SAD 8035
Saddle Brook	SAD 8001
Saddle Brook	SAD 8007
Saddle Brook	SAD 8001
Saddle Brook	SAD 8034
Saddle Brook	SAD 8045
Saddle Brook	SAD 8035
Saddle Brook	SAD 8034

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Saddle Brook	SAD 8033
Saddle Brook	SAD 8045
Saddle Brook	SAD 8031
Saddle Brook	SAD 8008
Saddle Brook	SAD 8007
Saddle Brook	SAD 8035
Saddle Brook	SAD 8032
Saddle Brook	SAD 8042
Saddle Brook	SAD 8042
Saddle Brook	SAD 8007
Saddle Brook	SAD 8008
Saddle Brook	SAD 8043
Saddle Brook	SAD 8031
Saddle Brook	SAD 8042
Saddle Brook	SAD 8007
Saddle Brook	SAD 8005
Saddle Brook	SAD 8043
Saddle Brook	SAD 8045
Saddle Brook	SAD 8008
Saddle Brook	SAD 8008
Saddle Brook	SAD 8008
Saddle Brook	SAD 8042
Saddle Brook	SAD 8042
Saddle Brook	SAD 8034
Saddle Brook	SAD 8007
Saddle Brook	SAD 8034
Saddle Brook	SAD 8008
Saddle Brook	SAD 8002
Saddle Brook	SAD 8003
Saddle Brook	SAD 8003
Saddle Brook	SAD 8044
Saddle Brook	SAD 8044
Saddle Brook	SAD 8044
Saddle Brook	SAD 8002
Saddle Brook	SAD 8044
Saddle Brook	SAD 8003
Saddle Brook	SAD 8005
Saddle Brook	SAD 8002
Saddle Brook	SAD 8002
Saddle Brook	SAD 8042
Saddle Brook	SAD 8031
Saddle Brook	SAD 8007
Saddle Brook	SAD 8005
Saddle Brook	SAD 8043
Saddle Brook	SAD 8043
Saddle Brook	SAD 8031

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Saddle Brook	SAD 8034
Saddle Brook	SAD 8003
Sand Hills	SDH 8024
Sand Hills	SDH 8032
Sand Hills	SDH 8032
Sand Hills	SDH 8024
Sand Hills	SDH 8024
Sand Hills	SDH 8024
Sand Hills	SDH 8023
Sand Hills	SDH 8024
Sand Hills	SDH 8032
Sand Hills	SDH 8032
Sand Hills	SDH 8025
Sand Hills	SDH 8026
Sand Hills	SDH 8026
Sand Hills	SDH 8033
Sand Hills	SDH 8024
Sand Hills	SDH 8035
Sand Hills	SDH 8035
Sand Hills	SDH 8025
Sand Hills	SDH 8023
Sand Hills	SDH 8033
Sand Hills	SDH 8033
Sand Hills	SDH 8034
Sand Hills	SDH 8034
Sand Hills	SDH 8034
Sand Hills	SDH 8023
Sand Hills	SDH 8024
Sand Hills	SDH 8023
Sand Hills	SDH 8024
Sand Hills	SDH 8031
Sand Hills	SDH 8025
Sand Hills	SDH 8034
Sand Hills	SDH 8033
Sand Hills	SDH 8034
Sand Hills	SDH 8031
Sand Hills	SDH 8021
Sand Hills	SDH 8024
Sand Hills	SDH 8024
Sand Hills	SDH 8033
Sand Hills	SDH 8021
Sand Hills	SDH 8033
Sand Hills	SDH 8031
Sand Hills	SDH 8034
Sand Hills	SDH 8034
Sand Hills	SDH 8021

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Sand Hills	SDH 8026
Sand Hills	SDH 8026
Sand Hills	SDH 8026
Sand Hills	SDH 8026
Sand Hills	SDH 8024
Sand Hills	SDH 8033
Sand Hills	SDH 8033
Sand Hills	SDH 8033
Sand Hills	SDH 8026
So Orange	SOO 4010
So Orange	SOO 4003
So Orange	SOO 4002
So Orange	SOO 4004
So Orange	SOO 4013
So Orange	SOO 4003
So Orange	SOO 4013
So Orange	SOO 4002
So Orange	SOO 4011
So Orange	SOO 4002
So Orange	SOO 4013
So Orange	SOO 4013
So Orange	SOO 4013
So Orange	SOO 4011
So Paterson	SOP 4008
So Paterson	SOP 4008
Somerville	SMV 8015
Somerville	SMV 8015
Somerville	SMV 8021
Somerville	SMV 8015
Somerville	SMV 8024
Somerville	SMV 8024
Somerville	SMV 8025
Somerville	SMV 8012
Somerville	SMV 8025
Somerville	SMV 8013
Somerville	SMV 8023
Somerville	SMV 8013
Somerville	SMV 8025
Somerville	SMV 8013
Somerville	SMV 8013
Somerville	SMV 8025
Somerville	SMV 8013
Somerville	SMV 8011
Somerville	SMV 8015
Somerville	SMV 8015
Somerville	SMV 8021

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Somerville	SMV 8021
Somerville	SMV 8025
South Second Street	SOS 8025
South Second Street	SOS 8026
South Second Street	SOS 8015
South Second Street	SOS 8026
South Second Street	SOS 8026
South Second Street	SOS 8026
South Second Street	SOS 8016
South Second Street	SOS 8026
South Second Street	SOS 8025
South Second Street	SOS 8016
South Second Street	SOS 8026
South Second Street	SOS 8016
South Second Street	SOS 8015
South Second Street	SOS 8026
South Second Street	SOS 8015
South Second Street	SOS 8016
South Second Street	SOS 8026
South Second Street	SOS 8016
South Second Street	SOS 8026
South Second Street	SOS 8026
South Second Street	SOS 8026
South Second Street	SOS 8026
South Second Street	SOS 8016
South Waterfront	SWT 8001
Southampton	SOH 8032
Southampton	SOH 8032
Southampton	SOH 8032
Southampton	SOH 8021
Southampton	SOH 8032
Southampton	SOH 8032
Spring Valley Rd	SPR 4005
Springfield Road	SPF 8025
Springfield Road	SPF 8022
Springfield Road	SPF 8026
Springfield Road	SPF 8022
Springfield Road	SPF 8022
Springfield Road	SPF 8026
Springfield Road	SPF 8013
Springfield Road	SPF 8022
Springfield Road	SPF 8025
Springfield Road	SPF 8013
Springfield Road	SPF 8025
Springfield Road	SPF 8025
Springfield Road	SPF 8024

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Springfield Road	SPF 8013
Springfield Road	SPF 8012
Springfield Road	SPF 8022
Springfield Road	SPF 8023
Springfield Road	SPF 8012
Springfield Road	SPF 8026
Springfield Road	SPF 8025
Springfield Road	SPF 8022
Springfield Road	SPF 8013
Springfield Road	SPF 8014
Springfield Road	SPF 8012
Springfield Road	SPF 8013
St Pauls	STP 8001
St Pauls	STP 8001
St Pauls	STP 8001
Stanwick Unit	STK 8003
Sunnymeade	SUN 8022
Sunnymeade	SUN 8012
Sunnymeade	SUN 8021
Sunnymeade	SUN 8022
Sunnymeade	SUN 8021
Sunnymeade	SUN 8034
Sunnymeade	SUN 8043
Sunnymeade	SUN 8024
Sunnymeade	SUN 8034
Sunnymeade	SUN 8035
Sunnymeade	SUN 8045
Sunnymeade	SUN 8023
Sunnymeade	SUN 8044
Sunnymeade	SUN 8033
Sunnymeade	SUN 8043
Sunnymeade	SUN 8012
Sunnymeade	SUN 8024
Sunnymeade	SUN 8012
Sunnymeade	SUN 8024
Sunnymeade	SUN 8044
Sunnymeade	SUN 8034
Sunnymeade	SUN 8034
Sunnymeade	SUN 8021
Sunnymeade	SUN 8034
Sunnymeade	SUN 8033
Sunnymeade	SUN 8021
Sunnymeade	SUN 8034
Sunnymeade	SUN 8045
Teaneck	TEA 4009
Texas Avenue	TEX 8003

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Texas Avenue	TEX 8003
Texas Avenue	TEX 8003
Texas Avenue	TEX 8003
Texas Avenue	TEX 8003
Thirty Second Street	THY 4010
Thirty Second Street	THY 4013
Thirty Second Street	THY 4007
Thirty Second Street	THY 4013
Thirty Second Street	THY 4005
Thirty Second Street	THY 4005
Thirty Second Street	THY 4012
Thirty Second Street	THY 4011
Thorofare	THO 8012
Thorofare	THO 8012
Thorofare	THO 8023
Thorofare	THO 8021
Thorofare	THO 8023
Thorofare	THO 8023
Thorofare	THO 8022
Thorofare	THO 8012
Thorofare	THO 8023
Thorofare	THO 8024
Thorofare	THO 8013
Thorofare	THO 8021
Thorofare	THO 8021
Thorofare	THO 8013
Thorofare	THO 8023
Thorofare	THO 8013
Thorofare	THO 8021
Thorofare	THO 8013
Toneys Brook	TNY 4003
Toneys Brook	TNY 4002
Toneys Brook	TNY 4010
Toneys Brook	TNY 4010
Toneys Brook	TNY 4003
Toneys Brook	TNY 4002
Toneys Brook	TNY 4010
Toneys Brook	TNY 4003
Toneys Brook	TNY 4004
Toneys Brook	TNY 4010
Toneys Brook	TNY 4010
Toneys Brook	TNY 4002
Toneys Brook	TNY 4003
Toneys Brook	TNY 4001
Toneys Brook	TNY 4002
Toneys Brook	TNY 4010

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Toneys Brook	TNY 4008
Toneys Brook	TNY 4003
Toneys Brook	TNY 4003
Toneys Brook	TNY 4002
Toneys Brook	TNY 4010
Toneys Brook	TNY 4002
Toneys Brook	TNY 4002
Totowa	TOT 4002
Turnpike	TUR 8015
Turnpike	TUR 8025
Turnpike	TUR 8015
Turnpike	TUR 8002
Turnpike	TUR 8025
Turnpike	TUR 8025
Turnpike	TUR 8025
Turnpike	TUR 8015
Turnpike	TUR 8002
Turnpike	TUR 8004
Turnpike	TUR 8015
Turnpike	TUR 8015
Turnpike	TUR 8002
Turnpike	TUR 8004
Turnpike	TUR 8002
Turnpike	TUR 8004
Turnpike	TUR 8004
Turnpike	TUR 8015
Turnpike	TUR 8002
Turnpike	TUR 8025
Turnpike	TUR 8015
Turnpike	TUR 8025
Turnpike	TUR 8015
Turnpike	TUR 8002
Turnpike	TUR 8004
Turnpike	TUR 8025
Turnpike	TUR 8025
Turnpike	TUR 8025
Turnpike	TUR 8015
Union	UN 4004
Union	UN 4001
Union	UN 4001
Union	UN 4008
Van Houten Ave	VNH 4002
Van Houten Ave	VNH 4002
Van Houten Ave	VNH 4002
Van Houten Ave	VNH 4006
Van Houten Ave	VNH 4002

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Van Houten Ave	VNH 4005
Van Houten Ave	VNH 4004
Van Houten Ave	VNH 4004
Van Houten Ave	VNH 4003
Van Winkle Street	VNL 8004
Van Winkle Street	VNL 8004
Van Winkle Street	VNL 8004
Van Winkle Street	VNL 8005
Van Winkle Street	VNL 8004
Van Winkle Street	VNL 8005
Van Winkle Street	VNL 8005
Van Winkle Street	VNL 8004
Van Winkle Street	VNL 8005
Van Winkle Street	VNL 8005
Vauxhall Road	VXL 4005
Vauxhall Road	VXL 4001
Vauxhall Road	VXL 4005
Vauxhall Road	VXL 4005
Vauxhall Road	VXL 4005
Village Rd	VIL 8001
Village Rd	VIL 8001
Waldwick	WAD 8032
Waldwick	WAD 8021
Waldwick	WAD 8014
Waldwick	WAD 8025
Waldwick	WAD 8023
Waldwick	WAD 8041
Waldwick	WAD 8032
Waldwick	WAD 8011
Waldwick	WAD 8025
Waldwick	WAD 8022
Waldwick	WAD 8015
Waldwick	WAD 8023
Waldwick	WAD 8011
Waldwick	WAD 8015
Waldwick	WAD 8021
Waldwick	WAD 8014
Waldwick	WAD 8022
Waldwick	WAD 8041
Waldwick	WAD 8011
Waldwick	WAD 8014
Waldwick	WAD 8025
Waldwick	WAD 8012
Waldwick	WAD 8013
Waldwick	WAD 8021
Waldwick	WAD 8024

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Waldwick	WAD 8022
Waldwick	WAD 8011
Waldwick	WAD 8025
Waldwick	WAD 8041
Waldwick	WAD 8024
Waldwick	WAD 8013
Waldwick	WAD 8022
Waldwick	WAD 8021
Waldwick	WAD 8014
Waldwick	WAD 8024
Waldwick	WAD 8031
Warinanco	WAN 8022
Warinanco	WAN 8013
Warinanco	WAN 8024
Warinanco	WAN 8021
Warinanco	WAN 8024
Warinanco	WAN 8015
Warinanco	WAN 8024
Warinanco	WAN 8022
Warinanco	WAN 8024
Warinanco	WAN 8021
Warinanco	WAN 8021
Warinanco	WAN 8015
Warinanco	WAN 8014
Warinanco	WAN 8014
Warinanco	WAN 8011
Warinanco	WAN 8011
Warinanco	WAN 8013
Warinanco	WAN 8024
Warinanco	WAN 8024
Warinanco	WAN 8024
Warinanco	WAN 8023
Warinanco	WAN 8023
Warinanco	WAN 8023
Warinanco	WAN 8021
Warinanco	WAN 8021
Warinanco	WAN 8021
Warinanco	WAN 8021
Warinanco	WAN 8025
Warinanco	WAN 8025
Warinanco	WAN 8021
Warinanco	WAN 8025
Warinanco	WAN 8025
Warinanco	WAN 8012
Warinanco	WAN 8015
Warren Point	WAR 4009

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Warren Point	WAR 4001
Warren Point	WAR 4001
Warren Point	WAR 4001
Waverly	WAV 4018
Waverly	WAV 4015
Waverly	WAV 4015
West Caldwell	WEW 8011
West Caldwell	WEW 8011
West Caldwell	WEW 8011
West Caldwell	WEW 8042
West Caldwell	WEW 8011
West Caldwell	WEW 8011
West Caldwell	WEW 8021
West Caldwell	WEW 8012
West Caldwell	WEW 8033
West Caldwell	WEW 8013
West Caldwell	WEW 8044
West Caldwell	WEW 8012
West Caldwell	WEW 8033
West Caldwell	WEW 8013
West Caldwell	WEW 8043
West Caldwell	WEW 8043
West Caldwell	WEW 8033
West Caldwell	WEW 8012
West Caldwell	WEW 8042
West Caldwell	WEW 8011
West Caldwell	WEW 8044
West Caldwell	WEW 8043
West Caldwell	WEW 8042
West Caldwell	WEW 8012
West Caldwell	WEW 8042
West Caldwell	WEW 8013
West Caldwell	WEW 8021
West Caldwell	WEW 8013
West Caldwell	WEW 8042
West Caldwell	WEW 8033
West Caldwell	WEW 8043
West Caldwell	WEW 8043
West Caldwell	WEW 8043
West Caldwell	WEW 8011
West Caldwell	WEW 8033
West Caldwell	WEW 8042
West Caldwell	WEW 8033
West Caldwell	WEW 8012
West Caldwell	WEW 8025
West Orange Substation	WOA 4003

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
West Orange Substation	WOA 4003
West Orange Substation	WOA 4003
Westfield	WFL 8034
Westfield	WFL 8032
Westfield	WFL 8012
Westfield	WFL 8032
Westfield	WFL 8012
Westfield	WFL 8032
Westfield	WFL 8034
Westfield	WFL 8012
Westfield	WFL 8023
Westfield	WFL 8034
Westfield	WFL 8021
Westfield	WFL 8041
Westfield	WFL 8032
Westfield	WFL 8041
Westfield	WFL 8032
Westfield	WFL 8023
Westfield	WFL 8034
Westfield	WFL 8023
Westfield	WFL 8011
Westfield	WFL 8032
Westfield	WFL 8012
Westfield	WFL 8034
Westfield	WFL 8032
Westfield	WFL 8041
Westfield	WFL 8012
Westfield	WFL 8012
Westfield	WFL 8011
Westfield	WFL 8043
Westfield	WFL 8043
Westfield	WFL 8011
Westfield	WFL 8023
Westfield	WFL 8023
Westfield	WFL 8023
Westfield	WFL 8034
Westfield	WFL 8012
Westfield	WFL 8012
Westfield	WFL 8043
Westfield	WFL 8034
Westmont	WMT 4007
Westmont	WMT 4005
Westmont	WMT 4003
Woodbridge	WOR 8039
Woodbridge	WOR 8017
Woodbridge	WOR 8039

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Woodbridge	WOR 8018
Woodbridge	WOR 8022
Woodbridge	WOR 8039
Woodbridge	WOR 8035
Woodbridge	WOR 8018
Woodbridge	WOR 8018
Woodbridge	WOR 8011
Woodbridge	WOR 8039
Woodbridge	WOR 8035
Woodbridge	WOR 8019
Woodbridge	WOR 8038
Woodbridge	WOR 8018
Woodbridge	WOR 8013
Woodbridge	WOR 8038
Woodbridge	WOR 8035
Woodbridge	WOR 8035
Woodbridge	WOR 8018
Woodbridge	WOR 8013
Woodbridge	WOR 8017
Woodbridge	WOR 8037
Woodbridge	WOR 8011
Woodbridge	WOR 8021
Woodbridge	WOR 8017
Woodbridge	WOR 8017
Woodbridge	WOR 8037
Woodbridge	WOR 8025
Woodbridge	WOR 8017
Woodbridge	WOR 8035
Woodbridge	WOR 8011
Woodbridge	WOR 8039
Woodbridge	WOR 8013
Woodbridge	WOR 8018
Woodbridge	WOR 8022
Woodbridge	WOR 8011
Woodbridge	WOR 8022
Woodbridge	WOR 8017
Woodbridge	WOR 8013
Woodbridge	WOR 8013
Woodbridge	WOR 8019
Woodbridge	WOR 8013
Woodbridge	WOR 8019
Woodbridge	WOR 8011
Woodbridge	WOR 8021
Woodbury	WRY 4005
Woodbury	WRY 4011
Woodbury	WRY 4010

EFG-ESII-8: Proposed Circuits for Adding Single Phase Reclosing Devices

Station	Circuit
Woodbury	WRY 4011
Woodlynne	WYN 4003
Woodlynne	WYN 4003
Woodlynne	WYN 4003
Woodlynne	WYN 4006
Woodlynne	WYN 4003
Woodlynne	WYN 4003
Woodlynne	WYN 4003
Yardville	YRD 8021
Yardville	YRD 8024
Yardville	YRD 8021
Yardville	YRD 8024
Yardville	YRD 8022
Yardville	YRD 8022
Yardville	YRD 8012
Yardville	YRD 8012
Yardville	YRD 8012
Yardville	YRD 8023
Yardville	YRD 8023
Yardville	YRD 8022
Yardville	YRD 8022
Yardville	YRD 8011

Advanced Distribution Management System	
Design - including software configuration and software interfaces	
4,432,000	Internal Labor
11,032,000	Outside Services - Vendors
15,464,000	**Subtotal**
Hardware	
1,000,000	Servers / Misc Material
Software - Coding	
8,800,000	Outside Services - Vendors
Testing - Product & Security	
2,500,000	Internal Labor
2,400,000	Outside Services - Vendors
4,900,000	**Subtotal**
Implementation (Supporting Business Activities/Business Impact Analysis/Communications)	
1,400,000	Internal Labor
3,500,000	Outside Services - Vendors
4,900,000	**Subtotal**
35,064,000	**Total**

Estimate Summary

Grid Modernization Program - Communication Network			
Initiative	**Cost**	**Timeframe**	**Estimate Level**
Wireless Network & Recloser	$ 49		
Operations Fiber Installation	$ 3		
Substation Fiber Installation	$ 14		
Substation Fiber Cutover	$ 7		

Wireless Network And Recloser Estimate

Recloser Migration

	Resource	AA Type	Quantity/Unit	Hours/Unit	Rate	CPU	Units	Total Hours	Total Cost
	Relay Technician	DivAvgD1220	2	4	$ 167.07	$ 1,337	2581	20648	$ 3,449,692
	UT Relay Technician	2905D1220	1	4	$ 86.53	$ 346	2581	10324	$ 893,324
Material	Material - Radios	N/A	1	N/A	$ 900.00	$ 900	2581	N/A	$ 2,322,900
	Material - Other	N/A	1	N/A	$ 100.00	$ 100	2581	N/A	$ 258,100
Total						**$ 2,683**	**2581**	**30972**	**$ 6,924,016**

Wireless Network - Routers

	Resource	AA Type	Quantity/Unit	Hours/Unit	Rate	CPU	Units	Total Hours	Total Cost
Labor	Inspector-St Lamp	DivAvgD1142	1	1.3	$ 148.04	$ 192	7000	9100	$ 1,347,144
Material	Material - Router	N/A	1	N/A	$ 3,800.00	$ 3,800	7000	N/A	$ 26,600,000
	Material - Other	N/A	1	N/A	$ 1,000.00	$ 1,000	7000	N/A	$ 7,000,000
Total						**$ 4,992**			**$ 34,947,144**

Wireless Network - Collectors

	Resource	AA Type	Quantity/Unit	Hours/Unit	Rate	CPU	Units	Total Hours	Total Cost
	Lineman/Linewoman	DivAvgD1200	3	8	$ 179.53	$ 4,309	135	3240	$ 581,676
	Relay Technician	DivAvgD1220	2	4	$ 167.07	$ 1,337	135	1080	$ 180,437
Labor	UT Relay Technician	2905D1220	1	2	$ 86.53	$ 173	135	270	$ 23,363
	Substation Mechanic	DivAvgD1180	2	4	$ 166.30	$ 1,330	135	1080	$ 179,609
	Engr Technician	DivAvgD1230	1	0.5	$ 151.69	$ 76	135	67.5	$ 10,239
	Material - Collector	N/A	1	N/A	$ 3,800.00	$ 3,800	135	N/A	$ 513,000
Material	Material - Other	N/A	1	N/A	$ 2,000.00	$ 2,000	135	N/A	$ 270,000
	Material - Pole	N/A	1	N/A	$ 1,500.00	$ 1,500	135		$ 202,500
Total						**$ 14,525**			**$ 1,960,824**

Wireless Network - Support Staff

Resource	FTE	Rate	Hrs/Year	Cost /year	Years	Total Cost
Project Engineers	8	62.24	1904	$ 118,505	5	4,740,198

Total	**$**	**48,572,183**

Operations Fiber Installation Estimate

Operations Fiber Installation								
Electric Site	TFI Site	Fiber Line #1 (Strands)	Distance (Mile)	TFI Site 2	Fiber Line #2 (Strands)	Distance (Mile)	Installation Estimate	Notes
Elizabeth Sub-HQ	Aldene Sw	O-2320 (12)	1	Warinanco SW	N-2240B (48)	1.5	$345,000	New Fiber Site
Hackensack Sub-HQ	Saddle Brook Sub	M-1339 (48)	1	Bergen Sw	M-1339 (48)	1.5	$345,000	New Fiber Site
Irvington Sub-HQ	Stanley Terrace Sw	J-2315A (48)	1	McCarter Sw	K-2211B (48)	1	$300,000	New Fiber Site
Central HQ	Somerville Sw	O-2215 (48)	5				$570,000	Fiber coming off Substation - 3rd Path
Metro HQ	Fourtieth St Sub	K-687 (48)	2				$300,000	- 3rd Path
Palisades HQ	Belleville Sw	I-2314 (12)	1.5				$255,000	If Strand count is a concern...move back 1 Mile back to splice Point for 48 Strand. - 3rd Path
Southern HQ	Bristol Myers Squib	Bristol (24)	5				$570,000	Coming off back of the building - 3rd Path
						Total	**$2,685,000**	

New Substation Fiber

Substation Fiber Installation				
Substation Class	Substation Name	Station Count	Customers	Total Cost
A	Bergen Point	1	11,422	750,000
A	Bloomfield	1	17,005	300,000
A	Chauncey St	1	10,032	840,000
A	Cranford	1	7,427	300,000
A	Elizabeth	1	7,777	210,000
A	First St (Elizabetl	1	6,219	300,000
A	Fort Lee	1	5,498	480,000
A	Keasbey	1	5,707	840,000
A	Lakeside	1	11,608	570,000
A	Market St	1	3,806	390,000
A	Mechanic St	1	10,133	1,200,000
A	Princeton	1	2,246	300,000
A	Rahway	1	6,491	390,000
A	Ridgewood	1	6,238	390,000
A	So Orange	1	8,601	390,000
A	State St	1	2,688	390,000
A	Waverly	1	6,094	300,000
A Total		17	128,992	8,340,000
AB	Harrison	1	10,369	300,000
AB Total		1	10,369	300,000
B	Central Ave	1	16,459	480,000
B	Irvington	1	16,227	300,000
B	Montclair	1	9,409	840,000
B	Norfolk St	1	8,436	300,000
B	West New York	1	10,635	300,000
B Total		5	61,166	2,220,000
C	East Orange	1	22,120	480,000
C	Hackensack	1	5,540	480,000
C	Haledon	1	7,727	300,000
C	Orange Valley	1	8,897	300,000
C	Roselle	1	6,082	390,000
C	Toneys Brook	1	9,158	480,000
C Total		6	59,524	2,430,000
CN	Nineteenth Ave	1	17,651	390,000
CN Total		1	17,651	390,000
CS	Oak St	1	7,592	300,000
CS Total		1	7,592	300,000
Grand Total		**31**	**285,294**	**13,980,000**

Substation Fiber Cutover Estimate

Substation Fiber Cutover	
Existing Sites w/Fiber	164
Est Completed Cutovers	31
Total Sites	133
Cost Per Site	$50,000
Total Estimated Cost	$6,650,000

ATTACHMENT 3

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

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 credentials are set forth in the attached Schedule SS-ESII-1.

Q. Please describe your responsibilities as the Senior Director – Corporate Rates and Revenue Requirements for PSEG Services Corporation.

A. As Senior Director - Corporate Rates and Revenue Requirements, my primary duties are to plan, develop and direct Public Service Electric and Gas Company's (PSE&G or the Company) calculation of electric and gas revenue requirements for the Company's base rates as well as all cost recovery clauses. I also direct the retail pricing strategies, retail rate design, embedded and marginal cost studies, and development and interpretation of tariff provisions.

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

A. My testimony provides the details for the calculation of PSE&G's Energy Strong II Program (ES II or the Program) revenue requirements, the associated cost recovery methodology and rate design for the ES II Petition filed with the New Jersey Board of Public Utilities (BPU or the Board). This testimony also provides detailed schedules setting forth the projected revenue requirements, rates and bill impacts over the expected Program life.

Q. Please briefly describe PSE&G's proposed ES II cost recovery methodology.

A. PSE&G is proposing a cost recovery mechanism for ES II consistent with the BPU's recently approved regulations entitled "Infrastructure Investment And Recovery" under which utilities would propose Infrastructure Investment Programs (IIP)[1]. The PSE&G cost recovery proposal is also consistent with the cost recovery mechanism in the electric portion of the existing Energy Strong Program (ESI), which was approved by the Board in Docket Nos. EO13020155 and GO13020156 on May 21, 2014 (ESI Order). The details of the costs to be recovered, as well as the mechanism to recover such costs, are set forth in this testimony.

Q. How does PSE&G propose to calculate the revenue requirements?

A. PSE&G proposes to calculate the revenue requirements associated with the Program costs using the following formula:

*Revenue Requirements = ((After Tax Cost of Capital * Rate Base) + Net of Tax Amortization and/or Depreciation + Tax Adjustment)* Revenue Factor*

This calculation is the same as the calculation in PSE&G's ESI approved by the Board in the ESI Order. The Company is proposing to recover the revenue requirements through semi-annual base rate adjustment filings as described below, which is consistent with the BPU's IIP regulations.

[1]. N.J.A.C. 14:3-2A.

Q. Please describe the components and defined terms in PSE&G's proposed revenue requirement calculation.

A. The following is a description of each term proposed in PSE&G's revenue requirement calculation. The term "Cost of Capital" is PSE&G's overall weighted average cost of capital (WACC) for the Program. PSE&G is proposing a return on its rate base in the ES II Program based upon an authorized return on equity (ROE) and capital structure including income tax effects. The Company is proposing to utilize the latest cost of capital authorized by the Board in a base rate case proceeding. The Company's first base rate adjustment proceeding as a result of this Program is not anticipated to occur until 2021. Thus, under PSE&G's proposal the ES II investments should earn at the WACC approved in our pending base rate case, which the Company filed January 12, 2018. See Schedule SS-ESII-3 for the calculation of the current After-Tax WACC utilized in the revenue requirement calculation. Any change in the WACC authorized by the Board in the pending or any subsequent electric, gas, or combined base rate case would be reflected in the appropriate corresponding base rate adjustment filing explained in more detail below. Any changes to current tax rates would also be reflected in an adjustment to the After-Tax WACC.

The term "Rate Base" refers to Gross Plant less the associated accumulated depreciation and/or amortization and less Accumulated Deferred Income Taxes (ADIT). Gross Plant is equal to all Plant In-Service, Construction Work in Progress (CWIP) that is transferred into Service and Allowance of Funds Used during Construction (AFUDC) – both debt and equity components.

The book recovery of each asset class will be based on the Board approved depreciation rates in effect at the time of each rate adjustment proceeding. For forecasting purposes, the depreciation rates used to calculate revenue requirements are based on the current depreciation rates approved in our last base rate case proceeding. Any change to depreciation rates in our pending or any subsequent base rate case proceeding authorized by the Board would be reflected in the revenue requirement calculation for any subsequent ES II rate adjustment filing.

ADIT is calculated as Book Depreciation (Tax Basis) less Tax Depreciation, multiplied by the Company's effective tax rate, which is currently 28.11%. Cost of Removal expenditures are depreciated 100% in the year incurred for tax purposes. Please see the table below for the book and tax depreciation rates for each sub-program. As a result of the recently enacted Tax reform legislation passed by Congress, no utility investment is eligible for bonus depreciation. Any future changes to the book or tax depreciation rates, such as, but not limited to, reinstatement of "bonus depreciation" during the construction period of the Program and at the time of each base rate adjustment, will be reflected in the accumulated depreciation and/or ADIT calculation described above.

Subprograms – Electric	Annual Book Depreciation Rates	Modified Accelerated Cost Recovery System (MACRS)
Substation Subprogram	2.49%	20 yr.
Higher Outside Plant Design Standards Subprogram	2.49%	20 yr.
Contingency Reconfiguration	2.49%	20 yr.
Grid Modernization Subprogram	10.00%	7 yr. / 5 yr.
Subprograms – Gas		
Curtailment Resiliency Subprogram	1.61% / 2.87%	20 yr. / 15 yr.
Metering and Regulating (M&R) Upgrade Subprogram	1.61%	20 yr.

The "Net of Tax Depreciation and/or Amortization" allows for recovery of the Company's investment in the Program assets over the useful book life of each asset class. PSE&G proposes to depreciate the ES II assets in accordance with the Company's BPU approved depreciation rates. The book recovery of each asset class will be based on their respective depreciation rates. For Plant in Service investment, the net of tax depreciation expense is calculated as the depreciation expense multiplied by one minus the current tax rate. For CWIP projects that accrue AFUDC because they are not yet in service, there is no tax deduction for the equity portion of the capitalized AFUDC. As a result, the net of tax depreciation expense is calculated as the depreciation expense associated with the Gross Plant (defined above), excluding the equity portion of AFUDC, multiplied by one minus the current tax rate. Since the equity portion of AFUDC will not be included in the tax basis of the Program assets, the equity portion must be grossed-up for taxes in order for the Company to earn its allowed rate of return. Any future changes to the book depreciation or tax rates during the construction period of the Program and at the time of each base rate adjustment, would be reflected in the net of tax depreciation expense calculation described above.

The term "Tax Adjustment" refers to any applicable tax items that may impact the revenue requirement calculation for the Program. For the electric portion of ES II, like that of ESI, the tax adjustment forecasted for the program at this time includes the flow through of cost of removal expenditures on pre-1981 assets. The tax expense for electric cost of removal expenditures associated with pre-1981 assets are currently flowed through to ratepayers over a five year amortization period rather than normalized over the life of the asset as is the tax treatment for post-1981 electric and all gas related cost of removal expenditures. The tax flow-through methodology for pre-1981 electric cost of removal expenditures is applied to Energy Strong cost of removal expenditures on pre-1981 assets to be consistent with the treatment of base rate assets. The Tax Adjustment for the Energy Strong Electric revenue requirement is calculated as the Cost of Removal expenditures multiplied by the percentage of electric pre-1981 asset retirements for the year and divided by five for the five-year amortization period. For forecasting purposes, the percentage of electric assets with a vintage before 1981 is estimated at 14.40%, which is based on 2017 retirements, and it is updated annually. Any future changes impacting the tax adjustment during the construction period of the Program and at the time of each base rate adjustment, would be reflected in the tax adjustment described above.

The "Revenue Factor" adjusts the Revenue Requirement Net of Tax for federal and state income taxes, the BPU and Rate Counsel (RC) Annual Assessments Fees and for Gas Revenue Uncollectibles, which is applicable only to the revenue requirements for the Gas portion of ES II. The tax rates reflect the current federal tax rate of 21% effective January 1, 2018 as a result of the recently enacted tax reform legislation. The BPU/RC Assessment

Expenses consist of payments, based upon a percentage of revenues collected (updated annually), to the State based on the electric and gas intrastate operating revenues for the utility. The Company has utilized the respective BPU and RC assessment rates based on the 2018 fiscal year assessment. The percentage used to calculate the gas uncollectible expense is based upon the rate utilized in the Company's last approved base rate case. Any change in the uncollectible rate utilized in the pending or any subsequent base rate case proceeding will be reflected in the subsequent ES II rate adjustment proceeding calculation. Any future changes impacting the revenue factor during the construction period of the Program and at the time of each base rate adjustment, would be reflected in the revenue factor described above.

Q. Please describe the type of expenditures to be included in Net Rate Base?

A. The Program will include requests for recovery in base rates of all capital expenditures associated with the ES II projects, including actual costs of engineering, design and construction, cost of removal (net of salvage) and property acquisition, including actual labor, materials, overhead, and capitalized AFUDC associated with the projects (the "Capital Investment Costs"). Capital Investment Costs will be recorded, during construction, in an associated CWIP account or in a Plant In-Service account upon the respective project being deemed used and useful.

Q. Are there any items that may affect the tax impacts of the Program?

A. Yes. While other tax issues may arise in the future, there are two areas the Company wishes to make the BPU aware of that may affect this Program in the future. These are:

1. The amount and vintage of assets that will be removed and retired may impact various tax deductions such as repair deduction, retirements, and cost of removal. At the time such actual information becomes available, the impact of these deductions on either rate-base or tax expense will be incorporated into the ADIT balance.
2. The IRS has announced it will be issuing further guidance regarding the Safe Harbor Adjusted Repair Expense ("SHARE") deductions that apply to gas distribution activities. The SHARE deductions are associated with projects that are claimed as deductible repair expenses but are capital assets for financial reporting purposes. This guidance is anticipated to be released and effective within the Program investment period. As these rules are not yet known, they have not been incorporated in this filing.

Q. Will any of the ES II expenditures be eligible for AFUDC?

A. Yes, but only for those projects that meet the Company's criteria for accrual of AFUDC. AFUDC is a component of construction costs representing the net cost of borrowed funds and an equity return rate used during the period of construction. Under the Company's current policy, only projects that have both costs exceeding $5,000 and a construction period longer than 60 days are eligible for accruing AFUDC. Some of the investments under this Program are not anticipated to be eligible to accrue AFUDC because they will take less than 60 days to construct. However, most projects will require more than 60 days of construction and will therefore accrue AFUDC. In the event the Company's criteria for the accrual of AFUDC changes, the Company's criteria in place at the time the expenditures are incurred would be applied.

Q. How will AFUDC be calculated on eligible projects?

A. The Company accrues AFUDC on eligible projects at a rate that is calculated utilizing the "full FERC method" as set forth in FERC Order 561. AFUDC is accrued monthly and added to CWIP until the project is placed into service[2].

Q. Will the Company utilize AFUDC once the projects are placed into service?

A. No. Consistent with the IIP regulations, the Company will not accrue any additional AFUDC on projects once they are placed into service.

Q. What is the source of the capital expenditures you use to calculate the revenue requirements?

A. The projected monthly cash flow for the Program projects was provided by Mr. Edward Gray for electric infrastructure and Mr. Wade Miller for gas infrastructure. See Schedules EFG-ESII-3 and WEM-ESII-3, respectively.

Q. Is the Company planning capital expenditures similar to those included in ES II not to be recovered via ES II?

A. Yes, the Company plans capital expenditures of at least 10% of the approved ES II expenditures on projects similar to those proposed in ES II. These capital expenditures shall be made in the normal course of business and recovered in future base rate proceedings and shall not be subject to the recovery via the ES II cost recovery mechanism.

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[2] Construction Work in Progress (CWIP) is an account into which the costs are recorded that are directly associated with constructing an asset which is not yet in-service.

Q. Is there a schedule showing the calculation of the revenue requirements?

A. Yes. See Schedule SS-ESII-2E for the calculation of the ES II electric revenue requirements for all forecasted electric rate adjustments based on the forecasted cash flow provided in Schedule EFG-ESII-3. See Schedule SS-ESII-2G for the calculation of the ES II gas revenue requirements for all forecasted gas rate adjustments based on the forecasted cash flow provided in Schedule WEM-ESII-3.

Q. How does the Company propose to recover the revenue requirements as described above?

A. The Company proposes to recover the revenue requirements associated with the Program through semi-annual base rate adjustment filings, which is consistent with the recently enacted BPU IIP regulations and the same used for the electric portion of PSE&G's Energy Strong program and the extension of the Gas System Modernization Program (GSMP II). The Company's ESI utilizes semi-annual base rate adjustments for the electrical infrastructure investment and annual base rate adjustments for gas infrastructure. The annual schedule of the gas base rate adjustments in ESI causes a significant amount of regulatory lag as investments are made, placed in service and depreciated, but not recovered in rates for as long as fifteen months.

The proposed schedule for the Initial Filing, Investment as of, Actual Historical Data Update Filing, and Rates Effective dates for all gas and electric base rate adjustment filings, assuming Board approval of the Program by February 2019, are listed below:

ATTACHMENT 3

PROPOSED SCHEDULE FOR POTENTIAL FILINGS			
Initial Filing	**Investment as of**	**Actual Historical Data Update Filing**	**Rates Effective**
9/30/19	11/30/19	12/15/19	3/1/20
3/31/20	5/31/20	6/15/20	9/1/20
9/30/20	11/30/20	12/15/20	3/1/21
3/31/21	5/31/21	6/15/21	9/1/21
9/30/21	11/30/21	12/15/21	3/1/22
3/31/22	5/31/22	6/15/22	9/1/22
9/30/22	11/30/22	12/15/22	3/1/23
3/31/23	5/31/23	6/15/23	9/1/23
9/30/23	11/30/23	12/15/23	3/1/24
3/31/24	5/31/24	6/15/24	9/1/24

The filings schedule, filings content, and rate effective dates under this proposed schedule are identical to the filings under the electric portion of ESI and consist of the following. The potential Initial filing, such as the potential filing due September 30, 2020, shall provide cost and investment data, revenue requirement calculations, proposed rates, and related data to support rates based on ES II investment not already in rates that are anticipated to be in-service by the end of the second month following the initial filing due date. Thus, the Initial filing due September 30, 2020 would include this information on ES II investments not already in rates that are anticipated to be in-service November 30, 2020.

The Actual Historical Data Update Filing is due on the 15th of the third month following the due date for the Initial Filing and updates all cost and investment data, revenue requirement calculations, proposed rates, and related information from the Initial Filing to data based on actual historical data. ES II investments included in rates in the Actual Historical Data Filing shall only include ES II investment not in rates and actually in-service the end of the second full month following the initial filing due date. Thus, the Actual Historical Update Data Filing listed above as due December 15, 2020 shall provide this update based on ES II investments not in rates that were actually in service on or before November 30, 2020.

The rate effective date shall be as indicated above – the first day of the sixth full month following the due date of the Initial Filing. Thus, the Initial filing due September 30, 2020 would result in rates effective March 1, 2021 subject to Board approval.

The IIP regulations limit each electric and gas base rate adjustment request to a minimum investment level of 10 percent of each respective electric and gas program. Therefore, actual base rate adjustments filings may occur less frequently then reflected in the table above.

Assuming Board approval by February 2019, ES II is scheduled to be complete February 29, 2024, except for certain close out work that may occur 3 to 6 months following the conclusion of the Program. In addition, trailing charges from contractors may lag through 2024. Without a firm date for completion of this close out work, the Company is proposing a rate filing no later than September 15, 2024 comprised of all actual (as opposed to projected) cost data for rates effective January 1, 2025. Given the nature of the close out work, the final roll-in may be less than 10% of the Program, but is appropriate to provide completion of the Program.

Q. Is the Company proposing a minimum investment level to request a base rate adjustment?

A. Yes. Consistent with the IIP regulations, the Company proposes to limit each electric and gas base rate adjustment request to a minimum investment level of 10 percent of the total program investment, respectively, with the exception of certain close out work at the end of the Program as discussed above. The program investment is defined as all capital expenditures as defined previously in my testimony excluding AFUDC. As a result, based on the current proposed capital expenditure forecast, PSE&G anticipates the first ES II base rate adjustment filing will not occur until September 2020 and March 2022 for electric and gas, respectively, with rates effective March 1, 2021 and September 1, 2022, respectively.

Q. Is there any other proposed limit that could impact the amount of investment to be included in a rate base adjustment?

A. Yes, the Company is also proposing to limit the amount of investment to be included in the rate base adjustment by an earnings test. If the Company exceeds the allowed ROE from the utility's last base rate case by fifty (50) basis points or more for the most recent twelve (12) month period, the pending base rate adjustment shall not be allowed for the applicable filing period.

Q. How does the Company propose to calculate this earnings test?

A. Per IIP regulations, the earnings test shall be determined based on the actual net income of the utility for the most recent twelve (12) month period divided by the average of the beginning and ending common equity balances for the corresponding period.

Q. What is the corresponding period for the earnings test?

A. The Company will utilize the 12 month period corresponding to the latest available SEC quarterly/annual filing. In the same manner as capital expenditures, the Company will provide 9 months of actual data and 3 months of forecast data at the time of its initial filing. The 3 months of forecasted data will be updated with actual information at the same time the Company updates investment for actuals per the schedule above.

Q. Is there any issue with calculating common equity balances?

A. Yes. As the only combined Electric, Gas and Transmission Company in the State, calculating deferred taxes and rate base specific to the Electric and Gas utility on a monthly basis is impractical. Further, the components of rate base, such as working capital requirements and any consolidated tax adjustment, can be controversial and are typically resolved in a rate case. Therefore, calculating the common equity balance would involve proposing and resolving every component of rate base, including working capital requirements as a result of a lead-lag study and any consolidated tax adjustment, on a semi-annual basis, which is impractical.

Q. So how do you propose to calculate the starting and ending common equity balance for the earnings test?

A. I'm proposing the Common Equity balance to be used in the Company's earnings test be calculated based on the starting and ending Net Plant balances multiplied by the ratio of Net Plant to Common Equity determined in the Company's most recently approved base rate case.

Q. Is there precedence for this approach?

A. Yes. This is the same methodology utilized in the Company's Board-approved Weather Normalization Clause and GSMP II.

Q. Under this proposal, what opportunity will the BPU and/or Rate Counsel have to review the actual expenditures of the Program?

A. Upon BPU approval of the Program, PSE&G will make semi-annual filings, pursuant with the IIP regulations, subject to the minimum investment level of 10 percent of the total program investment, with actual expenditures based on the schedule described above. BPU Staff and Rate Counsel can review each base rate adjustment filing to ensure the revenue requirements and proposed rates are being calculated in accordance with the BPU Order approving the Program. The actual prudency of the Company's expenditures involved in implementing ES II will be reviewed as part of PSE&G's subsequent base rate case(s) following the base rate adjustment(s).

Q. Does the Company plan to file a base rate case in connection to the proposed ES II?

A. Yes. The Company proposes that it will file a base rate case no later than five (5) years after the commencement of ES II.

Q. What is the electric and gas revenue requirements for the initial rate adjustment?

A. The electric revenue requirement for the first base rate adjustment is expected to be for plant in-service from Board approval through November 30, 2020, and is currently forecasted to be $20 million. See Schedule SS-ESII-2E. The gas revenue requirement for the first rate adjustment is expected to be for plant in-service from Board approval through May 31, 2021, and is currently forecasted to be $17 million. See Schedules SS-ESII-2G.

Q. Does the Company plan to do additional engineering work once Board approval is received for ES II?

A. Yes. While engineering work has been done on the ES II projects, the Company anticipates conducting more detailed engineering work as soon as Board approval is received and would include those costs in the base rate adjustments.

Q. What rate design is the Company proposing to use for this base rate adjustment?

A. The detailed calculations supporting the electric and gas rate design for the first forecasted base rate adjustment is shown in Schedule SS-ESII-4 and Schedule SS-ESII-5, respectively. The rate design for the base rate adjustments made prior to new base rates being set from the Company's pending Base Rate Case would use the same methodology as in ESI, which was approved by the Board in the ESI Order. For base rate adjustments made as part of or after the pending base rate case, or any subsequent base rate case, all subsequent base rate adjustments shall use the rate design methodology corresponding to the latest Board approved electric and/or gas base rate case. The Company reserves the right to request changes in rate design for the program. In addition, Schedule SS-ESII-6 and Schedule SS-ESII-7 provide a summary of the proposed rates for all forecasted base rate adjustments for electric and gas, respectively. The weather normalized billing determinants from the calendar year 2012 were used to estimate the change in base rates for this Program to reflect current usage.

Q. What billing determinants does the Company propose to use for each base rate adjustment filing?

A. The Company proposes to use the weather normalized billing determinants currently utilized in ESI. The estimated rates are shown in Schedule SS-ESII-6 and Schedule SS-ESII-7. To the extent the Company seeks to utilize more current weather normalized billing determinants for any future base rate adjustment filings subsequent to the latest approved base rate case or to change the methodology used to weather normalize billing determinants, PSE&G shall provide those updated billing determinants and supporting data to Board Staff and Rate Counsel a minimum of 60 days prior to any ES II base rate adjustment filing. This is the same procedure to update billing determinants provided for in the ESI Order.

Q. What are the annual rate impacts to the typical residential customer?

A. Based upon the forecasted rates shown in Schedule SS-ESII-4 and Schedule SS-ESII-5, the typical annual bill impacts for a typical residential customer as well as rate class average customers compared to rates as of June 1, 2018 are set forth in Schedule SS-ESII-8 and Schedule SS-ESII-9.[3] The initial annual impact is expected to be effective on March 1, 2021 for electric customers and September 1, 2022 for gas customers. Based on the estimated base rate adjustment revenue requirements provided in Schedule SS-ESII-2E, the initial annual impact of the proposed rates for the first base rate adjustment to the typical residential electric customer who uses 750 kWh in a summer month and 7,200 kWh annually is an increase of $5.20 or approximately 0.43%. The forecasted **cumulative** impact (impact from the entire Program) on the typical residential electric customer is an increase of

[3]The bill impacts assume that customers receive commodity service from PSE&G under the applicable Basic Generation Service (BGS) or Basic Gas Supply Service (BGSS) rate.

approximately 3.99% on an average annual bill or about a $4.04 increase in their average monthly bill. Based on the estimated base rate adjustment revenue requirements provided in Schedule SS-ESII-2G, the initial annual impact of the proposed rates for the first base rate adjustment to the typical residential gas heating customer who uses 165 therms in a winter month and 1,010 therms annually is an increase of $9.52 or approximately 1.08%. The forecasted **<u>cumulative</u>** impact (impact from the entire Program) on the typical residential gas heating customer is an increase of approximately 6.80% on an average annual bill or about a $4.98 increase in their average monthly bill. The total impact for a combined typical electric and gas residential customer would average about 1% per year over the five year period.

Q. Will the Company hold public comment hearings?

A. Although PSE&G is not proposing a rate increase at this time, the Company proposes public comment hearings similar to those that are held when rate increases are proposed. A proposed form of public notice of filing and public hearings, including the forecasted rates and bill impacts attributable to the proposed implementation of the Program are set forth in Attachment 7 to the Petition.

Q. Does this conclude your testimony?

A. Yes, it does.

ATTACHMENT 3

SCHEDULE INDEX

Schedule SS-ESII-1	Credentials of Stephen Swetz
Schedule SS-ESII-2E	Electric Revenue Requirements Calculation
Schedule SS-ESII-2G	Gas Revenue Requirements Calculation
Schedule SS-ESII-3	Weighted Average Cost of Capital (WACC)
Schedule SS-ESII-4	Electric Proof of Revenue
Schedule SS-ESII-5	Gas Proof of Revenue
Schedule SS-ESII-6	Electric Tariff Summary
Schedule SS-ESII-7	Gas Tariff Summary
Schedule SS-ESII-8	Electric Bill Impact Summary
Schedule SS-ESII-9	Gas Bill Impact Summary

CREDENTIALS
OF
STEPHEN SWETZ
SR. DIRECTOR-CORPORATE RATES AND REVENUE REQUIREMENTS

My name is Stephen Swetz and I am employed by PSEG Services Corporation. I am the Sr. Director - Corporate Rates and Revenue Requirements where my main responsibility is to contribute to the development and implementation of electric and gas rates for Public Service Electric and Gas Company (PSE&G, the Company).

WORK EXPERIENCE

I have over 25 years of experience in Rates, Financial Analysis and Operations for three Fortune 500 companies. Since 1991, I have worked in various positions within PSEG. I have spent most of my career contributing to the development and implementation of PSE&G electric and gas rates, revenue requirements, pricing and corporate planning with over 20 years of direct experience in Northeastern retail and wholesale electric and gas markets.

As Sr. Director of the Corporate Rates and Revenue Requirements department, I have submitted pre-filed direct cost recovery testimony as well as oral testimony to the New Jersey Board of Public Utilities and the New Jersey Office of Administrative Law for base rate cases, as well as a number of clauses including infrastructure investments, renewable energy, and energy efficiency programs. A list of my prior testimonies can be found on pages 3 and 4 of this document. I have also contributed to other filings including unbundling electric rates and Off-Tariff Rate Agreements. I have had a leadership role in various economic analyses, asset valuations, rate design, pricing efforts and cost of service studies.

I am an active member of the American Gas Association's Rate and Strategic Issues Committee, the Edison Electric Institute's Rates and Regulatory Affairs Committee and the New Jersey Utility Association (NJUA) Finance and Regulatory Committee.

EDUCATIONAL BACKGROUND

I hold a B.S. in Mechanical Engineering from Worcester Polytechnic Institute and an MBA from Fairleigh Dickinson University.

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
	G		written	Jun-18	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER18030231	written	Mar-18	Tax Cuts and Job Acts of 2017
Public Service Electric & Gas Company	E/G	GR18020093	written	Feb-18	Remediation Adjustment Charge-RAC 25
Public Service Electric & Gas Company	E/G	ER18010029 and GR18010030	written	Jan-18	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E	ER17101027	written	Sep-17	Energy Strong / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	G	GR17070776	written	Jul-17	Gas System Modernization Program II (GSMP II)
Public Service Electric & Gas Company	G	GR17070775	written	Jul-17	Gas System Modernization Program (GSMP) - Second Roll-In
Public Service Electric & Gas Company	G	GR17060720	written	Jul-17	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER17070724 - GR17070725	written	Jul-17	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, S4AEXT II, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER17070723	written	Jul-17	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR17060593	written	Jun-17	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER17030324 - GR17030325	written	Mar-17	Energy Strong / Revenue Requirements & Rate Design - Sixth Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Mar-17	Energy Efficiency 2017 Program
Public Service Electric & Gas Company	E	ER17020136	written	Feb-17	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR16111064	written	Nov-16	Remediation Adjustment Charge-RAC 24
Public Service Electric & Gas Company	E	ER16090918	written	Sep-16	Energy Strong / Revenue Requirements & Rate Design - Fifth Roll-in
Public Service Electric & Gas Company	E	EO16080788	written	Aug-16	Construction of Mason St Substation
Public Service Electric & Gas Company	E	ER16080785	written	Aug-16	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	G	GR16070711	written	Jul-16	Gas System Modernization Program (GSMP) - First Roll-In
Public Service Electric & Gas Company	G	GR16070617	written	Jul-16	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER16070613 - GR16070614	written	Jul-16	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER16070616	written	Jul-16	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR16060484	written	Jun-16	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E	EO16050412	written	May-16	Solar 4 All Extension II (S4Allext II) / Revenue Requirements & Rate Design
Public Service Electric & Gas Company	E/G	ER16030272 - GR16030273	written	Mar-16	Energy Strong / Revenue Requirements & Rate Design - Fourth Roll-in
Public Service Electric & Gas Company	E/G	GR15111294	written	Nov-15	Remediation Adjustment Charge-RAC 23
Public Service Electric & Gas Company	E	ER15101180	written	Sep-15	Energy Strong / Revenue Requirements & Rate Design - Third Roll-in
Public Service Electric & Gas Company	E/G	ER15070757-GR15070758	written	Jul-15	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER15060754	written	Jul-15	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR15060748	written	Jul-15	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR15060646	written	Jun-15	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15050558	written	May-15	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER15050558	written	May-15	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER15030389-GR15030390	written	Mar-15	Energy Strong / Revenue Requirements & Rate Design - Second Roll-in
Public Service Electric & Gas Company	G	GR15030272	written	Feb-15	Gas System Modernization Program (GSMP)
Public Service Electric & Gas Company	E/G	GR14121411	written	Dec-14	Remediation Adjustment Charge-RAC 22
Public Service Electric & Gas Company	E/G	ER14091074	written	Sep-14	Energy Strong / Revenue Requirements & Rate Design - First Roll-in
Public Service Electric & Gas Company	E/G	EO14080897	written	Aug-14	EEE Ext II
Public Service Electric & Gas Company	G	ER14070656	written	Jul-14	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER14070651-GR14070652	written	Jul-14	Green Programs Recovery Charge (GPRC)-Including CA, DR, EEE, EEE Ext, S4All, S4AEXT, SLII, SLIII / Cost Recovery
Public Service Electric & Gas Company	E	ER14070650	written	Jul-14	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR14050511	written	May-14	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR14040375	written	Apr-14	Remediation Adjustment Charge-RAC 21
Public Service Electric & Gas Company	E/G	ER13070603-GR13070604	written	Jun-13	Green Programs Recovery Charge (GPRC)-Including DR, EEE, EEE Ext, CA, S4All, SLII / Cost Recovery
Public Service Electric & Gas Company	E	ER13070605	written	Jul-13	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	G	GR13070615	written	Jun-13	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	G	GR13060445	written	May-13	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	E/G	EO13020155-GO13020156	written/oral	Mar-13	Energy Strong / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	G	GO12030188	written/oral	Mar-13	Appliance Service / Tariff Support
Public Service Electric & Gas Company	E	ER12070599	written	Jul-12	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	E/G	ER12070606-GR12070605	written	Jul-12	RGGI Recovery Charges (RRC)-Including DR, EEE, EEE Ext, CA, S4All, SLII / Cost Recovery
Public Service Electric & Gas Company	E	EO12080721	written/oral	Jul-12	Solar Loan III (SLIII) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO12080721	written/oral	Jul-12	Solar 4 All Extension(S4Allext) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	G	GR12060489	written	Jun-12	Margin Adjustment Charge (MAC) / Cost Recovery
Public Service Electric & Gas Company	G	GR12060583	written	Jun-12	Weather Normalization Charge / Cost Recovery
Public Service Electric & Gas Company	E/G	ER12030207	written	Mar-12	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER12030207	written	Mar-12	Non-Utility Generation Charge (NGC) / Cost Recovery

LIST OF PRIOR TESTIMONIES

Company	Utility	Docket	Testimony	Date	Case / Topic
Public Service Electric & Gas Company	G	GR11060338	written	Jun-11	Margin Adjustment Charge (MAC) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	G	GR11060395	written	Jun-11	Weather Normalization Charge / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO11010030	written	Jan-11	Economic Energy Efficiency Extension (EEEext) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E/G	ER10100737	written	Oct-10	RGGI Recovery Charges (RRC)-Including DR, EEE, CA, S4All, SLII / Cost Recovery
Public Service Electric & Gas Company	E/G	ER10080550	written	Aug-10	Societal Benefits Charge (SBC) / Cost Recovery
Public Service Electric & Gas Company	E	ER10080550	written	Aug-10	Non-Utility Generation Charge (NGC) / Cost Recovery
Public Service Electric & Gas Company	E/G	GR09050422	written/oral	Mar-10	Base Rate Proceeding / Cost of Service & Rate Design
Public Service Electric & Gas Company	E	ER10030220	written	Mar-10	Solar Pilot Recovery Charge (SPRC-Solar Loan I) / Cost Recovery
Public Service Electric & Gas Company	E	EO09030249	written	Mar-09	Solar Loan II(SLII) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E/G	EO09010056	written	Feb-09	Economic Energy Efficiency(EEE) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO09020125	written	Feb-09	Solar 4 All (S4All) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E	EO08080544	written	Aug-08	Demand Response (DR) / Revenue Requirements & Rate Design - Program Approval
Public Service Electric & Gas Company	E/G	ER10100737	written	Jun-08	Carbon Abatement (CA) / Revenue Requirements & Rate Design - Program Approval

PSE&G Energy Strong II
Electric Annual Roll-in Calculation

Schedule SS-ESII-2E

in ($000)

Roll-in Filing

	Roll-in 1	Roll-in 2	Roll-in 3	Roll-in 4	Roll-in 5	Roll-in 6	Roll-in 7
Rate Effective Date	3/1/2021	9/1/2021	3/1/2022	9/1/2022	9/1/2023	3/1/2024	9/1/2024
Plant In Service as of Date	11/30/2020	5/31/2021	11/30/2021	5/31/2022	5/31/2023	11/30/2023	5/31/2024
Rate Base Balance as of Date	2/28/2021	8/31/2021	2/28/2022	8/31/2022	8/31/2023	2/29/2024	8/31/2024

RATE BASE CALCULATION

		Roll-in 1	Roll-in 2	Roll-in 3	Roll-in 4	Roll-in 5	Roll-in 6	Roll-in 7	Total	
1	Gross Plant	$145,705	$151,310	$136,270	$393,376	$396,800	$200,001	$15,398	$1,438,860	= ln 16
2	Accumulated Depreciation	$28,464	$20,962	$22,503	$13,688	$20,755	$7,225	$1,614	$115,211	= ln 19
3	Net Plant	$174,170	$172,272	$158,773	$407,064	$417,554	$207,226	$17,012	$1,554,071	= ln 1 + ln 2
4	Accumulated Deferred Taxes	-$11,469	-$7,185	-$8,686	-$6,432	-$11,722	-$6,572	-$877	-$52,943	= See "Dep-" Wkps Row 616
5	Rate Base	$162,700	$165,086	$150,087	$400,632	$405,833	$200,654	$16,134	$1,501,127	= ln 3 + ln 4
6	Rate of Return - After Tax (Schedule WACC)	6.88%	6.88%	6.88%	6.88%	6.88%	6.88%	6.88%	6.88%	See Schedule SS-ESII-3
7	Return Requirement (After Tax)	$11,187	$11,351	$10,319	$27,546	$27,903	$13,796	$1,109	$103,211	= ln 5 * ln 6
8	Depreciation Exp, net	$3,442	$3,177	$2,920	$7,639	$8,167	$6,327	$390	$32,061	= ln 25
9	Tax Adjustment	-$194	-$137	-$146	-$104	-$163	-$62	-$12	-$817	= ln 31
10	Revenue Factor	1.3944	1.3944	1.3944	1.3944	1.3944	1.3944	1.3944	1.3944	
11	**Total Revenue Requirement**	**$20,127**	**$20,067**	**$18,257**	**$48,916**	**$50,070**	**$27,974**	**$2,074**	**$187,484**	= (ln 7 + ln 8 + ln 9) * ln 10

SUPPORT

Gross Plant

		Roll-in 1	Roll-in 2	Roll-in 3	Roll-in 4	Roll-in 5	Roll-in 6	Roll-in 7	Total	
12	Plant in-service	$111,533	$60,344	$62,425	$62,425	$124,850	$62,425	$15,398	$499,400	= See "Dep-" Wkps Row 594
13	CWIP Transferred into Service	$32,918	$87,246	$70,803	$306,498	$247,966	$123,338	$0	$868,769	= See "Dep-" Wkps Row 595
14	AFUDC on CWIP Transferred Into Service - Debt	$323	$957	$782	$6,289	$6,168	$3,662	$0	$18,180	= See "Dep-" Wkps Row 596
15	AFUDC on CWIP Transferred Into Service - Equity	$932	$2,763	$2,259	$18,164	$17,816	$10,576	$0	$52,511	= See "Dep-" Wkps Row 597
16	**Total Gross Plant**	**$145,705**	**$151,310**	**$136,270**	**$393,376**	**$396,800**	**$200,001**	**$15,398**	**$1,438,860**	= ln 12 + ln 13 + ln 14 + ln 15

Accumulated Depreciation

		Roll-in 1	Roll-in 2	Roll-in 3	Roll-in 4	Roll-in 5	Roll-in 6	Roll-in 7	Total	
17	Accumulated Depreciation	-$3,581	-$1,707	-$1,635	-$3,502	-$6,177	-$2,973	-$317	-$19,891	= See "Dep-" Wkps Row 603
18	Cost of Removal	$32,046	$22,669	$24,138	$17,190	$26,932	$10,198	$1,930	$135,102	= See "Dep-" Wkps Row 598
19	**Net Accumulated Depreciation**	**$28,464**	**$20,962**	**$22,503**	$13,688	$20,755	$7,225	**$1,614**	**$115,211**	= ln 17 + ln 18

Depreciation Expense (Net of Tax)

		Roll-in 1	Roll-in 2	Roll-in 3	Roll-in 4	Roll-in 5	Roll-in 6	Roll-in 7	Total	
20	Depreciable Plant (xAFUDC-E)	$144,773	$148,547	$134,010	$375,212	$378,984	$189,425	$15,398	$1,386,349	= ln 12 + ln 13 + ln 14
21	AFUDC-E	$932	$2,763	$2,259	$18,164	$17,816	$10,576	$0	$52,511	= ln 15
22	Depreciation Rates - Composite/Blended Rate	3.28%	2.90%	2.96%	2.65%	2.81%	4.31%	3.52%	22.44%	= See "Dep-" Wkps Row 598
23	Depreciation Expense	$4,775	$4,388	$4,035	$10,437	$11,165	$8,623	$542	$43,965	= (ln 20 + ln 21) * ln 22
24	Tax @28.11%	$1,333.7	$1,211.0	$1,115.5	$2,798.4	$2,997.4	$2,295.6	$152.3	$11,904.1	= ln 20 * ln 22 * Tax Rate
25	Depreciation Expense (Net of Tax)	**$3,442**	**$3,177**	**$2,920**	**$7,639**	**$8,167**	**$6,327**	**$390**	**$32,061**	= ln 23 - ln 24

Tax Adjustment

		Roll-in 1	Roll-in 2	Roll-in 3	Roll-in 4	Roll-in 5	Roll-in 6	Roll-in 7	Total	
26	Cost of Removal*	$32,046	$22,669	$24,138	$17,190	$26,932	$10,198	$1,930	$96,042	= ln 18
27	Estimated pre-1981 %	14%	14%	14%	14%	14%	14%	14%	14%	= See "Dep-UPCI" Wkp
28	Amortization Period	5	5	5	5	5	5	5	5	= See "Dep-UPCI" Wkp
29	Tax Amortization	$923.00	$652.92	$695.24	$495.11	$775.71	$293.72	$55.59	$2,766	= ln 26 * ln 27 / ln 28
30	Federal Tax Rate	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	= See "WACC" Wkp
31	Tax Adjustment	$194	$137	$146	$104	$163	$62	$12	$581	= ln 29 * ln 30

* Does not apply to Gas assets that have a COR allowance instead of COR in depreciation rate

PSE&G Energy Strong II
Gas Annual Roll-in Calculation

Schedule SS-ESII-2G

in ($000)

Roll-in Filing

	Roll-in 1	Roll-in 2	Roll-in 3
Rate Effective Date	9/1/2022	9/1/2023	9/1/2024
Plant In Service as of Date	5/31/2022	5/31/2023	5/31/2024
Rate Base Balance as of Date	8/31/2022	8/31/2023	8/31/2024

RATE BASE CALCULATION

		Roll-in 1	Roll-in 2	Roll-in 3	Total	
1	Gross Plant	$151,246	$115,998	$673,417	**$940,661**	= ln 16
2	Accumulated Depreciation	$2,252	$908	-$4,754	**-$1,594**	= ln 19
3	Net Plant	$153,498	$116,906	$668,663	**$939,068**	= ln 1 + ln 2
4	Accumulated Deferred Taxes	-$1,425	-$865	-$3,136	**-$5,426**	= See "Dep-" Wkps Row 616
5	Rate Base	$152,074	$116,042	$665,527	**$933,642**	= ln 3 + ln 4
6	Rate of Return - After Tax (Schedule WACC)	6.88%	6.88%	6.88%	**6.88%**	See Schedule SS-ESII-3
7	Return Requirement (After Tax)	$10,456	$7,979	$45,759	**$64,193**	= ln 5 * ln 6
8	Depreciation Exp, net	$1,757	$1,345	$9,338	**$12,440**	= ln 25
9	Tax Adjustment	$0	$0	$0	**$0**	N/A
10	Revenue Factor	1.4121	1.4121	1.4121	**1.4121**	
11	**Total Revenue Requirement**	**$17,246**	**$13,166**	**$77,802**	**$108,214**	= (ln 7 + ln 8 + ln 9) * ln 10

SUPPORT

Gross Plant

		Roll-in 1	Roll-in 2	Roll-in 3	Total	
12	Plant in-service	$0	$0	$0	**$0.0**	= See "Dep-" Wkps Row 594
13	CWIP Transferred into Service	$146,796	$112,316	$646,210	**$905,321.3**	= See "Dep-" Wkps Row 595
14	AFUDC on CWIP Transferred Into Service - Debt	$3,042	$3,170	$5,496	**$11,708.9**	= See "Dep-" Wkps Row 596
15	AFUDC on CWIP Transferred Into Service - Equity	$1,408	$511	$21,711	**$23,631.2**	= See "Dep-" Wkps Row 597
16	**Total Gross Plant**	**$151,246**	**$115,998**	**$673,417**	**$940,661**	= ln 12 + ln 13 + ln 14 + ln 15

Accumulated Depreciation

		Roll-in 1	Roll-in 2	Roll-in 3	Total	
17	Accumulated Depreciation	-$710	-$545	-$5,879	**-$7,134.3**	= See "Dep-" Wkps Row 603
18	Cost of Removal	$2,962	$1,453	$1,125	**$5,540.7**	= See "Dep-" Wkps Row 598
19	**Net Accumulated Depreciation**	**$2,252**	**$908**	**-$4,754**	**-$1,594**	= ln 17 + ln 18

Depreciation Expense (Net of Tax)

		Roll-in 1	Roll-in 2	Roll-in 3	Total	
20	Depreciable Plant (xAFUDC-E)	$149,838	$115,486	$651,706	**$917,030.1**	= ln 12 + ln 13 + ln 14
21	AFUDC-E	$1,408	$511	$21,711	**$23,631.2**	= ln 15
22	Depreciation Rates - Composite/Blended Rate	1.61%	1.61%	1.90%		= See "Dep-" Wkps Row 598
23	Depreciation Expense	$2,435	$1,868	$12,828	**$17,130.3**	= (ln 20 + ln 21) * ln 22
24	Tax @ 28.11%	$678.1	$522.7	$3,489.6	**$4,690.4**	= ln 20 * ln 22 * Tax Rate
25	Depreciation Expense (Net of Tax)	**$1,757**	**$1,345**	**$9,338**	**$12,439.9**	= ln 23 - ln 24

PSE&G Energy Strong II
Weighted Average Cost of Capital (WACC)

Schedule SS-ESII-3

	Percent	Embedded Cost	Weighted Cost	Pre-Tax Weighted Cost	After Tax Weighted Cost
Common Equity	54.00%	10.30%	5.56%	7.73%	5.56%
Customer Deposits	0.49%	0.87%	0.00%	0.00%	0.00%
Other Capital	45.51%	4.03%	1.83%	1.83%	1.32%
Total	100.00%		7.39%	9.56%	6.88%

Federal Income Tax	21.00%
State NJ Business Incm Tax	9.00%
Tax Rate	28.11%

Electric Rate Design (Proof of Revenue by Rate Class)

Explanation of Format

The summary and each rate schedule provide the details of Annualized Weather Normalized (all customers assumed to be on BGS) revenue based on current tariff rates and on the proposed rate design. The pages presented in Schedule SS-ESII-4 are the selected applicable columns of the relevant pages from the rate design workpapers from the Company's 2009 Electric and Gas Base Rate Case and have been appropriately modified per my testimony to reflect this Energy Strong filing.

Annualized Weather Normalized (all customers assumed to be on BGS) and the Proposed Rate Design

In the detail rate designed pages, all the components are separated into Delivery and Supply. In addition to the Distribution components of Delivery, also included in the schedule are lines for Societal Benefits Charge, Non-Utility Generation Charge, Securitization Transition Charges, Base Rate Distribution Kilowatt-hour Adjustment, System Control Charge, Solar Pilot Recovery Charge, CIEP Standby Fee (as applicable), Green Programs Recovery Charge, CIP 1 Capital Adjustment Charges (CAC), Miscellaneous items, and Unbilled Revenue.

Column (1) shows the 2012 annualized weather normalized billing units. Column (2) shows Delivery rates without Sales and Use Tax (SUT) effective June 1, 2018. The Supply-BGS rates in the Column (2) reflect the rates in effect as of June 1, 2018 and for CIEP energy, reflect the class average hourly rates from January 1, 2017 to December 31, 2017. Column (3) presents annualized revenue assuming all customers are provided service under their applicable BGS provision. Column (4) repeats the billing units of Column (1). Column (5) shows the proposed rates without SUT that result in the proposed revenues shown in Column (6). Columns (7) and (8) show the proposed base rate revenue increase, in thousands of dollars and percent increase, respectively, for each of the billing unit blocks. The proposed tariff charges (with and without SUT) are provided on pages 22 and 23 of this schedule.

ELECTRIC PROOF OF REVENUE SUMMARY
ELECTRIC RATE INCREASE
12 Months Ended December 31, 2012
(kWhrs & Revenue in Thousands)

Annualized

	Rate Schedule		Weather Normalized		Proposed with CIP II Rollin		Increase	
			kWhrs	Revenue	kWhrs	Revenue	Revenue	Percent
			(1)	(2)	(3)	(4)	(5)	(6)
1	Residential	RS	12,980,384	$2,071,229	12,980,384	$2,080,103	$8,874	0.43
2	Residential Heating	RHS	165,683	20,903	165,683	$20,991	88	0.42
3	Residential Load Management	RLM	247,183	38,963	247,183	$39,098	135	0.35
4	Water Heating	WH	2,074	208	2,074	$210	2	0.78
5	Water Heating Storage	WHS	39	2.375	39	$2.378	0.003	0.13
6								
7	Building Heating	HS	20,485	3,022	20,485	$3,038	16	0.53
8	General Lighting and Power	GLP	7,830,948	1,163,479	7,830,948	$1,167,963	4,484	0.39
9	Large Power & Lighting-Sec	LPL-S	11,410,771	1,382,641	11,410,771	$1,386,463	3,822	0.28
10	Large Power & Lighting-Pri	LPL-P	3,607,561	346,303	3,607,561	$347,015	712	0.21
11	High Tension-Subtr.	HTS-S	4,466,791	369,543	4,466,791	$370,037	494	0.13
12	High Tension-HV	HTS-HV	332,186	23,641	332,186	$23,669	28	0.12
13								
14								
15	Body Politic Lighting	BPL	286,486	68,835	286,486	$69,782	947	1.38
16	Body Politic Lighting-POF	BPL-POF	14,312	1,074	14,312	$1,080	5	0.51
17	Private Street & Area Lighting	PSAL	168,875	38,271	168,875	$38,791	520	1.36
18								
19								
20	Totals		41,533,778	$5,528,115	41,533,778	$5,548,242	$20,127	0.36

Notes: All customers assumed to be on BGS.
WHS revenues shown to 3 decimals.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018

RATE SCHEDULE RS
RESIDENTIAL SERVICE
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

Annualized

		Weather Normalized			Proposed with CIP II Rollin			Increase	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
1	**Delivery**	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	Service Charge	21,660.597	2.27	$49,170	21,660.597	2.27	$49,170	$0	0.00
3	Distribution 0-600 June - September	3,225,106	0.034775	112,153	3,225,106	0.036403	117,404	5,251	4.68
4	Distribution 0-600 October - May	5,844,909	0.033344	194,893	5,844,909	0.033344	194,893	0	0.00
5	Distribution over 600 June - September	2,199,544	0.038596	84,894	2,199,544	0.040224	88,474	3,580	4.22
6	Distribution over 600 October - May	1,710,825	0.033344	57,046	1,710,825	0.033344	57,046	0	0.00
7	SBC	12,980,384	0.007385	95,860	12,980,384	0.007385	95,860	0	0.00
8	NGC	12,980,384	-0.000139	-1,804	12,980,384	-0.000139	-1,804	0	0.00
9	STC-TBC	12,980,384	0.000000	0	12,980,384	0.000000	0	0	0.00
10	STC-MTC-Tax	12,980,384	0.000000	0	12,980,384	0.000000	0	0	0.00
11	BRDKA	12,980,384	0.000000	0	12,980,384	0.000000	0	0	0.00
12	System Control Charge	12,980,384	0.000000	0	12,980,384	0.000000	0	0	0.00
13	Solar Pilot Recovery Charge	12,980,384	0.000136	1,765	12,980,384	0.000136	1,765	0	0.00
14									
15	Green Programs Recovery Charge	12,980,384	0.001006	13,058	12,980,384	0.001006	13,058	0	0.00
16	Capital Adjustment Charge (CIP I)								
17	Service Charge	21,660.597	0.00	0	21,660.597	0.00	0	0	0.00
18	Distribution 0-600, June-September	3,225,106	0.000000	0	3,225,106	0.000000	0	0	0.00
19	Distribution 0-600, October-May	5,844,909	0.000000	0	5,844,909	0.000000	0	0	0.00
20	Distribution over 600, June-September	2,199,544	0.000000	0	2,199,544	0.000000	0	0	0.00
21	Distribution over 600, October-May	1,710,825	0.000000	0	1,710,825	0.000000	0	0	0.00
22	BRDKA	12,980,384	0.000000	0	12,980,384	0.000000	0	0	0.00
23									
24	Facilities Chg.			0			0	0	0.00
25	Minimum			0			0	0	0.00
26	Miscellaneous			(48)			(52)	(4)	8.33
27	Delivery Subtotal	12,980,384		$606,987	12,980,384		$615,814	$8,827	1.45
28	Unbilled Delivery			3,253			3,300	47	1.44
29	Delivery Subtotal w unbilled			$610,240			$619,114	$8,874	1.45
30									
31	**Supply-BGS**								
32	BGS 0-600 June - September	3,225,106	0.111163	$358,512	3,225,106	0.111163	$358,512	$0	0.00
33	BGS 0-600 October - May	5,844,909	0.111188	649,884	5,844,909	0.111188	649,884	0	0.00
34	BGS over 600 June - September	2,199,544	0.120259	264,515	2,199,544	0.120259	264,515	0	0.00
35	BGS over 600 October - May	1,710,825	0.111188	190,223	1,710,825	0.111188	190,223	0	0.00
36	BGS Reconciliation-FP	12,980,384	0.000000	0	12,980,384	0.000000	0	0	0.00
37	Miscellaneous			0			0	0	0.00
38	Supply subtotal	12,980,384		$1,463,134	12,980,384		$1,463,134	$0	0.00
39	Unbilled Supply			(2,145)			(2,145)	0	0.00
40	Supply Subtotal w unbilled			$1,460,989			$1,460,989	$0	0.00
41									
42	Total Delivery + Supply	12,980,384		$2,071,229	12,980,384		$2,080,103	$8,874	0.43

Notes: All customers assumed to be on BGS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018

RATE SCHEDULE RHS
RESIDENTIAL HEATING SERVICE
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

Annualized

		Weather Normalized			Proposed with CIP II Rollin			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
1	**Delivery**	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	Service Charge	146.592	2.27	$333	146.592	2.27	$333	$0	0.00
3	Distribution 0-600 June - September	24,076	0.048045	1,157	24,076	0.048957	1,179	22	1.90
4	Distribution 0-600 October - May	60,927	0.030985	1,888	60,927	0.031573	1,924	36	1.91
5	Distribution over 600 June - September	14,760	0.053503	790	14,760	0.054518	805	15	1.90
6	Distribution over 600 October - May	65,920	0.011382	750	65,920	0.011598	765	15	2.00
7	SBC	165,683	0.006892	1,142	165,683	0.006892	1,142	0	0.00
8	NGC	165,683	-0.000131	-22	165,683	-0.000131	-22	0	0.00
9	STC-TBC	165,683	0.000000	0	165,683	0.000000	0	0	0.00
10	STC-MTC-Tax	165,683	0.000000	0	165,683	0.000000	0	0	0.00
11	BRDKA	165,683	0.000000	0	165,683	0.000000	0	0	0.00
12	System Control Charge	165,683	0.000000	0	165,683	0.000000	0	0	0.00
13	Solar Pilot Recovery Charge	165,683	0.000068	11	165,683	0.000068	11	0	0.00
14									
15	Green Programs Recovery Charge	165,683	0.001006	167	165,683	0.001006	167	0	0.00
16	Capital Adjustment Charge (CIP I)								
17	Service Charge	146.592	0.00	0	146.592	0.00	0	0	0.00
18	Distribution 0-600, June-September	24,076	0.000000	0	24,076	0.000000	0	0	0.00
19	Distribution 0-600, October-May	60,927	0.000000	0	60,927	0.000000	0	0	0.00
20	Distribution over 600, June-September	14,760	0.000000	0	14,760	0.000000	0	0	0.00
21	Distribution over 600, October-May	65,920	0.000000	0	65,920	0.000000	0	0	0.00
22	BRDKA	165,683	0.000000	0	165,683	0.000000	0	0	0.00
23									
24	Facilities Chg.			0			0	0	0.00
25	Minimum			0			0	0	0.00
26	Miscellaneous			(1)			(2)	(1)	100.00
27	Delivery Subtotal	165,683		$6,215	165,683		$6,302	$87	1.40
28	Unbilled Delivery			41			42	1	2.44
29	Delivery Subtotal w unbilled			$6,256			$6,344	$88	1.41
30									
31	**Supply-BGS**								
32	BGS 0-600 June - September	24,076	0.084219	$2,028	24,076	0.084219	$2,028	$0	0.00
33	BGS 0-600 October - May	60,927	0.088824	5,412	60,927	0.088824	5,412	0	0.00
34	BGS over 600 June - September	14,760	0.096381	1,423	14,760	0.096381	1,423	0	0.00
35	BGS over 600 October - May	65,920	0.088824	5,855	65,920	0.088824	5,855	0	0.00
36	BGS Reconciliation-FP	165,683	0.000000	0	165,683	0.000000	0	0	0.00
37	Miscellaneous			0			0	0	0.00
38	Supply subtotal	165,683		$14,718	165,683		$14,718	$0	0.00
39	Unbilled Supply			(71)			(71)	0	0.00
40	Supply subtotal w unbilled			$14,647			$14,647	$0	0.00
41									
42	Total Delivery + Supply	165,683		$20,903	165,683		$20,991	$88	0.42

Notes: All customers assumed to be on BGS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018

ATTACHMENT 3

RATE SCHEDULE RLM
RESIDENTIAL LOAD MANAGEMENT SERVICE
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

		Annualized Weather Normalized			Proposed with CIP II Rollin			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
1	**Delivery**	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	Service Charge	154.849	13.07	$2,024	154.849	13.07	$2,024	$0	0.00
3	Distribution June - September On Peak	50,287	0.057593	2,896	50,287	0.058988	2,966	70	2.42
4	Distribution June - September Off Peak	55,840	0.013382	747	55,840	0.013706	765	18	2.41
5	Distribution October - May On Peak	60,829	0.013382	814	60,829	0.013706	834	20	2.46
6	Distribution October - May Off Peak	80,227	0.013382	1,074	80,227	0.013706	1,100	26	2.42
7	SBC	247,183	0.006892	1,704	247,183	0.006892	1,704	0	0.00
8	NGC	247,183	-0.000131	-32	247,183	-0.000131	-32	0	0.00
9	STC-TBC	247,183	0.000000	0	247,183	0.000000	0	0	0.00
10	STC-MTC-Tax	247,183	0.000000	0	247,183	0.000000	0	0	0.00
11	BRDKA	247,183	0.000000	0	247,183	0.000000	0	0	0.00
12	System Control Charge	247,183	0.000000	0	247,183	0.000000	0	0	0.00
13	Solar Pilot Recovery Charge	247,183	0.000068	17	247,183	0.000068	17	0	0.00
14									
15	Green Programs Recovery Charge	247,183	0.001006	249	247,183	0.001006	249	0	0.00
16	Capital Adjustment Charge (CIP I)								
17	Service Charge	154.849	0.00	0	154.849	0.00	0	0	0.00
18	Distribution June - September On Peak	50,287	0.000000	0	50,287	0.000000	0	0	0.00
19	Distribution June - September Off Peak	55,840	0.000000	0	55,840	0.000000	0	0	0.00
20	Distribution October - May On Peak	60,829	0.000000	0	60,829	0.000000	0	0	0.00
21	Distribution October - May Off Peak	80,227	0.000000	0	80,227	0.000000	0	0	0.00
22	BRDKA	247,183	0.000000	0	247,183	0.000000	0	0	0.00
23									
24	Facilities Chg.			0			0	0	0.00
25	Minimum			0			0	0	0.00
26	Miscellaneous			(1)			(1)	0	0.00
27	Delivery Subtotal	247,183		$9,492	247,183		$9,626	$134	1.41
28	Unbilled Delivery			90			91	1	1.11
29	Delivery Subtotal w unbilled			$9,582			$9,717	$135	1.41
30									
31	**Supply-BGS**								
32	BGS June - September On Peak	50,287	0.212092	$10,665	50,287	0.212092	$10,665	$0	0.00
33	BGS June - September Off Peak	55,840	0.045364	2,533	55,840	0.045364	2,533	0	0.00
34	BGS October - May On Peak	60,829	0.199265	12,121	60,829	0.199265	12,121	0	0.00
35	BGS October - May Off Peak	80,227	0.050453	4,048	80,227	0.050453	4,048	0	0.00
36	BGS Reconciliation-FP	247,183	0.000000	0	247,183	0.000000	0	0	0.00
37	Miscellaneous			0			0	0	0.00
38	Supply subtotal	247,183		$29,367	247,183		$29,367	$0	0.00
39	Unbilled Supply			14			14	0	0.00
40	Supply subtotal w unbilled			$29,381			$29,381	$0	0.00
41									
42	Total Delivery + Supply	247,183		$38,963	247,183		$39,098	$135	0.35

Notes: All customers assumed to be on BGS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018

RATE SCHEDULE WH
WATER HEATING SERVICE
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

		Annualized Weather Normalized			Proposed with CIP II Rollin			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
1	**Delivery**	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	Distribution Sum	580	0.044336	$26	580	0.045121	$26	$0.455	1.77
3	Distribution Win	1,494	0.044336	$66	1,494	0.045121	$67	$1.173	1.77
4	SBC	2,074	0.006892	$14	2,074	0.006892	$14	$0.000	0.00
5	NGC	2,074	-0.000093	$0	2,074	-0.000093	$0	$0.000	0.00
6	STC-TBC	2,074	0.000000	$0	2,074	0.000000	$0	$0.000	0.00
7	STC-MTC-Tax	2,074	0.000000	$0	2,074	0.000000	$0	$0.000	0.00
8	BRDKA	2,074	0.000000	$0	2,074	0.000000	$0	$0.000	0.00
9	System Control Charge	2,074	0.000000	$0	2,074	0.000000	$0	$0.000	0.00
10	Solar Pilot Recovery Charge	2,074	0.000068	$0	2,074	0.000068	$0	$0.000	0.00
11									
12	Green Programs Recovery Charge	2,074	0.001006	2	2,074	0.001006	2	$0.000	0.00
13	Capital Adjustment Charge (CIP I)								
14	Distribution Summer	580	0.000000	0	580	0.000000	0	$0.000	0.00
15	Distribution Winter	1,494	0.000000	0	1,494	0.000000	0	$0.000	0.00
16	BRDKA	2,074	0.000000	0	2,074	0.000000	0	$0.000	0.00
17									
18	Facilities Chg.			0			0	$0.000	0.00
19	Minimum			0			0	$0.000	0.00
20	Miscellaneous			0			0	$0.001	0.00
21	Delivery Subtotal	2,074		$108	2,074		$110	$1.629	1.50
22	Unbilled Delivery			0			0	$0.000	0.00
23	Delivery Subtotal w unbilled			$108			$110	$1.629	1.50
24									
25	**Supply-BGS**								
26	BGS Summer	580	0.046813	$27	580	0.046813	$27	$0.000	0.00
27	BGS Winter	1,494	0.049065	73	1,494	0.049065	73	$0.000	0.00
28	BGS Reconciliation-FP	2,074	0.000000	0	2,074	0.000000	0	$0.000	0.00
29	Miscellaneous			0			0	$0.000	0.00
30	Supply subtotal	2,074		$100	2,074		$100	$0.000	0.00
31	Unbilled Supply			0			0	$0.000	0.00
32	Supply subtotal w unbilled			$100			$100	$0.000	0.00
33									
34	Total Delivery + Supply	2,074		$208	2,074		$210	$1.629	0.78

Notes: All customers assumed to be on BGS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018

Energy Strong II Roll In

RATE SCHEDULE WHS
WATER HEATING STORAGE SERVICE
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

		Annualized Weather Normalized			Proposed with CIP II Rollin			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
1	**Delivery**	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	Service Charge	0.313	0.52	$0.163	0.313	0.52	$0.163	$0.000	0.00
3	Distribution June - September	11	0.000054	0.001	11	0.000055	0.001	0.000	0.00
4	Distribution October - May	28	0.000054	0.002	28	0.000055	0.002	0.000	0.00
5	SBC	39	0.006892	0.268	39	0.006892	0.268	0.000	0.00
6	NGC	39	-0.000093	(0.004)	39	-0.000093	-0.004	0.000	0.00
7	STC-TBC	39	0.000000	0.000	39	0.000000	0.000	0.000	0.00
8	STC-MTC-Tax	39	0.000000	0.000	39	0.000000	0.000	0.000	0.00
9	BRDKA	39	0.000000	0.000	39	0.000000	0.000	0.000	0.00
10	System Control Charge	39	0.000000	0.000	39	0.000000	0.000	0.000	0.00
11	Solar Pilot Recovery Charge	39	0.000068	0.003	39	0.000068	0.003	0.000	0.00
12									
13	Green Programs Recovery Charge	39	0.001006	0.039	39	0.001006	0.039	0.000	0.00
14	Capital Adjustment Charge (CIP I)								
15	Service Charge	0.313	0.00	0.000	0.313	0.00	0.000	0.000	0.00
16	Distribution June - September	11	0.000000	0.000	11	0.000000	0.000	0.000	0.00
17	Distribution October - May	28	0.000000	0.000	28	0.000000	0.000	0.000	0.00
18	BRDKA	39	0.000000	0.000	39	0.000000	0.000	0.000	0.00
19									
20	Facilities Chg.			0.000			0.000	0.000	0.00
21	Minimum			0.000			0.000	0.000	0.00
22	Miscellaneous			0.000			0.003	0.003	0.00
23	Delivery Subtotal	39		$0.472	39		$0.475	$0.003	0.64
24	Unbilled Delivery			0.027			0.027	0.000	0.00
25	Delivery Subtotal w unbilled			$0.499			$0.502	$0.003	0.60
26									
27	**Supply-BGS**								
28	BGS- June - September	10.875	0.046520	$0.506	11	0.046520	$0.506	$0.000	0.00
29	BGS- October - May	28	0.049245	1.381	28	0.049245	1.381	0.000	0.00
30	BGS Reconciliation-FP	39	0.000000	0.000	39	0.000000	0.000	0.000	0.00
31	Miscellaneous			0.000			0.000	0.000	0.00
32	Supply subtotal	39		$1.887	39		$1.887	$0.000	0.00
33	Unbilled Supply			(0.011)			(0.011)	0.000	0.00
34	Supply subtotal w unbilled			$1.876			$1.876	$0.000	0.00
35									
36	Total Delivery + Supply	39		$2.375	39		$2.378	$0.003	0.13

Notes: All customers assumed to be on BGS.
WHS revenues shown to 3 decimals.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018

Energy Strong II Roll In

RATE SCHEDULE HS
BUILDING HEATING SERVICE
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

		Annualized Weather Normalized			Proposed with CIP II Rollin			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
1	**Delivery**	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	Service Charge	19.26	3.11	$60	19.260	3.11	$60	$0	0.00
3	Distribution June - September	4,362	0.082837	361	4,362	0.084394	368	7	1.94
4	Distribution October - May	16,123	0.030413	490	16,123	0.030985	500	10	2.04
5	SBC	20,485	0.006892	141	20,485	0.006892	141	0	0.00
6	NGC	20,485	-0.000093	-2	20,485	-0.000093	-2	0	0.00
7	STC-TBC	20,485	0.000000	0	20,485	0.000000	0	0	0.00
8	STC-MTC-Tax	20,485	0.000000	0	20,485	0.000000	0	0	0.00
9	BRDKA	20,485	0.000000	0	20,485	0.000000	0	0	0.00
10	System Control Charge	20,485	0.000000	0	20,485	0.000000	0	0	0.00
11	Solar Pilot Recovery Charge	20,485	0.000068	1	20,485	0.000068	1	0	0.00
12									
13	Green Programs Recovery Charge	20,485	0.001006	21	20,485	0.001006	21	0	0.00
14	Capital Adjustment Charge (CIP I)								
15	Service Charge	19.260	0.00	0	19.260	0.00	0	0	0.00
16	Distribution June - September	4,362	0.000000	0	4,362	0.000000	0	0	0.00
17	Distribution October - May	16,123	0.000000	0	16,123	0.000000	0	0	0.00
18	BRDKA	20,485	0.000000	0	20,485	0.000000	0	0	0.00
19									
20	Facilities Chg.			0			0	0	0.00
21	Minimum			0			0	0	0.00
22	Miscellaneous			(1)			(2)	-1	100.00
23	Delivery Subtotal	20,485		$1,071	20,485		$1,087	$16	1.49
24	Unbilled Delivery			0			0	0	0.00
25	Delivery Subtotal w unbilled			$1,071			$1,087	$16	1.49
26									
27	**Supply-BGS**								
28	BGS- June - September	4,362	0.097446	$425	4,362	0.097446	$425	$0	0.00
29	BGS- October - May	16,123	0.095524	1,540	16,123	0.095524	1,540	0	0.00
30	BGS Reconciliation-FP	20,485	0.000000	0	20,485	0.000000	0	0	0.00
31	Miscellaneous			0			0	0	0.00
32	Supply subtotal	20,485		$1,965	20,485		$1,965	$0	0.00
33	Unbilled Supply			(14)			(14)	0	0.00
34	Supply subtotal w unbilled			$1,951			$1,951	$0	0.00
35									
36	Total Delivery + Supply	20,485		$3,022	20,485		$3,038	$16	0.53

Notes: All customers assumed to be on BGS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018

Energy Strong II Roll In

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

		Annualized Weather Normalized			Proposed with CIP II Rollin			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
1	**Delivery**	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	Service Charge	3,068.595	3.96	$12,152	3,068.595	3.96	$12,152	$0	0.00
3	Service Charge-unmetered	75.200	1.83	138	75.200	1.83	138	0	0.00
4	Service Charge-Night Use	0.989	347.77	344	0.989	347.77	344	0	0.00
5	Distrib. KW Annual	29,559	4.0591	119,983	29,559	4.1342	122,203	2,220	1.85
6	Distrib. KW Summer	10,443	7.5335	78,672	10,443	7.6729	80,128	1,456	1.85
7	Distribution kWhr, June-September	2,832,575	0.009532	27,000	2,832,575	0.009708	27,499	499	1.85
8	Distribution kWhr, October-May	4,968,239	0.003349	16,639	4,968,239	0.003411	16,947	308	1.85
9	Distribution kWhr, Night use, June-September	11,184	0.003349	37	11,184	0.003411	38	1	2.70
10	Distribution kWhr, Night use, October-May	18,950	0.003349	63	18,950	0.003411	65	2	3.17
11	SBC	7,830,948	0.006892	53,971	7,830,948	0.006892	53,971	0	0.00
12	NGC	7,830,948	-0.000093	-728	7,830,948	-0.000093	-728	0	0.00
13	STC-TBC	7,830,948	0.000000	0	7,830,948	0.000000	0	0	0.00
14	STC-MTC-Tax	7,830,948	0.000000	0	7,830,948	0.000000	0	0	0.00
15	BRDKA	7,830,948	0.000000	0	7,830,948	0.000000	0	0	0.00
16	System Control Charge	7,830,948	0.000000	0	7,830,948	0.000000	0	0	0.00
17	Solar Pilot Recovery Charge	7,830,948	0.000068	533	7,830,948	0.000068	533	0	0.00
18									
19	Green Programs Recovery Charge	7,830,948	0.001006	7,878	7,830,948	0.001006	7,878	0	0.00
20	Capital Adjustment Charge (CIP I)								
21	Service Charge	3,068.595	0.00	0	3,068.595	0.00	0	0	0.00
22	Service Charge-Unmetered	75.200	0.00	0	75.200	0.00	0	0	0.00
23	Service Charge-Night Use	0.989	0.00	0	0.989	0.00	0	0	0.00
24	Annual Demand	29,559	0.0000	0	29,559	0.0000	0	0	0.00
25	Summer Demand, June-September	10,443	0.0000	0	10,443	0.0000	0	0	0.00
26	Distribution kWhr, June-September	2,832,575	0.000000	0	2,832,575	0.000000	0	0	0.00
27	Distribution kWhr, October-May	4,968,239	0.000000	0	4,968,239	0.000000	0	0	0.00
28	Distribution kWhr, Night use, June-September	11,184	0.000000	0	11,184	0.000000	0	0	0.00
29	Distribution kWhr, Night use, October-May	18,950	0.000000	0	18,950	0.000000	0	0	0.00
30	BRDKA	7,830,948	0.000000	0	7,830,948	0.000000	0	0	0.00
31									
32	Duplicate Svc (Same Sub/Different Sub)		$2.22/$3.20	6		$2.22/$3.20	6	0	0.00
33	Facilities Chg.		1.45%	70		1.45%	70	0	0.00
34	Minimum			41			41	0	0.00
35	Distrib. Miscellaneous			(1,998)			(1,998)	0	0.00
36	Delivery subtotal	7,830,948		$314,801	7,830,948		$319,287	$4,486	1.43
37	Unbilled Delivery			(168)			(170)	(2)	1.19
38	Delivery subtotal w unbilled			$314,633			$319,117	$4,484	1.43

RATE SCHEDULE GLP
GENERAL LIGHTING AND POWER SERVICE
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

		Annualized Weather Normalized			Proposed with CIP II Rollin			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
1	Supply-BGS	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	Generation Capacity Obl June-September	10,069	5.1628	$51,984	10,069	5.1628	$51,984	$0	0.00
3	Generation Capacity Obl October-May	21,037	5.1628	108,610	21,037	5.1628	108,610	0	0.00
4	Transmission Capacity Obl	27,909	8.8088	245,845	27,909	8.8088	245,845	0	0.00
5	BGS kWhr June - September not night use	2,832,575	0.055377	156,860	2,832,575	0.055377	156,860	0	0.00
6	BGS kWhr October - May not night use	4,968,239	0.057101	283,691	4,968,239	0.057101	283,691	0	0.00
7	BGS kWhr June - September night use	11,184	0.039483	442	11,184	0.039483	442	0	0.00
8	BGS kWhr October - May night use	18,950	0.044122	836	18,950	0.044122	836	0	0.00
9	BGS Reconciliation-FP	7,830,948	0.000000	0	7,830,948	0.000000	0	0	0.00
10	BGS Miscellaneous			(200)			(200)	0	0.00
11	Supply subtotal	7,830,948		$848,068	7,830,948		$848,068	$0	0.00
12	Unbilled Supply			778			778	0	0.00
13	Supply Subtotal w Unbilled			$848,846			$848,846	$0	0.00
14									
15	Total Delivery + Supply	7,830,948		$1,163,479	7,830,948		$1,167,963	$4,484	0.39

Notes: All customers assumed to be on BGS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018

RATE SCHEDULE LPL-Sec
LARGE POWER & LIGHTING SERVICE-SECONDARY
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

		Annualized Weather Normalized			Proposed with CIP II Rollin			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
1	**Delivery**	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	Service Charge	105.315	347.77	$36,625	105.315	347.77	$36,625	$0	0.00
3	Distrib. KW Annual	29,101	3.3530	97,576	29,101	3.4239	99,639	2,063	2.11
4	Distrib. KW June - September	10,418	7.9769	83,103	10,418	8.1455	84,860	1,757	2.11
5	Distribution kWhr On Peak June-September	2,117,080	0.000000	0	2,117,080	0.000000	0	0	0.00
6	Distribution kWhr Off Peak June-September	2,065,647	0.000000	0	2,065,647	0.000000	0	0	0.00
7	Distribution kWhr On Peak October-May	3,561,184	0.000000	0	3,561,184	0.000000	0	0	0.00
8	Distribution kWhr Off Peak October-May	3,666,860	0.000000	0	3,666,860	0.000000	0	0	0.00
9	SBC	11,410,771	0.006892	78,643	11,410,771	0.006892	78,643	0	0.00
10	NGC	11,410,771	-0.000093	-1,061	11,410,771	-0.000093	-1,061	0	0.00
11	STC-TBC	11,410,771	0.000000	0	11,410,771	0.000000	0	0	0.00
12	STC-MTC-Tax	11,410,771	0.000000	0	11,410,771	0.000000	0	0	0.00
13	BRDKA	11,410,771	0.000000	-	11,410,771	0.000000	-	0	0.00
14	System Control Charge	11,410,771	0.000000	-	11,410,771	0.000000	-	0	0.00
15	Solar Pilot Recovery Charge	11,410,771	0.000068	776	11,410,771	0.000068	776	0	0.00
16	CIEP Standby Fee	5,795,363	0.000150	869	5,795,363	0.000150	869	0	0.00
17									
18	Green Programs Recovery Charge	11,410,771	0.001006	11,479	11,410,771	0.001006	11,479	0	0.00
19	Capital Adjustment Charge (CIP I)								
20	Service Charge	105.315	0.00	0	105.315	0.00	0	0	0.00
21	Annual Demand	29,101	0.0000	0	29,101	0.0000	0	0	0.00
22	Summer Demand, June-September	10,418	0.0000	0	10,418	0.0000	0	0	0.00
23	Distribution	11,410,771	0.000000	-	11,410,771	0.000000	-	0	0.00
24	BRDKA	11,410,771	0.000000	-	11,410,771	0.000000	-	0	0.00
25									
26	Duplicate Svc (Same Sub/Different Sub)		$2.22/$3.20	127		$2.22/$3.20	127	0	0.00
27	Facilities Chg.		1.45%	247		1.45%	247	0	0.00
28	Minimum			0			0	0	0.00
29	Dist. Miscellaneous			(2,188)			(2,189)	(1)	0.05
30	Delivery subtotal	11,410,771		$306,196	11,410,771		$310,015	$3,819	1.25
31	Unbilled Delivery			257			260	3	1.17
32	Delivery subtotal w unbilled			$306,453			$310,275	$3,822	1.25

Energy Strong II Roll In

RATE SCHEDULE LPL-Sec
LARGE POWER & LIGHTING SERVICE-SECONDARY
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

		Annualized Weather Normalized			Proposed with CIP II Rollin			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
1	**Supply-BGS**	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	**0-499**								
3	Generation Capacity Obl - June-September	9,088	5.1628	$46,920	9,088	5.1628	$46,920	$0	0.00
4	Generation Capacity Obl - October-May	18,215	5.1628	94,040	18,215	5.1628	94,040	0	0.00
5	Transmission Capacity Obl	24,836	8.8088	218,775	24,836	8.8088	218,775	0	0.00
6	BGS kWhr June-September On Peak	1,661,425	0.065862	109,425	1,661,425	0.065862	109,425	0	0.00
7	BGS kWhr June-September Off Peak	1,621,062	0.039483	64,004	1,621,062	0.039483	64,004	0	0.00
8	BGS kWhr October-May On Peak	2,794,717	0.064870	181,293	2,794,717	0.064870	181,293	0	0.00
9	BGS kWhr October-May Off Peak	2,877,649	0.044122	126,968	2,877,649	0.044122	126,968	0	0.00
10	**500 and over**								
11	Generation Capacity Obl - June-September	2,422	8.7587	21,214	2,422	8.7587	21,214	0	0.00
12	Generation Capacity Obl - October-May	5,066	8.7587	44,372	5,066	8.7587	44,372	0	0.00
13	Transmission Capacity Obl	6,826	8.8088	60,129	6,826	8.8088	60,129	0	0.00
14	BGS kWhr June-September	900,240	0.036662	33,005	900,240	0.036662	33,005	0	0.00
15	Spare	-	0.036662	-	-	0.036662	-	0	0.00
16	BGS kWhr October-May	1,555,678	0.040859	63,563	1,555,678	0.040859	63,563	0	0.00
17	Spare	-	0.040859	-	-	0.040859	-	0	0.00
18									
19	BGS Reconciliation-FP	8,954,853	0.000000	-	8,954,853	0.000000	-	0	0.00
20	BGS Reconciliation-CIEP	2,455,918	0.000000	-	2,455,918	0.000000	-	0	0.00
21	BGS Miscellaneous			(117)			(117)	0	0.00
22	Supply subtotal	11,410,771		$1,063,591	11,410,771		$1,063,591	$0	0.00
23	Unbilled Supply			12,597			12,597	0	0.00
24	Supply w Unbilled			$1,076,188			$1,076,188	$0	0.00
25									
26	Total Delivery + Supply	11,410,771		$1,382,641	11,410,771		$1,386,463	$3,822	0.28

Notes: All customers assumed to be on BGS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018

Energy Strong II Roll In

RATE SCHEDULE LPL-Pri
LARGE POWER & LIGHTING SERVICE-PRIMARY
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

		Annualized Weather Normalized			Proposed with CIP II Rollin			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
1	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	Service Charge	9.241	347.77	$3,214	9.241	347.77	$3,214	$0	0.00
3	Service Charge-Alternate	0.475	17.88	8	0.475	17.88	8	0	0.00
4	Distrib. KW Annual	7,855	1.5684	12,320	7,855	1.5990	12,560	240	1.95
5	Distrib. KW June - September	2,769	8.7064	24,108	2,769	8.8763	24,578	470	1.95
6	Distribution kWhr On Peak June-September	612,105	0.000000	0	612,105	0.000000	0	0	0.00
7	Distribution kWhr Off Peak June-September	700,645	0.000000	0	700,645	0.000000	0	0	0.00
8	Distribution kWhr On Peak October-May	1,056,389	0.000000	0	1,056,389	0.000000	0	0	0.00
9	Distribution kWhr Off Peak October-May	1,238,422	0.000000	0	1,238,422	0.000000	0	0	0.00
10	SBC	3,607,561	0.007251	26,158	3,607,561	0.007251	26,158	0	0.00
11	NGC	3,607,561	-0.000091	-328	3,607,561	-0.000091	-328	0	0.00
12	STC-TBC	3,607,561	0.000000	0	3,607,561	0.000000	0	0	0.00
13	STC-MTC-Tax	3,607,561	0.000000	0	3,607,561	0.000000	0	0	0.00
14	BRDKA	3,607,561	0.000000	0	3,607,561	0.000000	0	0	0.00
15	System Control Charge	3,607,561	0.000000	0	3,607,561	0.000000	0	0	0.00
16	Solar Pilot Recovery Charge	3,607,561	0.000068	245	3,607,561	0.000068	245	0	0.00
17	CIEP Standby Fee	3,607,561	0.000150	541	3,607,561	0.000150	541	0	0.00
18									
19	Green Programs Recovery Charge	3,607,561	0.001006	3,629	3,607,561	0.001006	3,629	0	0.00
20	Capital Adjustment Charge (CIP I)								
21	Service Charge	9.241	0.00	0	9.241	0.00	0	0	0.00
22	Service Charge-Primary Alternate	0.475	0.00	0	0.475	0.00	0	0	0.00
23	Annual Demand	7,855	0.0000	0	7,855	0.0000	0	0	0.00
24	Summer Demand, June-September	2,769	0.0000	0	2,769	0.0000	0	0	0.00
25	Distribution	3,607,561	0.000000	0	3,607,561	0.000000	0	0	0.00
26	BRDKA	3,607,561	0.000000	0	3,607,561	0.000000	0	0	0.00
27									
28	Duplicate Svc (Same Sub/Different Sub)		$2.22/$3.20	647		$2.22/$3.20	647	0	0.00
29	Facilities Chg.		1.45%	471		1.45%	471	0	0.00
30	Minimum			3			3	0	0.00
31	Dist. Miscellaneous			(655)			(654)	1	-0.15
32	Delivery subtotal	3,607,561		$70,361	3,607,561		$71,072	$711	1.01
33	Unbilled Delivery			96			97	1	1.04
34	Delivery subtotal w unbilled			$70,457			$71,169	$712	1.01

Energy Strong II Roll In

RATE SCHEDULE LPL-Pri
LARGE POWER & LIGHTING SERVICE-PRIMARY
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

		Annualized Weather Normalized			Proposed with CIP II Rollin			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
		(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	**Supply-BGS**								
2	Generation Capacity Obl June-September	2,767	8.7587	24,235	2,767	8.7587	$24,235	$0	0.00
3	Generation Capacity Obl October-May	5,546	8.7587	48,576	5,546	8.7587	48,576	0	0.00
4	Transmission Capacity Obl	7,584	8.8088	66,806	7,584	8.8088	66,806	0	0.00
5	BGS kWhr June-September On Peak	612,105	0.034744	21,267	612,105	0.034744	21,267	0	0.00
6	BGS kWhr June-September Off Peak	700,645	0.034744	24,343	700,645	0.034744	24,343	0	0.00
7	BGS kWhr October-May On Peak	1,056,389	0.039220	41,432	1,056,389	0.039220	41,432	0	0.00
8	BGS kWhr October-May Off Peak	1,238,422	0.039220	48,571	1,238,422	0.039220	48,571	0	0.00
9	BGS Reconciliation-CIEP	3,607,561	0.000000	0	3,607,561	0.000000	0	0	0.00
10	BGS Miscellaneous			0			0	0	0.00
11	Supply subtotal	3,607,561		$275,230	3,607,561		$275,230	$0	0.00
12	Unbilled Supply			616			616	0	0.00
13	Supply w Unbilled			$275,846			$275,846	$0	0.00
14									
15	Total Delivery + Supply	3,607,561		$346,303	3,607,561		$347,015	$712	0.21

Notes: All customers assumed to be on BGS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018

RATE SCHEDULE HTS-SUBTR.
HIGH TENSION SERVICE-SUBTRANSMISSION
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

		Annualized Weather Normalized			Proposed with CIP II Rollin			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
1	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	Service Charge	2.260	1,911.39	$4,320	2.260	1,911.39	$4,320	$0	0.00
3	Distrib. KW Annual	13,072	0.9701	12,681	13,072	0.9905	12,948	267	2.11
4	Distrib. KW June - September	3,073	3.5067	10,776	3,073	3.5806	11,003	227	2.11
5	Distribution kWhr On Peak	1,613,843	0.000000	0	1,613,843	0.000000	0	0	0.00
6	Spare	0	0.000000	0	0	0.000000	0	0	0.00
7	Distribution kWhr On Peak	2,852,948	0.000000	0	2,852,948	0.000000	0	0	0.00
8	Spare	0	0.000000	0	0	0.000000	0	0	0.00
9	SBC	4,466,791	0.007136	31,875	4,466,791	0.007136	31,875	0	0.00
10	NGC	4,466,791	-0.000089	-398	4,466,791	-0.000089	-398	0	0.00
11	STC-TBC	4,466,791	0.000000	0	4,466,791	0.000000	0	0	0.00
12	STC-MTC-Tax	4,466,791	0.000000	0	4,466,791	0.000000	0	0	0.00
13	BRDKA	4,466,791	0.000000	0	4,466,791	0.000000	0	0	0.00
14	System Control Charge	4,466,791	0.000000	0	4,466,791	0.000000	0	0	0.00
15	Solar Pilot Recovery Charge	4,466,791	0.000068	304	4,466,791	0.000068	304	0	0.00
16	CIEP Standby Fee	4,466,791	0.000150	670	4,466,791	0.000150	670	0	0.00
17									
18	Green Programs Recovery Charge	4,466,791	0.001006	4,494	4,466,791	0.001006	4,494	0	0.00
19	Capital Adjustment Charge (CIP I)								
20	Service Charge	2.260	0.00	0	2.260	0.00	0	0	0.00
21	Annual Demand	13,072	0.0000	0	13,072	0.0000	0	0	0.00
22	Summer Demand, June-September	3,073	0.0000	0	3,073	0.0000	0	0	0.00
23	Distribution	4,466,791	0.000000	0	4,466,791	0.000000	0	0	0.00
24	BRDKA	4,466,791	0.000000	0	4,466,791	0.000000	0	0	0.00
25									
26	Duplicate Svc (Same Sub/Different Sub)		$1.83/$2.20	4		$1.83/$2.20	4	0	0.00
27	Facilities Chg.		1.45%	393		1.45%	393	0	0.00
28	Minimum			0			0	0	0.00
29	Dist. Miscellaneous			(289)			(289)	0	0.00
30	Delivery subtotal	4,466,791		$64,830	4,466,791		$65,324	$494	0.76
31	Unbilled Delivery			6			6	0	0.00
32	Delivery subtotal w unbilled			$64,836			$65,330	$494	0.76

ATTACHMENT 3

RATE SCHEDULE HTS-SUBTR.
HIGH TENSION SERVICE-SUBTRANSMISSION
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

		Annualized Weather Normalized			Proposed with CIP II Rollin			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
1	**Supply-BGS**	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	Generation Capacity Obl June-September	2,820	8.7587	$24,700	2820	8.7587	$24,700	$0	0.00
3	Generation Capacity Obl October-May	5,825	8.7587	51,019	5825	8.7587	51,019	0	0.00
4	Transmission Capacity Obl	7,904	8.8088	69,625	7904	8.8088	69,625	0	0.00
5	BGS kWhr June-September	1,613,843	0.033860	54,645	1,613,843	0.033860	54,645	0	0.00
6	Spare	0	0.033860	0	0	0.033860	0	0	0.00
7	BGS kWhr October-May	2,852,948	0.038054	108,566	2,852,948	0.038054	108,566	0	0.00
8	Spare	0	0.038054	0	0	0.038054	0	0	0.00
9	BGS Reconciliation-CIEP	4,466,791	0.000000	0	4,466,791	0.000000	0	0	0.00
10	BGS Miscellaneous			(14)			(14)	0	0.00
11	Supply subtotal	4,466,791		$308,541	4,466,791		$308,541	$0	0.00
12	Unbilled Supply			(3,834)			(3,834)	0	0.00
13	Supply w Unbilled			$304,707			$304,707	$0	0.00
14									
15	Total Delivery + Supply	4,466,791		$369,543	4,466,791		$370,037	$494	0.13

Notes: All customers assumed to be on BGS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018

Energy Strong II Roll In

RATE SCHEDULE HTS-HV
HIGH TENSION SERVICE-HIGH VOLTAGE
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

		Annualized Weather Normalized			Proposed with CIP II Rollin			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
1	**Delivery**	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	Service Charge	0.097	1,720.25	$167	0.097	1,720.25	$167	$0	0.00
3	Distrib. KW Annual	2,424	0.5876	1,424	2,424	0.5996	1,453	29	2.04
4	Distrib. KW June - September	0	0.000000	0	0	0.0000	0	0	0.00
5	Distribution kWhr June - September	85,014	0.000000	0	85,014	0.000000	0	0	0.00
6	Spare	0	0.000000	0	0	0.000000	0	0	0.00
7	Distribution kWhr October - May	247,172	0.000000	0	247,172	0.000000	0	0	0.00
8	Spare	0	0.000000	0	0	0.000000	0	0	0.00
9	SBC	332,186	0.007060	2,345	332,186	0.007060	2,345	0	0.00
10	NGC	332,186	-0.000087	-29	332,186	-0.000087	-29	0	0.00
11	STC-TBC	332,186	0.000000	0	332,186	0.000000	0	0	0.00
12	STC-MTC-Tax	332,186	0.000000	0	332,186	0.000000	0	0	0.00
13	BRDKA	332,186	0.000000	0	332,186	0.000000	0	0	0.00
14	System Control Charge	332,186	0.000000	0	332,186	0.000000	0	0	0.00
15	Solar Pilot Recovery Charge	332,186	0.000068	23	332,186	0.000068	23	0	0.00
16	CIEP Standby Fee	332,186	0.000150	50	332,186	0.000150	50	0	0.00
17									
18	Green Programs Recovery Charge	332,186	0.001006	334	332,186	0.001006	334	0	0.00
19	Capital Adjustment Charge (CIP I)								
20	Service Charge	0.097	0.00	0	0.097	0.00	0	0	0.00
21	Annual Demand	2,424	0.0000	0	2,424	0.0000	0	0	0.00
22	Distribution	332,186	0.000000	0	332,186	0.000000	0	0	0.00
23	BRDKA	332,186	0.000000	0	332,186	0.000000	0	0	0.00
24									
25	Facilities Chg.			34			34	0	0.00
26	Minimum			0			0	0	0.00
27	Dist. Miscellaneous			11			11	0	0.00
28	Delivery subtotal	332,186		$4,359	332,186		$4,388	$29	0.67
29	Unbilled Delivery			(140)			(141)	(1)	0.71
30	Delivery subtotal w unbilled			$4,219			$4,247	$28	0.66

Energy Strong II Roll In

RATE SCHEDULE HTS-HV
HIGH TENSION SERVICE-HIGH VOLTAGE
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

		Annualized Weather Normalized			Proposed with CIP II Rollin			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
1	**Supply-BGS**	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	Generation Capacity Obl June-September	139	8.7587	$1,217	139	8.7587	$1,217	$0	0.00
3	Generation Capacity Obl October-May	280	8.7587	2,452	280	8.7587	2,452	0	0.00
4	Transmission Capacity Obl	380	8.8088	3,347	380	8.8088	3,347	0	0.00
5	BGS kWhr June-September	85,014	0.032041	2,724	85,014	0.032041	2,724	0	0.00
6	Spare	0	0.032041	0	0	0.032041	0	0	0.00
7	BGS kWhr October-May	247,172	0.039170	9,682	247,172	0.039170	9,682	0	0.00
8	Spare	0	0.039170	0	0	0.039170	0	0	0.00
9	BGS Reconciliation-CIEP	332,186	0.000000	0	332,186	0.000000	0	0	0.00
10	BGS Miscellaneous			0			0	0	0.00
11	Supply subtotal	332,186		$19,422	332,186		$19,422	$0	0.00
12	Unbilled Supply			0			0	0	0.00
13	Supply w Unbilled			$19,422			$19,422	$0	0.00
14									
15	Total Delivery + Supply	332,186		$23,641	332,186		$23,669	$28	0.12

Notes: All customers assumed to be on BGS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018

RATE SCHEDULE BPL
BODY POLITIC LIGHTING SERVICE
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

		Annualized Weather Normalized			Proposed w CIP I & II Rollin			Difference	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
1	**Delivery**	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	High Pressure Sodium	2,310.120	0	$26,297	2,310.120	0	$26,297	$0	0.00
3	Metal Halide	246.612	0	5,549	246.612	0	$5,549	0	0.00
4	Filament	173.868	0	678	173.868	0	$678	0	0.00
5	Mercury Vapor	1,671.252	0	14,445	1,671.252	0	$14,445	0	0.00
6	Fluorescent	0.216	0	3	0.216	0	$3	0	0.00
7									
8	Distribution June-September	80,289	0.015837	1,272	80,289	0.019146	$1,537	265	20.83
9	Distribution October-May	206,197	0.015837	3,266	206,197	0.019146	$3,948	682	20.88
10	SBC	286,486	0.006892	1,974	286,486	0.006892	$1,974	0	0.00
11	NGC	286,486	-0.000093	-27	286,486	-0.000093	-$27	0	0.00
12	STC-TBC	286,486	0.000000	0	286,486	0.000000	$0	0	0.00
13	STC-MTC-Tax	286,486	0.000000	0	286,486	0.000000	$0	0	0.00
14	BRDKA	286,486	0.000000	0	286,486	0.000000	$0	0	0.00
15	System Control Charge	286,486	0.000000	0	286,486	0.000000	$0	0	0.00
16	Solar Pilot Recovery Charge	286,486	0.000068	19	286,486	0.000068	$19	0	0.00
17									
18	Green Programs Recovery Charge	286,486	0.001006	288	286,486	0.001006	$288	0	0.00
19	Capital Adjustment Charge (CIP I)								
20	Distribution June-September	80,289	0.000000	0	80,289	0.000000	$0	0	0.00
21	Distribution October-May	206,197	0.000000	0	206,197	0.000000	$0	0	0.00
22	BRDKA	286,486	0.000000	0	286,486	0.000000	$0	0	0.00
23									
24	Pole Charges	418.856		1,604	418.856		1,604	0	0.00
25	Minimum			0			0	0	0.00
26	Miscellaneous			291			290	(1)	(0.34)
27	Delivery Subtotal			$55,659			$56,605	$946	1.70
28	Unbilled Delivery			31			32	1	3.23
29	Delivery Subtotal w unbilled			$55,690			$56,637	$947	1.70
30									
31	**Supply-BGS**								
32	BGS June-September	80,289	0.041926	3,366	80,289	0.041926	3,366	0	0.00
33	BGS October-May	206,197	0.046908	9,672	206,197	0.046908	9,672	0	0.00
34	BGS Reconciliation-FP	286,486	0.000000	0	286,486	0.000000	0	0	0.00
35	Miscellaneous			147			147	0	0.00
36	Supply subtotal			$13,185			$13,185	$0	0.00
37	Unbilled Supply			(40)			(40)	0	0.00
38	Supply subtotal w unbilled			$13,145			$13,145	$0	0.00
39									
40	Total Delivery + Supply	286,486		$68,835	286,486		$69,782	$947	1.38

Notes: All customers assumed to be on BGS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 3/1/2012

Energy Strong II Roll In

RATE SCHEDULE BPL-POF
BODY POLITIC LIGHTING SERVICE-POF
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

		Annualized Weather Normalized			Proposed w CIP I & II Rollin			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
1	**Delivery**	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	High Pressure Sodium	126.756	0	$183	126.756	0	$183	$0	0.00
3	Metal Halide	1.476	0	5	1.476	0	5	0	0.00
4	Filament	5.952	0	23	5.952	0	23	0	0.00
5	Mercury Vapor	4.260	0	4	4.260	0	4	0	0.00
6	Fluorescent	0.024	0	0	0.024	0	0	0	0.00
7									
8	Distribution June-September	4,011	0.006524	26.168	4,011	0.006907	27.704	2	5.87
9	Distribution October-May	10,301	0.006524	67	10,301	0.006907	71.149	4	5.87
10	SBC	14,312	0.006892	99	14,312	0.006892	98.638	0	0.00
11	NGC	14,312	-0.000093	-1	14,312	-0.000093	-1.331	0	0.00
12	STC-TBC	14,312	0.000000	0	14,312	0.000000	0.000	0	0.00
13	STC-MTC-Tax	14,312	0.000000	0	14,312	0.000000	0.000	0	0.00
14	BRDKA	14,312	0.000000	0	14,312	0.000000	0.000	0	0.00
15	System Control Charge	14,312	0.000000	0	14,312	0.000000	0.000	0	0.00
16	Solar Pilot Recovery Charge	14,312	0.000068	1	14,312	0.000068	0.973	0	0.00
17									
18	Green Programs Recovery Charge	14,312	0.001006	14	14,312	0.001006	14.398	0	0.00
19	Capital Adjustment Charge (CIP I)								
20	Distribution June-September	4,011	0.000000	0	4,011	0.000000	0.000	0	0.00
21	Distribution October-May	10,301	0.000000	0	10,301	0.000000	0.000	0	0.00
22	BRDKA	14,312	0.000000	0	14,312	0.000000	0.000	0	0.00
23									
24	Pole Charges			0			0.000	0	0.00
25	Minimum			0			0.000	0	0.00
26	Miscellaneous			1			1	0	0.10
27	Delivery Subtotal			$422			$428	$5	1.30
28	Unbilled Delivery			0			0	0	0.00
29	Delivery Subtotal w unbilled			$422			$427.532	$5	1.30
30									
31	**Supply-BGS**								
32	BGS June-September	4,011	0.041926	168	4,011	0.041926	168	0	0.00
33	BGS October-May	10,301	0.046908	483	10,301	0.046908	483	0	0.00
34	BGS Reconciliation-FP	14,312	0.000000	0	14,312	0.000000	0	0	0.00
35	Miscellaneous			1			1	0	0.00
36	Supply subtotal			$652			$652	$0	0.00
37	Unbilled Supply			0			0	0	0.00
38	Supply subtotal w unbilled			$652			$652	$0	0.00
39									
40	Total Delivery + Supply	14,312		$1,074	14,312		$1,080	$5	0.51

Notes: All customers assumed to be on BGS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018

Energy Strong II Roll In

RATE SCHEDULE PSAL
PRIVATE STREET AND AREA LIGHTING SERVICE
12 Months Ended December 31, 2012
(Units & Revenue inThousands)

		Annualized Weather Normalized			Proposed w CIP I & II Rollin			Difference	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
1	**Delivery**	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
2	High Pressure Sodium	864.576	0	$16,257	864.576	0	$16,257	$0	0.00
3	Metal Halide	234.132	0	6,259	234.132	0	6,259	0	0.00
4	Filament	1.104	0	6	1.104	0	6	0	0.00
5	Mercury Vapor	104.196	0	1,249	104.196	0	1,249	0	0.00
6	Fluorescent	0.012	0	0	0.012	0	0	0	0.00
7									
8	Distribution June-September	47,328	0.015201	719	47,328	0.018280	865	146	20.31
9	Distribution October-May	121,547	0.015201	1,848	121,547	0.018280	2,222	374	20.24
10	SBC	168,875	0.006892	1,164	168,875	0.006892	1,164	0	0.00
11	NGC	168,875	-0.000093	-16	168,875	-0.000093	-16	0	0.00
12	STC-TBC	168,875	0.000000	0	168,875	0.000000	0	0	0.00
13	STC-MTC-Tax	168,875	0.000000	0	168,875	0.000000	0	0	0.00
14	BRDKA	168,875	0.000000	0	168,875	0.000000	0	0	0.00
15	System Control Charge	168,875	0.000000	0	168,875	0.000000	0	0	0.00
16	Solar Pilot Recovery Charge	168,875	0.000068	11	168,875	0.000068	11	0	0.00
17									
18	Green Programs Recovery Charge	168,875	0.001006	170	168,875	0.001006	170	0	0.00
19	Capital Adjustment Charge (CIP I)								
20	Distribution Summer	47,328	0.000000	0	47,328	0.000000	0	0	0.00
21	Distribution Winter	121,547	0.000000	0	121,547	0.000000	0	0	0.00
22	BRDKA	168,875	0.000000	0	168,875	0.000000	0	0	0.00
23									
24	Pole Charges	443.616		3,883	443.616		3,883	0	0.00
25	Minimum			0			0	0	0.00
26	Miscellaneous			(944)			(945)	(1)	0.11
27	Delivery Subtotal			$30,606			$31,125	$519	1.70
28	Unbilled Delivery			72			73	1	1.39
29	Delivery Subtotal w unbilled			$30,678			$31,198	$520	1.70
30									
31	**Supply-BGS**								
32	BGS June-September	47,328	0.041926	1,984	47,328	0.041926	1,984	0	0.00
33	BGS October-May	121,547	0.046908	5,702	121,547	0.046908	5,702	0	0.00
34	BGS Reconciliation-FP	168,875	0.000000	0	168,875	0.000000	0	0	0.00
35	Miscellaneous			(55)			(55)	0	0.00
36	Supply subtotal			$7,631			$7,631	$0	0.00
37	Unbilled Supply			(38)			(38)	0	0.00
38	Supply subtotal w unbilled			$7,593			$7,593	$0	0.00
39									
40	Total Delivery + Supply	168,875		$38,271	168,875		$38,791	$520	1.36

Notes: All customers assumed to be on BGS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018

Gas Rate Design (Proof of Revenue by Rate Class)

Explanation of Format

The summary provides by rate schedule the Annualized Weather Normalized (all customers assumed to be on BGSS) revenue based on current tariff rates and the proposed initial rate change. The detailed rate design by rate schedule follows the summary page. The pages presented in Schedule SS-ESII-5 are the 9 relevant pages from the complete rate change workpapers from the Company's 2009 Gas Base Rate Case and have been appropriately modified per my testimony to reflect this Energy Strong filing.

Annualized Weather Normalized (all customers assumed to be on BGSS) and the Proposed Detailed Rate Design.

In the detailed rate design pages, all the components are separated into Delivery and Supply. In addition to the Distribution components of Delivery, also included in the schedule are lines for Balancing, Societal Benefits Charge, Realignment Adjustment Charge, Margin Adjustment Charge, Weather Normalization Charge, Green Programs Recovery Charge, CIP 1 Capital Adjustment Charges (CAC), Miscellaneous items, and Unbilled Revenue.

Column (1) shows the annualized weather normalized billing units. Column (2) shows present Delivery rates (without Sales and Use Tax, SUT) effective June 1, 2018. The commodity rates in the Column (2) reflect the 2012 class-weighted averages (BGSS-RSG uses the rate as of 6/1/2018 not including any BGSS-RSG Bill Credits). Column (3) presents annualized revenue assuming all customers are provided service under their applicable BGSS provision. Column (4) repeats the billing units of Column (1). Column (5) shows the proposed rates without SUT that result in the proposed revenues shown in Column (6). Columns (7) and (8) show the proposed base rate revenue increase, in thousands of dollars and percent increase, respectively, for each of the billing unit blocks.

Energy Strong II Roll In

GAS PROOF OF REVENUE
SUMMARY
GAS RATE INCREASE
12 Months Ended December 31, 2012
(Therms & Revenue - Thousands, Rate - $/Therm)

Annualized

	Rate Schedule		Weather Normalized Therms	Weather Normalized Revenue	Proposed with GSMP Roll-in Therms	Proposed with GSMP Roll-in Revenue	Increase Revenue	Increase Percent
			(1)	(2)	(3)	(4)	(5)	(6)
1	RSG		1,381,959	$1,152,074	1,381,959	$1,164,413	$12,339	1.07
2	GSG		263,897	243,770	263,897	245,733	$1,963	0.81
3	LVG		641,990	486,725	641,990	489,502	$2,777	0.57
6	SLG		682.345	671.095	682.345	679.941	$8.846	1.32
7		Subtotal	2,288,528	1,883,240	2,288,528	1,900,328	$17,088	0.91
8								
9	TSG-F		28,062	15,865.641	28,062	15,945.641	$80.000	0.50
10	TSG-NF		864,596	152,150	864,596	152,550	$400	0.26
11	CIG		58,147	25,134	58,147	25,218	$84	0.33
12		Subtotal	950,805	193,150	950,805	193,714	$564	0.29
13								
14		Totals	3,239,333	$2,076,390	3,239,333	$2,094,042	$17,652	0.85

Less change in MAC included above	$406	
Gas Revenue Requirement	$17,246	proposed roll-in

	Increase Before Mac Adjustment	Increase Above	MAC Adjustment
RSG	$12,098	$12,339	$241
GSG	1,918	1,963	45
LVG	2,665	2,777	112
SLG	8.728	8.846	0.118
Subtotal	$16,690	$17,088	$398
TSG-F	$75.240	$80.000	$4.760
TSG-NF	400	400	0
CIG	84	84	0
Subtotal	$559	$564	$5
Totals	$17,249	$17,652	$403

Notes: All customers assumed to be on BGSS.
SLG units and revenues shown to 3 decimals.
TSG-F revenues shown to 3 decimals.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018
plus applicable BGSS charges.

Energy Strong II Roll In

RATE SCHEDULE RSG
RESIDENTIAL SERVICE
12 Months Ended December 31, 2012
(Therms & Revenue - Thousands, Rate - $/Therm)

Annualized

		Weather Normalized			Proposed with GSMP Roll-in			Increase	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	19,018.784	5.46	$103,843	19,018.784	5.46	$103,843	$0	0.00
2	Distribution Charge	1,381,894	0.300343	415,042	1,381,894	0.309284	427,398	12,356	2.98
3	Off-Peak Dist	65	0.150172	10	65	0.154642	10	0	0.00
4	Balancing Charge	840,052	0.084457	70,948	840,052	0.084457	70,948	0	0.00
5	SBC	1,381,959	0.041721	57,657	1,381,959	0.041721	57,657	0	0.00
6	Realignment Adjustment	1,381,959	0.000000	0	1,381,959	0.000000	0	0	0.00
7	Margin Adjustment	1,381,959	(0.006338)	(8,759)	1,381,959	(0.006338)	(8,759)	0	0.00
8	Weather Normalization	840,052	0.021647	18,185	840,052	0.021647	18,185	0	0.00
9	Green Programs Recovery Charge	1,381,959	0.005563	7,688	1,381,959	0.005563	7,688	0	0.00
10	Capital Adjustment Charges (CIP I)								
11	Service Charge	19,018.784	0.00	0	19,018.784	0.00	0	0	0.00
12	Distribution Charge	1,381,894	0.000000	0	1,381,894	0.000000	0	0	0.00
13	Off-Peak Use	65	0.000000	0.000	65	0.000000	0.000	0	0.00
14	Margin Adjustment Charge	1,381,959	0.000000	0	1,381,959	0.000000	0	0	0.00
15									
16	Facilities Charges			0			0	0	0.00
17	Minimum			0			0	0	0.00
18	Miscellaneous			189			189	0	0.00
19	Delivery Subtotal	1,381,959		664,803	1,381,959		677,159	$12,356	1.86
20	Unbilled Delivery			5,642			5,747	105	1.86
21	Delivery Subtotal w unbilled			670,445			682,906	$12,461	1.86
22									
23	**Supply**								
24	BGSS-RSG	1,381,959	0.344195	$475,663	1,381,959	0.344195	$475,663	$0	0.00
25	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
26	BGSS Contrib. from TSG-F, TSG-NF & CIG	0	0.000000	0	1,381,959	(0.000087)	(120)	(120)	0.00
27	Off-Peak Comm. Charge	62	0.333100	21	62	0.333100	21	0	0.00
28	Capital Adjustment Charges	1,381,959	0.000000	0	1,381,959	0.000000	0	0	0.00
29	Miscellaneous			(22)			(22)	0	0.00
30	Supply subtotal	1,382,021		$475,662	1,382,021		$475,542	($120)	(0.03)
31	Unbilled Supply			5,967			5,965	(2)	(0.03)
32	Supply Subtotal w unbilled			$481,629			$481,507	($122)	(0.03)
33									
34	Total Delivery + Supply	1,381,959		$1,152,074	1,381,959		$1,164,413	$12,339	1.07
35									
36									
37									
38	Notes:								
39	All customers assumed to be on BGSS.								
40	Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018								
41	plus applicable BGSS charges.								
42									

Energy Strong II Roll In

RATE SCHEDULE GSG
GENERAL SERVICE
12 Months Ended December 31, 2012
(Therms & Revenue - Thousands, Rate - $/Therm)

Annualized

	Weather Normalized			Proposed with GSMP Roll-in			Increase	
	Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
Service Charge	1,683.715	11.28	$18,992	1,683.715	11.68	$19,666	$674	3.55
Distribution Charge - Pre 7/14/97	2,367	0.247071	585	2,367	0.251998	596	11	1.88
Distribution Charge - All Others	261,497	0.247071	64,608	261,497	0.251998	65,897	1,289	2.00
Off-Peak Dist Charge - Pre 7/14/97	0	0.123536	0	0	0.125999	0	0	0.00
Off-Peak Dist Charge - All Others	33	0.123536	4	33	0.125999	4	0	0.00
Balancing Charge	160,049	0.084457	13,517	160,049	0.084457	13,517	0	0.00
SBC	263,897	0.041721	11,010	263,897	0.041721	11,010	0	0.00
Realignment Adjustment	263,897	0.000000	0	263,897	0.000000	0	0	0.00
Margin Adjustment	263,897	(0.006338)	(1,673)	263,897	(0.006338)	(1,673)	0	0.00
Weather Normalization	160,049	0.021647	3,465	160,049	0.021647	3,465	0	0.00
Green Programs Recovery Charge	263,897	0.005563	1,468	263,897	0.005563	1468	0	0.00
Capital Adjustment Charges (CIP I)								
Service Charge	1,683.715	0.00	0	1,683.715	0.00	0	0	0.00
Distribution Charge - Pre July 14, 1997	2,367	0.000000	0	2,367	0.000000	0	0	0.00
Distribution Charge - All Others	261,497	0.000000	0	261,497	0.000000	0	0	0.00
Off-Peak Use Dist Charge - Pre July 14, 1997	0	0.000000	0	0	0.000000	0	0	0.00
Off-Peak Use Dist Charge - All Others	33	0.000000	0	33	0.000000	0	0	0.00
Margin Adjustment Charge	263,897	0.000000	0	263,897	0.000000	0	0	0.00
Facilities Charges			0			0	0	0.00
Minimum			6			6	0	0.00
Miscellaneous			(1,275)			(1,274)	1	-0.08
Delivery Subtotal	263,897		$110,707	263,897		$112,682	$1,975	1.78
Unbilled Delivery			66			67	1	1.52
Delivery Subtotal w unbilled			$110,773			$112,749	$1,976	1.78
Supply								
BGSS	263,897	0.505845	$133,491	263,897	0.505845	$133,491	$0	0.00
Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
BGSS Contrib. from TSG-F, TSG-NF & CIG	0	0.000000	0	263,897	(0.000048)	(13)	(13)	0
Capital Adjustment Charges	263,897	0.000000	0	263,897	0.000000	0	0	0
Miscellaneous			(1,705)			(1,705)	0	0.00
Supply subtotal	263,897		$131,786	263,897		$131,773	(13)	(0.01)
Unbilled Supply			1,211			1,211	0	0.00
Supply Subtotal w unbilled			$132,997			$132,984	(13)	(0.01)
Total Delivery + Supply	263,897		$243,770	263,897		$245,733	$1,963	0.81

Notes:
All customers assumed to be on BGSS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018
plus applicable BGSS charges.

Energy Strong II Roll In

RATE SCHEDULE LVG
LARGE VOLUME SERVICE
12 Months Ended December 31, 2012
(Therms & Revenue - Thousands, Rate - $/Therm)

Annualized

	Weather Normalized			Proposed with GSMP Roll-in			Increase	
	Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
Service Charge	221.074	100.12	$22,134	221.074	100.12	$22,134	$0	0.00
Demand Charge	17,876	3.7352	66,770	17,876	3.8474	68,776	2,006	3.00
Distribution Charge 0-1,000 pre 7/14/97	10,437	0.041215	430	10,437	0.042709	446	16	3.72
Distribution Charge over 1,000 pre 7/14/97	57,522	0.039335	2,263	57,522	0.040436	2,326	63	2.78
Distribution Charge 0-1,000 post 7/14/97	138,521	0.041215	5,709	138,521	0.042709	5,916	207	3.63
Distribution Charge over 1,000 post 7/14/97	435,510	0.039335	17,131	435,510	0.040436	17,610	479	2.80
Balancing Charge	321,889	0.084457	27,186	321,889	0.084457	27,186	0	0.00
SBC	641,990	0.041721	26,784	641,990	0.041721	26,784	0	0.00
Realignment Adjustment	641,990	0.000000	0	641,990	0.000000	0	0	0.00
Margin Adjustment	641,990	(0.006338)	(4,069)	641,990	(0.006338)	(4069)	0	0.00
Weather Normalization	321,889	0.021647	6,968	321,889	0.021647	6,968	0	0.00
Green Programs Recovery Charge	641,990	0.005563	3,571	641,990	0.005563	3,571	0	0.00
Capital Adjustment Charges (CIP I)								
Service Charge	221.074	0.00	0	221.074	0.00	0	0	0.00
Demand Charge	17,876	0.0000	0	17,876	0.0000	0	0	0.00
Distribution Charge 0-1,000 pre July 14, 1997	10,437	0.000000	0	10,437	0.000000	0	0	0.00
Distribution Charge over 1,000 pre July 14, 1997	57,522	0.000000	0	57,522	0.000000	0	0	0.00
Distribution Charge 0-1,000 post July 14, 1997	138,521	0.000000	0	138,521	0.000000	0	0	0.00
Distribution Charge over 1,000 post July 14, 1997	435,510	0.000000	0	435,510	0.000000	0	0	0.00
Margin Adjustment Charge	641,990	0.000000	0	641,990	0.000000	0	0	0.00
Facilities Charges			0			0	0	0.00
Minimum			227			227	0	0.00
Miscellaneous			(764)			(764)	0	0.00
Delivery Subtotal	641,990		174,340	641,990		177,111	$2,771	1.59
Unbilled Delivery			2,045			2,081	36	1.76
Delivery Subtotal w unbilled			$176,385			$179,192	$2,807	1.59
Supply								
BGSS	641,990	0.504491	$323,878	641,990	0.504491	$323,878	$0	0.00
Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
BGSS Contrib. from TSG-F, TSG-NF & CIG	0	0.000000	0	641,990	(0.000048)	(31)	(31)	0.00
Capital Adjustment Charges	641,990	0.000000	0	641,990	0.000000	0	0	0.00
Miscellaneous			2,184			2,184	0	0.00
Supply Subtotal	641,990		$326,062	641,990		$326,031	(31)	(0.01)
Unbilled Supply			(15,722)			(15,721)	1	(0.01)
Supply Subtotal w unbilled			$310,340			$310,310	(30)	(0.01)
Total Delivery + Supply	641,990		$486,725	641,990		$489,502	$2,777	0.57

Notes:
All customers assumed to be on BGSS.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018
plus applicable BGSS charges.

Energy Strong II Roll In

RATE SCHEDULE SLG
STREET LIGHTING SERVICE
12 Months Ended December 31, 2012
(Therms & Revenue - Thousands, Rate - $/Therm)

Annualized

		Weather Normalized			Proposed with GSMP Roll-in			Increase	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Single	10.392	9.6316	$100.092	10.392	9.6316	$100.092	$0.000	0.00
2	Double Inverted	0.108	9.4856	1.024	0.108	9.4856	1.024	0.000	0.00
3	Double Upright	0.588	8.3906	4.934	0.588	8.3906	4.934	0.000	0.00
4	Triple prior to 1/1/93	18.156	9.4856	172.221	18.156	9.4856	172.221	0.000	0.00
5	Triple on and after 1/1/93	0.432	61.9958	26.782	0.432	61.9958	26.782	0.000	0.00
6	Distribution Therm Charge	682.345	0.083452	56.943	682.345	0.096467	65.824	8.881	15.60
7									
8	SBC	682.345	0.041721	28.468	682.345	0.041721	28.468	0.000	0.00
9	Realignment Adjustment	682.345	0.000000	0.000	682.345	0.000000	0.000	0.000	0.00
10	Margin Adjustment	682.345	(0.006338)	(4.325)	682.345	(0.006338)	(4.325)	0.000	0.00
11									
12	Green Programs Recovery Charge	682.345	0.005563	3.796	682.345	0.005563	3.796	0.000	0.00
13	Capital Adjustment Charges (CIP I)								
14	Single-Mantle Lamp	10.392	0.0000	0.000	10.392	0.0000	0.000	0.000	0.00
15	Double-Mantle Lamp, inverted	0.108	0.0000	0.000	0.108	0.0000	0.000	0.000	0.00
16	Double Mantle Lamp, upright	0.588	0.0000	0.000	0.588	0.0000	0.000	0.000	0.00
17	Triple-Mantle Lamp, prior to January 1, 19933	18.156	0.0000	0.000	18.156	0.000000	0	0	0.00
18	Triple-Mantle Lamp, on and after January 1, 1993	0.432	0.0000	0.000	0.432	0.0000	0.000	0.000	0.00
19	Distribution Therm Charge	682.345	0.000000	0.000	682.345	0.000000	0.000	0.000	0.00
20	Margin Adjustment Charge	682.345	0.000000	0.000	682.345	0.000000	0.000	0.000	0.00
21									
22	Facilities Charges			0.000			0.000	0.000	0.00
23	Minimum			0.000			0.000	0.000	0.00
24	Miscellaneous			15.746			15.744	(0.002)	(0.01)
25	Delivery Subtotal	682.345		$405.681	682.345		$414.560	$8.879	2.19
26	Unbilled Delivery			0.000			0.000	0.000	0.00
27	Delivery Subtotal w unbilled			$405.681			$414.560	$8.879	2.19
28									
29	**Supply**								
30	BGSS	682.063	0.500402	$341.306	682.063	0.500402	$341.306	$0.000	0.00
31	Emergency Sales Service	0.000	0.000000	0.000	0.000	0.000000	0.000	0.000	0.00
32	BGSS Contrib. from TSG-F, TSG-NF & CIG	0.000	0.000000	0.000	682.345	(0.000048)	(0.033)	(0.033)	0.00
33	Capital Adjustment Charges	682.345	0.000000	0.000	682.345	0.000000	0.000	0.000	0.00
34	Miscellaneous			(75.892)			(75.892)	0.000	0.00
35	Supply Subtotal	682.063		$265.414	682.063		$265.381	($0.033)	(0.01)
36	Unbilled Supply			0.000			0.000	0.000	0.00
37	Supply Subtotal w unbilled			$265.414			$265.381	($0.033)	(0.01)
38									
39	Total Delivery + Supply	682.345		$671.095	682.345		$679.941	$8.846	1.32
40									
41									
42									

43 Notes:
44 All customers assumed to be on BGSS.
45 SLG units and revenues shown to 3 decimals.
46 Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018
47 plus applicable BGSS charges.
48

Energy Strong II Roll In

RATE SCHEDULE TSG-F
FIRM TRANSPORTATION GAS SERVICE
12 Months Ended December 31, 2012
(Therms & Revenue - Thousands, Rate - $/Therm)

Annualized

	Weather Normalized			Proposed with GSMP Roll-in			Increase	
	Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
Service Charge	0.622	536.08	$333.442	0.622	555.29	$345.390	$11.948	3.58
Demand Charge	575	1.8550	1,066.625	575	1.8982	1,091.465	24.840	2.33
Demand Charge, Agreements	16	1.6563	26.501	16	1.6563	26.501	0.000	0.00
Distribution Charge	27,094	0.070907	1,921.154	27,094	0.072560	1,965.941	44.787	2.33
Distribution Charge, Agreements	968	0.031380	30.376	968	0.031380	30.376	0.000	0.00
SBC	27,094	0.041721	1,130.389	27,094	0.041721	1,130.389	0.000	0.00
SBC, Agreements	968	0.050438	48.824	968	0.050438	48.824	0.000	0.00
Margin Adjustment	27,094	(0.006338)	(171.722)	27,094	(0.006338)	(171.722)	0.000	0.00
Margin Adjustment, Agreements	968	(0.006338)	(6.135)	968	(0.006338)	(6.135)	0.000	0.00
Green Programs Recovery Charge	27,094	0.005563	150.724	27,094	0.005563	151	0	0.00
Green Programs Recovery Charge, Agreemer	968	0.003908	3.783	968	0.003908	3.783	0.000	0.00
Capital Adjustment Charges (CIP I)								
Service Charge	0.622	0.00	0.000	0.622	0.00	0.000	0.000	0.00
Demand Charge	575	0.0000	0.000	575	0.0000	0.000	0.000	0.00
Demand Charge, Agreements	16	0.0000	0.000	16	0.0000	0.000	0.000	0.00
Distribution Charge	27,094	0.000000	0.000	27,094	0.000000	0.000	0.000	0.00
Distribution Charge, Agreements	968	0.000000	0.000	968	0.000000	0.000	0.000	0.00
Margin Adjustment Charge	27,094	0.000000	0.000	27,094	0.000000	0.000	0.000	0.00
Margin Adjustment Charge, Agreements	968	0.000000	0.000	968	0.000000	0.000	0.000	0.00
Facilities Charges			0.000			0.000	0.000	0.00
Minimum			0.000			0.000	0.000	0.00
Miscellaneous			(20.523)			(20.512)	0.011	(0.05)
Delivery Subtotal	28,062		4,513.438	28,062		4,595.024	$81.586	1.81
Unbilled Delivery			(87.722)			(89.308)	(1.586)	1.81
Delivery Subtotal w unbilled			$4,425.716			$4,505.716	$80.000	1.81
Supply								
Commodity Charge, BGSS-F	27,094	0.502621	$13,618.000	27,094	0.502621	$13,618.000	$0.000	0.00
Emergency Sales Service	0	0.000000	0.000	0	0.000000	0.000	0.000	0.00
Miscellaneous			0.000			0.000	0.000	0.00
Supply Subtotal	27,094		$13,618.000	27,094		$13,618.000	$0.000	0.00
Unbilled Supply			(2,178.075)			(2,178.075)	0.000	0.00
Supply Subtotal w unbilled			$11,439.925			$11,439.925	$0.000	0.00
Total Delivery + Supply	28,062		$15,865.641	28,062		$15,945.641	$80.000	0.50

Notes:
All customers assumed to be on BGSS.
TSG-F revenues shown to 3 decimals.
Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018
plus applicable BGSS charges.

Energy Strong II Roll In

RATE SCHEDULE TSG-NF
NON-FIRM TRANSPORTATION GAS SERVICE
12 Months Ended December 31, 2012
(Therms & Revenue - Thousands, Rate - $/Therm)

Annualized

		Weather Normalized			Proposed with GSMP Roll-in			Increase	
		Units	Rate	Revenue	Units	Rate	Revenue	Revenue	Percent
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	2.703	536.08	$1,449	2.703	555.29	$1,501	$52	3.59
2	Dist Charge 0-50,000	99,166	0.070731	7,014	99,166	0.072243	7,164	150	2.14
3	Dist Charge 0-50,000, Agreements	26,064	0.017035	444	26,064	0.017035	444	0	0.00
4	Dist Charge over 50,000	136,943	0.070731	9,686	136,943	0.072243	9,893	207	2.14
5	Dist Charge over 50,000, Agreements	602,423	0.017061	10,278	602,423	0.017061	10,278	0	0.00
6	SBC	236,109	0.041721	9,851	236,109	0.041721	9,851	0	0.00
7	SBC, Agreements	628,487	0.005338	3,355	628,487	0.005338	3,355	0	0.00
8									
9	Green Programs Recovery Charge	236,109	0.005563	1,313	236,109	0.005563	1,313	0	0.00
10	Green Programs Recovery Charge, Agreements	628,487	0.000430	270	628,487	0.000430	270	0	0.00
11	Capital Adjustment Charges (CIP I)								
12	Service Charge	2.703	0.00	0	2.703	0.00	0	0	0.00
13	Distribution Charge 0-50,000	99,166	0.000000	0	99,166	0.000000	0	0	0.00
14	Distribution Charge 0-50,000, Agreements	26,064	0.000000	0	26,064	0.000000	0	0	0.00
15	Distribution Charge over 50,000	136,943	0.000000	0	136,943	0.000000	0	0	0.00
16	Distribution Charge over 50,000, Agreements	602,423	0.000000	0	602,423	0.000000	0	0	0.00
17									
18	Facilities Charges			936			936	0	0.00
19	Minimum			0			0	0	0.00
20	Miscellaneous			(970)			(970)	0	0.00
21	Delivery Subtotal	864,596		$43,626	864,596		$44,035	$409	0.94
22	Unbilled Delivery			(1,063)			(1,072)	(9)	0.85
23	Delivery Subtotal w unbilled			$42,563			$42,963	$400	0.94
24									
25	**Supply**								
26	Commodity Charge, BGSS-I	236,109	0.475784	$112,337	236,109	0.475784	$112,337	$0	0.00
27	Emergency Sales Service	0	0.000000	0	0	0.000000	0	0	0.00
28	Pilot Use	0	1.89	0	0	1.89	0	0	0.00
29	Penalty Use	0	0.000000	0	0	0.000000	0	0	0.00
30	Miscellaneous			160			160	0	0.00
31	Supply Subtotal	236,109		$112,497	236,109		$112,497	$0	0.00
32	Unbilled Supply			(2,910)			(2,910)	0	0.00
33	Supply Subtotal w unbilled			$109,587			$109,587	$0	0.00
34									
35	Total Delivery + Supply	864,596		$152,150	864,596		$152,550	$400	0.26
36									
37									
38									
39	Notes:								
40	All customers assumed to be on BGSS.								
41	Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018								
42	plus applicable BGSS charges.								
43									

Energy Strong II Roll In

RATE SCHEDULE CIG
COGENERATION INTERRUPTIBLE SERVICE
12 Months Ended December 31, 2012
(Therms & Revenue - Thousands, Rate - $/Therm)

Annualized

		Weather Normalized			Proposed with GSMP Roll-in			Increase	
		Units	**Rate**	**Revenue**	**Units**	**Rate**	**Revenue**	**Revenue**	**Percent**
	Delivery	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=6-3)	(8=7/3)
1	Service Charge	0.240	139.85	$34	0.240	143.19	$34	$0	0.00
2	Margin 0-600,000	52,881	0.063389	3,352	52,881	0.064857	3,430	78	2.33
3	Margin over 600,000	5,266	0.052013	274	5,266	0.053218	280	6	2.19
4	Extended Gas Service	0	0.150000	0	0	0.150000	0	0	0.00
5	SBC	58,147	0.041721	2,426	58,147	0.041721	2,426	0	0.00
6									
7	Green Programs Recovery Charge	58,147	0.005563	323	58,147	0.005563	323	0	0.00
8	Capital Adjustment Charges (CIP I)								
9	Service Charge	0.240	0.00	0	0.240	0.00	0	0	0.00
10	Distribution Charge 0-600,000	52,881	0.000000	0	52,881	0.000000	0	0	0.00
11	Distribution Charge over 600,000	5,266	0.000000	0	5,266	0.000000	0	0	0.00
12	Extended Gas Service, Special Delivery Charge	0	0.000000	0	0	0.000000	0	0	0.00
13									
14	Facilities Charges			0			0	0	0.00
15	Minimum			0			0	0	0.00
16	Miscellaneous			0			0	0	0.00
17	Delivery Subtotal	58,147		$6,409	58,147		$6,493	$84	1.31
18	Unbilled Delivery			(27)			(27)	0	0.00
19	Delivery Subtotal w unbilled			$6,382			$6,466	$84	1.32
20									
21	**Supply**								
22	Commodity Component	58,147	0.320171	$18,617	58,147	0.320171	$18,617	$0	0.00
23	Pilot Use	0	1.89	0	0	1.89	0	0	0.00
24	Penalty Use	0		0	0		0	0	0.00
25	Extended Gas Service	0		0	0		0	0	0.00
26	Miscellaneous			0			0	0	0.00
27	Supply Subtotal	58,147		$18,617	58,147		$18,617	$0	0.00
28	Unbilled Supply			135			135	0	0.00
29	Supply Subtotal w unbilled			$18,752			$18,752	$0	0.00
30									
31	Total Delivery + Supply	58,147		$25,134	58,147		$25,218	$84	0.33
32									
33									
34									

35 Notes:
36 All customers assumed to be on BGSS.
37 Annualized Weather Normalized Revenue reflects Delivery rates in effect 6/1/2018
38 plus applicable BGSS charges.
39

PSE&G Energy Strong Program II
Electric Annual Tariff Rate Summary

		Present		3/1/2021		9/1/2021		3/1/2022		9/1/2022		9/1/2023		3/1/2024		9/1/2024	
Rate Schedule		Charge w/o SUT	Charge Including SUT	Charge w/o SUT	Charge Including SUT	Charge w/o SUT	Charge Including SUT	Charge w/o SUT	Charge Including SUT	Charge w/o SUT	Charge Including SUT	Charge w/o SUT	Charge Including SUT	Charge w/o SUT	Charge Including SUT	Charge w/o SUT	Charge Including SUT
RS	Service Charge	$2.27	$2.42	$2.27	$2.42	$2.27	$2.42	$2.27	$2.42	$2.27	$2.42	$2.27	$2.42	$2.27	$2.42	$2.27	$2.42
	Distribution 0-600 Sum	$0.034775	$0.037079	$0.036403	$0.038815	$0.038026	$0.040545	$0.039502	$0.042119	$0.043457	$0.046336	$0.047505	$0.050652	$0.049767	$0.053064	$0.049935	$0.053243
	Distribution 0-600 Win	$0.033344	$0.035553	$0.033344	$0.035553	$0.033344	$0.035553	$0.033344	$0.035553	$0.033344	$0.035553	$0.033344	$0.035553	$0.033344	$0.035553	$0.033344	$0.035553
	Distribution over 600 Sum	$0.038596	$0.041153	$0.040224	$0.042889	$0.041847	$0.044619	$0.043323	$0.046193	$0.047278	$0.050410	$0.051326	$0.054726	$0.053588	$0.057138	$0.053756	$0.057317
	Distribution over 600 Win	$0.033344	$0.035553	$0.033344	$0.035553	$0.033344	$0.035553	$0.033344	$0.035553	$0.033344	$0.035553	$0.033344	$0.035553	$0.033344	$0.035553	$0.033344	$0.035553
RHS	Service Charge	$2.27	$2.42	$2.27	$2.42	$2.27	$2.42	$2.27	$2.42	$2.27	$2.42	$2.27	$2.42	$2.27	$2.42	$2.27	$2.42
	Distribution 0-600 Sum	$0.048045	$0.051228	$0.048957	$0.052200	$0.049858	$0.053161	$0.050686	$0.054044	$0.052908	$0.056413	$0.055182	$0.058838	$0.056450	$0.060190	$0.056544	$0.060290
	Distribution 0-600 Win	$0.030985	$0.033038	$0.031573	$0.033665	$0.032154	$0.034284	$0.032688	$0.034854	$0.034121	$0.036382	$0.035587	$0.037945	$0.036405	$0.038817	$0.036466	$0.038882
	Distribution over 600 Sum	$0.053503	$0.057048	$0.054518	$0.058130	$0.055521	$0.059199	$0.056443	$0.060182	$0.058917	$0.062820	$0.061449	$0.065520	$0.062861	$0.067026	$0.062966	$0.067137
	Distribution over 600 Win	$0.011382	$0.012136	$0.011598	$0.012366	$0.011811	$0.012593	$0.012007	$0.012802	$0.012533	$0.013363	$0.013072	$0.013938	$0.013372	$0.014258	$0.013394	$0.014281
	Common Use	$0.053503	$0.057048	$0.054518	$0.058130	$0.055521	$0.059199	$0.056443	$0.060182	$0.058917	$0.062820	$0.061449	$0.065520	$0.062861	$0.067026	$0.062966	$0.067137
RLM	Service Charge	$13.07	$13.94	$13.07	$13.94	$13.07	$13.94	$13.07	$13.94	$13.07	$13.94	$13.07	$13.94	$13.07	$13.94	$13.07	$13.94
	Distrib. kWhr Summer On	$0.057593	$0.061409	$0.058988	$0.062896	$0.060383	$0.064383	$0.061654	$0.065739	$0.065039	$0.069348	$0.068506	$0.073045	$0.070443	$0.075110	$0.070589	$0.075266
	Distrib. kWhr Summer Off	$0.013382	$0.014269	$0.013706	$0.014614	$0.014030	$0.014959	$0.014325	$0.015274	$0.015111	$0.016112	$0.015917	$0.016972	$0.016367	$0.017451	$0.016401	$0.017488
	Distrib. kWhr Winter On	$0.013382	$0.014269	$0.013706	$0.014614	$0.014030	$0.014959	$0.014325	$0.015274	$0.015111	$0.016112	$0.015917	$0.016972	$0.016367	$0.017451	$0.016401	$0.017488
	Distrib. kWhr Winter Off	$0.013382	$0.014269	$0.013706	$0.014614	$0.014030	$0.014959	$0.014325	$0.015274	$0.015111	$0.016112	$0.015917	$0.016972	$0.016367	$0.017451	$0.016401	$0.017488
WH	Distribution	$0.044336	$0.047273	$0.045121	$0.048110	$0.045905	$0.048946	$0.046618	$0.049706	$0.048527	$0.051742	$0.050482	$0.053826	$0.051574	$0.054991	$0.051655	$0.055077
WHS	Service Charge	$0.52	$0.55	$0.52	$0.55	$0.52	$0.55	$0.52	$0.55	$0.52	$0.55	$0.52	$0.55	$0.52	$0.55	$0.52	$0.55
	Distribution	$0.000054	$0.000058	$0.000055	$0.000059	$0.000056	$0.000060	$0.000057	$0.000061	$0.000059	$0.000063	$0.000061	$0.000065	$0.000062	$0.000066	$0.000062	$0.000066
HS	Service Charge	$3.11	$3.32	$3.11	$3.32	$3.11	$3.32	$3.11	$3.32	$3.11	$3.32	$3.11	$3.32	$3.11	$3.32	$3.11	$3.32
	Distribution June-September	$0.082837	$0.088325	$0.084394	$0.089985	$0.085950	$0.091644	$0.087408	$0.093199	$0.091204	$0.097246	$0.095093	$0.101393	$0.097232	$0.103674	$0.097426	$0.103880
	Distribution October-May	$0.030413	$0.032428	$0.030985	$0.033038	$0.031556	$0.033647	$0.032091	$0.034217	$0.033485	$0.035703	$0.034913	$0.037226	$0.035698	$0.038063	$0.035769	$0.038139
GLP	Service Charge	$3.96	$4.22	$3.96	$4.22	$3.96	$4.22	$3.96	$4.22	$3.96	$4.22	$3.96	$4.22	$3.96	$4.22	$3.96	$4.22
	Service Charge-unmetered	$1.83	$1.95	$1.83	$1.95	$1.83	$1.95	$1.83	$1.95	$1.83	$1.95	$1.83	$1.95	$1.83	$1.95	$1.83	$1.95
	Service Charge-Night Use	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81
	Distrib. KW Annual	$4.0591	$4.3280	$4.1342	$4.4081	$4.2091	$4.4880	$4.2772	$4.5606	$4.4598	$4.7553	$4.6467	$4.9545	$4.7511	$5.0659	$4.7588	$5.0741
	Distrib. KW Summer	$7.5335	$8.0326	$7.6729	$8.1812	$7.8119	$8.3294	$7.9384	$8.4643	$8.2773	$8.8257	$8.6241	$9.1954	$8.8179	$9.4021	$8.8323	$9.4174
	Distribution kWhr, June-September	$0.009532	$0.010163	$0.009708	$0.010351	$0.009884	$0.010539	$0.010044	$0.010709	$0.010473	$0.011167	$0.010912	$0.011635	$0.011157	$0.011896	$0.011175	$0.011915
	Distribution kWhr, October-May	$0.003349	$0.003571	$0.003411	$0.003637	$0.003473	$0.003703	$0.003529	$0.003763	$0.003680	$0.003924	$0.003834	$0.004088	$0.003920	$0.004180	$0.003926	$0.004186
	Distribution kWhr, Night use, June-September	$0.003349	$0.003571	$0.003411	$0.003637	$0.003473	$0.003703	$0.003529	$0.003763	$0.003680	$0.003924	$0.003834	$0.004088	$0.003920	$0.004180	$0.003926	$0.004186
	Distribution kWhr, Night use, October-May	$0.003349	$0.003571	$0.003411	$0.003637	$0.003473	$0.003703	$0.003529	$0.003763	$0.003680	$0.003924	$0.003834	$0.004088	$0.003920	$0.004180	$0.003926	$0.004186
LPL-Secondary	Service Charge	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81
	Distrib. KW Annual	$3.3530	$3.5751	$3.4239	$3.6507	$3.4945	$3.7260	$3.5588	$3.7946	$3.7310	$3.9782	$3.9073	$4.1662	$4.0058	$4.2712	$4.0131	$4.2790
	Distrib. KW Summer	$7.9769	$8.5054	$8.1455	$8.6851	$8.3136	$8.8644	$8.4665	$9.0274	$8.8763	$9.4644	$9.2957	$9.9115	$9.5300	$10.1614	$9.5474	$10.1799
	Distribution kWhr	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000
LPL-Primary	Service Charge	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81	$347.77	$370.81
	Service Charge-Alternate	$17.88	$19.06	$17.88	$19.06	$17.88	$19.06	$17.88	$19.06	$17.88	$19.06	$17.88	$19.06	$17.88	$19.06	$17.88	$19.06
	Distrib. KW Annual	$1.5684	$1.6723	$1.5990	$1.7049	$1.6295	$1.7375	$1.6573	$1.7671	$1.7317	$1.8464	$1.8079	$1.9277	$1.8504	$1.9730	$1.8535	$1.9763
	Distrib. KW Summer	$8.7064	$9.2832	$8.8763	$9.4644	$9.0458	$9.6451	$9.2000	$9.8095	$9.6130	$10.2499	$10.0358	$10.7007	$10.2719	$10.9524	$10.2894	$10.9711
	Distribution kWhr	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000
HTS-Subtransmission	Service Charge	$1,911.39	$2,038.02	$1,911.39	$2,038.02	$1,911.39	$2,038.02	$1,911.39	$2,038.02	$1,911.39	$2,038.02	$1,911.39	$2,038.02	$1,911.39	$2,038.02	$1,911.39	$2,038.02
	Distrib. KW Annual	$0.9701	$1.0344	$0.9905	$1.0561	$1.0109	$1.0779	$1.0294	$1.0976	$1.0791	$1.1506	$1.1299	$1.2048	$1.1583	$1.2350	$1.1604	$1.2373
	Distrib. KW Summer	$3.5067	$3.7390	$3.5806	$3.8178	$3.6543	$3.8964	$3.7213	$3.9678	$3.9008	$4.1592	$4.0845	$4.3551	$4.1872	$4.4646	$4.1948	$4.4727
	Distribution kWhr	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000
HTS-HV	Service Charge	$1,720.25	$1,834.22	$1,720.25	$1,834.22	$1,720.25	$1,834.22	$1,720.25	$1,834.22	$1,720.25	$1,834.22	$1,720.25	$1,834.22	$1,720.25	$1,834.22	$1,720.25	$1,834.22
	Distrib. KW Annual	$0.5876	$0.6265	$0.5996	$0.6393	$0.6116	$0.6521	$0.6223	$0.6635	$0.6512	$0.6943	$0.6809	$0.7260	$0.6974	$0.7436	$0.6986	$0.7449
	Distribution kWhr	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000	$0.000000
BPL	Distribution Sum	$0.015837	$0.016886	$0.019146	$0.020414	$0.022441	$0.023928	$0.025439	$0.027124	$0.033468	$0.035685	$0.041691	$0.044453	$0.046285	$0.049351	$0.046627	$0.049716
	Distribution Winter	$0.015837	$0.016886	$0.019146	$0.020414	$0.022441	$0.023928	$0.025439	$0.027124	$0.033468	$0.035685	$0.041691	$0.044453	$0.046285	$0.049351	$0.046627	$0.049716
BPL-POF	Distribution Sum	$0.006524	$0.006956	$0.006907	$0.007365	$0.007289	$0.007772	$0.007636	$0.008142	$0.008567	$0.009135	$0.009520	$0.010151	$0.010052	$0.010718	$0.010092	$0.010761
	Distribution Winter	$0.006524	$0.006956	$0.006907	$0.007365	$0.007289	$0.007772	$0.007636	$0.008142	$0.008567	$0.009135	$0.009520	$0.010151	$0.010052	$0.010718	$0.010092	$0.010761
PSAL	Distribution Sum	$0.015201	$0.016208	$0.018280	$0.019491	$0.021353	$0.022768	$0.024148	$0.025748	$0.031633	$0.033729	$0.039295	$0.041898	$0.043577	$0.046464	$0.043896	$0.046804
	Distribution Winter	$0.015201	$0.016208	$0.018280	$0.019491	$0.021353	$0.022768	$0.024148	$0.025748	$0.031633	$0.033729	$0.039295	$0.041898	$0.043577	$0.046464	$0.043896	$0.046804

PSE&G Energy Strong Program II
Gas Annual Tariff Rate Summary

		Present		9/1/2022		9/1/2023		9/1/2024	
Rate Schedule		Charge w/o SUT	Charge Including SUT	Charge w/o SUT	Charge Including SUT	Charge w/o SUT	Charge Including SUT	Charge w/o SUT	Charge Including SUT
RSG	Service Charge	$5.46	$5.82	$5.46	$5.82	$5.46	$5.82	$5.46	$5.82
	Distribution Charges	$0.300343	$0.320241	$0.309284	$0.329774	$0.316109	$0.337051	$0.356436	$0.380050
	Balancing Charge	$0.084457	$0.090052	$0.084457	$0.090052	$0.084457	$0.090052	$0.084457	$0.090052
	Off-Peak Use	$0.150172	$0.160120	$0.154642	$0.164887	$0.158054	$0.168525	$0.178217	$0.190024
GSG	Service Charge	$11.28	$12.03	$11.68	$12.45	$11.99	$12.78	$13.85	$14.77
	Distribution Charge - Pre July 14, 1997	$0.247071	$0.263439	$0.251998	$0.268693	$0.255731	$0.272673	$0.277620	$0.296012
	Distribution Charge - All Others	$0.247071	$0.263439	$0.251998	$0.268693	$0.255731	$0.272673	$0.277620	$0.296012
	Balancing Charge	$0.084457	$0.090052	$0.084457	$0.090052	$0.084457	$0.090052	$0.084457	$0.090052
	Off-Peak Use Dist Charge - Pre July 14, 1997	$0.123536	$0.131720	$0.125999	$0.134346	$0.127866	$0.136337	$0.138810	$0.148006
	Off-Peak Use Dist Charge - All Others	$0.123536	$0.131720	$0.131720	$0.125999	$0.127866	$0.136337	$0.138810	$0.148006
LVG	Service Charge	$100.12	$106.75	$100.12	$106.75	$100.12	$106.75	$100.12	$106.75
	Demand Charge	$3.7352	$3.9827	$3.8474	$4.1023	$3.9331	$4.1937	$4.4395	$4.7336
	Distribution Charge 0-1,000 pre July 14, 1997	$0.041215	$0.043945	$0.042709	$0.045538	$0.045155	$0.048147	$0.054851	$0.058485
	Distribution Charge over 1,000 pre July 14, 1997	$0.039335	$0.041941	$0.040436	$0.043115	$0.040883	$0.043591	$0.044978	$0.047958
	Distribution Charge 0-1,000 post July 14, 1997	$0.041215	$0.043945	$0.042709	$0.045538	$0.045155	$0.048147	$0.054851	$0.058485
	Distribution Charge over 1,000 post July 14, 1997	$0.039335	$0.041941	$0.040436	$0.043115	$0.040883	$0.043591	$0.044978	$0.047958
	Balancing Charge	$0.084457	$0.090052	$0.084457	$0.090052	$0.084457	$0.090052	$0.084457	$0.090052
SLG	Single-Mantle Lamp	$9.6316	$10.2697	$9.6316	$10.2697	$9.6316	$10.2697	$9.6316	$10.2697
	Double-Mantle Lamp, inverted	$9.4856	$10.1140	$9.4856	$10.1140	$9.4856	$10.1140	$9.4856	$10.1140
	Double Mantle Lamp, upright	$8.3906	$8.9465	$8.3906	$8.9465	$8.3906	$8.9465	$8.3906	$8.9465
	Triple-Mantle Lamp, prior to January 1, 19933	$9.4856	$10.1140	$9.4856	$10.1140	$9.4856	$10.1140	$9.4856	$10.1140
	Triple-Mantle Lamp, on and after January 1, 1993	$61.9958	$66.1030	$61.9958	$66.1030	$61.9958	$66.1030	$61.9958	$66.1030
	Distribution Therm Charge	$0.083452	$0.088981	$0.096467	$0.102858	$0.106399	$0.113448	$0.165073	$0.176009
TSG-F	Service Charge	$536.08	$571.60	$555.29	$592.08	$570.12	$607.89	$658.54	$702.17
	Demand Charge	$1.8550	$1.9779	$1.8982	$2.0240	$1.9311	$2.0590	$2.1274	$2.2683
	Distribution Charges	$0.070907	$0.075605	$0.072560	$0.077367	$0.073817	$0.078707	$0.081322	$0.086710
TSG-NF	Service Charge	$536.08	$571.60	$555.29	$592.08	$570.12	$607.89	$658.54	$702.17
	Distribution Charge 0-50,000	$0.070731	$0.075417	$0.072243	$0.077029	$0.073399	$0.078262	$0.080184	$0.085496
	Distribution Charge over 50,000	$0.070731	$0.075417	$0.072243	$0.077029	$0.073399	$0.078262	$0.080184	$0.085496
	Special Provision (d)	$1.89	$2.02	$1.89	$2.02	$1.89	$2.02	$1.89	$2.02
CIG	Service Charge	$139.85	$149.12	$143.19	$152.68	$145.74	$155.40	$160.81	$171.46
	Distribution Charge 0-600,000	$0.063389	$0.067589	$0.064857	$0.069154	$0.065958	$0.070328	$0.072549	$0.077355
	Distribution Charge over 600,000	$0.052013	$0.055459	$0.053218	$0.056744	$0.054122	$0.057708	$0.059530	$0.063474
	Special Provision (c) 1st para	$1.89	$2.02	$1.89	$2.02	$1.89	$2.02	$1.89	$2.02
BGSS RSG	Commodity Charge including Losses	$0.346015	$0.368938	$0.345926	$0.368844	$0.345859	$0.368772	$0.345457	$0.368344
CSG	Service Charge	$ 536.08	$ 571.60	$ 555.29	$ 592.08	$ 570.12	$ 607.89	$ 658.54	$ 702.17

PSE&G Energy Strong Program II
Electric Annual Bill Impact Summary

Incremental Typical Annual Bill Impacts
By Rate Class

Rate Class	If Your Annual kWhr Use Is:	Current Bill ($)	Roll-In Date 3/1/2021	9/1/2021	3/1/2022	9/1/2022	9/1/2023	3/1/2024	9/1/2024	End of Program Customer Bill ($)
RS	7,200	1,215.76	5.20	5.20	4.72	12.64	12.96	7.24	0.56	1,264.28
RHS	13,804	1,854.08	7.64	7.44	6.88	18.44	18.92	10.52	0.80	1,924.72
RLM	19,012	3,178.04	10.60	10.49	9.68	25.54	26.28	14.56	1.11	3,276.30
GLP	29,767	4,743.64	18.24	18.36	16.52	44.44	45.48	25.48	1.84	4,914.00
LPL-S	1,300,225	163,769.44	463.96	462.56	420.88	1,127.60	1,154.12	644.76	47.88	168,091.20
LPL-P	4,453,779	454,846.32	935.72	934.00	849.12	2,274.80	2,329.68	1,299.88	96.00	463,565.52
HTS-S	23,759,526	2,118,750.12	2,796.96	2,800.64	2,536.88	6,813.84	6,970.80	3,889.76	292.24	2,144,851.24

Incremental Annual Percent Change From Current Typical Annual Bill
By Rate Class[1]

Rate Class	If Your Annual kWhr Use Is:	Current Bill ($)	Roll-In Date 3/1/2021	9/1/2021	3/1/2022	9/1/2022	9/1/2023	3/1/2024	9/1/2024	Total Percent Change from Current Bill
RS	7,200	1,215.76	0.43%	0.43%	0.39%	1.04%	1.07%	0.60%	0.05%	4.01%
RHS	13,804	1,854.08	0.41%	0.40%	0.37%	0.99%	1.02%	0.57%	0.04%	3.80%
RLM	19,012	3,178.04	0.33%	0.33%	0.30%	0.80%	0.83%	0.46%	0.03%	3.08%
GLP	29,767	4,743.64	0.38%	0.39%	0.35%	0.94%	0.96%	0.54%	0.04%	3.60%
LPL-S	1,300,225	163,769.44	0.28%	0.28%	0.26%	0.69%	0.70%	0.39%	0.03%	2.63%
LPL-P	4,453,779	454,846.32	0.21%	0.21%	0.19%	0.50%	0.51%	0.29%	0.02%	1.93%
HTS-S	23,759,526	2,118,750.12	0.13%	0.13%	0.12%	0.32%	0.33%	0.18%	0.01%	1.22%

PSE&G Energy Strong Program II
Electric Annual Bill Impact Summary

Schedule SS-ESII-8

Cumulative Typical Annual Bill Impacts
By Rate Class

Rate Class	If Your Annual kWhr Use Is:	Current Bill ($)	Roll-In Date 3/1/2021	9/1/2021	3/1/2022	9/1/2022	9/1/2023	3/1/2024	9/1/2024
RS	7,200	1,215.76	5.20	10.40	15.12	27.76	40.72	47.96	48.52
RHS	13,804	1,854.08	7.64	15.08	21.96	40.40	59.32	69.84	70.64
RLM	19,012	3,178.04	10.60	21.09	30.77	56.31	82.59	97.15	98.26
GLP	29,767	4,743.64	18.24	36.60	53.12	97.56	143.04	168.52	170.36
LPL-S	1,300,225	163,769.44	463.96	926.52	1,347.40	2,475.00	3,629.12	4,273.88	4,321.76
LPL-P	4,453,779	454,846.32	935.72	1,869.72	2,718.84	4,993.64	7,323.32	8,623.20	8,719.20
HTS-S	23,759,526	2,118,750.12	2,796.96	5,597.60	8,134.48	14,948.32	21,919.12	25,808.88	26,101.12

Cumulative Percent Changes From Current Typical Annual Bill
By Rate Class

Rate Class	If Your Annual kWhr Use Is:	Current Bill ($)	Roll-In Date 3/1/2021	9/1/2021	3/1/2022	9/1/2022	9/1/2023	3/1/2024	9/1/2024
RS	7,200	1,215.76	0.43%	0.86%	1.24%	2.28%	3.35%	3.94%	3.99%
RHS	13,804	1,854.08	0.41%	0.81%	1.18%	2.18%	3.20%	3.77%	3.81%
RLM	19,012	3,178.04	0.33%	0.66%	0.97%	1.77%	2.60%	3.06%	3.09%
GLP	29,767	4,743.64	0.38%	0.77%	1.12%	2.06%	3.02%	3.55%	3.59%
LPL-S	1,300,225	163,769.44	0.28%	0.57%	0.82%	1.51%	2.22%	2.61%	2.64%
LPL-P	4,453,779	454,846.32	0.21%	0.41%	0.60%	1.10%	1.61%	1.90%	1.92%
HTS-S	23,759,526	2,118,750.12	0.13%	0.26%	0.38%	0.71%	1.03%	1.22%	1.23%

[1]Total percent change may not tie to the cumulative percent due to rounding

PSE&G Energy Strong Program II
Gas Annual Bill Impact Summary

Incremental Typical Annual Bill Impacts By Rate Class

Rate Class	If Your Annual Therm Use Is:	Current Bill ($)	Roll-In Date 9/1/2022	Roll-In Date 9/1/2023	Roll-In Date 9/1/2024	End of Program Customer Bill ($)
RSG	1,010	879.16	9.52	7.34	42.94	938.96
GSG	1,882	1,867.06	14.83	11.40	67.35	1,960.64
LVG	34,846	28,866.59	161.32	130.47	745.09	29,903.47
TSG-F	541,882	360,720.40	1,724.63	1,313.75	7,847.54	371,606.32
TSG-NF	1,118,999	658,924.53	2,049.60	1,569.47	9,226.16	671,769.76
CIG	2,907,364	1,254,298.56	4,308.07	3,231.61	19,343.29	1,281,181.53

Cumulative Typical Annual Bill Impacts By Rate Class

Rate Class	If Your Annual Therm Use Is:	Current Bill ($)	Roll-In Date 9/1/2022	Roll-In Date 9/1/2023	Roll-In Date 9/1/2024
RSG	1,010	879.16	9.52	16.86	59.80
GSG	1,882	1,867.06	14.83	26.23	93.58
LVG	34,846	28,866.59	161.32	291.79	1,036.88
TSG-F	541,882	360,720.40	1,724.63	3,038.38	10,885.92
TSG-NF	1,118,999	658,924.53	2,049.60	3,619.07	12,845.23
CIG	2,907,364	1,254,298.56	4,308.07	7,539.68	26,882.97

Incremental Annual Percent Change From Current Typical Annual Bill By Rate Class[1]

Rate Class	If Your Annual Therm Use Is:	Current Bill ($)	Roll-In Date 9/1/2022	Roll-In Date 9/1/2023	Roll-In Date 9/1/2024	Total Percent Change from Current Bill
RSG	1,010	879.16	1.08%	0.83%	4.88%	6.79%
GSG	1,882	1,867.06	0.79%	0.61%	3.61%	5.01%
LVG	34,846	28,866.59	0.56%	0.45%	2.58%	3.59%
TSG-F	541,882	360,720.40	0.48%	0.36%	2.18%	3.02%
TSG-NF	1,118,999	658,924.53	0.31%	0.24%	1.40%	1.95%
CIG	2,907,364	1,254,298.56	0.34%	0.26%	1.54%	2.14%

Cumulative Percent Changes From Current Typical Annual Bill By Rate Class

Rate Class	If Your Annual Therm Use Is:	Current Bill ($)	Roll-In Date 9/1/2022	Roll-In Date 9/1/2023	Roll-In Date 9/1/2024
RSG	1,010	879.16	1.08%	1.92%	6.80%
GSG	1,882	1,867.06	0.79%	1.40%	5.01%
LVG	34,846	28,866.59	0.56%	1.01%	3.59%
TSG-F	541,882	360,720.40	0.48%	0.84%	3.02%
TSG-NF	1,118,999	658,924.53	0.31%	0.55%	1.95%
CIG	2,907,364	1,254,298.56	0.34%	0.60%	2.14%

[1]Total percent change may not tie to the cumulative percent due to rounding

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
WILLIAM D. WILLIAMS
ASSOCIATE VICE PRESIDENT – ASSET MANAGEMENT PRACTICE OF BLACK & VEATCH CORPORATION

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

A. My name is William D. Williams. My business address is 1120 Sanctuary Parkway, Alpharetta, GA 30009. I am an Associate Vice President in the Asset Management Practice of Black & Veatch Corporation. I obtained my Bachelor of Arts degree in Geography from Royal Holloway and Bedford New College, University of London, United Kingdom in 1989.

Q. Please describe your responsibilities in the Black & Veatch Asset Management Practice.

A. My primary responsibilities are business development and project delivery within the Asset Management Practice. This typically entails managing multi-disciplinary teams to deliver programs of work for utility clients.

Q. Please describe your professional experience.

A. I have extensive experience in asset management planning, including capital prioritization, asset failure analysis, risk assessment, performance benchmarking, maintenance optimization, business planning, serviceability assessment, whole life costing, operational efficiency, International Organization for Standardization standard for asset management maturity assessments (ISO55001), business change management, and infrastructure rehabilitation. Prior to joining Black & Veatch, I served as the Vice President and Global Director of Asset Management of water and power for Halcrow, a multinational engineering and consultancy company. Prior to that, I was Director of Asset Management and Planning and an Executive Director at the United Kingdom Water Research Centre. I have more than 27 years of asset management experience. Attached as Schedule WDW-ESII-1 is my resume and list of prior testimonies.

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

A. My testimony will summarize the methodology used by Black & Veatch to develop a risk-based model of PSE&G's electric distribution assets and describe the use of the model in identifying priority investments in "inside plant", i.e., substation assets for the Energy Strong II program (ES II), and estimating the risk reduction attributable to both the ES II life cycle substation projects and Station Flood and Storm Surge Mitigation projects PSE&G has identified. This risk-based model is referred to as the "Risk Model" in my testimony. As part of this testimony, I: (1) discuss the analysis Black & Veatch conducted for PSE&G; (2) describe the Risk Model and how it is used to assess risk reduction for both the lifecycle Substation Upgrades 26/4 kV Stations and Station Flood and Storm Surge Mitigation subprograms of PSE&G's ES II program; (3) describe how risk is defined, with emphasis on consequence of failure ("CoF") and likelihood of failure ("LoF"); (4) explain how the calculations in the Risk Model are performed; and (5) describe the results and conclusions of the Risk Model. Additionally, I am sponsoring Schedule WDW-ESII-2, which supports the aforementioned components of my testimony.

Q. Describe the analysis Black & Veatch conducted for PSE&G.

A. Black & Veatch conducted a risk-based assessment of the distribution system in order to help PSE&G identify and prioritize assets for end of life replacement, including the life cycle substation upgrade aspects of the ES II program. Utility investment programs based upon this risk-based approach have been approved in regulatory proceedings in Indiana and Pennsylvania. This risk-based approach is based on the ISO31000 framework for risk management and the ISO55001 standard for asset management practices. The objective of ISO55001 is to guide and influence the design of an organization's asset management activities by embedding a number of key concepts and fundamental principles within a framework (referred to by ISO55001 as a management system) for asset management. ISO55001 defines asset management as the "*coordinated activities of an organization to realize value from assets.*" It also describes asset management as balancing the costs, opportunities and risks against the desired performance of the assets to achieve the organization's strategic objectives. The ISO31000 standard focuses on the risk management process, which is grouped into a series of activities, namely: communication and consultation, establishing the context, risk assessment, risk treatment, and monitoring and review. As part of the approach, Black & Veatch's tool captures the current state of the assets and produces results that can be easily communicated to key stakeholders. This communication is a critical link discussed in the ISO31000 framework.

Black & Veatch used the collected asset data from PSE&G for its overhead system, underground system, and substations as inputs to the model. The project team, under my direction, developed an asset-level Risk Model that prioritizes assets based on the amount of risk they pose to the PSE&G system. The framework for the Risk Model was developed through close collaboration with PSE&G subject matter experts.

Q. Please describe the Risk Model Black & Veatch used to conduct its analysis.

A. The Risk Model consists of asset data, such as serial numbers, model numbers, voltage class, manufacturing and/or installation year, location, condition data and other information that allows the Black & Veatch and PSE&G teams to individually assess each asset and determine its CoF and LoF. An asset's CoF is derived by developing several criticality criteria that consider the impact to PSE&G's customers or its system should the asset fail, such as the amount of system load lost, any environmental impacts, or the number of customers that would experience an outage. The criteria are assigned a weighting factor and each asset in the Risk Model is given a score for each of these criteria. This process produces a weighted score for CoF for each asset. Additionally, assets are given a LoF based on their age and Asset Health Index ("AHI"), which is derived from available asset condition information, inspection information, service history or test data.

The Risk Model uses this information to calculate risk for each of the assets that have been included in the model. Based on the risk score, replacement cost, and other resource constraints, the Risk Model provides a prioritized list of all these assets and highlights the highest risk assets.

The model can also be used to represent the risk reduction achieved by specific investment programs, like the replacement of particular classes of substations. The output of the Risk Model was reviewed and was one of the tools used by PSE&G to develop the life cycle aspect of ES II. This is described in more detail below and in the direct testimony of Edward F. Gray.

Q. How does the risk model identify projects to be included in the ES II?

A. Specifically, the Risk Model has been used to assess the risk reduction for both the Substation Upgrades 26/4 kV Stations and Station Flood and Storm Surge Mitigation subprograms. The Risk Model generated a prioritized list, based on the risk score and replacement cost, of the 32,785 substation assets included in the model.

Using the Risk Model and other management knowledge and tools, the PSE&G team developed the life cycle aspects of the ES II electric subprogram. The model was also used to quantify the risk reduction achieved by replacing complete substations of particular classes. The risk reduction achieved by these substation replacement programs was compared to a "do nothing" scenario (as a baseline) to arrive at the relative risk reduction. This approach is described in Section 1.1 of Schedule WDW-ESII-2.

Costs for replacing the substations were based on actual estimates provided by PSE&G for each substation that was identified for replacement. Utilizing the Risk Model in this manner provided PSE&G a tool to develop the life cycle aspects of the ES II electric subprogram that cost effectively reduces its overall system risk.

Q. How is asset risk defined?

A. In the Risk Model, asset risk is defined as:

Asset Risk = Consequence of Failure x Likelihood of Failure

The total system asset risk is the summation of asset risks for individual groups of assets identified for investment, which collectively form the entire portfolio of the electric distribution system assets included in the Risk Model.

Q. How was CoF estimated?

A. The consequences of failure (CoF) of PSE&G's substation assets were scored on a scale of 1 (low) to 5 (high). Scores were developed using several consequence criteria factors. Each of these factors was given a weighting and the sum of these weighted scores was used to determine the CoF score for each asset. The CoF for a specific asset represents the total impact to PSE&G's system if the asset fails. That impact is estimated using qualitative and quantitative arguments and analysis. PSE&G subject matter experts and staff provided Black & Veatch input on the CoF criteria, associated definitions for the ordinal scale values (1-5), scoring of each asset, and determination of the CoF criteria weighting factors. Based on this input, consequence criteria were developed for each asset. The criteria consider a number of factors related to an asset failure on the system and are categorized as follows:

- Customer Impact – The customer's impact criteria consider three factors that impact customers on the system, which are Customer Type, Peak/connected Load, and Number of Customers.
- Reliability – The reliability impact criteria consider three factors that impact reliability of the system, which are Replacement Availability, Restoration Time, and Restoration Complexity.
- Safety – The safety impact criteria consider the impact to safety associated with an asset failure. Safety criticality is based on the risk of direct harm to personnel, or the public, as a result of asset failure (e.g. conductor drop, fire or explosion).
- Environmental – The environmental impact criteria consider the impact to the environment associated with an asset failure. Environmental criticality is based on the environmental impact caused by asset failure and considers the impact of failure and the sensitivity of the environment in the vicinity of the asset.

Each asset is rated using these criteria on a 1 (low) to 5 (high) scale and the ratings are used to calculate a cumulative CoF score for each asset. The detailed definitions for each system asset in the Risk Model are included in Schedule WDW-ESII-2.

Q. How was likelihood of failure estimated?

A. LoF is the second component of asset risk. For this assessment, the defined and modeled risk event was based on a deterioration-related asset failure, where the asset has reached end of life and must be replaced. To help determine reasonable estimates of end-of-life timeframes and likelihood, survivor curves are used widely in the utility industry to forecast end of life and the deterioration of assets for likelihood of failure asset management analyses. Survivor curves create a continuous function relating to the likelihood of an asset failure event (a value from 0 to

1) to the time period in years of this likelihood. Survivor curves were developed for each PSE&G asset class included in the model that represented end of life probabilities for these assets to be used in the LoF analysis. In order to generate the likelihood of failure percentages for the Risk Model, a survivor curve model calculates the discrete failure probabilities by year, and then sums the cumulative likelihood of failure for the next 5 years for each individual asset (assuming a 5 year capital plan duration). This means that the likelihood of failure is calculated looking into the future along the survivor curve from the current functional age of each asset in the Risk Model. Each survivor curve used in the analysis combines the Iowa survivor curve type, by asset class, from PSE&G's depreciation study filed in its 2018 base rate case with the average service life of that asset class from Black & Veatch data on 15 U.S. electric utilities. The likelihood of failure scores were then calculated for each asset based on its actual or its effective age and asset class survivor curve.

Q. What is an Iowa survivor curve?

A. Survivor curves are widely used by utilities as part of depreciation studies to estimate the probable average service life of different assets and set depreciation rates in line with those lives. The continuing property records ("CPR") for a utility track the initial purchase date of equipment to its retirement from service. A plot of the retirement dispersions calculated from the CPR data for each FERC account is used to determine "best fit" Iowa survivor curves and probable life. Referred to as "Iowa" curves, the Iowa Type Curves are a codified system commonly used in utility depreciation analysis. They were developed at the University of Iowa in the early 1900s, hence the name "Iowa curve." Iowa survivor curves were chosen for each asset class based on its FERC account. Each asset class has a survivor curve that is representative of its CPR retirement history.

Q. What is the difference between actual age and effective age?

A. As part of the analysis, Black & Veatch obtained manufacturing and/or install date information for each of the distribution assets included in the Risk Model to calculate its chronological or "actual" age. While the use of actual age is appropriate in determining LoF, the estimation of LoF can be enhanced by incorporating available information on asset health or condition obtained from utility inspections, service history, test data, or other sources. For example, if transformers and circuit breakers had sufficient data, Black & Veatch could develop an "effective age" based on the asset's condition. Thus, if an asset's actual age exceeds the median useful life, but PSE&G's data shows it to be in good condition based on maintenance and monitoring activities, its actual age is reduced to create an effective age that is more representative of its current health. For all assets where sufficient data was available, the "effective age" was calculated and used to assess LoF. When this data was not available, then chronological age was used to assess LoF.

Q. Please explain how the age of PSE&G's assets compares to other utilities.

A. PSE&G has a history of running its equipment longer than many comparable utilities. The ages used for numerous assets in the Risk Model are older than comparable assets of utilities for which Black & Veatch has performed similar evaluations over the past 5 years.

Q. Please explain how the asset risk calculations were used.

A. With the CoF and LoF of each asset assessed as described above, the asset risk scores and a total system asset risk score were then calculated. Through this process, the model identified the highest risk assets. The PSE&G team utilized the initial Risk Model results as a tool in developing the life cycle aspects of ES II.

Q. What was the purpose of conducting the risk analysis in this manner?

A. Applying a risk-based approach to developing and optimizing capital budgets is recognized within the industry as good management practice under several industry asset management standards such as the ISO55000 and Publically Available Standard 55 (PAS55). Rather than the traditional approach of reliance on historic spending levels and priorities, adopting a risk-based approach enables utilities to both optimize the level of overall expenditure as well as targeting that expenditure on areas of the distribution system where system risk is reduced most. The ISO31000 provides a standardized definition of risk (CoF x LoF) and an approach for risk assessment and management which has been widely adopted by the utility industry. By these standards, utilization of a risk-based approach is good management practice.

Q. What were the results of the risk analysis for substations?

A. Based on using the risk analysis to quantify the risk reduction for substation projects PSE&G identified, the Black & Veatch team determined that the ES II Substation Subprogram would reduce the total substation likelihood and consequence of failure in excess of 20% over the study period compared to the “do nothing” scenario (baseline). Please refer to Section 4.1.5 of Schedule WDW-ESII-2 for details.

Q. Does this conclude your testimony?

A. Yes.

ASSOCIATE VICE PRESIDENT

Expertise:
Asset Management Planning; Resilience Planning; Risk Based Capital Prioritization/Planning; Risk Management

Education
Bachelor of Arts, Geography, Royal Holloway and Bedford New College, 1989, United Kingdom

Total Years of Experience
27.1

Years of Experience with B&V
6.2

Language Capabilities
English

Office Location
, Georgia

William D Williams, BA (Hons), FRGS

Mr. Williams has extensive experience in asset management planning, including asset failure analysis, risk assessment, performance benchmarking, maintenance optimization, business planning, serviceability assessment, whole life costing, operational efficiency, business change management and infrastructure rehabilitation.

Prior to joining Black & Veatch, Mr. Williams served the Vice President and Global Director of Asset Management for water and power for Halcrow. He was previously Director of Asset Management and Planning at the UK Water Research Centre. Mr. Williams has more than 27 years asset management experience and is a committee member of the International Water Association Asset Management Specialist Group.

PROJECT EXPERIENCE

California Department of Water Resources; Dam Safety Program; California, United States; 2017-In-Progress

Project Director - Black & Veatch. Led a multi-disciplinary team of asset management consultants and Dam Safety Professionals to undertake a gap analysis of California DWR's Dam Safety program using the ISO55001 Framework. This involved working with the consultant and client team to define good practice dam lifecycle management and undertaking a cross enterprise assessment of the current maturity of the Owners Dam Safety Plan and Dam Safety Program. Specific recommendations were developed that will closer align DWR's Dam Safety and Asset Management Programs.

Pacific Gas and Electric (PG&E); 115kV Cables Seismic Resilience Study; California, United States; 2016-In-Progress

Project Director - Black & Veatch. The project entails the development of a risk based model to examine the current resilience of the 115kV system in downtown San Francisco for seismic resilience. A number of potential replacement and rehabilitation approaches have been developed by an engineering feasibility study, which were compared to select the combination that produced the most favorable cost/risk balance.

Vectren Corporation; Long Term Electric Transmission and Distribution Capital Plan; Indiana; 2016-2017

Project Director. Project Director for development of a risk-based electric T&D capital plan for Vectren's long-term electric T&D investments. Oversaw the work to develop a T&D system risk model to quantify the incremental benefits of Vectren's 7-year capital plan. This work provided a means of justifying the need for Vectren's investments in its system provided risk reduction benefits and focused spending on high risk assets. Mr Williams provided testimony for Vectren's TDSIC filing.

HRSD; Asset Management Program; Virginia; 2016-In-Progress

Project Director. Managing a three year ISO 55001 gap assessment and Asset Management Program Implementation. The program includes, developing an Asset Management Framework that includes a Policy, Strategic Asset Management Plan (SAMP) capital prioritization, maintenance optimization, data management and the development of Asset Management Plans.

California Department of Water Resources; Asset Management Program; California; 2015-In-Progress

Project Director. Phase A of the program included an ISO 55001 gap assessment, development of an Asset Management Policy, Program Development Strategy that included an organizational review, and an Implementation Plan that included over 20 improvement initiatives and a Management of Change Plan. Phase B is now commencing with implementation of the Management of Change Plan, development of the Asset Management Framework, levels of service, Risk Framework and Maintenance Management Strategy.

Tulsa Metropolitan Utility Authority; Utility Enterprise Initiative; Tulsa, Oklahoma; 2013-In-Progress

Principal Director. Principal Director for team developing and implementing an asset management change program and capital prioritization plan for the Water and Sewer Department and the Engineering Department of the city of Tulsa. Led Publicly Available Specification (PAS 55) assessment and roadmap development, and currently developing an asset management framework including strategy and objectives. Recently updated assessment using International Organization for Standardization (ISO) 55001.

Public Service Electric and Gas (PSE&G); Electric and gas distribution risk based asset lifecycle planning; New Jersey, Long Island, United States; 2016-2017

Project Director - Black & Veatch. The project focused on the development of risk based asset lifecycle plans for the electric distribution systems in New Jersey and Long Island and the gas distribution system in New Jersey. This involved the development of likelihood and consequence criteria and the development of an excel based model that enabled risk to be assessed at the asset level as well as for replacement programs e.g. at the substation level. Asset lifecycle plans for various asset classes were produced and BV trained PSE&G staff in the use of the model.

Palm Beach County Water Utilities Department; Asset Management Strategy; Florida; 2014-2016

Project Director. Led the development of an ISO55001 based asset management strategy. Project involved undertaking a gap analysis, developing specific improvement recommendations and developing a prioritized improvement roadmap.

ATCO Pipelines; U.S./Canada ISO 55001 Assessment; Global; 2015-2016

Project Director. Managed a team that undertook an ISO 55001 gap assessment of ATCO Pipelines, a gas transmission company in Alberta Canada. The project developed a prioritized implementation roadmap for ATCO Pipelines to achieve ISO 55001 certification.

Duquesne Light Company; Asset Management Projects; United States; 2015

Project Director. Managed a team of consultants to undertake a two phased project aimed at improving Duquesne lights approach to asset management. The first phase entailed the development of a risk based prioritization model of their T&D network. The model was used to develop a Long Term Investment Plan (LTIP) which ultimately gained Regulatory approval. Phase two entailed an ISO 55001 gap assessment of Duquesne Light's transmission and distribution (T&D) organization, and organizational review of the existing Asset Management group. The output of Phase two was an improvement plan based on gaps identified.

Salt River Project (SRP); Substation Transformer Asset Investment Management Project; Arizona; 2013-2015

Project Director. Project Director for this study to review the way SRP manages its 230 and 500 kilovolt transformer fleet. The review considered the complete asset lifecycle, from how SRP engineers, specifies, procures, installs, commissions, maintains, tests and manages these critical assets. This work included a review of SRP's processes, procedures, organizational structure, data and systems to compare them to best practice and identification of any gaps that need to be filled in the short-term and whether there are any longer term improvement opportunities. Mr. Williams' roles have included managing all Black & Veatch resources committed to the project, developing recommendations regarding SRP's transformer asset management program, and he also provided assistance with the development of an asset management-related risk management framework.

Duke Energy Indiana; Long Term Electric Transmission and Distribution Capital Plan; Indiana; 2013-2015

Project Director. Project Director for development of a risk-based electric T&D capital plan that included Duke's long-term electric T&D investments. Black & Veatch developed a T&D system risk model to quantify the incremental benefits of Duke's 7-year capital plan. This work provided evidence of how Duke's investments in its system provided risk reduction benefits and focused spending on high risk assets. As project manager, he also led delivery of an economic impact assessment and cost estimate review of the $1.9 billion capital plan.

Northern Indiana Public Service Company (NIPSCO); Long Term Electric Transmission and Distribution Capital Plan; Indiana; 2013-2015

Project Director. Project Director for development of a long-term $1 billion plus capital plan for NIPSCO's electric transmission and distribution (T&D) infrastructure. Black & Veatch developed a system risk model to analyze and score asset risk across the T&D system for NIPSCO. This model highlights the risk reduction benefits achieved through NIPSCO's long-term asset replacement program, which is focused on addressing high risk assets that are nearing the end of their useful life.

Portland General Electric (PGE); T&D Asset Management Maturity Assessment; Oregon; 2014

Project Director. Project Director on an asset management program maturity assessment for PGE, using the PAS 55 framework. This project also included the identification of gaps, development of improvement initiatives and a related roadmap, and the development of a business case.

BC Hydro; T&D Asset Management Maturity Assessment; British Columbia, Canada; 2014

Project Director. Project Director for a T&D Asset Management Maturity Assessment project at BC Hydro. As part of this project, Black & Veatch is assessing the maturity of BC Hydro's asset management program relative to the PAS 55 framework. This project also includes the identification of good practice gaps.

Salt River Project; Budget Optimization Pilot Program; Arizona; 2014

Project Director. Project Director for a Budget Optimization Pilot Program at SRP. Black & Veatch is working with a SRP working group to evaluate a process and related analytical tool for the optimization of a select group of generation, transmission and distribution capital projects and programs.

Iberdrola USA; Capital Planning and Risk Assessment Training; United States; 2013-2014

Project Director- Black & Veatch. The project involved performing a gap analysis of Iberdrola's approach to investment planning for electricity and gas transmission and distribution assets. It entailed the facilitation of training workshops on investment planning best practice including the development of best practice case studies. During the course of the work, criticality criteria were developed for asset risk assessment and workshops were undertaken to refine the criteria. In addition an asset risk register spreadsheet tool was developed and training in its use was provided.

City of Santa Ana; Asset Rehabilitation and Replacement Assessment; Santa Ana, California; 2013

Specialist. Provided specialist advice to the project team in evaluating the improvement and application of asset data and information systems for use in assessing useful remaining life of infrastructure assets. The project focused on establishing the city's capital and maintenance programs over the next 10-20 years, defining the scale and timing of rehabilitation and replacement need and using this information to develop a rate case. The next phase of the project will be assisting the city to put in place a good practice approach to data improvement, and the establishment of an asset management program.

Miami Dade Water and Sewer Department (MDWASD); CIP Implementation and Gap Analysis; Miami, Florida; 2012

Project Director. The project undertook a review of MDWASD's approach to Capital Improvement Program development, including budgeting and project implementation, focused on high-level review of processes and organizational structure. Specific process and organizational changes were recommended to improve investment targeting and efficiency of project delivery

Grupo Mexico; U.S./Mexico Asset Management Organizational Design; Global; 2012

Subject Matter Expert. Grupo Mexico is a mining company that developed a gas fired power plant with the aim of generating their own power. The project involved the development of an asset management organization (México Generadora de Energía) to manage the power plant. Specific activities included the development of an organizational structure, job descriptions and roles/responsibilities, as well as an assessment of the required asset management structure, processes and procedures using the PAS 55 asset management standard as a checklist.

Winston-Salem/Forsyth County Utilities Commission; PAS 55 Assessment; North Carolina; 2012

IAM Endorsed Assessor Assessor. Led a team undertaking a PAS 55-based assessment of Winston Salem's approach to management of their wastewater collection system. The project scope included undertaking staff interviews, documentation review, and a gap analysis using the PAS 55 AM standard.

Hillsborough County; Bond Engineer; Florida; 2010-2011

Project Director - Halcrow Inc. Project Director for this five-year project, which entailed assessing the operational efficiency and capital maintenance policies of Hillsborough County for Bond Rating purposes. $800,000.

Gwinnett County Department of Water Resources (GCDWR); Asset Management Strategy Development; Georgia; 2010-2011

Project Director - Halcrow Inc. Project Director for this study to develop an asset management strategy for the Department of Water Resources. The project covered all aspects of the County's water, wastewater and storm water assets and was aimed at establishing Gwinnett County's current level of asset management "maturity" and comparing this to U.S. and international best practice to identify and prioritize areas for improvement. The study produced a five- year strategy and improvement roadmap to help GCDWR adopt best-in-class management approaches across its operations.

Abu Dhabi Transmission and Dispatch Company (TRANSCO); PAS 55 Study; United Arab Emirates; 2010-2011

Project Director - Halcrow Inc. Project Director for this study for the Abu Dhabi Transmission and Dispatch Company to both assist it achieve PAS 55 accreditation and improve the efficiency of its capital delivery and assurance processes. The project included five main PAS 55 accreditation work streams, including developing policy and standards framework and standards, auditing, and review of management processes and understanding preliminary assessments of PAS 55 compliance prior to certification. TRANSCO identified the success of this project as key to attaining its vision of being acknowledged as the region's leader in the provision of transmission services.

Tampa Bay Water (TBW); Energy Efficiency Study; Florida; 2010

Specialist - Halcrow Inc. Provided specialist technical input to this study, which investigated the options available to Tampa Bay Water to reduce energy use. Primarily focused in two areas, the project investigated the feasibility and application of renewable energy and the cost benefit of pump replacement. Mr. Williams' inputs centered on the application of advanced genetic algorithm optimization tools to access the potential for operational savings. The project identified potential savings of 25-35 percent. Project deliverables included an energy efficiency roadmap for TBW over the next 10 years.

Weber Valley Water Authority; Condition Assessment of the Weber and Davis Aqueduct; Salt Lake City, Utah; 2010

Project Director - Halcrow Inc. Project Director for this study to determine the condition and subsequent rehabilitation needs of the Weber and Davis Aqueducts in Salt Lake City, Utah. Covering some 26 miles, the aqueducts were constructed in the late 1950s to provide irrigation, municipal and industrial water to residents and industry. The aqueducts have been in continual service since and little was known about their condition. A risk-based prioritization was applied to identify aqueduct segments that were highest priority for inspection. Leading edge technology was used to assess the internal and external condition. Results were used to develop a predictive model of useful remaining life, which is used to identify necessary capital and maintenance expenditures over the next 30-year period.

Hillsborough County; Assessment; Florida; 2008

Project Director - Halcrow Inc. Project Director for the development of a system-level useful remaining life model, as well as a compilation of an asset inventory database with condition and data confidence grading. The project included strategic planning, field survey, asset inventory, water distribution system assets, useful remaining life, criticality, advanced condition and system improvement. Additionally a cost benefit analysis was performed to identify priorities and scale of investment required.

City of Sandy Springs; Water Management Plan and Main Condition Assessment; Georgia; 2008

Project Director - Halcrow Inc. Project Director for development of design criteria, a water service options assessment and planning sequence, options and assessment for the city to better plan future water demands. The project consisted of creating a hydraulic model of the system, developing water demand scenarios, evaluating system deficiencies, identifying CIPs to remediate deficiencies, assessing system conditions, valuation of assets, assessing future alternatives for system improvements, finding new sources of water and making recommendations to the city.

Gwinnett County Department of Water Resources; Business Case Evaluation of Mid-Term and Long-Term Capital Improvement Program; Georgia; 2008

Project Director - Halcrow Inc. Project Director who assisted the DWR in a Business Case Evaluation of mid-term and long-term CIP for the water distribution system. A calibrated hydraulic model of the water distribution system was used to evaluate system performance for future demand conditions, identifying areas that did not meet criteria and developing potential improvement projects to resolve non-compliance issues.

Sydney Water; Assessment; Sydney, New South Wales, Australia; 2007

Project Director - Halcrow Inc. Project Director for an audit of Sydney Water's asset management plans on behalf of its economic regulator, IPART, where adequacy and ability to meet requirements of an external review process could be improved. The audit required integrated planning, analysis and data quality, long-term planning, policy, procedures, strategy documents, technical reports, asset registers, asset condition and performance data, operation and maintenance plans, investment programs and customer service information.

Thames Water; Strategic Asset Management; Reading, England, United Kingdom; 2007

Project Director - Halcrow Inc. Project Director for the strategic asset management process for Thames Water's Strategic Business Plan. Responsibilities included performing survey and desk study of infrastructure and non-infrastructure throughout the Thames Water region, development of a risk-based assessment approach for maintenance prioritization, collecting field data, compiling an asset risk database and investment quantification and prioritization at a company level.

Computer Aided Rehabilitation of Sewer Networks (CARE-S); Global; 2006

Project Director - WRc PLC. Project Director, responsible for aiding research institutes, universities and water utilities from 10 European countries in the development of computerized decision support tools for optimization of sewer system maintenance and repair. Additional responsibilities included developing tools for prioritization of rehabilitation schemes and developing investment programs for the European Commission.

Development of Risk Impact Matrices; United Kingdom; 2006

Project Director - WRc PLC. Project Director responsible for evaluating the cost consequences of failure of serviceability criteria as part of a United Kingdom Water Industry Research (UKWIR) Common Framework compliant risk-based approach to investment planning.

Atomic Weapons Establishment; Infrastructure Re-development Project; Aldermaston, England, United Kingdom; 2006

Project Director - WRc PLC. Project Director responsible for directing the Water Research Center WRc team in evaluating and selecting capital and operational schemes for water and wastewater asset upgrading on behalf of the Atomic Weapons Establishment.

Computer Aided Rehabilitation of Water Networks (CARE-W); Global; 2005

Team Member - WRc PLC. Team member responsible for aiding research institutes, universities and water utilities from eight European countries in the development of computerized decision support tools for optimization of the maintenance and repair of water distribution networks.

Assessment of Sewage Pumping Station Risk; West Sussex, England, United Kingdom; 2005

Project Director - WRc PLC. Project Director responsible for use of risk-based (Failure Modes & Effects Analysis [FMEA]) approaches to assess non-routine risks associated with sewage pumping station equipment failures and load capacity relationships. Duties included costing and scenario analysis in accordance with the requirements of the UKWIR Common Framework for Capital Maintenance Planning.

Scottish Water; Ensuring the Suitability of Asset Condition and Performance Data; Scotland, United Kingdom; 2005

Project Director - WRc PLC. Project Director responsible for providing a comprehensive review of regulatory reporting regimes within the UK, assessing data systems and holdings for Scottish Water, reappraising the condition and performance of Scotland's non infrastructure (works) asset stock, and creating an action plan to allow Scottish Water to implement risk and serviceability-based asset management.

Benchmarking Capital Expenditure (Capex) for Operational Expenditure (Opex) Efficiency; Scotland, United Kingdom; 2005

Project Director - WRc PLC. Project Director responsible for identifying the gap between the capital investment required to adopt best practices and achieving regulatory compliance at the lowest capex. Additional responsibilities included identifying current best practice using both WRc's expertise and process benchmarking, and identifying how to achieve optimum balance between capex and opex.

OFWAT Training Course: 'Introduction to the Water Industry'; United Kingdom; 2005

Project Director - WRc PLC. Project Director responsible for overseeing the delivery of a three-day training course for a UK Economic Regulator (OFWAT) that provided new and non- specialist OFWAT staff with an overview of the industry including regulatory, legal and technical issues.

Urban Pollution Management (UPM) and Control; United Kingdom; 2001

Business Manager - WRc PLC. Business Manager responsible for technical and strategic development of the UPM capability within WRc. Also served as a committee member of the International Modeling User Group (IMUG) and a member of the Foundation for Water Research (FWR) Waste Water Forum.

River Tame and Hockley Brook; UPM Scoping Study; Birmingham, England, United Kingdom; 1999

Project Director - WRc PLC. Project Director for the study applying "FAST UPM" assessment techniques to investment planning in a large scale, complex, highly urbanized catchment in the Birmingham conurbation.

Bolton Republican Town Committee (RTC); Demonstration Study; United Kingdom; 1998

Technical Advisor - WRc PLC. Technical Advisor to client's project team to support RTC control strategy development and approve negotiations with the Environment Agency (EA). Responsibilities included advising WRc project team on RTC risk assessment, FMEA.

EU Technology Valuation Project (TVP); Global; 1998

Project Director - WRc PLC. Europe-wide project integrating modeling of the main components of the wastewater collection, treatment and receiving water systems through the use of pilot demonstration studies in Italy, Spain, Sweden, France and the UK (Oldham).

Active Control of Large Urban Drainage Systems Utilizing the Spatial Variation of Inflows; United Kingdom; 1995

Contract Manager - WRc PLC. Contract Manager for a research project which developed a planning methodology incorporating spatially varying rainfall data and Real Time Control techniques to meet environmental objectives at significantly reduced cost.

Sewerage Rehabilitation Manual, Third Edition; Global; 1994

Project Director - WRc PLC. Project Director who was responsible for updating the hydraulic analysis sections of the third edition of the Sewerage Rehabilitation Manual.

National Rivers Authority Research and Development Project; Regulation of Real Time Control in Urban Drainage System; United Kingdom; 1994

Team Member - WRc PLC. Team member of a small team, which identified the issues pertinent to the Regulation of Real Time Control Schemes for urban drainage systems. Responsibilities included suggesting actions and research to allow effective approval to be set for drainage systems.

European Union SP 226; Project Bolton SPRINT; Bolton, England, United Kingdom; 1993

Project Modeler - WRc PLC. Project modeler for the investigation of the application of RTC technology to the Bolton sewer system. Responsibilities involved the use of the MOUSE software suite and working closely with North West Water staff who were the end users of the system.

PRESENTATIONS & PUBLICATIONS

Williams, William: Malkawi, Anas. The Development of HRSD's Asset Management Program: Tricon August 2017

Williams, William: Malkawi, Anas. The Development of HRSD's Asset Management Program: Tricon August 2017

Williams William, McLaughlin Patrick, Wernsing, Richard "The Risk of Getting Old" Risk Based Capital Prioritization: Distributech February 2017

Williams, William: "A Strategy for Asset Replacement and Maintenance Prioritization": Distrubutech February 2015

Jones, Martin, Williams, William and Stillman, Jeff: "the Evolution of Asset Management in the Water Industry" Article - Journal of the American Water Works Association. June 2014

Williams, William: "Business Case Development for Infrastructure Investment" North East Transformer Group Conference. October 2013

M. Jones, W. Williams. "Opportunity of ISO 55001." UIM/SWIM Conference. November 2013

M. Jones, M. Elenbaas, W. Williams, A. Mire. "Risk Based Asset Investment Approaches to Improve System Resilience." The CIP Report. September 2013

M. Jones, W. Williams, J. Stillman. "Asset Management - How U.S. Utilities Can Leverage International Experience." Journal American Water Works Association. May 2013

M. Jones, W. Williams. "Asset Management Leadership - PAS 55 as a Framework." Western Energy. March 2012

Williams, William; Martin Jones, Scott Anderson. "Managing Critical Power Transformer Assets: A Good Practice Asset Management Framework for Salt River Project." Electric Energy T&D. November 2012

Williams, William. "The Benefits of Asset Management for Georgia Utilities of All Sizes." The Georgia Operator. June 2009

Williams, William. "Asset Inventory and Condition Assessment of Pressure Pipes/Force Mains in Hillsborough County, Florida." Georgia Association of Water Professionals Spring Conference. April 2009

Williams, William. "Asset Inventory and Condition Assessment of Pressure Pipes/Force Mains in Hillsborough County, Florida." Annual Conference, New England Water Environment Association. January 2009

Williams, William. "The Sewerage Rehabilitation Manual, 4th Edition." WRc. January 2001

PSE&G'S SUBSTATION ASSET RISK MODEL

B&V PROJECT NO. 189025

PREPARED FOR

Public Service Electric and Gas Company (PSE&G)

8 JUNE 2018

BLACK & VEATCH

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1.0 Executive Summary

Black & Veatch conducted a risk-based assessment of Public Service Electric and Gas Company's (PSE&G's) electric distribution system assets. The approach involved development of an asset-based Risk Model that combines the consequence of an asset's failure with its likelihood of failure. Assets with a high consequence and likelihood of failure post the highest risk to PSE&G's distribution system. This scenario is depicted on Figure 1-1.

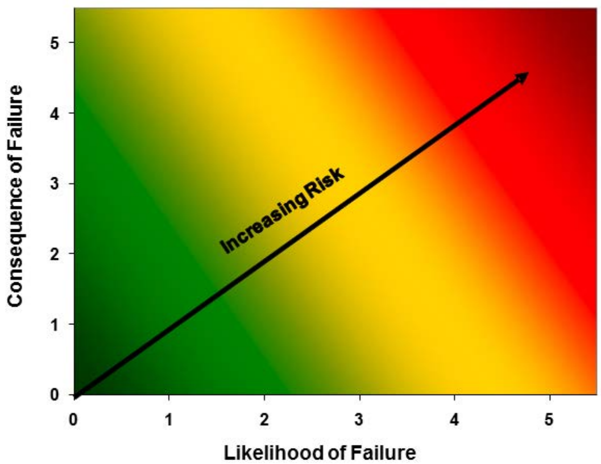

Figure 1-1 Sample Risk Rating Matrix ("Risk Matrix")

This report focuses on the way the Risk Model has been used to help develop the Substation subprogram for the Energy Strong II ("ES II") Electric Program. PSE&G's distribution system consists of 26 kV, 13 kV, and 4 kV voltages, and a low voltage secondary system. The system is comprised of a variety of assets that work together to deliver electricity to the customer. The substation asset Risk Model discussed in this report concerns inside plant assets that have been prioritized based on the approach in Section 2.0. Table 1-1 lists the asset classes included in the substation Risk Model. A brief description of the assets is included in Section 3.0.

Table 1-1 Distribution System Asset Classes

PLANT CATEGORY	ASSET CLASS
Inside Plant (i.e., substations)	Substation transformers Circuit breakers Distribution relays Disconnect switches Regulators Reactors Load tap changers (LTCs) Bus ducts

1.1 ENERGY STRONG II RISK REDUCTION

The Risk Model was used to help develop the Substation Upgrades 26/4 kV Stations and Station Flood and Storm Surge Mitigation subprograms of the ES II Electric Program. Black & Veatch and PSE&G decided that quantifying the risk reduction of these subprograms with the Risk Model is an appropriate way to support the many benefits provided by these subprograms. As shown in this report, each of the subprograms quantified here individually reduce PSE&G's substation risk. The aggregate effect of these subprograms is also provided here to show the cumulative effect of these subprograms on PSE&G's substation risk.

The following are two types of risk matrices included in the assessment of the ES II Electric Program:

- 2023 Station Class Risk Matrix ("Heat Map")– Do Nothing: This risk matrix represents the number of assets that will be in each consequence of failure (COF) (1 through 5) and likelihood of failure (LOF) (1 through 5) box in 2023 if PSE&G chose not to proactively replace assets over the next 5 years and instead chose to repair assets that fail.
- 2023 Energy Strong II Electric Program Risk Matrix: This risk matrix represents the number of assets that will be in each COF (1 through 5) and LOF (1 through 5) box in 2023 after PSE&G has invested in both the substation replacements and eliminations under the Substation Upgrades 26/4 kV Stations Subprogram, and the station upgrades under the Station Flood and Storm Surge Mitigation subprogram. For each of the subprograms, the Risk Model reflects replacement or elimination of the asset classes discussed in Section 3.0 of this report.

Figure 1-2 shows the 2023 Station Class Risk Matrix for the Do Nothing scenario. There are a total of 32,785 substation assets in the Risk Model, which accounts for all of PSE&G's distribution substation assets.

2023 Station Class Heat Map - Do Nothing

Consequence Failure	Likelihood of Failure 1	2	3	4	5
5	0	0	0	0	0
4	19	84	2	2	57
3	309	786	64	1	832
2	4,190	4,180	690	149	1,781
1	9,559	6,058	1,297	824	1,901

Total Asset Records 32,785

Figure 1-2 2023 Station Class Risk Map - Do Nothing

The effects of both subprograms are illustrated on Figure 1-3. The effects of the subprograms can be seen by comparing this risk matrix to the Do Nothing scenario. For example, in the Do Nothing scenario, there are 832 assets that have a COF of 3 and a LOF of 5, whereas in the ES II Risk Matrix there are 555 assets, which means 277 assets in the COF 3, LOF 5 box are being replaced or eliminated. Those assets being replaced are moved into the COF 3, LOF 1 box since they will be replaced with new assets. The assets that are being eliminated have been removed from the risk matrix altogether.

2023 Energy Strong II Heat Map

Consequence of Failure	Likelihood of Failure 1	2	3	4	5
5	0	0	0	0	0
4	48	72	2	0	38
3	672	688	59	0	555
2	5,265	3,734	547	141	1,158
1	10,958	5,307	1,125	804	1,341

Total Asset Records **32,514**

Figure 1-3 2023 Energy Strong II Electric Program Risk Matrix

Figure 1-4 illustrates the annual expenditures and risk reduction achieved by the ES II Substation Upgrades 26/4 kV Stations and Station Flood and Storm Surge Mitigation subprograms. As shown on the figure, expenditures are assumed to begin in 2020. Therefore, the overall risk profile is the same as the Do Nothing scenario until 2020. Once the subprograms are completed at the end of 2023, the overall substation assets risk profile is reduced to a level below the current risk level, resulting in a 24 percent risk reduction over the 5 year analysis period.

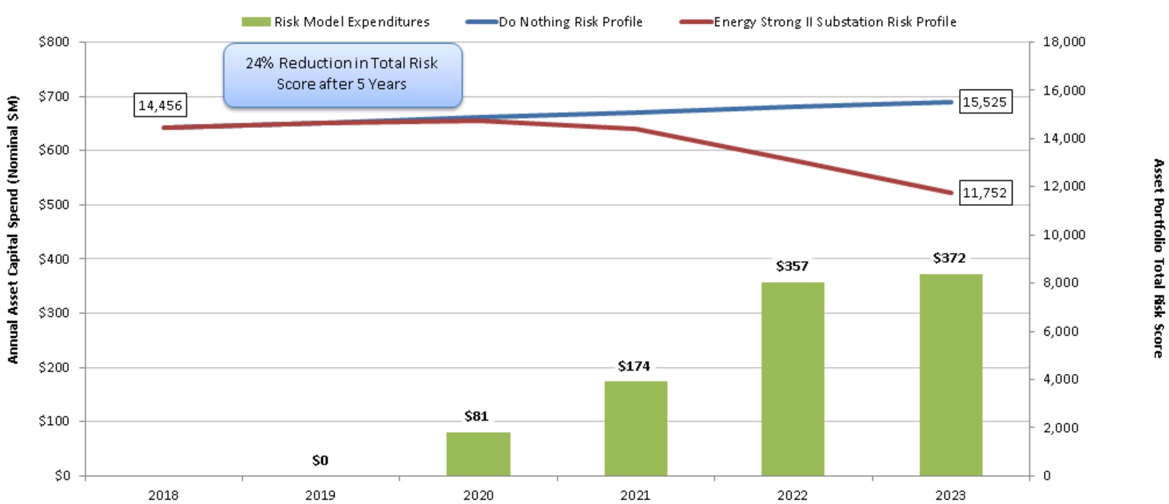

Figure 1-4 Energy Strong II Electric Program Risk Reduction

The following sections of this report detail the methodology undertaken by PSE&G and Black & Veatch in the development and application of the asset Risk Model.

2.0 Risk Model Approach

2.1 OVERVIEW

This section provides an overview of the PSE&G distribution asset Risk Model framework and risk matrix scoring approach. This risk-based prioritization approach is used as a guide by PSE&G in its long-term plan to identify the highest risk assets within the electric distribution system and will help focus replacement capital spending towards the assets with the highest risk of failure.

PSE&G's system is older; many of the distribution system assets were installed as early as the 1930s and 1940s. The Risk Model was used to quantify the risk associated with these assets, evaluate how this risk increases with time under a Do Nothing scenario, and examine the risk reduction achieved by PSE&G's programmatic replacement of substation assets.

2.1.1 An Introduction to Risk Management

Risk is defined as the combination of the likelihood of an event occurring and the impact or consequence caused by the event.

Risk management is a systematic method for identifying, assessing, mitigating, and monitoring the risks involved in any activity or process.

The basic framework for risk assessment uses the following process:

- Risk identification.
- Risk assessment.
- Development of risk mitigation measures.
- Implementation of mitigation measures.

One method for assessing risks is to use a risk matrix of likelihood against consequence. Both of these measures (likelihood and consequence) can be divided into five levels that PSE&G uses to view risk and is aligned according to its acceptable risk tolerance levels as shown in Table 2-1.

Table 2-1 Consequence of Failure Impact Level Definitions

IMPACT	DEFINITION
1 – Incidental	There is little to no consequence of failure.
2 – Minor	The consequence of failure is restricted to a minimum.
3 – Moderate	The consequence of failure is within acceptable or tolerable limits.
4 – Major	The consequence of failure is near the limit of acceptability or tolerability.
5 – Severe	The consequence of failure is unacceptable or above tolerable limits.

When defining the scores for likelihoods of events occurring they also need to be clearly defined. Once defined, these measures can then be plotted for each asset in a risk rating matrix like that shown on Figure 2-2.

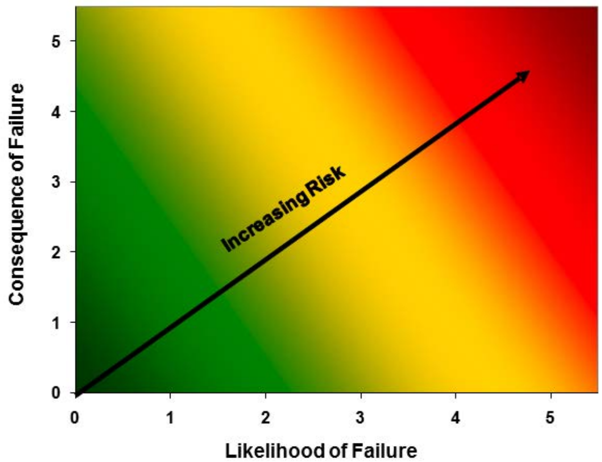

Figure 2-1 Sample Risk Rating Matrix

Figure 2-3 illustrates how the conceptual Figure 2-2 steps through the different risk ratings as the color changes when risk increases.

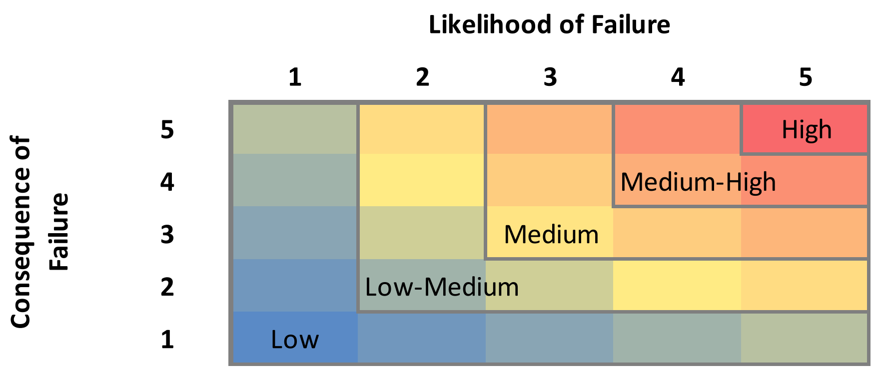

Figure 2-2 Risk Rating Levels in Risk Matrix

2.2 RISK FACTORS – LIKELIHOOD OF AN EVENT

The first step in the risk assessment is estimating the likelihood of the event occurring. The likelihood is selected based on the definition of risk to the organization and contained in the risk matrix.

For this study, the risk event is predominately an age- or deterioration-related asset failure that results in an outage and is not repairable. This is referred to by some in the energy industry as "end-of-life" failure. In the distribution Risk Model, end-of-life is defined as violent asset failure, failure to operate when called upon, failure of maintenance testing/inspection, or generally considered to be past useful life by industry standards. Survivor curves are used widely in the utility industry to forecast end-of-life LOF and deterioration of assets for asset management analyses. To develop end-of-life probabilities for PSE&G's distribution assets, survivor curves were developed and used. This process is described in detail in Subsection 2.2.1.

PSE&G has a history of longer, useful lives for equipment than many comparable utilities. Black & Veatch has developed failure curves that reflect PSE&Gs experience in running equipment longer than other utilities. Over time, PSE&G can gather more asset condition data to refine these curves and further improve predictability.

2.2.1 Overview of Survivor Curves and Likelihood of Failure Calculations/Approach

2.2.1.1 Survivor Curves

Survivor curves are widely used by utilities as part of depreciation studies to estimate the probable average service life of different assets and set depreciation rates in line with those lives. Service life is defined as the period in years from the initial purchase to the retirement date from service as recorded in the property records unit of the utility. A plot of the retirement dispersions calculated from the continuing property records (CPR) data for each FERC account is used to determine "best fit" Iowa survivor (mortality) curves and probable life. Referred to as Iowa curves, the Iowa type curves are a codified system commonly used in utility depreciation analyses. An example survivor curve for distribution power transformers is shown on Figure 2-4.

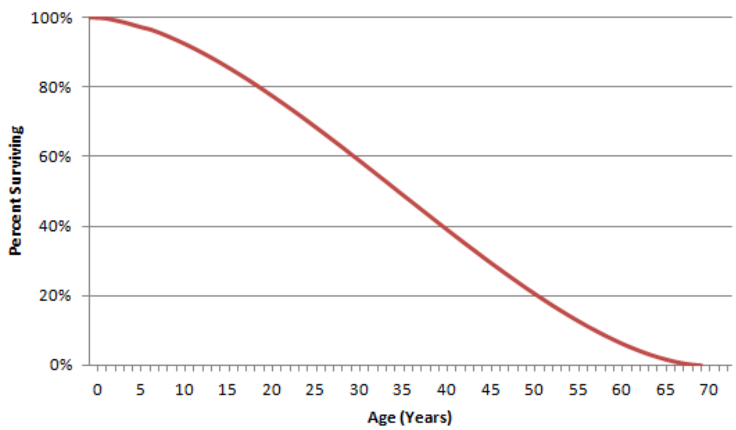

Figure 2-3 Example Survivor Curve

The survivor curves for each asset are based on the depreciable life estimates from the recent PSE&G depreciation study submitted with the Company's currently pending base rate case. The study was also used to determine the average service lives for the asset classes included in the Risk Model. For the PSE&G Risk Model, average lives are used in deriving the appropriate survivor curves. The reference to "curve type" refers to the fact that differently shaped survivor curves are selected for different asset classes and vintages of asset classes, such as Right-Modal Curve ("R" Curves), Left-Modal Curve ("L" Curves), Symmetrical Curve ("S" Curve), and Original Modal Curve ("O" Curve).

2.2.1.2 Likelihood of Failure Calculations Using Survivor Curves

Survivor curves can be used to calculate age-based LOF percentages. Black & Veatch used this approach in identifying LOF percentages for the PSE&G distribution Risk Model. An important concept to understand when using survivor curves and explaining them is that the survivor curve percentages on the y-axis show the "percent surviving" among a given asset population.

The percentage should not be read as an LOF directly from the curve. For example, Figure 2-5 shows a survivor curve of 138 kV transformers. The diamond near the center of the curve highlights an asset with an age of 35 years. Even though the y-axis value for a 35 year transformer is 50 percent, that value should not be read as the LOF. Since this is a survivor curve and not a likelihood distribution, the conclusion that a transformer that is 35 years old has a 50 percent LOF is not accurate. Rather, calculating the LOF for a given asset age is derived by looking forward along the curve and disregarding the portion of the curve to the left of age 35 (refer to Figure 2-6).

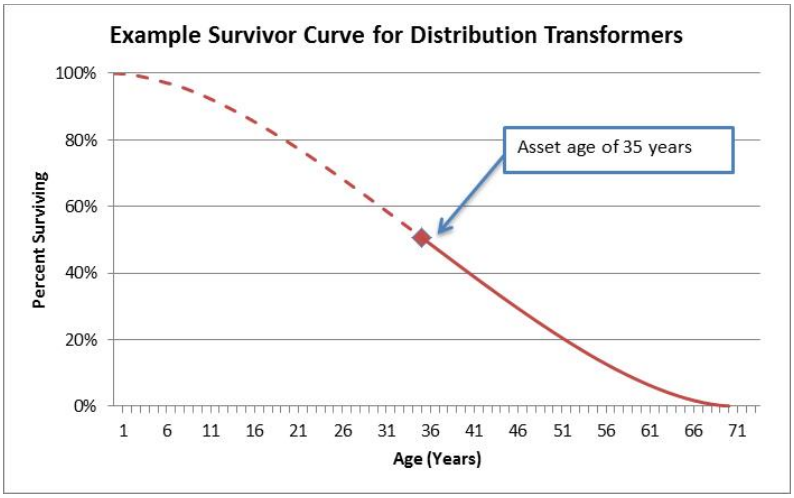

Figure 2-4 Example Distribution Transformer Survivor Curve

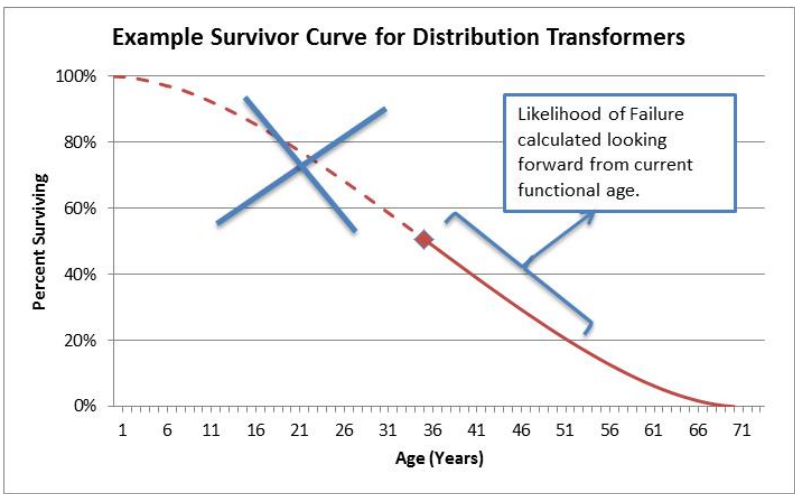

Figure 2-5 Likelihood of Failure Calculated Using the Portion of the S-Curve to the Right of the Current Age

The PSE&G Risk Model combines COF scoring factors with an age-based LOF to arrive at a risk score for each asset in the Risk Model. To generate the LOF percentages for the Risk Model, a survivor curve model calculates the discrete failure probabilities by year, and then sums the cumulative LOF for the next 5 years for each individual asset (for a 5 year capital plan duration). The age of each specific asset is incorporated in these calculations. Table 2-2 shows example calculations of a 5 year cumulative LOF, while Figure 2-7 visually demonstrates the calculations.

Table 2-2 Example LOF Calculations

Current Age of Asset

38

Age	Forecast Year	Discrete LoF	Cumulative LoF
38	1	4%	4%
39	2	4%	8%
40	3	4%	12%
41	4	4%	16%
42	5	4%	**20%**

Building upon the survivor curve example on Figure 2-6, Figure 2-7 focuses on the LOF calculations. It highlights how discrete annual LOF percentages are calculated for each year in the future. Each blue vertical line illustrates this annual calculation. These are then summed over the next 5 years to arrive at a 5 year cumulative LOF for each asset that is loaded into the Risk Model.

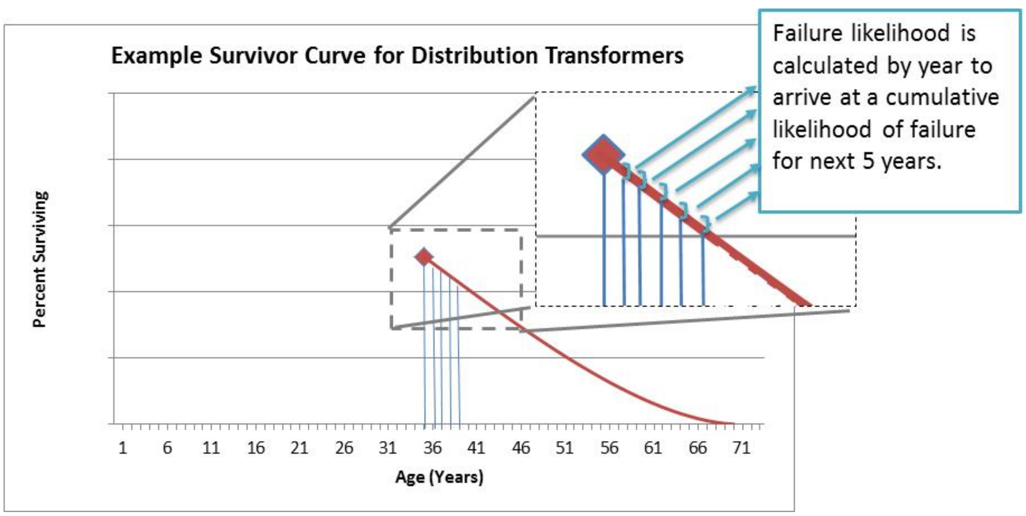

Figure 2-6 Discrete Annual Likelihood of Failure Percentages Summed into a 5 Year Cumulative Value for Use in the Risk Model

These calculations can be plotted as a curve shown on Figure 2-8 below.

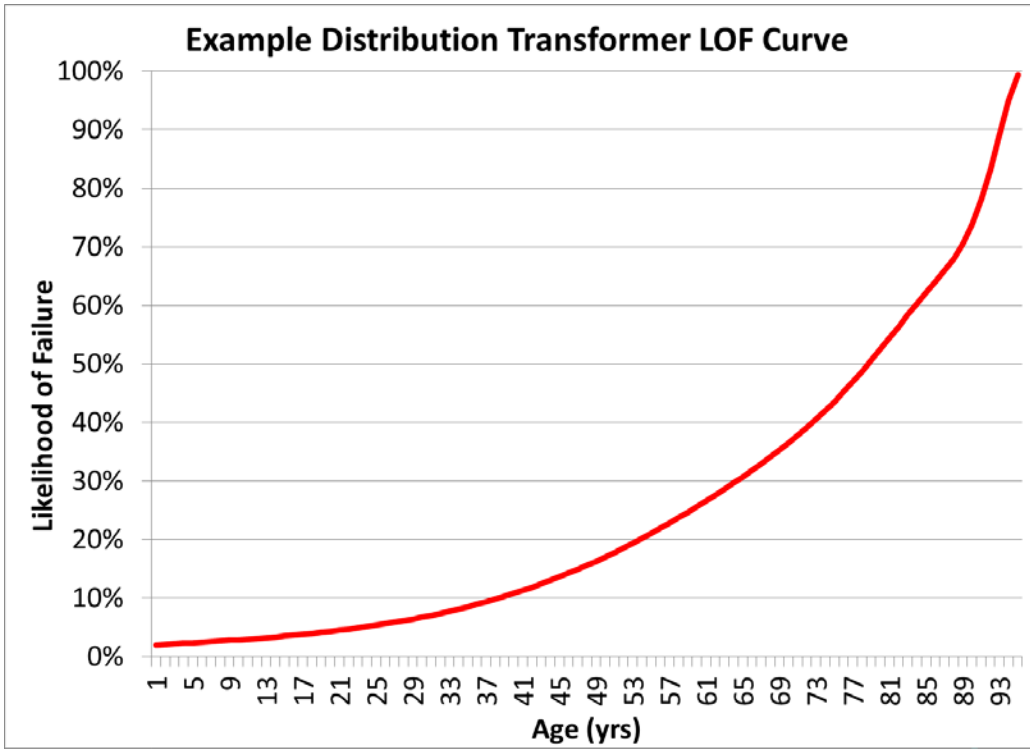

Figure 2-7 Example Likelihood of Failure Curve

2.2.2 Integrating Likelihood of Failure into the Risk Assessment Model

For PSE&G, these LOF factors are defined in the risk rating matrix as shown in Table 2-3.

Table 2-3 Likelihood of Failure Impact Level Definitions

IMPACT	DEFINITION
1 – Highly Unlikely	≤ 10% likelihood of reaching end of life within 5 years
2 – Unlikely	>10% ≤ 25% likelihood of reaching end of life within 5 years
3 – Possible	>25% ≤ 50% likelihood of reaching end of life within 5 years
4 – Likely	>50% ≤ 75% likelihood of reaching end of life within 5 years
5 – Almost Certain	>75% likelihood of reaching end of life within 5 years

Each asset within each system is assigned an LOF based on age and asset class. For example, an asset that is 40 years old may have a 70 percent cumulative likelihood of reaching end of life in the next 5 years. Within the risk rating matrix, this would be input as a "4" in the column for the LOF.

2.2.3 Enhancing the Risk Assessment Model

To incorporate condition data and assessment of assets scheduled for replacement into the Risk Model and capital plan, the Risk Model utilizes PSE&G's condition assessment program to further refine LOF estimates. This subsection details the methodology used to incorporate asset condition data into PSE&G's risk assessment process and how that condition data can be used to establish the effective age of an asset.

2.2.3.1 Effective Age Overview

The effective age of an asset is an assessment of the age of an asset relative to its condition where that condition may have accelerated (or decelerated) compared to the chronological age of the asset. The effective age of an asset is the result of adjusting an asset's chronological age due to relative differences in the asset's current condition as compared to an expected condition. An asset's expected condition is dependent upon its chronological age and general equipment type.

The condition of an asset can be influenced by many factors, such as the following:

- Operating conditions.
- Service history.
- Quality of maintenance.
- Number of operations.
- Loadings.
- Exposure.
- Latent defects and patent defects.
- Environmental effects.
- Demand cycles.

In general, the three cases of effective age relative to chronological age are as follows:

- Higher – The condition of an asset results in an assessment of potential premature aging.
- Same – The condition of an asset is reflective of its chronological age.
- Lower – The condition of an asset is better than expected compared to its chronological age.

Examples of applications of effective life are used in real estate appraisals and in computations of remaining useful life in a reserve study.

Black & Veatch and PSE&G use the concept of effective age to incorporate asset condition data into the Risk Model. Working with PSE&G, Black & Veatch examined and analyzed PSE&G's existing condition assessment data and systems, and developed a methodology to assess the effective age of several of the asset classes within the Risk Model.

2.2.3.2 Asset Health Index

The methodology used to assess the effective age of an asset is through an Asset Health Index (AHI). AHI is an indexed score of an asset's relative health based on a number of measures. These measures are gathered from PSE&G's maintenance and testing programs and include information and data from analytical testing as well as visual inspections and engineering and professional judgment regarding asset condition. In addition, these measures are asset specific and can vary from asset class to asset class. The measures used can be based on industry standards (for example, IEEE C57.104 and IEC 60559 for dissolved gas analysis), industry leading practices (Doble testing and recommendations), visual inspections, and asset management practices utilized at other North American electric utilities.

For the AHI, an asset is scored for each appropriate measure based on a condition rating scale for that measure. Each measured score is then used to derive the AHI for an asset. The range of PSE&G's AHI scores is scaled from 1 to 10, where each of the scores correlates to an asset replacement practice based on condition rating. PSE&G uses a color coding system for asset health scores as listed in Table 2-4.

Table 2-4 PSE&G Asset Health Score Definitions

HEALTH SCORE	MANAGEMENT TREATMENT
Green = 0 through 6	Generally considered in good health and no additional monitoring or testing is required outside of regular maintenance, testing, and inspection procedures.
Yellow = 6 through 8	Fair condition. Risk mitigation may include additional testing to validate condition and/or increased testing frequency to monitor changes. Plans for replacement may also be started.
Red = 8 through 10	Poor condition. Plan for Immediate replacement with additional monitoring and/or operational changes as needed as risk mitigation measures

For example, any asset that has a condition rating of "Green" would operate under normal maintenance conditions. However, an asset with a condition rating of "Red" should start being considered for either capital replacement or refurbishment.

2.2.3.3 Effective Age Estimation

By establishing a condition rating (or AHI score) of an asset based on condition data, the effective age of an asset can be estimated by comparing the condition rating to the survivor curve.

For example, a 10 year old power transformer may have a condition rating of "poor" based on its condition data. As a result, its estimated effective age would be adjusted to be closer to its service life, thus closer to end of service, which would require a plan for replacement. Figure 2-10 illustrates this example.

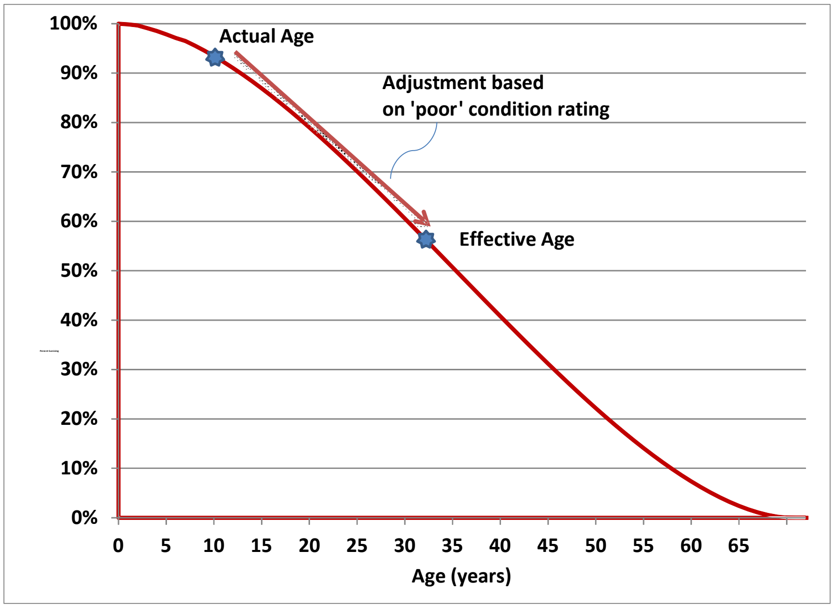

Figure 2-8 Example Effective Age Estimate

By using this methodology for estimating effective age, the Risk Model incorporates condition assessment data.

2.3 RISK FACTORS – CONSEQUENCE OF AN EVENT

In the second step, the consequence level (low to high) was estimated across a number of consequence criteria. There are many different methods to apply the consequence score to determine the premitigation risk score from the risk matrix. For this study, a weighted average of the consequence criteria was used to determine risk. The subsequent risk score then corresponds to a specific risk level.

The consequence of an event was estimated through a qualitative analysis involving inputs from subject matter experts, including staff involved in the design, operation, and maintenance of the asset.

Next, consequence criteria were determined for each asset within the set of inside plant (substation) distribution system assets. The criteria considered a number of factors related to an asset end-of-life failure on the system and are categorized as follows:

- Safety impact
- Reliability impact
- Customer impact
- Environmental impact

Each of these criteria was scored on a 1 to 5 scale (low to high) based on expert experience, system knowledge, and quantifiable data, as applicable. Once tabulated, the ratings were used to calculate a consequence score on a weighted average of the criteria. The detailed definitions are described in the following subsections.

2.3.1 Safety Impact

The safety impact criteria consider the impact to safety associated with an asset failure. Safety criticality is based on the risk of direct harm to personnel, or the public, as a result of asset failure (e.g., conductor drop, fire, or explosion).

Table 2-5 details the score level definitions for these criteria.

Table 2-5 Safety Impact Criteria Definitions

IMPACT	DEFINITION
5 – Severe	Safety: High levels of personnel and/or public activity within vicinity of asset.
3 – Moderate	Safety: Regular personnel/public activity within vicinity of asset.
1 – Incidental	Safety: Limited personnel access. No likely public access.

2.3.2 Reliability Impact

The reliability impact criteria consider the following two factors that impact reliability of the system:

- Replacement availability
- Restoration time

Table 2-6 and Table 2-7 detail the score level definitions for these criteria.

Table 2-6 Replacement Availability Criteria Definitions

IMPACT	DEFINITION
5 – Severe	No spare available and replacement requires lead time greater than 12 months.
4 – Major	No spare available and replacement requires lead time up to 12 months.
3 – Moderate	Spare available but restock up to 6-12 months.
2 – Minor	Spare available but restock up to 1-6 months.
1 – Incidental	Spare readily available.

Table 2-7 Restoration Time Criteria Definitions

IMPACT	DEFINITION
5 – Severe	Restoration greater than 24 hours.
4 – Major	Restoration between 6 to 24 hours.
3 – Moderate	Restoration between 2 to 6 hours.
2 – Minor	Restoration up to 2 hours.
1 – Incidental	Automatic switching available.

2.3.3 Customers Impact

The customers impact criteria consider the following three factors that impact customers on the system:

- Customer type.
- Peak/connected load.
- Number of customers served.

The intent of these criteria is to capture the impact of an asset failure on customers and the utility's ability to provide service to these customers. Table 2-8 through Table 2-10 detail the score level definitions for each of these criteria.

Table 2-8 Customer Type Criteria Definitions

IMPACT	DEFINITION
5 – Severe	Most Critical Services
4 – Major	Not used at this time
3 – Moderate	Not used at this time
2 – Minor	Not used at this time
1 – Incidental	Non-Critical Services

Table 2-9 Peak/Connected Load Criteria Definitions

IMPACT	DEFINITION
5 – Severe	> 35 MVA
4 – Major	> 25 – 35 MVA
3 – Moderate	> 15 – 25 MVA
2 – Minor	2.5 – 15 MVA
1 – Incidental	Less than 2.5 MVA

Table 2-10 Number of Customers Criteria Definitions

IMPACT	DEFINITION
5 – Severe	Greater than 25,000
4 – Major	10,001 – 25,000
3 – Moderate	5,001 – 10,000
2 – Minor	501 – 5,000
1 – Incidental	0 – 500

2.3.4 Environmental Impact

The environmental impact criteria consider the impact to the environment associated with an asset failure. Environmental criticality is based on the environmental impact caused by asset failure and considers the impact of failure and the sensitivity of the geographical area local to the asset.

Table 2-11 details the score level definitions for these criteria.

Table 2-11 Environmental Impact Criteria Definitions

IMPACT	SF6 / OIL VOLUME (50%)	ADJACENT AREA (50%)
5 – Severe	SF6 > 200 psig or Oil > 5000 gallons	Located in Sensitive Area
4 – Major	SF6 =< 200 psig or Oil =< 5000 gallons	
3 – Moderate	SF6 =< 100 psig or Oil =< 2000 gallons	
2 – Minor	SF6 =< 50 psig or Oil =< 1000 gallons	
1 – Incidental	SF6 0 - 5 psig or Oil = 0-250 gallons	Not located in a Sensitive Area

Environmental impact scores were a weighted average of the two criteria listed in Table 2-12. For example, if an asset had an oil volume of 6,000 gallons located in a designated environmentally non-sensitive area, the asset scored a "5" for the SF_6/oil component and a "1" for the adjacent area component, for a final score of "3" for this criterion.

2.4 OVERALL ASSET CRITICALITY

The overall asset criticality score is calculated by multiplying each weight factor times each criteria score. Table 2-12 shows the total criticality score weightings.

Table 2-12 Overall Criticality Criteria Weightings

CRITERIA	CRITERIA WEIGHT	MEASURE	MEASURE WEIGHT
Safety	35%		35%
Reliability	35%	Restoration Time	25%
		Replacement Availability	10%
Customer Impact	20%	Number Served	8%
		Connected Load	6%
		Customer Type	6%
Environmental	10%		10%

3.0 Substation Asset Classes Included in the Risk Model

3.1 OVERVIEW

PSE&G's distribution system consists of 26 kV, 13 kV, and 4 kV voltages, and a low voltage secondary system. The system is comprised of a variety of assets that work together to deliver electricity to the customer. For the system to work effectively, all of the individual assets must be managed together. The substation asset Risk Model includes inside plant assets that have been prioritized based on the approach in Section 2.0. Table 3-1 lists the asset classes included in the substation Risk Model. A brief description of the assets is included in this section.

Table 3-1 Distribution System Asset Classes

PLANT CATEGORY	ASSET CLASS
Inside Plant (i.e., substations)	Substation transformers Circuit breakers Distribution relays Disconnect switches Regulators Reactors Load tap changers (LTCs) Bus ducts

3.2 SUBSTATION TRANSFORMERS

3.2.1 Description

The transformers in the PSE&G territory include transformers with operating voltages of 69/13 kV, 26/4 kV, and 13/4 kV.

There are 417 transformers in the PSE&G territory. Approximately 93 percent of these transformers are used in the 26 kV systems, 6 percent in the 69 kV systems, and the remaining 1 percent are distributed across the system.

The average age of transformers in the system is approximately 47 years. The transformers are between 2 and 89 years old. The average service life of a transformer is 55 years. There are 206 transformers in the system that are chronologically older than the 55 year average service life of the transformer. Figure 3-1 provides an age distribution of transformers as of 2016.

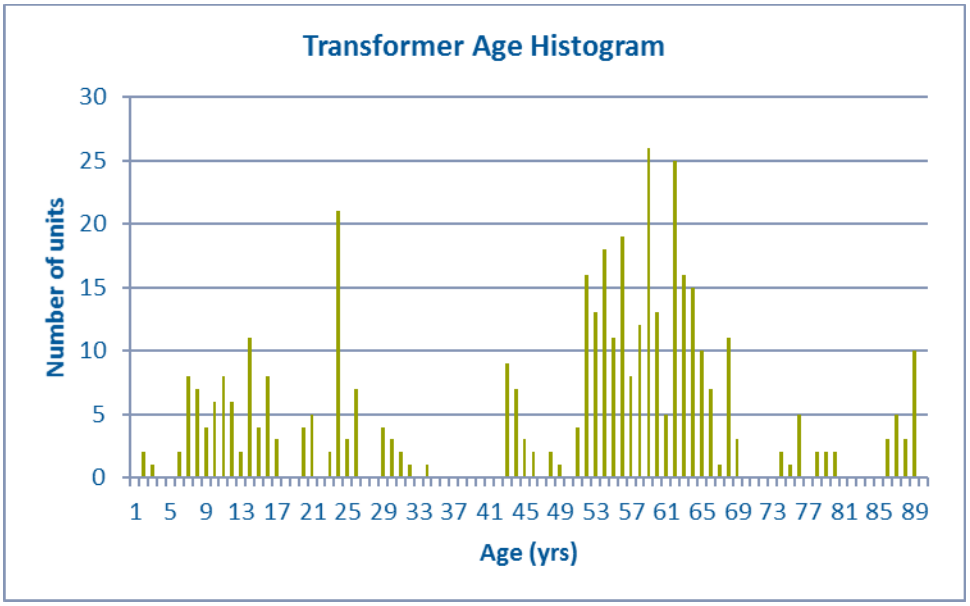

Figure 3-1 Transformers Histogram

3.3 CIRCUIT BREAKERS

3.3.1 Description

The circuit breakers in the PSE&G territory include air circuit breakers, gas circuit breakers, oil circuit breakers, and vacuum circuit breakers with operating voltages of 0.44 kV, 11 kV, 13 kV, 26 kV, and 69 kV.

There are 4,682 circuit breakers in the PSE&G territory. Approximately, 40 percent of these circuit breakers are operating in the 4 kV systems, 36 percent in the 13 kV systems, 22 percent in the 26 kV systems, and the remaining 2 percent are distributed across the 0.44 kV, 11 kV, and 69 kV systems.

The average age of circuit breakers in the system is approximately 44 years. The circuit breakers are between 2 and 109 years old. The average service life of a circuit breaker is 55 years. There are 1,688 circuit breakers in the system that are older than the average service life. Figure 3-2 provides an age distribution of circuit breakers as of 2016.

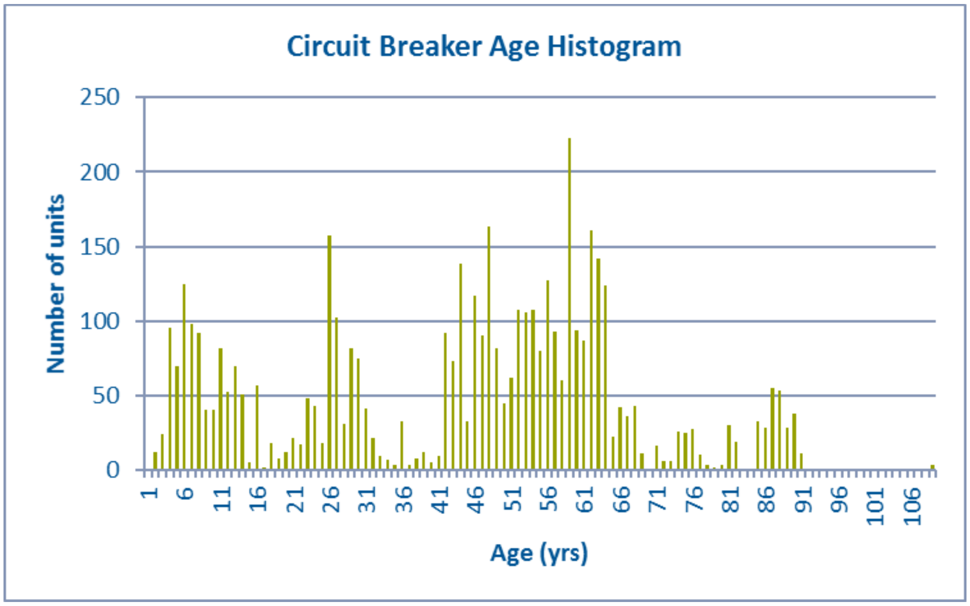

Figure 3-2 Circuit Breakers Histogram

3.4 DISTRIBUTION RELAYS

3.4.1 Description

PSE&G has installed electromechanical and solid state type of protection and control relays in their system for protection and control of different assets and system operating voltages of 4 kV, 11 kV, 13 kV, 26 kV, and 69 kV.

There are 8,143 relays in the PSE&G territory. Approximately 37 percent of these relays are used in the 4 kV systems, 18 percent in the 13 kV systems, 31 percent in the 26 kV system, and 14 percent in the 69 kV systems.

The average age of relays in the system is approximately 38 years. The relays are between 1 and 110 years old. The average service life of a relay is 55 years. There are 3,113 relays in the system that are older than the average service life. Figure 3-3 provides an age distribution of relays as of 2016.

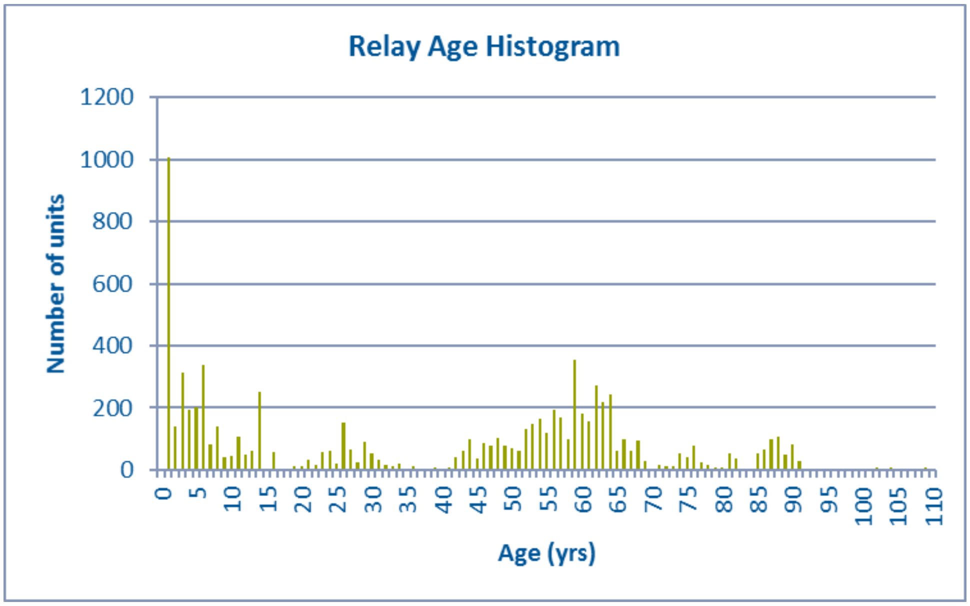

Figure 3-3 Distribution Relays Histogram

Figure 3-3 shows that approximately 1,100 relays are new and have been installed in the past year. The remaining relays are distributed in the age ranges of 25 to 35 years and 43 to 55 years. In addition, as previously stated, a large number of relays (3,113) are above the average service life.

3.5 LOAD TAP CHANGERS

3.5.1 Description

The LTCs for distribution transformers in the PSE&G territory are installed in transformers with operating voltages of 26 kV, 13 kV, and 4 kV.

There are 146 LTCs in the PSE&G. Approximately 71 percent of these LTCs are used in the 13 kV systems, 22 percent in the 4 kV systems, and the remaining 7 percent is used in 26 kV systems.

The average age of LTCs in the system is approximately 38.5 years. The LTCs are between 3 and 68 years old. The average service life of an LTC is 55 years. There are 28 LTCs in the system that are older than the average service life. Figure 3-4 provides an age distribution of LTCs as of 2016.

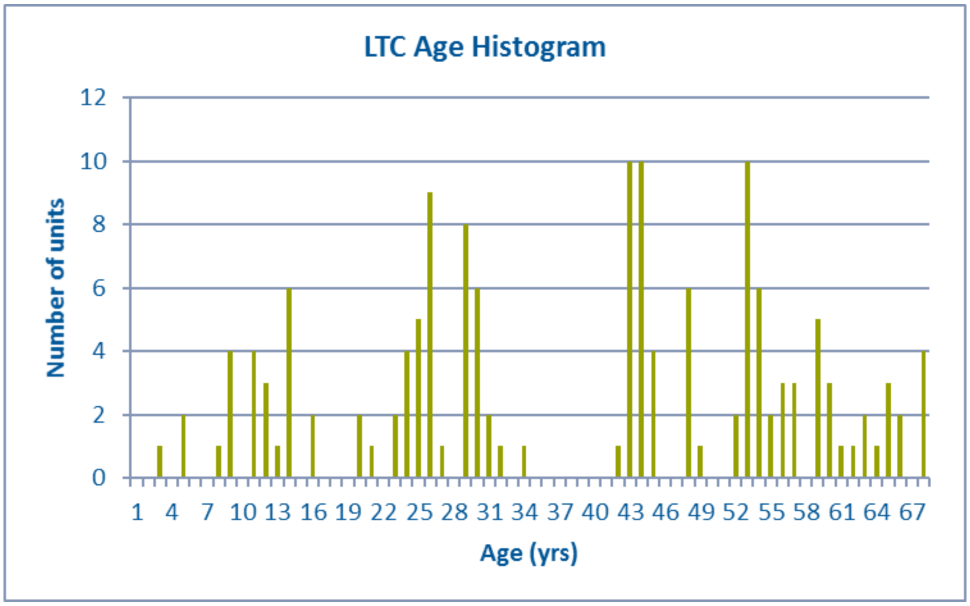

Figure 3-4 Load Tap Changers Histogram

3.6 REACTORS

3.6.1 Description

PSE&G has installed reactors for system operating voltages of 4 kV, 13 kV, 26 kV, and 69 kV.

There are 4,356 reactors in the PSE&G territory. Approximately 97 percent of these reactors are used in the 4 kV systems while the remaining 3 percent are distributed across 13 kV, 26 kV, and 69 kV systems.

The average age of reactors in the system is approximately 61.3 years. The reactors are between 2 and 112 years old. The average service life of a reactor is 55 years. There are 3,206 reactors in the system that are older than the average service life. Figure 3-5 provides an age distribution of reactors as of 2016.

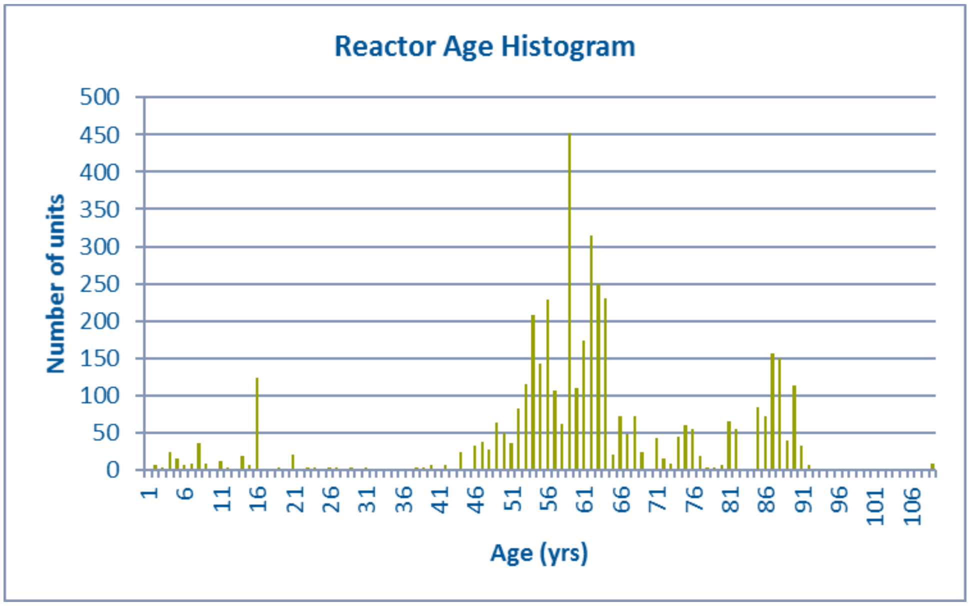

Figure 3-5 Reactors Histogram

Figure 3-5 shows approximately 3,000 reactors in the age range of 45 to 70 years and 800 reactors in the age range between 80 to 92 years.

3.7 DISCONNECT SWITCHES

3.7.1 Description

PSE&G has installed disconnect switches for protection and maintenance practices for the system bus, circuit breaker, transformer, lines, capacitor banks, and other assets in the substations. The disconnect switches are installed for system operating voltages of 4 kV, 13 kV, 26 kV, and 69 kV.

There are 10,483 disconnect switches (disconnects) in the PSE&G territory. Approximately 44 percent of these disconnect switches are used in the 4 kV systems, 11 percent in the 13 kV systems, 43 percent in the 26 kV system, and 2 percent in the 69 kV systems.

The average age of disconnect switches in the system is approximately 50.7 years. The disconnect switches are between 2 and 112 years old. The average service life of a disconnect switch is 55 years. There are 5,584 disconnect switches in the system that are older than the average service life. Figure 3-6 provides an age distribution of disconnect switches as of 2016.

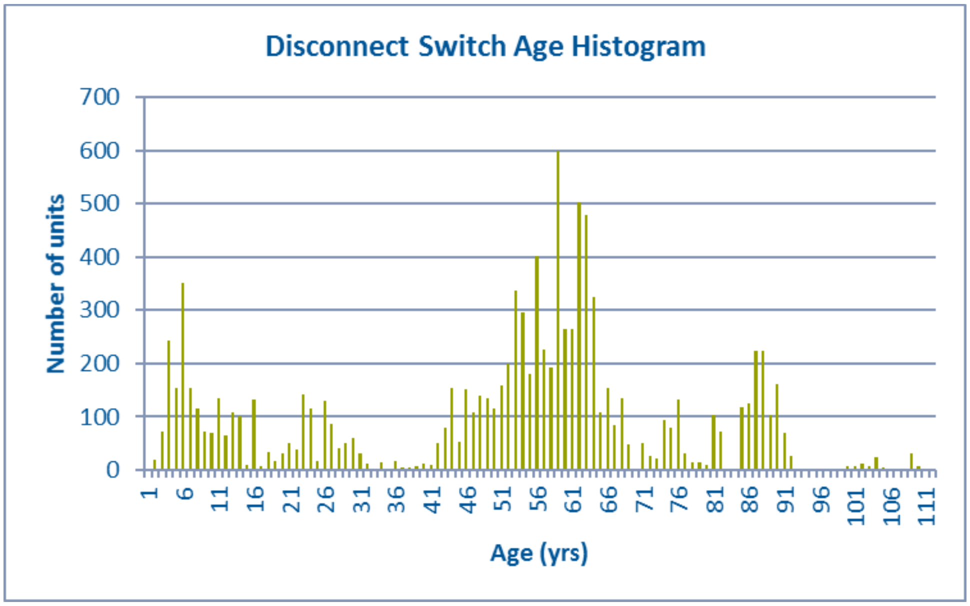

Figure 3-6 Disconnect Switches Histogram

Figure 3-6 shows that approximately 1,000 disconnects are new and have been installed in the past 10 years. The remaining disconnects are distributed in the age ranges of 11 to 31 years and 44 to 55 years. In addition, as previously stated, a large number of disconnects (5,584) are above the average service life.

3.8 REGULATORS

3.8.1 Description

PSE&G has installed regulators at 4 kV system operating voltage. They are installed in single-phase configuration and three-phase configuration in the system.

There are 3,971 regulators in the PSE&G territory. The average age of regulators in the system is approximately 40.8 years. The regulators are between 1 and 112 years old. The average service life of regulators is 55 years. There are 1,763 regulators in the system that are older than the average service life. Figure 3-7 provides an age distribution of regulators as of 2016.

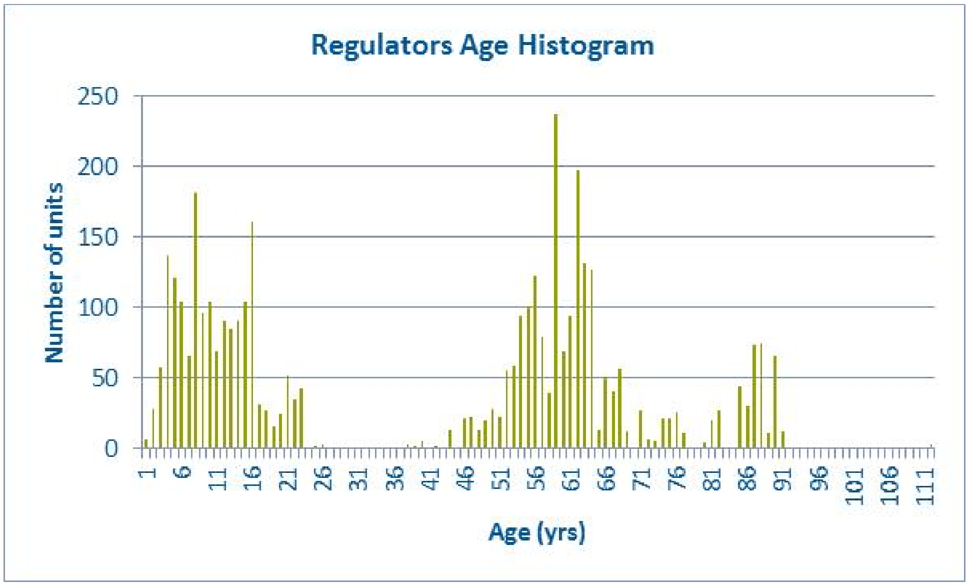

Figure 3-7 Regulators Histogram

Figure 3-7 shows that approximately 1,714 regulators have been installed in the age range of 45 to 70 years and 367 regulators in the age range between 80 to 91 years.

3.9 BUS DUCTS

3.9.1 Description

PSE&G has installed bus ducts at 4 kV, 13 kV, and 26 kV system operating voltages. They are installed indoor and outdoor in single-phase configuration or three-phase configuration in the system.

There are 423 bus ducts in the PSE&G territory. The average age of bus ducts in the system is approximately 54.1 years. The bus ducts are between 13 and 91 years old. The average service life of bus ducts is 55 years. There are 207 bus ducts in the system that are older than the average service life. Figure 3-8 provides an age distribution of regulators as of 2016.

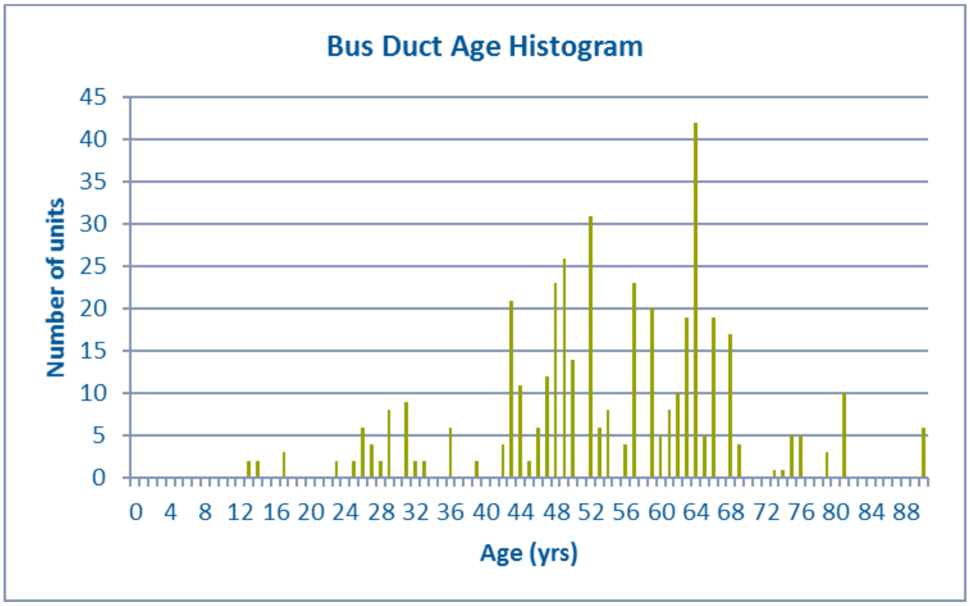

Figure 3-8 Bus Ducts Histogram

Figure 3-8 shows that approximately 216 bus ducts have been installed in the age range of 13 to 54 years and the remaining 207 bus ducts in the age range between 55 to 91 years.

4.0 Risk Model Results

4.1 OVERVIEW

The Risk Model generated a prioritized list of all the 32,785 substation assets included in the model. based on the risk score, replacement cost, and other resource constraints. In the development of ES II, the model was used to assess the risk reduction achieved by replacing high priority assets and other assets that PSE&G will repair or install to promote system modernization or enhanced functionality. Specifically, the Risk Model has been used to assess the risk reduction for both the Substation Upgrades 26/4 kV Stations and Station Flood and Storm Surge Mitigation subprograms. This section describes the risk reduction associated with each of these subprograms.

4.1.1 Substation Upgrades 26/4 kV Stations Subprogram

PSE&G proposes to replace or retire substations with 26 kV and/or 4 kV assets that are either at or near the end of their useful life. There are 93 stations with 26 kV and/or 4 kV assets that are of sufficient age to warrant inclusion in the subprogram. Class A/B station designs have 4 kV facilities in a masonry building. The stations were constructed between 1905 and 1952. Class C stations have all facilities outdoors with 4 kV equipment in metal-clad switchgear. The stations were constructed between 1938 and 1976. The following is a breakdown of these stations:

- Class A/B substations
  - Number of stations - 35
  - Average age - 93 years
- Class C substations
  - Number of stations - 58
  - Average age - 61 years

The majority of the 26 kV or 4 kV equipment in these stations is the original equipment installed at the time the stations were constructed. PSE&G evaluated each station to determine if the station is still required or if its circuits can be cost effectively converted to 13 kV operation.

Using the Risk Model and other management knowledge and tools, the PSE&G team developed the Substation Upgrades 26/4 kV Stations Subprogram. The Risk Model also quantified the risk reduction achieved by replacing complete substations of particular classes, such as the A, B, and C substations. The risk reduction achieved by these substation replacement subprograms was compared to a "Do Nothing" scenario (as a baseline) to arrive at the relative risk reduction. Utilizing the Risk Model in this manner provided PSE&G a tool to develop the life cycle aspects of ESII that cost-effectively reduce its overall system risk.

Because of the antiquated (circa 1940s) design and condition of the 4 kV equipment in the Class C stations, PSE&G is proposing that this equipment be completely replaced with modern insulation, equipment, and protection schemes as part of this effort. The proposed list of stations being upgraded in the first 5 years of this subprogram is listed in Table 4-1.

Table 4-1 Substations Included in Substation Upgrades 26/4 kV Stations Subprogram

STATION NAME	STATION CLASS
Plainfield	C
Front Street	C
McClean Boulevard	C
Warren Point	C
Great Notch	C
Fortieth St	C
Totowa	C
Spring Valley Road	C
Paramus	C
Teaneck	C
Tonnelle Avenue	C
Dumont	C
Mount Holly	C
Woodbury	C
Hamilton	C

4.1.2 Substation Upgrades 26/4 kV Stations Subprogram Risk Reduction

Black & Veatch used the Risk Model to assess the risk reduction achieved by the Substation Upgrades 26/4 kV Stations Subprogram. As part of this assessment, the Risk Model outputs include risk matrices that provide insight into the COF and LOF breakdown for each asset in the Risk Model. There are two types of risk matrices included in the assessment of the Substation Upgrades 26/4 kV Stations Subprogram:

- 2023 Station Class Risk Matrix – Do Nothing: This risk matrix represents the number of assets that will be in each COF (1 through 5) and LOF (1 through 5) box in 2023 if PSE&G chose not to proactively replace assets over the next 5 years and instead chose to repair assets that fail.
- 2023 Substation Upgrades 26/4 kV Stations Risk Matrix: This risk matrix represents the number of assets that will be in each COF (1 through 5) and LOF (1 through 5) box in 2023 after PSE&G has invested in the substation replacements identified in Table 4-1. For each of the substations, the Risk Model reflects replacement of the asset classes discussion in Section 3 of this report.

Figure 4-1 is the 2023 Station Class Risk Matrix for the Do Nothing scenario. There are a total of 32,785 substation assets in the Risk Model, which accounts for all of PSE&G's distribution substation assets. As shown on the figure, there are no assets with a COF of 5 in the substation Risk Model and a small percentage that have a COF of 4.

2023 Station Class Heat Map - Do Nothing

Consequence of Failure	Likelihood of Failure 1	2	3	4	5
5	0	0	0	0	0
4	19	84	2	2	57
3	309	786	64	1	832
2	4,190	4,180	690	149	1,781
1	9,559	6,058	1,297	824	1,901

Total Asset Records 32,785

Figure 4-1 2023 Station Class Risk Matrix - Do Nothing

The effects of the Substation Upgrades 26/4 kV Stations Subprogram are illustrated on Figure 4-2. The substations included in the Substation Upgrades 26/4 kV Stations Subprogram are driven by several factors. In many cases, the oldest assets in the substation Risk Matrix are replaced by the subprogram, but since entire substations are being replaced, other middle-aged assets might be replaced as well. This is appropriate since the Risk Model is only one tool used by PSE&G to determine which substations need to be replaced in the subprogram. The effects of the subprogram can be seen by comparing this risk matrix to the Do Nothing scenario. For example, in the Do Nothing scenario, there are 832 assets that have a COF of 3 and a LOF of 5, whereas in the Substation Upgrades 26/4 kV Stations Risk Matrix, there are 639 assets, which means 193 assets in the COF 3, LOF 5 box are being replaced. Those 193 assets are moved into the COF 3, LOF 1 box in 2023 since these assets will be replaced with new ones.

2023 Substation Upgrades 26/4 kV Stations Heat Map

Consequence of Failure	Likelihood of Failure 1	2	3	4	5
5	0	0	0	0	0
4	25	82	2	2	53
3	509	781	62	1	639
2	4,700	4,131	642	149	1,368
1	10,534	5,654	1,196	823	1,432

Total Asset Records 32,785

Figure 4-2 2023 Substation Upgrades 26/4 kV Stations Risk Matrix

Figure 4-3 illustrates the annual expenditures and risk reduction achieved by the Substation Upgrades 26/4 kV Stations Subprogram. As shown on the figure, there are no expenditures in this subprogram until 2022. Therefore, the overall substation assets risk profile is the same as the Do Nothing scenario until 2022. Once the subprogram is completed at the end of 2023, the overall substation assets risk profile is reduced to a level lower than that of today, resulting in a 15 percent risk reduction over the 5 year analysis period.

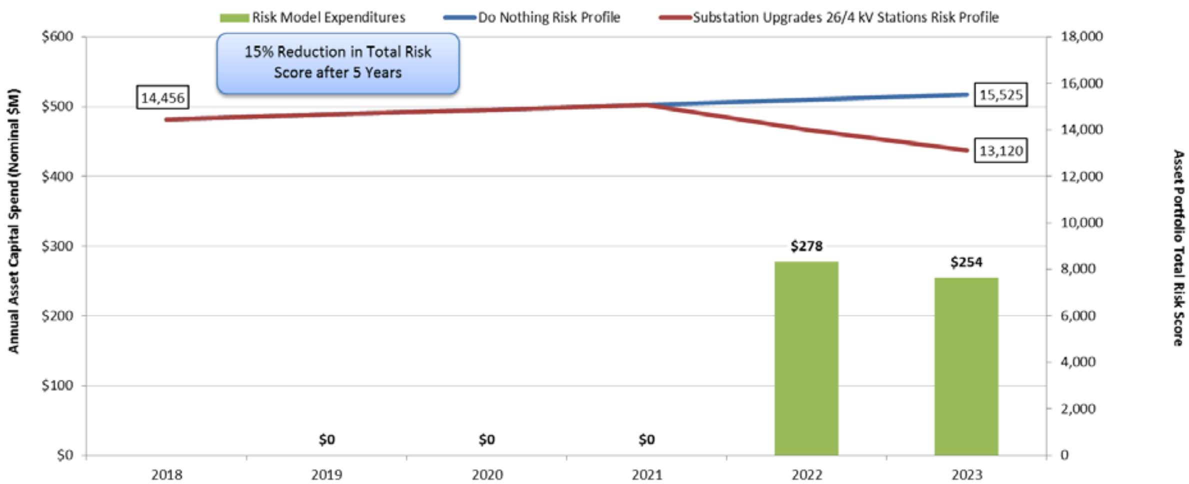

Figure 4-3 Substation Upgrades 26/4 kV Stations Subprogram Risk Reduction

4.1.3 Station Flood and Storm Surge Mitigation Subprogram

Through Energy Strong II, PSE&G also proposes to raise or eliminate substations to mitigate the risk posed by a flood or storm surge. PSE&G utilized the newly defined Federal Emergency Management Agency advisory-based flood elevations to identify those substations that are below the base flood elevations plus 1 foot. PSE&G has identified 21 stations that meet this criterion. For those substations that are being raised, the assets are being replaced with new equipment and there is risk reduction achieved by replacing aging equipment with new infrastructure. For those substations that are being eliminated, the removal of those assets from PSE&G's system also results in risk reduction. Five of those stations are already being raised as part of PSE&G's base capital program in part to facilitate PJM's Regional Transmission Expansion Plan. Since this report focuses on the risk reduction achieved by the Energy Strong II program, the risk reduction associated with those five substations is not quantified here; we focus on the 16 stations that are part of the Energy Strong II proposal. The current proposed stations in this project are listed in Table 4-2. It should also be noted that the Constable Hook Substation in Table 4-2 is a unit substation and does not have assets in the Risk Model. Therefore, its risk reduction is not quantified in this report, but it has been included it in the table for consistency with other Station Flood and Storm Surge Mitigation Subprogram documentation.

Table 4-2 Station Flood and Storm Surge Mitigation Substations

STATION NAME	STATION CLASS	RECOMMENDATION
Meadow Road	H	Raise
Leonia Substation	H	Raise
Kingsland Substation	H	Raise
Ridgefield 13 kV	H	Raise
Ridgefield 4 kV	C	Eliminate
Hasbrouck Heights Substation	C	Raise
Academy Street Substation	C	Raise
Woodlynne Substation	C	Eliminate
Toney's Brook Substation	C	Raise
Waverly Substation	A	Raise
State Street Substation	A	Raise
Orange Valley Substation	C	Raise
Market Street Substation	A	Raise
Lakeside Avenue Substation	A	Raise
Clay Street Substation	A	Raise
Constable Hook Substation	Unit	Raise

4.1.4 Station Flood and Storm Surge Mitigation Subprogram Risk Reduction

Black & Veatch used the Risk Model to assess the risk reduction achieved by the Station Flood and Storm Surge Mitigation Subprogram. As part of this assessment, the Risk Model outputs include risk matrices that provide insight into the COF and LOF breakdown for each asset in the Risk Model. There are two types of risk matrices included in the assessment of the Station Flood and Storm Surge Mitigation Subprogram:

- 2023 Station Class Risk Matrix – Do Nothing: This risk matrix represents the number of assets that will be in each COF (1 through 5) and LOF (1 through 5) box in 2023 if PSE&G chose not to proactively replace assets over the next 5 years and instead chose to repair assets that fail.
- 2023 Station Flood and Storm Surge Mitigation Risk Matrix: This risk matrix represents the number of assets that will be in each COF (1 through 5) and LOF (1 through 5) box in 2023 after PSE&G has invested in the substation replacements and eliminations identified in Table 4-2. For each of the substations, the Risk Model reflects replacement or elimination of the asset classes discussed in Section 3.0 of this report.

Figure 4-4 is the 2023 Station Class Risk Matrix for the Do Nothing scenario. There are a total of 32,785 substation assets in the Risk Model, which accounts for all of PSE&G's distribution substation assets. As shown on the figure, there are no assets with a COF of 5 in the substation Risk Model and a small percentage that have a COF of 4.

2023 Station Class Heat Map - Do Nothing

Consequence of Failure	Likelihood of Failure 1	2	3	4	5
5	0	0	0	0	0
4	19	84	2	2	57
3	309	786	64	1	832
2	4,190	4,180	690	149	1,781
1	9,559	6,058	1,297	824	1,901

Total Asset Records **32,785**

Figure 4-4 2023 Station Class Risk Matrix - Do Nothing

The effects of the Station Flood and Storm Surge Mitigation are illustrated on Figure 4-5. The substations included in the Station Flood and Storm Surge Mitigation Subprogram are driven by factors other than the Risk Model prioritization of assets. In many cases, the oldest assets in the substation Risk Matrix are replaced by the subprogram, but since entire substations are being replaced, other assets might be replaced as well. This is appropriate since the Risk Model is being utilized here to illustrate the risk reduction achieved by the subprogram. The effects of the subprogram can be seen by comparing this risk matrix to the Do Nothing scenario. For example, in the Do Nothing scenario, there are 832 assets that have a COF of 3 and a LOF of 5, whereas in the Station Flood and Storm Surge Mitigation Risk Matrix, there are 748 assets, which means 84 assets in the COF 3, LOF 5 box are being replaced or eliminated. Those assets being replaced are moved into the COF 3, LOF 1 box since they will be replaced with new assets. Those assets that are being eliminated have been removed from the risk matrix altogether.

2023 Station Flood and Storm Surge Mitigation Heat Map

Consequence of Failure	Likelihood of Failure 1	2	3	4	5
5	0	0	0	0	0
4	42	74	2	0	42
3	472	693	61	0	748
2	4,755	3,783	595	141	1,571
1	9,983	5,711	1,226	805	1,810

Total Asset Records **32,514**

Figure 4-5 2023 Station Flood and Storm Surge Mitigation Risk Matrix

Figure 4-6 illustrates the annual expenditures and risk reduction achieved by the Station Flood and Storm Surge Mitigation subprogram. As shown on the figure, expenditures for this subprogram begin in 2020. Therefore, the overall substation assets risk profile is the same as the Do Nothing scenario until 2020. Once the subprogram is completed at the end of 2023, the overall substation assets risk profile is reduced to a level similar to the current risk level, resulting in a 9 percent risk reduction over the 5 year analysis period.

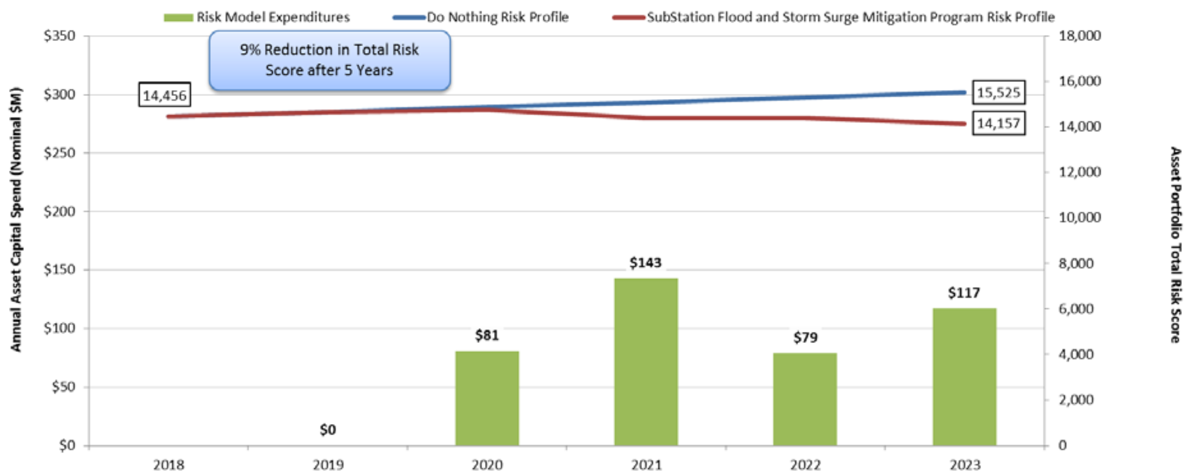

Figure 4-6 Station Flood and Storm Surge Mitigation Subprogram Risk Reduction

4.1.5 Energy Strong II Electric Program Risk Reduction

The ES II Electric Program has other subprograms that reduce system risk similar to the Substation Upgrades 26/4 kV Stations and Station Flood and Storm Surge Mitigation subprograms, but quantifying the risk reduced by those subprograms based on the Risk Model approach is challenging. Black & Veatch and PSE&G decided that quantifying the risk reduction of these two subprograms with the Risk Model is an appropriate way to support the many benefits provided by these programs. As shown in the previous sections, both of the two subprograms quantified here individually reduce PSE&G's substation risk. In this section, the aggregate effect of these two subprograms is provided to show the cumulative effect of these subprograms on PSE&G's substation risk. There are two types of risk matrices included in the assessment of the Energy Strong II Electric Program:

- 2023 Station Class Risk Matrix – Do Nothing: This risk matrix represents the number of assets that will be in each COF (1 through 5) and LOF (1 through 5) box in 2023 if PSE&G chose not to proactively replace assets over the next 5 years and instead chose to repair assets that fail.
- 2023 Energy Strong II Electric Program Risk Matrix: This risk matrix represents the number of assets that will be in each COF (1 through 5) and LOF (1 through 5) box in 2023 after PSE&G has invested in the substation replacements and eliminations in the Substation Upgrades 26/4 kV Stations and Station Flood and Storm Surge Mitigation subprograms. For each of the substations, the Risk Model reflects replacement or elimination of the asset classes discussed in Section 3.0 of this report.

Figure 4-7 is the 2023 Station Class Risk Matrix for the Do Nothing scenario. There are a total of 32,785 substation assets in the Risk Model, which accounts for all of PSE&G's distribution substation assets. As shown on the figure, there are no assets with a COF of 5 in the substation Risk Model and a small percentage that have a COF of 4.

2023 Station Class Heat Map - Do Nothing

Consequence Failure	Likelihood of Failure 1	2	3	4	5
5	0	0	0	0	0
4	19	84	2	2	57
3	309	786	64	1	832
2	4,190	4,180	690	149	1,781
1	9,559	6,058	1,297	824	1,901

Total Asset Records 32,785

Figure 4-7 2023 Station Class Risk Matrix - Do Nothing

The effects of both subprograms are illustrated on Figure 4-8. The substations included in the subprograms are driven by many factors, which include the Risk Model prioritization of assets. In many cases, the oldest assets in the substation Risk Matrix are replaced by the subprogram, but since entire substations are being replaced, other assets might be replaced as well. This is appropriate since the Risk Model is being utilized here to illustrate the risk reduction achieved by the subprograms. The effects of the subprograms can be seen by comparing this risk matrix to the Do Nothing scenario. For example, in the Do Nothing scenario, there are 832 assets that have a COF of 3 and a LOF of 5, whereas in the Energy Strong II Electric Program Risk Matrix, there are 555 assets, which means 277 assets in the COF 3, LOF 5 box are being replaced or eliminated. Those assets being replaced are moved into the COF 3, LOF 1 box since they will be replaced with new assets. Those assets that are being eliminated have been removed from the risk matrix altogether.

2023 Energy Strong II Heat Map

Consequence Failure	Likelihood of Failure 1	2	3	4	5
5	0	0	0	0	0
4	48	72	2	0	38
3	672	688	59	0	555
2	5,265	3,734	547	141	1,158
1	10,958	5,307	1,125	804	1,341

Total Asset Records 32,514

Figure 4-8 2023 Energy Strong II Electric Program Risk Matrix

Figure 4-9 illustrates the annual expenditures and risk reduction achieved by the Energy Strong II Electric Program. As shown on the figure, expenditures begin in 2020. Therefore, the overall risk profile is the same as the Do Nothing scenario until 2020. Once the subprograms are completed at the end of 2023, the overall substation assets risk profile is reduced to a level below the current risk level, resulting in a 24 percent risk reduction over the 5 year analysis period.

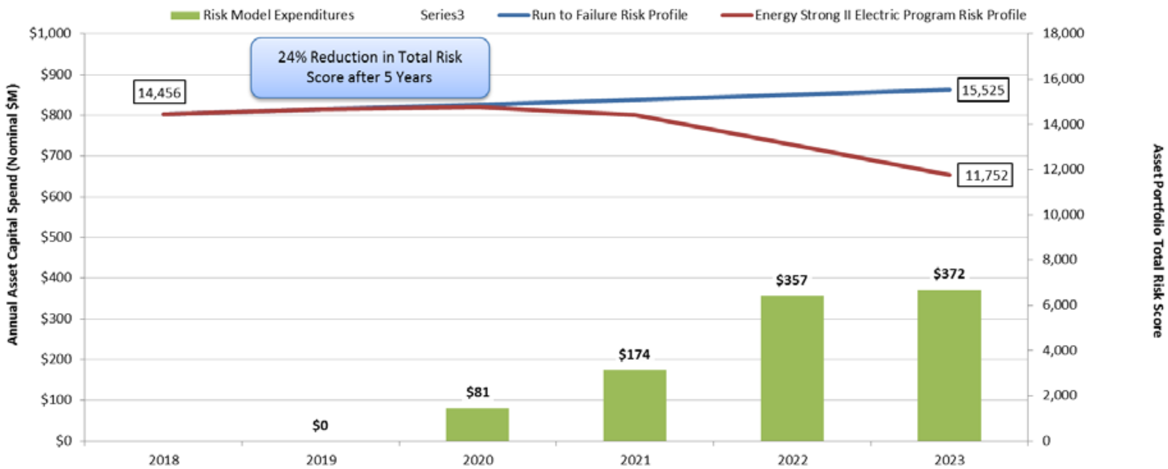

Figure 4-9 Energy Strong II Program Risk Reduction

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF THE
COST-BENEFIT ANALYSIS PANEL
ENERGY STRONG II PROGRAM – ELECTRIC

Q. Please introduce the members of the Cost-Benefit Panel, Energy Strong II Program – Electric (the "ESII-Electric CBA Panel" or "Panel").

A. The witnesses comprising the ESII-Gas CBA Panel are Krystal R. Richart, Craig Preuss and Andrew L. Trump.

Q. Ms. Richart, please state your name and business address.

A. My name is Krystal R. Richart, and my business address is 11401 Lamar Avenue Overland Park, Kansas 66211.

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

A. I am a Manager, Management Consulting employed by Black & Veatch Management Consulting, LLC ("Black & Veatch").

Q. Please describe your educational background and business experience.

A. The information is provided in Schedule-BV-ESII-ELEC-1.

Q. Mr. Preuss, please state your name and business address.

A. My name is Craig Preuss, and my business address is 6800 W. 115th St., Suite 2292 Overland Park, Kansas 66211.

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

A. I am a System Architect at Black & Veatch.

Q. Please describe your educational background and business experience.

A. The information is provided in Schedule-BV-ESII-ELEC-2.

Q. Mr. Trump, please state your name and business address.

A. My name is Andrew L. Trump, and my business address is 832 Media Line Road, Newtown Square, Pennsylvania.

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

A. I am a Director employed by Black & Veatch.

Q. Please describe your educational background and business experience.

A. The information is provided in Schedule-BV-ESII-ELEC-3.

Q. What is the purpose of the Panel's testimony?

A. The Panel is sponsoring the cost-benefit analyses of the electric portion of the Energy Strong II Program ("ES II" or the "Program"). Our full report ("Report") is provided in Schedule-BV-ESII-ELEC-4.

Q. What does the study entail?

A. As explained in our Report and in the PSE&G testimony, the electric portion of ES II has four subprograms: Station Subprogram, Outside Plant Higher Design and Construction Standards Subprogram, Contingency Reconfiguration Subprogram, and Grid Modernization Subprogram. The Station Subprogram is further broken down into two subparts -- Station Flood and Storm Surge Mitigation, and Substation Upgrades, 26/4kV Stations. The Contingency Reconfiguration Subprogram also has two subparts – Increased Sectionalization, and Reclosing Devices. Similarly, the Grid Modernization Subprogram has two subparts – Advanced Distribution Management System ("ADMS"), and Communication Network. Within these Subprograms and subparts, the ES II Electric Program includes storm hardening and resiliency investments, as well as "life cycle" investments, which address replacement of selected types of aging facilities.

Our team examined the investments and a variety of data and information to develop a cost-benefit analysis of these investments. In this analysis, the costs are based on the estimated investment costs provided by PSE&G. Black & Veatch worked with the data and facts related to these investments to identify and, where possible, quantify the benefits provided by these investments. We also identified benefits that could not be quantified and thus are qualitative in nature. The work included review of possible positive and negative impacts on operating and maintenance costs that may result from these proposed investments. In this review, our focus was on strictly new, incremental costs that can be reasonably identified today given the state of ES II planning.

Q. Please describe the quantification of benefits.

A. Our team, under the assumptions of the study, estimates that over an approximately 20-year period, quantified monetary benefits exceed costs by approximately $2.6 billion, for a net present value ("NPV") of $526 million, or a ratio of quantifiable benefits to costs of 2.7. In addition, as noted above and discussed further below, the study identified many important but difficult to quantify and/or unquantifiable benefits that are not included in this ratio, and the study is conservative in other fundamental respects. Additionally, the benefit-to-cost ratio excludes the effects of another storm of the magnitude and nature of Superstorm Sandy. A storm of this magnitude and nature is treated as a sensitivity analysis of the cost benefit evaluation.

Q. How did Black & Veatch develop the quantification of benefits?

A. Black & Veatch compared the "business as usual" (BAU) scenario, in which PSE&G's

assumed operation is without the benefit of ES II, to the PSE&G system operation that includes the use and deployment of infrastructure created through the ES II investments. We compared these two scenarios over an approximately 20 year forecast period (March 2019-2038) to determine incremental effects. Assumptions were required for both the probability of occurrence and the degree of impact of storm-caused outage conditions during this approximately 20-year period. Assumptions were also required for short duration, or "reliability-scaled", outage conditions, meaning outages typically of a few minutes or hours and occurring during non-storm conditions. For the storm-caused outage conditions, and based on our review of the data, we assumed that throughout the approximately 20 forecast years the average yearly intensity of storm (outage) conditions would be the same as the intensities PSE&G experienced during the past seven years, while removing the effect of Superstorm Sandy, which we treat as an anomalous event and evaluate as a sensitivity condition. We also include reasonable and prudent estimates of incremental operations and maintenance ("O&M") costs that are identified at this time and that are required over time to support the investments.

Q. Please summarize the approach taken in your analyses to the evaluation of Program benefits.

A. The numerous considerations that went into our analyses are discussed in our Report, and a full discussion is beyond the scope of this introductory testimony. As explained in that Report, a fundamental methodological step in our effort was to link the benefits of each project to specific impacts, based on our understanding of how the technological investments function. Working with PSE&G subject matter experts, Black & Veatch created a formal benefit "mapping", which is presented in Appendix A – Benefit Matrix of the Report.[1]

Q. Please describe the benefit mapping shown on Appendix A – Benefit Matrix.

A. Certainly. For each subpart of each subprogram, we identified the most significant impacts of the technology, with the requirement that -- to qualify as an "impact" -- the team had to be able to develop a statement involving concrete consequences, and also had to describe the "driver of the impact." For example, for the Station Flood and Storm Surge Mitigation subpart within the Substation Subprogram, one "Impact" is that the projects will result in "Reduced risk of flood-related outages for the upgraded substations" ("Reduced Flood Risk") and the "Drivers" of that particular impact are the post-Sandy DEP regulations. Another impact of the Station Flood and Storm Surge projects is "Faster outage restoration times", with the impact driven by the replacement of aging equipment with modern Remote Terminal Units (RTUs) and relays. Applying this step-wise process – linking investment, technology, functionality, and multi-layer impacts – we captured 40 separate significant impacts of the ES II Subprograms, recognizing a wide range of effects and further beneficial outcomes.

Q. What was the next step in evaluating these impacts?

A. The next step was to determine the specific benefits that arise from the impact, that is, whether cost-related (i.e., an impact that reduces or avoids O&M and/or capital cost); outage-related (i.e., an impact that reduces outage frequency or duration, during blue sky conditions and/or major storm events); or other-related (i.e., impacts on safety or compliance, or support for future grid needs). Additionally, many of the 40 impacts provide multiple benefits. For example, the Reduced Flood Risk impact noted above, within the Substation Subprogram,

[1] Report, Attachment 5, Schedule-BV-ESII-ELEC-4, Pages 46 of 119 through 48 of 119.

provides a cost-related benefit (i.e., reduced/avoided O&M and/or capital expense, under outage circumstances); outage-related benefits (less frequent outages (that is, a system "hardening" benefit), during major storm events, including a Sandy-type event); and other benefits (that is, safety or compliance-related benefits).

Q. Were these benefits all quantified in your analysis?

A, Some were, but not all. As noted, benefits can be quantitative, and furthermore monetized, or benefits can be difficult or impossible to quantify, and thus deemed "qualitative." The Appendix A – Benefit Matrix further indicates, for each benefit associated with each impact, whether the benefit is a monetary benefit derived from PSE&G data and inputs (the green boxes); a monetary benefit derived from Customer Minute Interruption ("CMI") reduction and Value of Lost Load ("VoLL") calculations (the yellow boxes); or a Qualitative Benefit that could not be quantified (the grey boxes codes with a double-tilde symbol).

Q. Please summarize the results of your quantitative analysis.

A. Black & Veatch estimates that the ES II Electric Program will reduce PSE&G costs (both capital and annual O&M expense), improve system reliability, and lower system risk associated with major storm events, thereby resulting in a more hardened system with greater resiliency. Reducing the outage frequency and duration can be further valued in terms of VoLL, a financial measure of how customers and businesses perceive the value of improved system reliability, hardening, and resiliency. The estimated costs and benefits, and the resulting benefit-to-cost ratio, are detailed in our Report, and presented below:

Benefit Results and Benefit-Cost-Ratio, by Subprogram (2019-2038)

Subprogram	ES II Investment Cost (A)	Additional ES II Support Cost (B)	Total 20 Year Cost Estimate (C) = (A) + (B)	Cost Reductions (D)	Avoided Outage Costs – VoLL (E)	Total Monetized Benefits (F) = (D) + (E)	Simple Benefi t-Cost Factor (G) = (F) / (C)
Substation	$906,000.0	$0.0	$906,000.0	$419,207.9	$243,555.0	$662,762.9	0.7
Outside Plant, Higher Design and Construction Standards	$345,000	$0.0	$345,000.0	$1,600.9	$958,754.5	$960,355.5	2.8
Contingency Reconfiguration Strategies	$145,000.0	$0.0	$145,000.0	$3,915.0	$1,878,873.9	$1,882,788.9	13.0
Grid Modernization	$107,000.0	$27,226.2	$134,226.2	$110,080.9	$501,900.3	$611,981.3	4.6
TOTAL	$1,503,000.0	$27,226.2	$1,530,226.2	$534,804.7	$3,583,083.7	$4,117,888.5	2.7

Q. What are some of the qualitative benefits not reflected in the quantified benefits?

A. Black & Veatch emphasizes that the cost-benefit analysis results in the Table above are limited to those benefits that can be quantified and monetized. The results do not consider the additional value added by benefits that are qualitative in nature. In our Report we identify many of these qualitative benefits, in the general areas of improved safety, support for future grid operations, improved communications reliability and security, and enhanced asset management capabilities (through advanced control systems and analytic capabilities). For example, we estimate that through the Energy Strong II investments PSE&G will reduce the time it takes to investigate and resolve small nested outages during storm restoration efforts, but we identify this as qualitative because it is difficult to estimate the labor savings as part of the overall storm restoration effort. Additionally, strengthening circuits with spacer cable should lead to safer conditions in the field due to fewer downed circuits after storms. Rebuilding substations will also result in a higher degree of conformance to modern and current substation design standards, resulting in fewer emergency repair conditions that can pose a safety hazard to employees and customers alike.

Q. You stated that your analysis is conservative in other fundamental respects; please explain.

A. In Black & Veatch's view, the analysis is conservative for at least seven reasons.

1. The analysis is based on an approximately 20 year forecast period, whereas many of the ES II investments are expected to be in service for many decades, well beyond the benefit forecast period. In fact, the mitigation benefits provided by the ES II Electric Program will be provided on a continuous, 24 hour x 365-day basis over 50 or more years.

2. The base case results exclude outage data covering the region's experience during Superstorm Sandy, which hit the area with tremendous severity during October 2012. The impact of including Sandy in the analysis was addressed as a sensitivity analysis within the Report and, of course, would increase the calculated benefits of the Program.

3. The major outage event benefits are focused on Value of Lost Load ("VoLL") estimates, but there are additional indirect effects experienced during major events that are not included in VoLL. The analysis recognizes, but does not monetize, several important qualitative benefits, such as safety, and many indirect outage-related costs.

4. The analysis ignores the gradual "ramping in" of benefits during the five year ES II investment period as projects are completed. Instead it relies on the assumption that the benefits largely start to accrue in Year 6.

5. The ES II Electric Program includes the build out of an advanced communications and distribution management system, which positions PSE&G and all of its stakeholders, including its customers, to capture additional value as grid functions evolve through mandate or independent market forces. These additional benefits, which are spread across several sectors of the economy, are not included in the cost-benefit analysis results.

6. The ES II Electric Program creates additional flexibility for PSE&G to direct its base capital spending to other priority areas that otherwise might be deferred.

7. The analysis ignores the effects of growth in customers, load served, or the economy.

Q. You have also included sensitivity analyses in your Report. Please describe those analyses.

A. We developed several sensitivity analyses to explore how changes to key input variables and assumptions modify the benefit–to-cost ratio results. Specifically, we considered: the inclusion of a future storm event similar to Superstorm Sandy into the BAU and ES II scenarios; increased ES II Program capital costs; the impact of the "ramp in" of benefits: changes to escalation factors to track how costs and benefits change and inflate over time; and changes to the VoLL factors.

Q. Can you summarize the results of those sensitivity analyses?

A. Including Superstorm Sandy level impacts raises the benefit-to-cost ratio from 2.7 to 3.6, an increase of nearly 40 percent. Extending the forecast period to 40 years (reflecting the long service life of the substations and spacer cable, for example) raises the benefit-to-cost ratio to 7.4, an increase of a factor of 2.7. Assuming both raises the benefit-to-cost ratio to 10.1.

Q. What should one conclude from your study?

A. The study provides a cost benefit analysis of the electric portion of the proposed ES II Program and supports the PSE&G decision to make the electric ES II program investments.

Q. Does this complete the Panel's testimony?

A. Yes.

Krystal R. Richart, P.E., MBA

Krystal Richart is currently a project manager in Black & Veatch's management consulting business. She holds a Bachelor of Science in Industrial and Management Systems Engineering from the University of Nebraska and a Master of Business Administration with a concentration in Finance from the University of Kansas. She is also a licensed Professional Engineer of Industrial Engineering.

Ms. Richart has nine years of experience in project controls, estimating, and various management consulting projects at Black & Veatch. Her past experience includes extensive planning and scheduling experience including expertise in both Microsoft Project and Primavera products, costs control as well as experience in the preparation of opinions of probable construction cost. Ms. Richart's experience in Black & Veatch's management consulting business includes independent engineering technical due diligence for conventional energy, renewable energy, transmission lines, wind, and desalination plants.

PROJECT EXPERIENCE

Confidential Clients; Conventional-Fired Plants/Portfolios Independent Engineering; United States; 2014-2018

Manager - Black & Veatch. Ms. Richart has provided independent engineering services in support of various potential acquisitions/sales/refinancing of portfolios of power generation assets or plants in the United States. Ms. Richart's responsibilities have included due diligence of asset characteristics, condition assessment, performance review, operations and maintenance review, review of major agreements and analysis of financial projections, with responsibilities varying by project. Ms. Richart has managed or participated in conducting independent engineering services on over 47 GW of conventional assets.

Confidential Client; Wind Portfolio Independent Engineering; United States; 2016-2016

Consultant - Black & Veatch. Ms. Richart has provided independent engineering services in support of the potential sale of a portfolio of wind assets in the United States. Ms. Richart's responsibilities included performance review, review of major agreements, and analysis of operating cost projections.

PROJECT MANAGER

Expertise:
Cost Controls; Data Analysis and Presentation; Planning and Scheduling; Project Management; Technical Due Diligence

Education
Masters, Business Administration, Finance, University of Kansas, 2011, United States
Bachelor of Science, Industrial Engineering, University of Nebraska - Lincoln, 2008, United States

Professional Registration
Certification, Krystal R. Richart, Industrial, E-14519, Nebraska, United States, 2012

Total Years of Experience
10

Black & Veatch Years of Experience
10

Confidential Client; Charrua-Ancoa Transmission Project; Chile; 2015-2015

Consultant - Black & Veatch. Analyzed the project schedule and the terms of the engineering, procurement and construction (EPC) contract for reasonableness, use of industry best practices, and consistency to identify potential areas and magnitudes of schedule delay risk for an approximately 200 km 500 kV transmission line.

Confidential Client; Wisconsin Utility Plant Independent Engineer; Madison, Wisconsin, United States; 2014-2015

Consultant - Black & Veatch. Senior analyst for independent engineering services in support of a potential sale of assets in Wisconsin. Collected and analyzed historical operating data, assisted in development of operating projections, and participated in site visits.

Confidential Client; Interchile Transmission Project; Chile; 2014-2015

Consultant - Black & Veatch. Analyzed the project schedule and the terms of the engineering, procurement and construction contracts for reasonableness, use of industry best practices, and consistency to identify potential areas and magnitudes of schedule delay risk for an approximately 1,000 kilometer (km) 500/220 kV transmission line.

Sewerage and Water Board of New Orleans; Annual Report on Operations; New Orleans, Louisiana, United States; 2015-2015

Consultant - Black & Veatch. Consultant assisting in the preparation of the 2014 annual report on operations for water, wastewater and storm drainage utilities, including evaluation of management, operations, financing and compliance with bond covenants.

Washington Suburban Sanitation Commission; FY2017 Executive Asset Management Plan Alternatives Evaluation; Laurel, Maryland, United States; 2015-2015

Senior Analyst - Black & Veatch. Senior analyst for alternatives evaluation to support WSSC in the development of their 2017 Enterprise Asset Management Plan Business Case. Effort included developing forecasted 30 year capital plans optimizing on level of service, risk, and cost.

BHP Billiton; Escondida Water Supply; Antofagasta, Chile; 2011-2014

Lead Planner - Black & Veatch. Lead Planner, assisted in preparation of a study level resource-loaded, quantity-loaded engineering, procurement and construction (EPC) schedule for the purpose of validating the proposed project timeline and assisting the client in obtaining project funding. Assisted in preparation of the baseline engineering and procurement portions of the EPC schedule and identification of contractual key performance indicators (KPIs).

Led schedule and cost control functions on an EPC project with over a $100 million total professional services fee, ensuring that the engineering documents and procurement services were delivered to support construction and planned KPI metrics were achieved. Developed, prepared and presented schedule and cost reports to clients, management, and team members, identifying trends and variances.

Analyzed schedule and cost deviations from plan to determine and forecast project variations and developed recovery plans, when necessary. Analyzed the EPC schedule to determine contractual milestones for suppliers. Evaluated supplier bids for conformance to required schedule and identified risks within the proposal schedule. Evaluated suppliers' baseline and monthly schedule updates for conformance to schedule requirements and contractual milestones.

Johnson County Wastewater; Mill Creek Regional Effluent Tunnel; Johnson County, Kansas, United States; 2010-2014

Project Controls - Black & Veatch. Helped to create a cost-loaded, logic driven schedule of design activities. Performed cost control functions and earned value analysis. Performed reviews of the contractor's P6 schedule to evaluate progress and performance, to assist in evaluation of pay applications, and to provide the client an estimate of the contractor's cash flows.

Irvine Ranch Water District; Biosolids & Energy Recovery Facilities Project; Irvine, California, United States; 2010-2013

Project Controls - Black & Veatch. Created a logic-driven schedule of design activities which progressed on a monthly basis. Performed cost control functions including production of cost reports, earned value analysis, production of cost forecasts, and trend management.

Various Clients; Cost Estimating Experience; United States; 2008-2013

Estimator - Black & Veatch. Ms. Richart's cost estimating experience includes assistance in creating engineering opinion of probable construction costs, including the following responsibilities:

○ Performed takeoffs from drawings and specifications to develop

quantities to use in the opinion of probable construction cost.
○ Assisted in the development of the estimate's work breakdown structure and reporting format.
○ Used the Timberline estimating tool to apply location-appropriate productivity rates and material costs to quantities in order to develop direct costs.
○ Assisted in identification and proper application of markups to achieve appropriate indirect costs.

These responsibilities were performed on a number projects. Below is a representative list of the types of projects estimated:

○ San Diego County Water Authority | San Vicente Dam Raise, Lakeside, California | 2009 – 2010
○ Irvine Ranch Water District | Biosolids & Energy Recovery Facilities Project; Irvine, California |2010-2013
○ Reading, PA | Reading Wastewater Treatment Plant, Reading, Pennsylvania | 2008-2009
○ Orange County Water District | Initial Expansion of the Groundwater Replenishment System; Orange County, California |2009 – 2010

Orange County Water District; Initial Expansion of the Groundwater Replenishment System; Orange County, California, United States; 2009-2010

Project Controls - Black & Veatch. Helped to create a logic-driven schedule of design activities that were progressed on a monthly basis. Analyzed the schedule to identify areas of potential impact and modified the schedule when scope changes affected the baseline schedule.

Developed a deliverables-based, earned value management system used to report progress internally and to create monthly progress reports to the client.

American Structurepoint; East Chicago Water Treatment Plant; Indiana, United States; 2009-2010

Project Controls - Black & Veatch. Created a cost loaded, logic-driven schedule of detailed design activities including subcontract responsibilities and vendor deliverables.

Modesto Irrigation District; Domestic Water Project – Phase 2, Plant Expansion CM Services; Modesto, California, United States; 2009-2009

Project Controls - Black & Veatch. Performed schedule reviews of contractor's Primavera schedule to ensure the contractor properly maintained the schedule and to identify areas of concern. Evaluated the impacts on the schedule's critical path and checked for conformance to the contract schedule specifications.

City of Reading; Reading Wastewater Treatment Plant; Pennsylvania, United States; 2008-2009

Project Controls - Black & Veatch. Created a detailed logic-driven Primavera schedule of design activities to be performed in multiple offices around the world. Created a work breakdown structure used to create various reports for submittal to client staff.

Craig M. Preuss, SMIEEE, MSEE, PE

Craig Preuss is the subject matter expert at Black & Veatch for IEC 61850, DNP3, and cybersecurity (both physical security and cyber security) associated with distribution automation and substation integration and automation systems. His extensive project experience includes project management, consulting, detailed engineering, and construction support tasks. He creates system architectures with the supporting cost/benefit models and technology, infrastructure, and application evaluations. He manages, leads, and performs the design, configuration, installation, testing, and commissioning of these systems. His architectures address integration and interoperability challenges and problems in protocols, configurations, North American Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) compliance, and networks. He is familiar with Energy Management Systems (EMS), Distribution Management Systems (DMS), Generation Management Systems (GMS), Outage Management Systems (OMS), and Supervisory Control and Data Acquisition (SCADA) systems.

Craig is a recognized industry leader and participates in and leads the development of IEEE standards. In 2016, he was appointed Secretary of the new IEEE Power and Energy Society (PES) Power System Communications and Cybersecurity (PSCC) Committee. In 2015 and 2016, he was involved in the reorganization of the IEEE PES to align the technical organization with the evolution towards smart grid. One result was the creation of the PSCC Committee to specifically address cybersecurity within the PES. A second result was the expansion of the Power System Relaying (PSR) Committee to the Power System Relaying and Control Committee, expanding coverage of utility automation across generation, transmission, and distribution. Under his guidance, both of these PES Committees have taken in work from the now-dissolved IEEE PES Substations Committee C0 Data Acquisition Processing and Control Systems Subcommittee. Between 2009 and 2016, Craig was the chair of the IEEE PES Substations Committee C0 Subcommittee. During his tenure the subcommittee expanded from eight active working groups to eighteen and in 2016 he was awarded the IEEE PES Technical Committee Distinguished Service Award. His IEEE work includes:

C37.1, chairing the completion in 2008 of the standard for SCADA and automation systems. He is chair again and responsible for the split of the standard into a series of standards, C37.1.x.

2030.100, implementing IEC 61850 substation automation systems, which addresses a significant gap in IEC 61850 - how to actually implement IEC 61850.

2030.101, addressing how to design and implement substation time synchronization systems.

ELECTRICAL ENGINEER LEVEL 06

Expertise:
Distribution Automation; DNP3 (IEEE 1815); IEC 61850; IEEE Standards; NERC CIP; Optical fiber cables in substation; Substation networking, TCP/IP, RS-232. RS-485; Substation Automation; SCADA

Education

Masters, Electrical Engineering, Power Systems, Illinois Institute of Technology, 1996, United States

Bachelors, Electrical Engineering, Power, Valparaiso University, 1990, United States

Professional Registration

License, Professional Engineer, Electrical, 37650, Washington, United States, 2001

License, Licensed Professional Engineer, Electrical, 62.051206, Illinois, United States, 1996

Total Years of Experience

26.9

Black & Veatch Years of Experience

19.1

Professional Associations

IEEE Standards Association - Member

Power and Energy Society - Member

Institute of Electrical and Electronics Engineers - Member

Language Capabilities

Office Location

Overland Park, Kansas, USA: United States

1815, specifying the DNP3 protocol and 1815.1 specifying its interoperability with IEC 61850. He was instrumental in DNP3 adoption as IEEE Std 1815 in 2010.

2030.102.1, providing a standard profile for IPSEC implementations to substations.

1615, creating a recommended practice for network communication in electric power substations from first publication to recent update.

1711 standards, creating cryptographic protocols for the cyber security of substation serial links.

1686, creating a standard for substation Intelligent Electronic Devices (IED) cyber security standards through initial publication and recent revision.

C37.238, creating the original IEEE 1588 profile for precision time protocol in power system applications, leading the creation of a joint working group with the PSR Committee.

1613 and 1613.1, creating environmental and testing requirements for communications networking devices and its expansion from substations to the smart grid, through several updates, most recently as the working group Secretary and as one of the technical editors.

C37.240, creating cyber security requirements for substation automation, protection and control systems, where he was vital in establishing this joint working group with the PSR.

PROJECT EXPERIENCE

Kansas City Power and Light (KCP&L); Various Generation Projects; United States; 2016-In-Progress

Engineering Manager - Black & Veatch. Engineering manager responsible for managing the scope, schedule, and budget for Telecom's subproject. Also responsible for overall system architecture, design approval and managing construction support.

The projects involved adding SEL RTACs to various switchgears to collect data from SEL IEDs and from Beckwith IEDs. The data collected via SEL and DNP3 protocols over RS232 and RS485 networks and is reported back the plant control system via Modbus. One plant uses a Modbus firewall manufactured by Tofino.

Detroit Edison; Zenon, Temple, Stone Pool, and Hilton Road Substations; Michigan, United States; 2012-In-Progress

Engineering Manager - Black & Veatch. Engineering manager responsible for managing the scope, schedule, and budget for Telecom's subproject. Also responsible for overall system architecture, design approval and managing construction support.

Black & Veatch began supporting Detroit Edison's migration to IEC 61850 in 2012 on the Zenon Substation project, a new substation installed with an IEC 61850-based substation automation system. As part of this project, provided engineering management and consulting services to support the transition from the old automation system design to a new Ethernet based system that implements IEC 61850 MMS for SCADA data collection and GOOSE messaging for two protection schemes. As part of the B&V design process, we were able to define gaps in IEC 61850 implementations that led to the incorporation of the DNP3 protocol and other protocols in the design. The design uses Cisco Connected Grid networking equipment, Basler relays, and SEL relays. The data concentrator is the SEL RTAC.

Following that work, Black & Veatch was awarded work on subsequent new substations: Temple, Stone Pool, and Hilton Road Substations. Theses project move all data collection to DNP3 TCP/IP and retained IEC 61850 GOOSE messaging, while providing a path to full IEC 61850 implementation when better supported by Detroit Edison's selected vendors. Work was completed in 2016 to implement a transformer paralleling scheme using GOOSE messaging as supported by the Beckwith M2001D units.

Cross Texas Transmission; CTT Engineering Services; Texas, United States; 2016-2016

Engineering Manager - Black & Veatch. Engineering manager responsible for managing the scope, schedule, and budget for Telecom's subproject. Also responsible for design approval and managing construction support.

This project involved engineering management for substation automation system configuration and construction support services supporting Black & Veatch Power Delivery's addition of facilities at two substations and a new substation. The system architecture includes DNP3 and IEC 61850 with GOOSE and MMS messaging.

Yuba County Water Authority; Colgate Powerhouse SCADA Upgrade; California, United States; 2015-2016

Engineering Manager - Black & Veatch. Engineering manager responsible for managing the scope, schedule, and budget for Telecom's subproject. Also responsible for overall system architecture, design approval and managing construction support.

This project involved engineering management for an upgraded generation protection, control and automation system with an SEL RTAC, collecting data from a variety of protection devices and reporting that data to the plant control system.

Recurrent Energy; SCADA Specification Review; United States; 2015-2015

Consultant - Black & Veatch. This project reviewed Recurrent Energy's solar plant SCADA specification for SCADA and cyber security best practices supporting NERC CIP version 5 and 6. The work also clarified data requirements, Ethernet network requirements, and deliverable requirements.

Hawaiian Electric; IEC 61850 and Fiber Implementation Strategy; Hawaii, United States; 2014-2015

Consultant - Black & Veatch. This project created an implementation strategy to migrate their substation automation systems to fiber-based and IEC 61850-based technologies. Black & Veatch evaluated the current state and desired future state, identifying gaps and strengths in the organization and in the existing deployment of technology that could be applied to an implementation strategy. The proposed strategy included the steps required, estimated schedule and an estimated budget.

Hawaiian Electric Companies; Distribution Automation Strategy; Hawaii, United States; 2014-2015

Consultant - Black & Veatch. This project created a distribution automation strategy based upon corporate goals, a definition of distribution automation, and financial cost benefit model for the selected applications. The output will be integrated into the overall smart grid filing.

United Illuminating; Substation Automation Projects; Shelton, Connecticut, United States; 2006-2015

Engineering Manager - Black & Veatch. Engineering manager responsible for managing the scope, schedule, and budget for Telecom's subproject. Also responsible for overall system architecture, design approval and managing construction support. Several projects for UI have been completed for distribution and transmission substations. Project work started in 2006 with creating a conceptual system design and architecture, including hardware scoping, network architecture, system design, functional specification, and NERC compliance at transmission and distribution substations. The design provided migration path from DNP3 to IEC 61850. The design has been implemented at the following substations: Trumbull, Singer, Grand Avenue, Broadway, Union Avenue, East Shore, and Pootatuck substations.

Confidential Client; NERC CIPv5 Migration Strategy; Kansas, United States; 2014-2014

Consultant - Black & Veatch. This project developed a migration strategy for meeting NERC CIP version 5 requirements at facilities expected to be Medium Impact BES Cyber Systems. B&V performed site assessments and provided a report detailing the migration strategy and conceptual design drawings for the selected architecture.

A consortium of three companies; CJ Switchyard; Central Java, Indonesia; 2013-2013

Consultant - Black & Veatch. This project developed a specification for an IEC 61850 based substation system. Revisions of the specification were made to specify IEC 61850 requirements.

SunPower; Solar Star; California, United States; 2012-2013

Engineering Manager - Black & Veatch. Engineering manager responsible for managing the scope, schedule, and budget for Telecom's subproject. Also responsible for overall system architecture, design approval and managing construction support.

This project constructed two solar farms with three substations and approximately 300 MW of generation capacity. As part of this larger project, provided engineering management for the substation automation system and all related communications interconnections related to the California ISO, Southern California Edison, and much of the plant external and internal communications. This included the specification of the hardware and connectivity for the substation automation design and communication with the SCADA system for the solar plant. The system utilizes client specified equipment for the network infrastructure, SEL RTAC for data concentration, SEL 735 meters for analog metering and reporting and various SEL IEDs for protection.

Texas Municipal Power Agency; Gibbons Creek Substation; Anderson, Texas, United States; 2009-2013

Engineering Manager - Black & Veatch. Engineering manager responsible for managing the scope, schedule, and budget for Telecom's subproject. Also responsible for overall system architecture, design approval and managing construction support.

This project involved engineering management for a the development of a substation integration and automation system, including network architecture, data flow diagrams, HMI and data concentrator programming, SCADA templates and standards, and cyber security requirements supporting NERC CIP requirements. The system utilizes Subnet Solutions SubstationExplorer as the HMI, SubstationServer for data concentration, and RuggedCom RX1100 and RX5000 network equipment. Subsequent work replaced the RuggedCom equipment with Cisco Connected Grid equipment per new standards. The design was accomplished to minimize network outages and the conversion was successfully accomplished over approximately two days.

Midland Cogeneration Venture; Meter Upgrade; Michigan, United States; 2011-2012

Engineering Manager - Black & Veatch. Engineering manager responsible for managing the scope, schedule, and budget for Telecom's subproject. Also responsible for overall system architecture, design approval and managing construction support.

This project involved engineering management for MCV to install new metering facilities at their generation plant. This project installed SEL-735 meters and SEL RTAC data concentrators on an Ethernet network, providing remote access to the meters through the RTAC and data to the plant DCS using Modbus TCP/IP. The RTAC collects data from the meters using DNP3 TCP/IP. The network design accounted for future support of NERC CIP cyber security requirements. B&V provided complete engineer, procurement, and construction support services. This included programming and testing of the meters and RTAC.

Sempra Generation; Mesquite Power Plants; Nevada, United States; 2010-2012

Engineering Manager - Black & Veatch. Engineering manager responsible for managing the scope, schedule, and budget for Telecom's subproject. Also responsible for overall system architecture, design approval and managing construction support.

This project involved engineering management for the expansion of an existing GE D20 at a combined cycle plant using SEL-2411 distributed I/O. Another project at a solar plant substation included the design of a substation integration and automation system at a solar plant substation including network architecture and data concentrator programming. The system utilizes Cisco CGR and CGS equipment for the network infrastructure and SEL RTAC for data concentration and remote access. Interfaces include the solar plant DCS, CAISO, and SRP.

Choptank Electric Cooperative; Smart Grid Assessment; Maryland, United States; 2011-2011

Consultant - Black & Veatch. The project provided Smart Grid assessment services for Choptank Electric Cooperative. The team evaluated the present environment for SCADA, distribution substation automation, and distribution automation against future needs and requirements. The result was a technology roadmap for implementing new Smart Grid technologies.

Burbank Water and Power; Smart Grid Assessment; Burbank, California, United States; 2011-2011

Consultant - Black & Veatch. This project provided Smart Grid assessment services for Burbank Water and Power. The team is evaluating the present environment for SCADA, distribution substation automation, and distribution automation against future needs and requirements. The result was a technology roadmap for implementing new Smart Grid technologies as part of the SGIG project.

Essar Steel; Substation Expansion; Michigan, United States; 2010-2011

Engineering Manager - Black & Veatch. Engineering manager responsible for managing the scope, schedule, and budget for Telecom's subproject. Also responsible for overall system architecture, design approval and managing construction support.

This project involved engineering management for the development of a substation automation system architecture for the expansion of substation facilities at Essar Steel.

Confidential Client; NERC CIP Readiness Review; Confidential, United States; 2009-2011

Subject Matter Expert - Black & Veatch. Black & Veatch performed a NERC CIP readiness review and served as subject matter expert for substation, SCADA, and network policy and procedure review.

Confidential Client: Southwest Utility; NERC CIP Compliance; Confidential, United States; 2008-2011

Engineering Manager - Black & Veatch. This project involved engineering management and consultancy for NERC CIP compliance at generation stations and SCADA master. This included review of the client's existing SCADA system, generation systems, physical security, and networking for compliance with NERC CIP standards. Also performed was review of processes, procedures, and documentation. A solution was proposed to close gaps in compliance and perform mitigation. A vulnerability assessment was performed on the final design. Work included site visits to generation sites and corporate offices.

PSE&G; Grid Modernization and Network Monitoring; New Jersey, United States; 2009-2010

Engineering Manager - Black & Veatch. This project involved engineering management for the development of a network architecture, bandwidth calculations, data flow diagrams, vendor drawing review, SCADA templates and standards, and cyber security requirements based upon NIST standards for distribution automation and distribution substation automation.

Sharyland; CREZ Transmission; Texas, United States; 2009-2010

Engineering Manager - Black & Veatch. Black & Veatch constructed four substations. This project involved engineering management for a substation integration and automation system, including network architecture, bandwidth calculations, data flow diagrams, HMI and data concentrator programming, SCADA templates and standards, and cyber security requirements based upon NERC CIP standards and IEC 61850 MMS and GOOSE at transmission substations.

American Electric Power; Revenue Metering and Disturbance Monitoring; United States; 2008-2010

Engineer - Black & Veatch. This project involved engineering management for upgrading GE D20 RTUs at transmission substations where B&V Power Delivery upgraded revenue metering. Also for AEP, the Disturbance Monitoring Equipment project installed disturbance monitoring equipment at AEP transmission substations. Work included site visits, procurement, design, D20 configuration upgrades, and upgrade / installation of the substation LAN for IEC 61850 implementation.

Pacific Gas and Eletric; Protection and Automation Projects, RTU Upgrade Projects; Oakland, California, United States; 2008-2010

Engineer - Black & Veatch. This project involved engineering management for upgrading GE D20 RTUs and protection schemes at PG&E substations. Work included design, RTU programming, installation and testing.

Iberdrola; Wind Farm SCADA and Automation Projects; United States; 2008-2009

Engineering Manager - Black & Veatch. Engineering manager responsible for managing the scope, schedule, and budget for Telecom's subproject. Also responsible for overall system architecture, design approval and managing construction support. This project involved engineering management for the development of the protection and control automation logic, SCADA RTU programming, and HMI programming on B&V Power Delivery projects at Iberdrola Wind Farms. Work includes site visits, programming SEL-2032s, SEL-2100s, and HMI.

First Energy; RTU Replacement; Akron, Ohio, United States; 2005-2009

Engineering Manager - Black & Veatch. Engineering manager responsible for managing the project's scope. Also responsible for overall system architecture, design approval and managing construction support.

This project involved engineering supervision for a large RTU replacement program involving RTU point lists, configuration, site assessments, hardware scoping, retrofit concept, vendor engineering, and procurement for the replacement of hundreds of RTUs over several years at transmission and distribution substations. He created point lists and RTU configurations. He supervised quality control process. He supported the field construction by solving installation problems with communications, RTU hardware, and RTU configurations.

First Energy; RIGEL; Akron, Ohio, United States; 2005-2009

Engineer - Black & Veatch. Assisted with RTU design, point lists, and configurations. He also assisted with procurement activities and installation troubleshooting.

Confidential Client: Northeast Utility; NERC CIP Compliance; Confidential, United States; 2007-2008

Engineer - Black & Veatch. This project involved engineering management for the development of NERC CIP compliance at transmission substations and included review of the client's existing SCADA system, substation systems, physical security, and networking for compliance with NERC CIP standards. Also performed was review of processes, procedures, and documentation. A solution was proposed to close gaps in compliance and perform mitigation. A vulnerability assessment was performed on the final design. Work included site visits to all substations and corporate offices.

National Grid; RTU Replacement; Syracuse, New York, United States; 2005-2006

Engineering Manager - Black & Veatch. This project included engineering supervision for the replacement of several transmission and distribution RTUs. The work created new RTU point lists and RTU configuration through site assessments, hardware scoping, creating a retrofit concept, vendor engineering, and procurement.

Pacific Gas and Electric; 500 kv Midway – Vincent Line Relaying Replacement; Oakland, California, United States; 2004-2005

Engineer - Black & Veatch. This project included the design of a substation integration and automation system. This system includes a GE IPServer polling SEL relays using SEL Fast Meter and polling GE UR relays using Modbus TCP. Scope also included integration with and expansion of the existing GE Harris D20. Also included were system design, installation support, procurement, testing, and field support.

Pacific Gas and Electric; MPAC Substation Project; Oakland, California, United States; 2003-2005

Engineer - Black & Veatch. This project included the design of a substation integration and automation system. The system uses a Hathaway SIS600 polling SEL relays using SEL Fast Meter and GE UR relays using Modbus TCP, and battery charger and Qualitrol 509-100 using serial DNP3. The project included system design, procurement, and testing.

Bonneville Power Administration; BPA Autosynch Projects; Vancouver, Washington, United States; 2004-2004

Engineer - Black & Veatch. This project created an autosynch system design and procurement to modernize the BPA autosynch scheme from Beckwith electromechanical relays to microprocessor-based devices.

Azusa Light & Water; Kirkwall Substation RTU Installation; Azusa, California, United States; 2003-2004

Project Engineer - Black & Veatch. This project created a substation automation system using Modbus TCP Ethernet network with RuggedCom switches and GE UR relays. A Wonderware HMI polls GE UR relays using a Modbus TCP I/O server from KepWare. SNMP data is collected from RuggedCom switch using iSNMP. SCADAlarm software is used for alarm call-out. Help and Manual software was used for manual and help files. The project included complete design, procurement, documentation, installation, testing, training, and field support.

Pacific Gas and Electric; Northeast San Jose Reinforcement; San Jose, California, United States; 2002-2002

Engineer - Black & Veatch. This project designed a substation integration and automation system. The system included a GE Harris D20 with SEL, GE UR, and other IEDs. Included were system installation, procurement, testing, and field support.

Portland General Electric; Leland Substation RTU Installation; Portland, Oregon, United States; 2002-2002

Engineer - Black & Veatch. This project created a substation integration and automation system using a Modbus TCP Ethernet network layout. Also involved were system point list modifications. Programming was accomplished using ProWorx NxT software for a Modicon Quantum PLC for polling GE UR relays using Modbus TCP and protocol conversion for Landis & Gyr 8979. Work also included field support.

City of Salem; Geren Island Treatment Facility Disinfection and Flouridation Improvements; Salem, Oregon, United States; 2002-2002

Engineer - Black & Veatch. This project included programming new Allen-Bradley SLC to monitor and control new disinfection and fluoridation facilities and a new laboratory. The program monitored outputs from two on-site hypochlorite generation system PLCs via Data Highway RS485 network. He programmed a PanelView human machine interface (HMI) for control at the PLC. He produce PLC map for use in programming of the City's SCADA system.

City of Salem; Franzen Reservoir Disinfection Improvements; Salem, Oregon, United States; 2002-2002

Engineer - Black & Veatch. This project revised existing PLC programming to incorporate new on-site hypochlorite generation system. This program monitored outputs from on-site generation system PLC via Data Highway RS485 network. He programmed flow pacing of two chemical metering pumps. He produced a PLC map for use in programming of the City's SCADA system.

Public Utility District No. 1 of Chelan County; RTU Replacement; Wenatchee, Washington, United States; 2002-2002

Project Engineer - Black & Veatch. This project implemented the previous standard design at distribution substations. Planned, scheduled, conducted, and coordinated detailed phases of engineering work for the total project. The integration system design used Landis & Gyr 8979, Allen-Bradley PLCs, and Modbus Plus. Tested a new ProSoft Landis & Gyr 8979 module. Assisted with system installation and provided client support.

Public Utility District No. 2 of Grant County; Frenchman Hills Design-Build; Ephrata, Washington, United States; 2000-2002

Project Engineer - Black & Veatch. This was an engineer-procure-construct project that included substation integration system design for a new transmission substation. Planned, scheduled, conducted, and coordinated detailed phases of all substation engineering work for the total project. Programmed Wonderware HMI, created a user guide, programmed SEL-2030s, and used ProWorX to program Quantum and Compact PLCs. Performed system installation, testing, checkout, training, and client support.

Public Utility District No. 1 of Chelan County; RTU Standard Design; Wenatchee, Washington, United States; 2000-2000

Project Engineer - Black & Veatch. The project scope included the design of a new distribution substation RTU design standard for distribution substation designs, including older substations with / without an RTU and newer substations with IEDs. Substation integration system included Landis & Gyr 8979, programming an SEL-2030 and Allen-Bradley PLCs, and used Modbus Plus. Developed a user guide and performed system installation, client training and client support.

Public Utility District No. 2 of Grant County; Rocky Ford 230 kV; Ephrata, Washington, United States; 1998-2000

Engineer - Black & Veatch. Project scope included substation integration system design for a engineer-procure-construct project at four transmission substations. Performed substation integration system design; programmed Wonderware HMI; created a comprehensive user guide; resolved problems with a Landis & Gyr 8065 protocol conversion and revenue metering; programmed SEL-2030 communications processors; and performed Y2K compliance testing and certification; programmed using Modsoft and ProWorX programming for Modicon Quantum PLC; and performed system installation, testing checkout, training and client support.

Public Utility District No. 1 of Snohomish County; Mariner Substation; Everett, Washington, United States; 1999-1999

Project Engineer - Black & Veatch. The project scope included the evaluation of available substation RTU designs using a PLC-based RTU and the implementation of the chosen design at a pilot project distribution substation. Compared two system architectures and recommended design best suited for the District. Provided material specification and procurement, programmed Rockwell Software RSView32 and SEL-2030. Developed a user guide for the operator interface. Performed system testing, installation and checkout, on-site client training, and client support.

PRESENTATIONS & PUBLICATIONS

. "GOOSEing Your Paralleling Scheme." 2017 Power Energy Automation Conference and Energy Summit. March 2017

Stefan Nohe, Eric Stranz, and Farel Becker from Siemens; and Dr. Chan Yet Wong (Entergy). "IEC 61850 9-2 Process Bus-Special Considerations for NERC CIP Compliance." Distributech 2017. January 2017

Woody Boles, Ron Nutter. "Are Fast-Flying, Secure GOOSE Messages a Myth?." Distributech 2017. January 2017

. "IEC 61850 Architecture and GOOSE." NERC Emerging Technologies Workshop. November 2016

. "What Happened to the IEEE PES PSR, PSC & Substations Committees…and where are we going from here?." IEEE PES ISGT NORTH AMERICA 2016. September 2016

Woody Boles, Ron Nutter. "Are Fast-Flying, Secure GOOSE Messages a Myth?." PAC World Americas. August 2016

. "Research Priorities and Open Problems in Power Systems Communications and Networking: Panel." IEEE PES General Meeting 2016. July 2016

. "ONE Black & Veatch Effort Demonstates the Application of Cybersecurity to IEC 61850 GOOSE Messaging." Black & Veatch Technical Conference 2016. April 2016

. "IEC 61850 Basics." Black & Veatch Technical Conference 2016. April 2016

. "Substation Timing." Power and Energy Automation Conference. March 2016

Woody Boles, Ron Nutter. "Are Fast-Flying, Secure GOOSE Messages a Myth?." Power and Energy Automation Conference. March 2016

. "IEC 61850: Battle of the Editions." PAC World Americas 2015. September 2015

. "On-line condition monitoring (OLCM) - experience and evolution." IEEE PES General Meeting 2015. July 2015

. "Standards Development in the IEEE." Power and Energy Automation Conference 2015. April 2015

. "To be Edition 1 or to be Edition 2? Which Edition of IEC 61850?." Black & Veatch Technical Conference 2015. April 2015

. "Standards Update From IEEE Substations Committee on Cyber and Physical Security ." DistribuTech 2015. February 2015

. "At least 36 presentations between 1999 and 2015 are not included.." Various. January In-Progress

Andrew Lewis Trump

Mr. Trump has extensive experience working with utility and energy organizations in areas of business development, licensing, and capital planning. He has a broad understanding of North American energy markets, experience leading business development licensing activities for a major North American merchant power plant developer, and expertise in capital planning associated with Smart Grid and Smart Metering. Particular areas of influence and experience include: project finance and capital planning in complex regulated energy markets. Mr. Trump has supported utility clients in:

○ Overall account leadership to the business team in the creation of smart grid infrastructure strategy, business cases, capital spending plans, cost recovery plans, and project evaluations

○ Capital planning and investment strategy updates, including progress-to-date audits and assessments. Metric plan development.

○ Leadership and responsibility for teams of expert witnesses in complex electric utility regulatory licensing and capital project approval proceedings

○ Preparation and delivery of testimony to regulatory agencies in areas of power plant development and smart metering

○ Creation and delivery of detailed financial analysis to support smart metering and generation project valuation (project finance)

○ Comprehensive sourcing (supply chain) team leadership and support, including procurement strategy, contracting process management, RFP development, pricing evaluations, and contract negotiations support (facilitation, negotiation lead, pricing and value analysis, contract development)

Mr. Trump has experience representing merchant power station and electrical transmission projects and rulemaking matters before decision makers at the California Public Utility Commission (CPUC), the California Energy Commission (CEC), the California Environmental Protection Agency, the California Coastal Commission, the California State Lands Commission, various regional California Regional Water Quality Control Boards, the South Coast Air Quality Management District, and the California Air Resources Board. He has authored and provided testimony and technical and feasibility reports in central power station development projects, and has led teams of expert witnesses in these matters before the CEC and other authorizing agencies in both formal hearings and public workshop settings.

Since 2008, Mr. Trump has applied his regulatory experience in the above matters to grid modernization and utility capital planning. He has represented clients in regulatory affairs on smart metering issues and

DIRECTOR

Expertise:
AMI; Capital Planning; Grid Modernization; Regulatory Initiatives; Smart Grid

Education
Master of Arts, Public Policy, Regulatory Affairs, George Mason University, 2010, United States
Certificate, Project Management, Risk, University of California Berkeley, 2000, United States
Bachelor of Arts, Physical Sciences, Harvard University, 1984, United States

Total Years of Experience
16.1

Black & Veatch Years of Experience
5.8

Office Location
Pennsylvania, USA: United States

capital planning, authoring and supporting testimony for utility executives, speaking at hearings, helping to create meaningful regulatory strategies for their smart metering projects, preparing analysis used in proceedings, and presenting at public workshops.

Mr. Trump's background includes positions with Duke Energy (Director, Project Development and Licensing), Schlumberger/CellNet Data Systems (Director, Business Development), California Environmental Associates (Senior Consultant), and Bain & Company (Associate). He also spent two years working in Malawi, Africa working on rural water infrastructure projects.

PROJECT EXPERIENCE

Vectren Corporation; Smart Meter Plan; Indiana, United States; 2016

Consultant - Black & Veatch. Mr. Trump provided strategy consulting services for the development of a comprehensive Smart Meter Plan.

New Jersey Natural Gas; Strategy Consulting; New Jersey, United States; 2016

Consulting - Black & Veatch. Mr. Trump provided strategy consulting services in support and development of the Company's cost benefit evaluation of a $175M natural gas pipeline line expansion project.

California American Water; Consulting Services; California, United States; 2016

Consultant - Black & Veatch. Mr. Trump provided strategy consulting services in support and development of the Company's smart meter regulatory initiative.

City Public Service (CPS); Smart Grid Business Case; Texas, United States; 2014-2016

Consultant - Black & Veatch. Mr. Trump provided leadership and expertise in the development of grid modernization Business Case and project valuation.

Commonwealth Edison (ComEd, subsidiary of Exelon); Smart Meter Business Case; Illinois, United States; 2011-2016

Consultant - Black & Veatch. Mr. Trump provided leadership in the development of ComEd's Smart Meter Business Case and project valuation.

PECO (subsidiary of Exelon); Smart Metering Business Case and Smart Metering Plan; Pennsylvania, United States; 2009-2014

Consultant - Black & Veatch. Mr. Trump provided strategy consulting services in support and development of the company's Smart Metering Business Case and Smart Metering Plan (pursuant to PA Act 129) filed with the Pennsylvania Public Utilities Commission, developing the business case financial model used to assess project economics.

Southern Maryland Electric Cooperative; Smart Meter and Demand Response Plan; Maryland, United States; 2010-2012

Consultant - Black & Veatch. Mr. Trump provided strategy consulting services leading to the development of a comprehensive Smart Meter and Demand Response Plan. He led the development of the company's financial business case, authored materials used for hearings, and represented the utility before the Commission.

Central Louisiana Electric Co-Op (CLECO) Power LLC; Smart Meter Business Case; Louisiana, United States; 2010

Consultant -. Mr. Trump led an engagement resulting in the development of a preliminary CLECO's Smart Meter Business Case and project valuation.

Pepco Holdings, Inc.; AMI Business Case; United States; 2009-2010

Consultant -. Mr. Trump developed key updates to the company's AMI Business Case financial models. He developed the strategy for RFP solicitation, led the evaluation of vendor commercial responses including the evaluation of pricing, and led various parts of the company's negotiation efforts leading to smart meter service contracts, including the development of key contract elements such as warranty, performance measures and incentive structures.

Baltimore Gas & Electric (BGE); MDMS Business Case; Maryland, United States; 2009-2010

Consultant -. Mr. Trump developed BGE's AMI Business Case financial model and RFP commercial and pricing tools, and led the evaluation of vendor pricing. He facilitated and supported BGE's evaluation of vendor proposals, and facilitated vendor negotiations in several areas of the AMI initiative. He also provided guidance and oversight of the cost and operational benefit models used to support BGE's regulatory filings.

San Diego Gas and Electric; AMI Business Case; California, United States; 2008

Consultant -. Mr. Trump developed key updates to the company's AMI Business Case financial models. He developed the strategy for RFP solicitation and led the evaluation of vendor community commercial responses including the evaluation of pricing.

ENERGY STRONG II
ELECTRIC COST-BENEFIT ANALYSIS

B&V PROJECT NO. 197405

PREPARED FOR

Public Service Electric and Gas (PSE&G)

8 JUNE 2018

BLACK & VEATCH

Foreword

During the fourth quarter of 2017, Public Service Electric and Gas Company (PSE&G) requested that Black & Veatch Management Consulting, LLC (Black & Veatch) conduct a cost-benefit analysis of its Energy Strong II Electric Program (ES II Electric Program). The ES II Electric Program is being proposed by PSE&G in its petition to the New Jersey Board of Public Utilities (BPU). A new rule[1] identifies "any applicable cost-benefit analysis for each project" as part of the minimum filing requirements of any Infrastructure Investment Program (IIP) petition to the BPU.

To conduct the cost-benefit analysis, a Black & Veatch team obtained data and information to evaluate the costs and benefits of the ES II Electric Program. The Black & Veatch staff met with PSE&G representatives to review the first Energy Strong program (ES I), to review the subprograms making up the ES II Electric Program, to identify and gather information needed for the analysis, and to review results and conclusions. This report represents the culmination of this effort. A companion report has been prepared for PSE&G's proposed ES II Gas Program.

For this effort, PSE&G provided cost estimates, subprogram descriptions, and other data and information to Black & Veatch to apply within this cost-benefit analysis. Black & Veatch did not provide an engineering review of this material. Rather, Black & Veatch's principal focus was to estimate the benefits of the ES II Electric Program and to place these estimates into a multi-period and over-arching cost-benefit framework.

The principal evaluators for this effort are:

ES II Electric Program
Krystal Richart
Craig Preuss
Andy Trump

[1] The rule became effective upon publication in the New Jersey Register on January 16, 2018, at 50 N.J.R. 630(a). It provides changes to the New Jersey Administrative Code at section 14:3-2A.

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Executive Summary

Public Service Electric and Gas (PSE&G) is seeking the New Jersey Board of Public Utilities' (BPU) approval for its five year, $1.5B Energy Strong II (ES II) Electric Program for hardening and improving its electric distribution system. PSE&G has aligned the ES II Electric Program to the new BPU Infrastructure Investment Program (IIP) rule, the purpose of which is to improve utility system reliability, resiliency, and/or safety. The five-year investment period encompassed by the ES II Electric Program begins in 2019 and continues for five years. This report documents the cost-benefits of the ES II Electric Program, in conformance with the IIP rule. The costs and benefit estimates are organized within four subprograms and are estimated over an approximately 20 year forecast period (2019-2038).

The ES II Electric Program aims to improve the electric distribution system's reliability, to strengthen it from major storms and other disturbances, to configure it in ways so that it can recover more quickly from outages, and to put in place a new communications network and asset control capability that will help PSE&G support future grid needs such as those driven by distributed energy resources (DER). To achieve these goals, the ES II Electric Program addresses both the replacement of aging assets and the installation of new smart infrastructure to help monitor and control the grid. Improving safety for customers and employees alike underlies these investments throughout.

Black & Veatch estimates that over the approximately 20-year period, quantified monetary benefits exceed costs by approximately $2.6B, for a net present value (NPV) of $526M. The cost-benefit analysis separately evaluates each of the four subprograms contained within the ES II Electric Program, and also describes their reliance on each other. Each subprogram has multiple benefits and beneficiaries. The benefits include a large value contribution based on the Value of Lost Load (VoLL). The benefits also include impacts to PSE&G's costs and productivity during both normal day-to-day activities as well as during storm restoration efforts. In short, the subprograms aim to address a wide range of outage conditions, from brief "momentary outages" to multi-day events caused by storms.[2] Significant qualitative program benefits are also identified in this report. These are important benefits but difficult to monetize for a variety of reasons.

Two scenarios have been constructed to develop an understanding of the change that is estimated to occur due to ES II investments. The first covers "business as usual" (BAU), and the second the ES II alternative. The two scenarios are then compared over an approximately 20 year forecast period (2019-2038) to determine incremental effects. This comparison of two scenarios creates a "base case".

The risk faced by the electric distribution system is central to the cost-benefit analysis. "Risk is the measure of the probability and consequence of uncertain future events."[3] Accordingly, to perform the cost-benefit analysis, assumptions are required for both the probability of outage conditions and their nature and severity. To determine assumptions for the later, Black & Veatch worked with

[2] The cost-benefit analysis evaluates outage events based on their estimated nature and scale. Outages are differentiated between "reportable events" (encountered during normal day-to-day events) and "major events" (typically lasting many hours if not days). Improvements that mitigate the impacts of major events are described in terms of hardening and resiliency. Hardening refers to protecting the system so that outages do not occur, while resiliency addresses improving the ability of the system to quickly and efficiently restore service after outages.

[3] Yoe, Charles, Principles of Risk Analysis, p. 1.

PSE&G to gather and inspect seven years (2010 – 2016) of historical outage data, much of it at the circuit and circuit segment level. To address probabilities of outage occurrences, the analysis assumes that the average yearly intensity of outage conditions during these past seven years continues over the approximately 20 year forecast period, and that future outage probabilities are the same as those experienced in the recent past.

COST-BENEFIT RESULTS

Black & Veatch gathered the ES II program costs from PSE&G and then estimated potential additional long-term support costs for this infrastructure extending beyond the ES II investment period.[4] Black & Veatch also worked with PSE&G to estimate benefits through a disciplined step-wise process. ES II Electric Program subprograms will reduce PSE&G operating costs (both capital and annual operations and maintenance (O&M) expense), improve reliability, and lower system risk associated with major storm events, thereby resulting in a hardened system with greater resiliency. Those subprograms that reduce outage frequency and duration are further valued in specific terms of VoLL, a measure of how customers and businesses perceive the value of improved reliability, hardening, and resiliency. VoLL is intended to capture the direct, private costs that are borne by market participants in relation to the hazards, damages, and inconveniences related to outage conditions. It does not reflect many additional indirect costs, externalities, and social welfare impacts.

The subprogram costs, quantifiable, monetized benefits, and the resulting benefit-to-cost ratios are presented in Table 1. The values are nominal dollar values based on a base year of 2018.

[4] This effort is limited to incremental support costs that can be reasonably identified today. The operating cost reductions shown under the benefits will offset some of these incremental costs, so care is needed in their interpretation.

Table 1 Cost and Benefit Estimates and Benefit-Cost-Ratio, by Subprogram (2019-2038)

Subprogram	Costs ($1,000s)			Benefits ($1,000s)			Ratio
	ES II 5 year Investment Cost [5] (A)	ES II Support Cost (B)	Total 20 Year Cost Estimate (C) = (A) + (B)	Cost Reductions (D)	Avoided Outage Costs - VoLL (E)	Total 20 Year Monetized Benefits (F) = (D) + (E)	Benefit-Cost (G) = (F) / (C)
Substation	$906,000.0	$0.0	$906,000.0	$419,207.9	$243,555.0	$662,762.9	0.7
Outside Plant, Higher Design and Construction Standards	$345,000.0	$0.0	$345,000.0	$1,600.9	$958,754.5	$960,355.5	2.8
Contingency Reconfiguration Strategies	$145,000.0	$0.0	$145,000.0	$3,915.0	$1,878,873.9	$1,882,788.9	13.0
Grid Modernization	$107,000.0	$27,226.2	$134,226.2	$110,080.9	$501,900.3	$611,981.3	4.6
Total	**$1,503,000.0**	**$27,226.2**	**$1,530,226.2**	**$534,804.7**	**$3,583,083.7**	**$4,117,888.5**	**2.7**

Of the benefit values identified in Table 1, a significant percentage (87 percent) is associated with the value to customers of reducing outage events. Approximately 71 percent is associated with reducing the effects of major storm events, and 29 percent is related to day-to-day outage events. Outages examined within the cost-benefit analysis range in duration from brief momentary outages to upwards of days in duration.[6] Moreover, 13 percent of total benefit value ($535M) is associated with the value of reducing operating costs during all operating conditions (during outages or otherwise). Importantly, the Superstorm Sandy impacts are not included in the Table 1 results.

The cost-benefit analysis results can be expressed in several ways. As shown, a simple comparison of costs and benefits reveals that for the entire ES II Electric Program, monetized benefits exceed costs by $2.6B, resulting in a benefit-to-cost ratio of 2.7 over the approximately 20-year period.

[5] The direct testimony of Mr. Edward F. Gray for the Energy Strong II Program should be referred to for ES II Program cost estimates.

[6] As noted earlier, VoLL is a measure of directly borne costs, and does not account for many indirect costs, externalities, and social welfare impacts. Additionally, Black & Veatch limits the outage duration reduction estimates due to limits in published VoLL factors. These facts tend to make the analysis conservative. Additionally, as explored in this Report, it is challenging to value improvements to reliability, hardening, or resiliency. This is due in part to the fact that electrical system attributes are not fungible in the short term; customers do not have easily accessible alternatives when electricity is not available. To address this challenge, economists have developed ways to measure a customer's "willingness to pay" for unserved electricity during outages. These measures – and published VoLL factors – are applied to the ES II Electric Program cost-benefit analysis to derive the estimates shown in Table 1.

Additionally, the net present value (NPV) of the benefit and cost impacts is $526M, using a discount factor of 6.9 percent, which aligns with the weighted average cost of capital (WACC) PSE&G utilized in its January 12, 2018 base rate case filing. Figure 1 depicts the approximately 20-year nominal and present value cost and benefit results.

Note that there is additional value associated with avoiding the indirect costs and other impacts caused by outage events. This additional value is not captured in the monetized benefit value displayed in Figure 1. Nor are the additional benefits related to reducing Superstorm Sandy-scaled effects (i.e., catastrophic events).

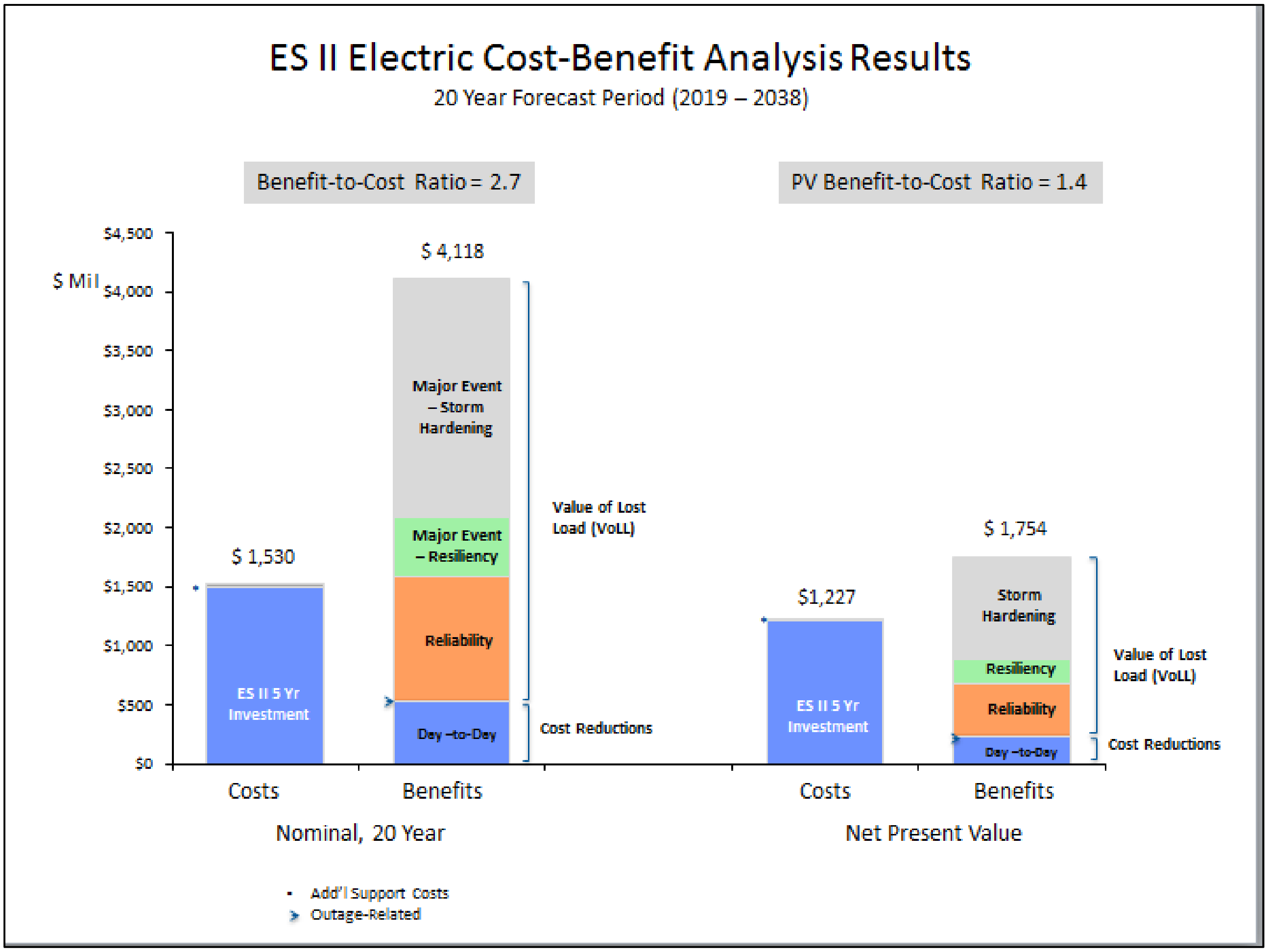

Figure 1 ES II Electric Program Costs and Monetized Benefits (excludes Superstorm Sandy)

Several sensitivity analyses have been developed to explore the range of impacts related to key variables. The most impactful sensitivities are (a) the inclusion of benefits related to reducing Superstorm Sandy-scaled impacts, and (b) changes in the VoLL factors. Including the potential effects of a storm event of the scale and duration of Superstorm Sandy increases total benefit value by $1.4B, resulting in a benefit-cost ratio of 3.6. Reducing the VoLL factors by 20 percent lowers total benefit value by $0.7B, resulting in a benefit-to-cost ratio of 2.2. Increasing the VoLL factors by 20 percent increases total benefit value by $0.7B, resulting in a benefit-to-cost ratio of 3.2.

In Black & Veatch's view, the analysis is conservative for at least seven reasons.

1. The analysis is based on an approximately 20 year forecast period, whereas many of the ES II investments are expected to be in service for many decades, well beyond the benefit forecast period.

2. The outage data excludes the region's experience during Superstorm Sandy, which hit the area with tremendous severity during October 2012.[7]

3. The major storm event outage benefit analysis recognizes, but does not monetize, several important qualitative benefits, such as safety, and many indirect outage-related costs. These benefits are not included in the monetary benefit-cost results discussed here.

4. The analysis ignores the "ramping in" of benefits during the five year ES II investment period. Instead it relies on the assumption that the benefits start to accrue in Year 6.[8]

5. The ES II Electric Program includes the build out of an advanced communications and distribution management system, which positions PSE&G and all of its stakeholders, including its customers, to capture additional future value as grid functions evolve through mandate or independent market forces. These additional benefits are not included in the cost-benefit analysis.

6. The ES II Electric Program allows PSE&G to proactively modernize the electric distribution infrastructure, thereby addressing lifecycle obsolescence concerns in ways not possible under its base capital spending plans.

7. The analysis ignores the effects of growth in customers, load served, or the relative value of electricity in an expanding digital economy.

Black & Veatch believes that the cost-benefit analysis – and especially the estimate of a specific monetary benefit-to-cost ratio -- is one of several inputs to decision makers about the merits of the ES II Electric Program, but it is not dispositive by itself. For example, a significant portion of the PSE&G investment is guided by important asset and risk management findings that are guided by a range of criteria, including safety and environmental performance, and which address the long-term effects of aging equipment.

[7] By way of comparison, PSE&G experienced a total of 2.8B customer interruption minutes (CMI) over the past seven years as part of major events, excluding Superstorm Sandy. Superstorm Sandy by itself contributed 9.8B CMI. Black & Veatch believes it is appropriate to treat Superstorm Sandy in a sensitivity analysis due in part to the unique severity of this event, the length of circuit and substation outages that resulted, and some technical limitations related to the outage data that has been used to compute the ES II program benefits.

[8] There is a minor exception involving the benefit for the Communications Network.

Introduction

OVERVIEW

Public Service Electric and Gas (PSE&G) is seeking the New Jersey Board of Public Utilities' (BPU) approval for its five year, $1.5B Energy Strong II (ES II) Electric Program for hardening and improving its electric distribution system. PSE&G has aligned the ES II Electric Program to the BPU's IIP rule, the purpose of which is to improve electric system reliability, resiliency, and/or safety. The five-year period encompassed by the ES II Electric Program begins in 2019 and concludes in early 2024. This report documents the cost-benefit analysis of the ES II Electric Program. The costs and benefits are organized within four subprograms and are estimated over an approximately 20 year forecast period (2019-2038).

The ES II Electric Program aims to improve the electric distribution system's reliability, to strengthen it from major storm and other disturbances, to configure it in ways so that it can recover more quickly from major outages, and to put in place a new communications network and asset control capability that will help PSE&G support future grid needs such as those driven by DER. To achieve these goals, the ES II Electric Program addresses both the replacement of aging assets and the installation of new smart infrastructure to help monitor and control the grid. Improving safety for customers and employees alike underlies these investments throughout.

The ES II Electric Program covers an extensive range of the utility's distribution system assets. As part of the cost-benefit analysis each subprogram has been evaluated as a stand-alone initiative. Cross-cutting contributions within the program are also identified.

PROGRAM HIGHLIGHTS

The components of the ES II Electric Program are being referred to as "subprograms," which are further subdivided into "subparts," and represent separate investment activities. The organization of the subprograms into their respective subparts along with descriptions is presented in Table 2. Each subprogram has multiple benefits and beneficiaries. The benefits include a large value contribution based on the Value of Lost Load (VoLL). The benefits also include impacts to PSE&G's costs and productivity during both normal day-to-day activities as well as during storm restoration efforts. In short, the subprograms aim to address a wide range of outage conditions, from brief momentary outages to multi-day events caused by storms.[9] Significant qualitative program benefits are also identified throughout. These are important but difficult to monetize for a variety of reasons.

Two scenarios have been constructed to develop an understanding of the change that is estimated to occur due to ES II investments. The first covers "business as usual" (BAU), and the second the ES II Program alternative. The two scenarios are then compared over an approximately 20 year forecast period (2019-2038) so as to determine incremental effects. This comparison of two scenarios creates a "base case".

ES II Electric Program's major objectives include:

[9] The cost-benefit analysis evaluates outage events based on their estimated nature and scale. Outages are differentiated between "reportable events" (encountered during normal day-to-day events) and "major events" (typically lasting many hours if not days). Improvements that mitigate the impacts of major events are described in terms of hardening and resiliency. Hardening refers to protecting the system so that outages do not occur, while resiliency addresses improving the ability of the system to quickly and efficiently restore service after outages.

- Improved system resiliency through the rebuilding of substations that, in addition to new substation equipment, will include the latest relays and SCADA controls. These improvements will help the system recover quickly and efficiently from outages.
- Improved system hardening through:
  - The raising or elimination of substations that are below base flood elevations plus one foot, reducing the likelihood of customer outages due to flooding.
  - The deployment of spacer cable, additional reclosers, and reclosing devices, all of which reduce the likelihood of major system disruptions due to major storm damage.
- Improved system reliability through:
  - The upgrading of aging substations with modern equipment. This will reduce the risk of outages due to equipment failures and bus duct faults.[10]
  - The deployment of spacer cable, reclosers, and reclosing devices, thus reducing customer inconvenience for localized system disruptions that are typically under one minute.
- Reduced system obsolescence through replacement of aging communications infrastructure. Communication systems are a critical technology supporting critical PSE&G operations and maintenance activities. Safety and reliability risks grow when PSE&G cannot adequately monitor, control, and respond to momentary and outage conditions.
- Reduced outage durations through the deployment of new communication system, smart infrastructure, and Advanced Distribution Management System (ADMS). Together these systems and tools will improve PSE&G's situational awareness when restoring the system after a major disturbance.
- Support advanced grid operations. The proposed communications system and ADMS provide a platform that will position PSE&G to be able to monitor, secure, interact with, and support the distribution grid as the demands of DER grow.

To achieve these goals, PSE&G is proposing to rebuild old and aging substations, replace substations at risk of flooding, install smart control and monitoring devices on distribution circuits (reclosers, ties, and fuses), and install spacer cable on miles of vulnerable "open wire" overhead circuits. A new communication system is also included in the ES II Electric Program because of the needs for a communications network that exhibits high reliability, high bandwidth, low latency[11], and enhanced security. The proposed communications system will be owned and operated by PSE&G and designed to meet the growing demands of smart infrastructure and asset management. It also enables the full capabilities of the new ADMS, which depends on highly reliable communication to field devices (e.g., substations, reclosers).

PROGRAM ORGANIZATION AND COST ESTIMATES

The organization of the ES II Electric Program along with a description of each subprogram subpart is presented in Table 2. Additionally, detailed descriptions of each subpart and a comprehensive review of the benefits associated with completion of each are presented in *Appendix B – ES II Electric Subprogram Details.*

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[10] A bus duct is an assembly of busbars energized at distribution level voltages with associated connectors and insulation support, all completely contained within a metal enclosure to protect from mechanical damage.

[11] *Latency* for a communication network is the time it takes for data to traverse a network from a sending device to a receiving device. Several industry-accepted methods of measurement are available, including measuring the time the data packet is on the wire and measuring time from signal input to output.

Table 2 ES II Electric Program Subprograms

SUBPROGRAM (AND SUBPARTS)	DESCRIPTION
Subprogram: Substation	
Station Flood and Storm Surge Mitigation	Raise 16 substations based on PSE&G field survey results and FEMA flood guidelines.
Station Upgrades 26/4kV Station	Upgrade 15 stations, selected using the Asset Risk Model and other management knowledge and tools.
Subprogram: Outside Plant Higher Design and Construction Standards	
Spacer Cable	Upgrade approximately 500 miles of circuits with open wire construction to spacer cable (including replacement of some poles). The proposed circuits are included based on historical performance and number of customers served.
Subprogram: Contingency Reconfiguration Strategies	
Increased Sectionalization	Convert all existing (690) two section overhead 13 kV circuits to three section circuits, enhance 500 overhead 4 kV radial circuits with a recloser to create two sections, and replace 100 three phase branches with and without fuses with branch reclosers. The proposed circuits were selected based on historical performance and number of customers served.
Reclosing Devices	Install approximately 3,200 reclosing devices. The proposed circuits were designated based on historical performance and number of customers served.
Subprogram: Grid Modernization	
ADMS	Implement an Advanced Distribution Management System to provide new and improved functionality in order to better manage the real-time electric distribution network within one integrated solution.
Communication Network	Construct a high-speed, wireless mesh network connecting reclosers and new reclosing devices to new and existing fiber optic cable infrastructure at PSE&G substations.

ANALYSIS METHODOLOGY

To perform the cost-benefit analysis, Black & Veatch relied on information from PSE&G (a) to develop the method of constructing a cost-benefit analysis, (b) to define assumptions and operating data, and (c) to define the scenarios that underpin the analysis.

The cost-benefit analysis relies on two scenarios. Both scenarios represent a view of the PSE&G business over the approximately 20 year forecast period (2019-2038). One scenario addresses "business as usual" (BAU) and assumes the ES II Electric Program does *not* occur. The other scenario assumes implementation of the ES II Electric Program. By comparing the costs and benefits of the two scenarios across a common time frame, it is possible to estimate incremental effects of the proposed ES II Electric Program improvements.

General Considerations

Black & Veatch has included other important cost-benefit analysis methodology considerations into the analysis, including:

- A focus on strictly incremental investment effects.
- Adoption of an evaluation period that has a reasonable relationship to the life of the investments.
- Acknowledgement of the important contribution of qualitative benefits.
- Linking benefits to specific causes and other intermediary impacts, rooted in judgment of how the technology functions.
- Addressing interdependencies.
- Identifying key assumptions, noting their degree of certainty, and evaluating how they influence results.

The cost-benefit analysis was constructed using nominal dollar values, with a base year of 2018. An inflation factor is applied to the calculated benefits in future years. A discount factor has been used that supports the avoidance of disagreement about the societal versus private nature of beneficiaries.

Approach on Benefit Determination

The ES II Electric Program cost-benefit analysis was conducted in a “bottoms up” way by addressing each subpart of the subprograms and related technology, identifying the nature of the improvements, and assessing the manner in which they impact outages and other conditions. Working with PSE&G SMEs, Black & Veatch introduced a structured process to estimate the specific beneficial outcomes by “mapping” each impact, identifying the cause and its downstream consequences, or effects. Some of the expected beneficial outcomes were determined to be significant and could be reasonably quantified and further monetized while others were determined to be significant but difficult to quantify and were, therefore, determined to be qualitative. The assumptions used to quantify impacts are well documented.

The benefit “mapping” is documented in the Benefits Matrix shown in *Appendix A – Benefit Matrix*. It includes all the significant benefits identified, and indicates their nature (monetized or qualitative). A review of this Appendix provides an effective overview of the study and should help readers understand the balance of this report.

Understanding the impact of an investment is an important step within of the cost-benefit analysis. Benefit estimates should be supported by explanations of how a proposed technology actually functions in order to drive impacts. This means, for example, one must describe how circuit reclosers reduce the occurrence of day-to-day sustained interruptions before applying data and reduction factors to estimate improvements. Additionally, secondary levels of impacts – such as reduced field trips to investigate outage conditions – should also be explored to understand how they too might translate into specific impacts (such as reduced O&M costs, in this instance). This discipline -- of linking investment, technology, functionality, and multi-layer impacts -- is a key step in the benefit development process. Applying this process, Black & Veatch has captured 40 separate significant impacts of ES II Subprograms, thereby recognizing a wide range of effects and further beneficial outcomes.

Following the benefit mapping process, Black & Veatch requested and obtained detailed data to support the benefit quantification. The cost-benefit analysis process included data inspection, filtering, structuring and analysis, and follow up with PSE&G SMEs to refine and complete the analysis.

DEFINITIONS

Black & Veatch discussed several key concepts with PSE&G to help categorize the purpose and benefits of PSE&G's ES II Electric Program. Several useful technical descriptions related to substations are also provided.

Reliability

For an electric distribution utility such as PSE&G, reliability is the ability to meet the electricity needs of end-use customers by providing uninterrupted electric service. Reliability-related outages are all outages experienced, recorded, and reported during each quarter _other_ than (a) momentary outages as defined by the Institute of Electrical and Electronics Engineers (IEEE) standard 1366, and (b) major events, in accordance with N.J.A.C. 14:5-8.7. Reliability events are also referred to as occurring during "blue sky" conditions. Each subprogram was inspected for how it would impact the system during normal day-to-day operations, potentially reducing outage conditions. Only historical circuit data meeting this day-to-day condition is used for *reliability-scale* events.[12]

Resiliency and Hardening

Broadly speaking, infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events on the electric system. The effectiveness of a resilient infrastructure depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a disruptive event.[13] Over time, utilities have worked to fine tune the understanding of resiliency.[14] For purposes of this report this concept is further decomposed to reflect frequency and duration attributes. If the improvements support reductions in outage *frequency*, this is classified as *hardening* the system. These changes reduce likelihood of the outage condition arising.[15] If the improvements support reductions in outage *duration*, this is classified as improving the system's *resiliency*. They help PSE&G restore the system more quickly after a major outage. In short, resiliency in this sense

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[12] For purposes of this report, reliability-scale events are outages that include (a) the effects of *momentary outages* (short-term effects) and (b) *power quality* events such as voltage sags and swells. Additionally, (c) they are extended outages that are _*not*_ included under the definition of a "major event". The term *momentary outage* in this report aligns to the definition in N.J.A.C. 14:5-8.7, which references IEEE 1366. *Momentary outages* can disrupt manufacturing processes and cause consumers inconveniences. *Power quality* is defined according to the N.J.A.C. 14:5-1.2, http://www.lexisnexis.com/hottopics/njcode/. "Power quality problems include, but are not limited to, disturbances such as high or low voltage, voltage spikes or transients, flickers and voltage sags, surges and short-time overvoltages, as well as harmonics and noise." Voltage swells can harm sensitive electronic equipment.

[13] Another view of resiliency is provided in a recent Sandia Lab report in which it defines resiliency as "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents." Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States, Sandia Report SAND2014-18019, September 2014, Sandia National Laboratories.

[14] Resiliency-scale events align in the literature with the New Jersey Administrative Code's definition of major events provided in footnote 16.

[15] In the recent Staff Report issued by the U.S. Department of Energy, hardening is defined as: "Hardening of an asset or system refers to physically changing infrastructure to make it less susceptible to damage. Hardening improves the durability and stability of an energy structure, making it better able to withstand the impacts of hurricanes, weather events or attacks." See Staff Report to the Secretary on Electricity Markets and Reliability, US Department of Energy, August 2017, page 63.

refers to the ability of an electric distribution utility to recover quickly and efficiently from outages, thereby reducing the outage durations.

Major Events

"Major events" as used by PSE&G and Black & Veatch in this report, are defined in the N.J.A.C. 14:5-1.2.[16, 17] Major events are mostly associated with storm and major outages.

Substations Distinctions

Class H substations are fed from transmission sources (e.g.,138 kV and above). The ES II Electric Program involves raising the 13kV switchgear at these substations, which is a breaker and one-half arrangement in switchgear. Class H substations were installed starting in the early 1960s and have been PSE&G's standard distribution substation since that time.

Class C substations are 26/4 kV substations with open air 26 kV high side equipment and 4 kV metalclad switchgear. The substations are fed from either two or three transformers that feed a common 4 kV bus that then feeds the individual circuits. Each circuit has a three-phase breaker and individual reactors and voltage regulators on each phase. Class C substations were first installed in 1938 and became the company standard after World War II until the early 1960s. PSE&G has an ongoing program to upgrade the 26kV portions of these stations to 69kV facilities.

Class A or B substations are 26/4 kV substations with open air 26 kV high side equipment and 4 kV equipment and relays in a brick building. Each circuit has a three-phase breaker and individual reactors and voltage regulators on each phase. Class A substations were first installed in the 1910s and utilized until the development of the Class C design around 1938. PSE&G has an ongoing program to upgrade the 26kV portions of these stations to 69kV facilities.

Unit substations are a single piece of equipment, which includes both a transformer and breaker that support a single circuit.

OUTAGE RISK

Electrical distribution system risks related to outage conditions are central to the cost-benefit analysis. "Risk is the measure of the probability and consequence of uncertain future events."[18] To

[16] "Major event" means any of the following as defined according to the N.J.A.C. 14:5-1.2 online at http://www.lexisnexis.com/hottopics/njcode/.

1) A sustained interruption of electric service resulting from conditions beyond the control of the EDC, which may include, but is not limited to, thunderstorms, tornadoes, hurricanes, heat waves or snow and ice storms, which affect at least 10 percent of the customers in an operating area. Due to an EDC's documentable need to allocate field resources to restore service to affected areas when one operating area experiences a major event, the major event shall be deemed to extend to those other operating areas of that EDC, which are providing assistance to the affected areas. The Board retains authority to examine the characterization of a major event;
2) An unscheduled interruption of electric service resulting from an action:
   i) Taken by an EDC under the direction of an Independent System Operator;
   ii) Taken by the EDC to prevent an uncontrolled or cascading interruption of electric service; or
   iii) Taken by the EDC to maintain the adequacy and security of the electric system, including emergency load control, emergency switching and energy conservation procedures, which affects one or more customers;
3) A sustained interruption occurring during an event, which is outside the control of the EDC and is of sufficient intensity to give rise to a state of emergency or disaster being declared by State government; or
4) When mutual aid is provided to another EDC or utility, the assisting EDC may apply to the Board for permission to exclude its sustained interruptions from its CAIDI and SAIFI calculations.

[17] Major events are subject to the reporting requirements outlined in N.J.A.C. 14:5-8.9 and 8.10.

perform the cost-benefit analysis, assumptions are required for both the probability of outage conditions (the likelihood of outage events) and their nature and severity (the consequence of the event occurring). Black & Veatch gathered seven years (2010 – 2016) of historical outage data, much of it at the level of specific circuits and circuit segments, which was then applied to the forecast period of the cost-benefit analysis.

To address probabilities of outage occurrences, the analysis assumes that the average yearly intensity of outage conditions during the past seven years continues over the approximately 20 year forecast period, that is, it is assumed that future outage occurrences are the same as those experienced in the recent past. One exception is the exclusions within the base case of Superstorm Sandy-level impacts (October 2012). However, the data for Superstorm Sandy impacts were used in a sensitivity analysis.[19]

The relationships of historical experiences and data to the approximately 20 year forecast period are illustrated in Figure 2.

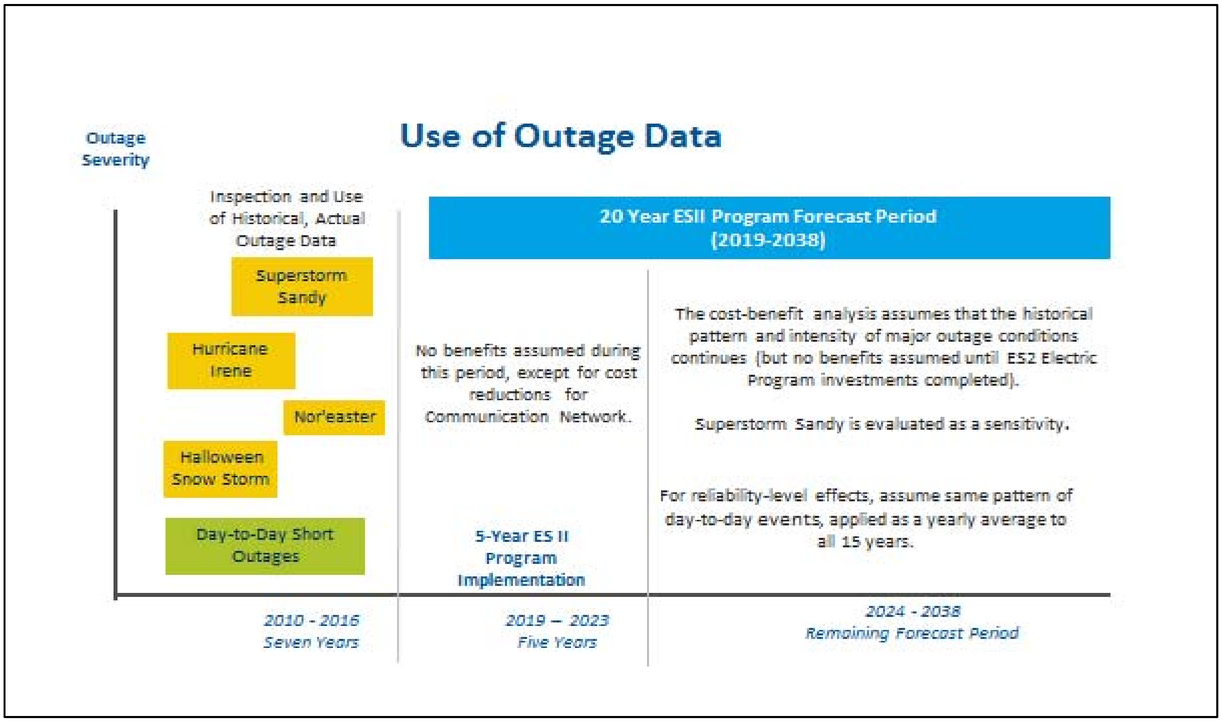

Figure 2 **Relationship of Historical Outage Data to the ES II Electric Forecast Period**

[18] Yoe, Charles, Principles of Risk Analysis: Decision Making Under Uncertainty, Baca Raton: CRC Press, Taylor & Francis Group, 2002, page 1.

[19] Excluding Superstorm Sandy from the base estimates omits the most significant major storm event of the recent past, and a large number of outage minutes from the benefit calculations. Outage minutes attributable to Superstorm Sandy were five times as great as the cumulative total of all other major storm events during the period. Therefore, storms that replicate actual historical experience would increase the estimated VoLL benefit values by several factors. However, due to the severe intensity of Superstorm Sandy and the amount of destruction to the distribution system that occurred as a result, PSE&G and Black & Veatch believe that making specific inferences about how the ES II improvements would reduce this level of impact through storm hardening is more error prone. This is why this catastrophic event is excluded from the base data but looked at in a sensitivity analysis.

Black & Veatch believes that this approach of applying an average rate of outage experience based on seven years of actual major event experience (excluding Superstorm Sandy) provides a reasonable way to consider the probability of future storms and major disruptions, and their degree of intensity and destructiveness. Upon inspection, applying the historical day-to-day sustained interruption rate to future years is also reasonable, in Black & Veatch's view, given the underlying pattern of occurrence of these outage conditions and the nature of the technology and systems being deployed to reduce them.

RECENT HISTORICAL DATA COLLECTION AND USE

PSE&G has collected outage data over the past seven years (2010 - 2016) by circuit and substation. The historical outage data includes information such as number of extended events per year, number of extended customers interrupted (CI) per year, and number of customer minutes of interruption (CMI) per year by circuit and by substation. The circuit outage data have been parsed between events that are sustained interruption events (reliability-related) and "major event" conditions. Additionally, all circuit outage data have been filtered to exclude outage data that is not applicable to the ES II Electric Program. For example, all outages related to underground circuits have been excluded (the ES II Electric Program does not include any underground scope in the subprograms).

Furthermore, for the Spacer Cable, Increased Sectionalization, and Reclosing Devices subparts, the circuits being proposed have been selected based on historical performance during "blue sky" conditions and the number of customers served. This is reasonable due to the unpredictable nature of major events. One cannot predict what circuits will be impacted by the next major storm event; however, for circuits that do not perform well during normal day-to-day operations (as observed over an extended period of time), it is reasonable to assume that the poor performance will persist. Finally, only the actual historical outage data associated with the selected circuits for each subpart have been analyzed and applied to the benefit estimates (broad averages have not been used).

Additionally, some overlap exists between the circuits amongst the subprogram subparts, particularly the selected circuits for the Spacer Cable (part of the Outside Plant Higher Design and Construction Standards subprogram) and the recloser installation (part of the Contingency Reconfiguration Strategies subprogram). This, in turn, means there is some (minor) double count of outage data. Black & Veatch carefully inspected these circumstances, identified the overlapping data, and adjusted the subprogram outage impact computations to eliminate the impact of this overlap.

Additional detail regarding how the seven year (2010 – 2016) empirical outage data were utilized to determine the estimated annual benefit for each subprogram subpart is located in *Appendix D – Historical Outage Data Applied to Benefit Estimates.*

ES II Electric Program Incremental Support Costs

PSE&G provided to Black & Veatch the forecasted ES II Electric Program expenditures, which is included in the direct testimony of Mr. Edward F. Gray of PSE&G. These costs are summarized in Table 1, which appears earlier in this report.

In addition to the upfront investment, the cost-benefit analysis considers *incremental* costs that may be needed to sustain and support the new investment over the long term. Black & Veatch worked with PSE&G to estimate the ongoing costs. The emphasis of this effort is to identify *incremental* costs that may impact future PSE&G operating budgets. *Appendix E – Incremental*

Support Costs describes how the on-going support cost estimates were developed.[20] Additionally, *Appendix G – Total Cost Forecast* provides a tally of all costs over the approximately 20 year forecast period.

PSE&G is in the early stages of planning so the estimates of incremental support costs will evolve. The values included in the cost-benefit analysis represent good faith efforts made to identify costs that can be identified today, without undue speculation. Additionally, the appearance of an incremental cost needs to be interpreted in light of possible offsetting avoided cost (benefit) values. For example, while PSE&G will incur new costs for supporting its ADMS system in the form of periodic software license upgrades, it will also avoid support costs for its legacy Outage Management System (OMS). The later appears as a benefit in the cost-benefit analysis. Part of the reason to include new incremental costs is because it is appropriate to balance a claim of a benefit with new costs that might offset it. The overarching goal of these estimates is to identify new cost demands that are reasonable to estimate at this time and that are not safely covered under today's normal revenue requirement. Potentially, these could be new cost burdens that would end up being passed on to customers through the rate making process.

Not all subprograms have identified incremental support cost estimates. For substations, for example, PSE&G expects that normal day-to-day support requirements will not impose significant new incremental costs compared to the substations that are being replaced.

[20] The direct testimony of Mr. Edward F. Gray for the Energy Strong 2 Program should be referred to for descriptions of the upfront ES II Program cost estimates.

ES II Electric Program Benefits

This section describes the ES II Electric Subprogram benefits. The descriptions are augmented by *Appendix B – ES II Electric Subprogram Details,* which includes a detailed description of each subprogram. Overall, the Black & Veatch cost-benefit analysis describes 40 separate significant impacts of ES II Subprograms, resulting in a wide range of effects and further beneficial outcomes.

Black & Veatch has prepared Figure 3 to help explain the stepwise process that has been used to uncover the specific subprogram and subpart benefits. (The intention of Figure 3 is to explain the method, recognizing that the words on the benefit matrix are obscured by the scale of the figure. A more readable, full version of the analysis is provided in *Appendix A – Benefit Matrix.*)

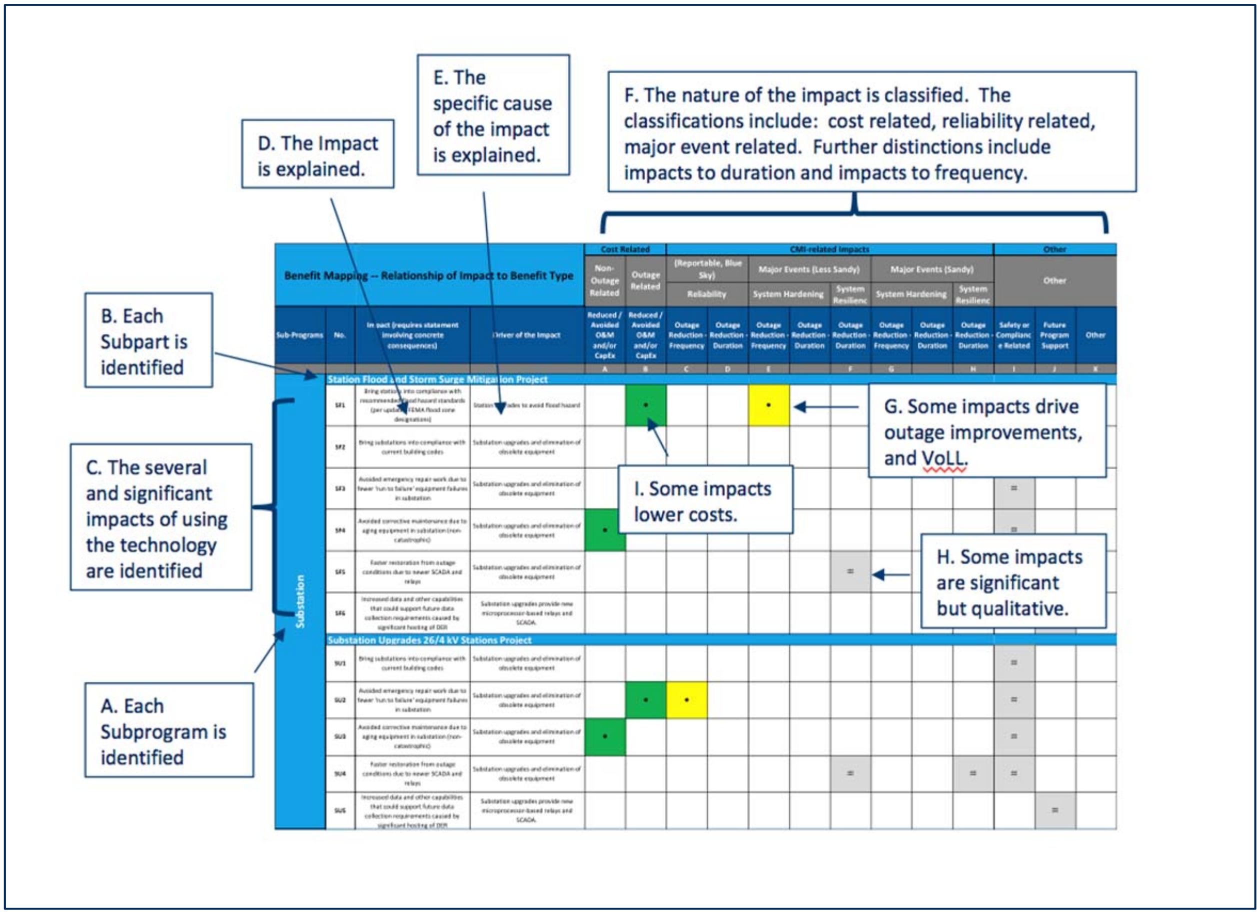

Figure 3 Illustration of Stepwise Process of Benefit Classification

Black & Veatch followed the following steps (as indicated on Figure 3) to uncover the specific subprogram and subpart benefits:

- The subprograms and their subparts were identified (A, B). For each, Black & Veatch obtained information about how PSE&G intends to utilize the technology and functionality to derive impacts. These findings were reduced to the most significant impacts (C). Impacts were given labels, which were further tracked and used in the cost-benefit analysis model. Impacts can be qualitative or quantitative (and thus monetized).

- For each impact, the specific impact was explained (D) as was the specific causes that explain the impact (E).
- Each impact was then inspected for the nature of the impact. A simple coding is used to show the intersection (F).
- Finally, Black & Veatch recommended the classification schema as shown on Figure 4. This is illustrated as (G, H, I). (G) indicates an outage-related impact, (H) is for qualitative impacts, and (I) is for operational cost savings.

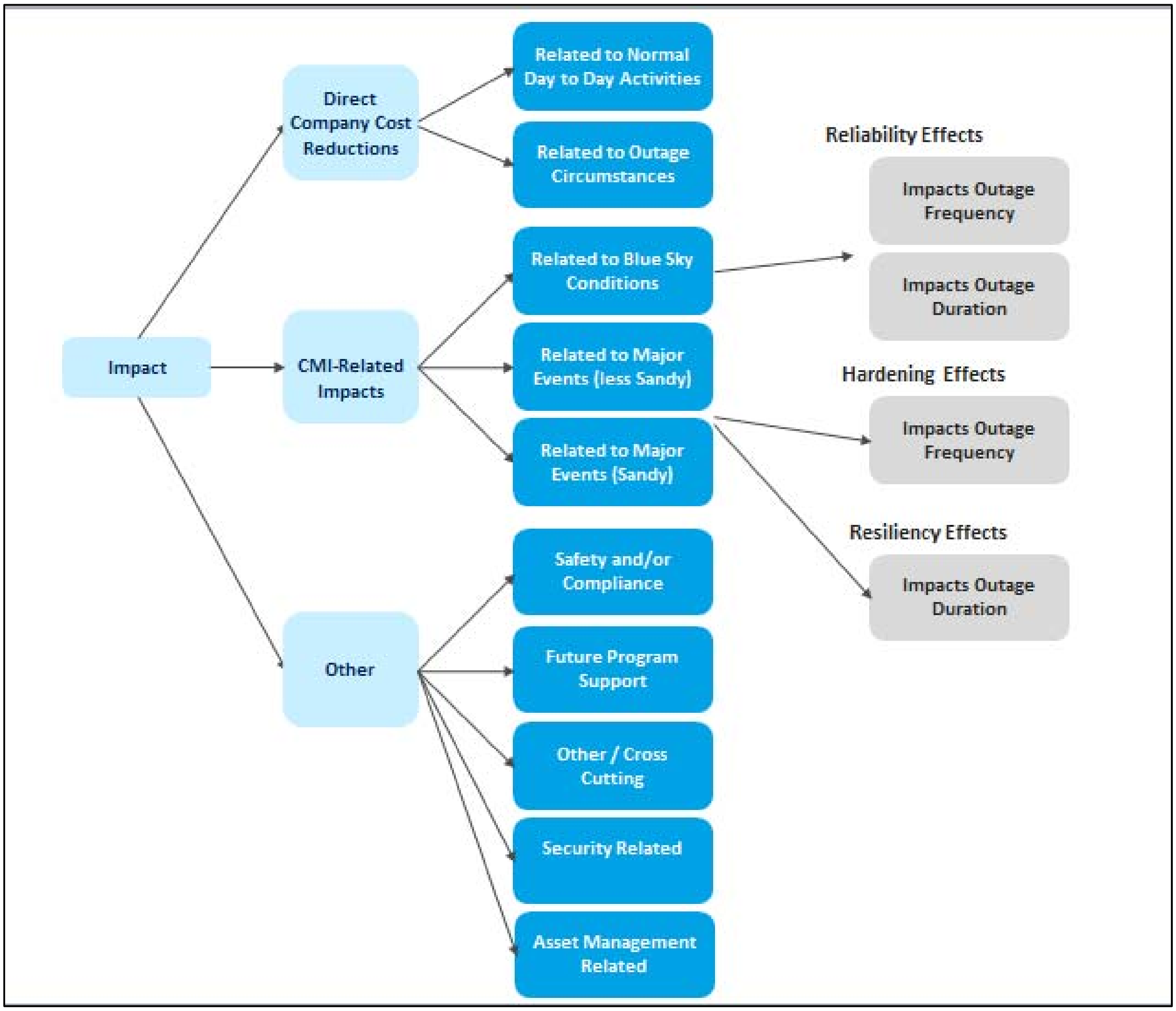

Figure 4 **Impact Types Applied in the Benefits Identification Process**

DIRECT COMPANY COST RELATED BENEFITS

Many of the subprograms and subparts drive operational cost savings. Some of the operational cost savings occur regardless of outage events, while others specifically pertain to outage restoration efforts. As is shown on *Appendix A – Benefit Matrix*, each benefit has been **given a short abbreviation and label** to organize the benefits and allow easy cross referencing of benefits throughout the report and within the analysis workbook. These labels are utilized in the bullets below as well as other places within the report, including within *Appendix A – Benefit Matrix*. "SF1" is one of the rows in Appendix A and refers to “Station Flood” and is one of the several enumerated benefits for this subprogram. Other abbreviations are as follows: “SU” refers to “Station Upgrades”; “SP” refers to “Spacer”; “IS” refers to “Increased Sectionalization”; “FS” refers to “Reclosing Devices”; “AD” refers to “ADMS”; and “HS” refers to “Communication Network”.

Highlights include the following:

- (SF1) Bring substations into compliance with the advisory FEMA post-Superstorm Sandy flood elevations and the flood elevation requirements established by the NJDEP Flood Hazard Rules, codified at N.J.A.C. 7:13, will reduce risk of flood-related outages for the upgraded substations .[21]
- (SF3, SF4, SU2, SU3) By rebuilding the substations, there will be fewer emergency maintenance trips due to aging equipment failing. (These repairs are referred to as corrective maintenance.) These events occur as part of both outage and non-outage circumstances.
- (SP1, SP2, SP3) Installing spacer cable will reduce outage restoration labor, reduce labor for repairs due to faults unrelated to an outage (qualitative), and assist in deferring some pole upgrades(qualitative).
- (IS5) Use of branch reclosers reduces field trips to investigate and resolve blown fuses.
- (HS1, HS2, HS3, HS4, HS5). The new communications network will result in savings due to costs to operate, maintain, and eventually replace the legacy communications system.

Although cost reduction benefits related to day-to-day operations are relatively minor in the overall cost-benefit analysis, these day-to-day cost reductions are fairly significant for certain portions of subprograms, specifically the Grid Modernization Subprogram (ADMS and Communication Network). Technology related projects of this type are typically partially justified through these day-to-day cost reduction benefits in addition to numerous and significant qualitative benefits.

AVOIDED COSTS WITHIN BASE CAPITAL SPENDING

The cost-benefit analysis identifies an avoided cost related to the ES II Electric Program and how it influences PSE&G’s base capital spending plan into the future. PSE&G has estimated that it will replace 12 of the Class C substations over the approximately 20 year forecast period under the BAU scenario, at a rate of approximately one substation rebuild every 18 months. By accelerating the Class C substation investment as part of the ES II Electric Program, in effect customers are relieved of this specific cost burden (and aging asset risk and exposure) as the costs under BAU form the basis of revenue requirement. This is an avoided cost – and therefore a benefit -- that is included in the cost-benefit analysis results.[22]

An additional dimension of this benefit is the fact that substation rebuild costs are expected to be slightly lower as part of the ES II Program because of scale economies associated with rebuilding approximately 21 substations over a five year period. *Appendix F – Substation Avoided Base Capital Activity Levels* illustrates the difference between the BAU and ES II scenarios.

[21] As noted earlier, the cost-benefit analysis assumes that historical outage experience will persist during the evaluation period; therefore, it is assumed that stations will flood one time during the period.

[22] *Appendix F – Substation Avoided Base Capital Activity Levels* documents the avoided substation rebuilds, which is the difference between the BAU and ES II scenarios. BAU would replace 12 substations over 20 years, compared to 21 with ES II, yielding a difference of 9 substations. This benefit is consistent with the inclusion in this cost-benefit analysis of the avoided costs associated with supporting the legacy communications network.

AVOIDED OUTAGE RESTORATION COSTS

The capabilities to manage outages will significantly improve with the planned ADMS and communications network. Working with PSE&G, Black & Veatch estimates that total outage restoration times will be lowered due to improved field restoration crew productivity and efficiencies. This is also explained in *Appendix B – ES II Electric Subprogram Details.*

OUTAGE-RELATED BENEFITS: CMI REDUCTIONS

Benefits related to outage reductions constitute the large majority of quantified benefits within the ES II Electric Program cost-benefit analysis. Outage reduction benefits include VoLL as well as cost savings due to reductions in outage restoration and repair costs. One of the principle metrics used to determine the outage benefits of these projects is the reduction in customer minutes of interruption, or CMI. CMI reductions are estimated in both reliability-centric and major event related outage conditions (with further recognition of frequency versus duration effects).

As it specifically relates to outage conditions, Table 3 extracts from the *Appendix A – Benefit Matrix* table the intersection of each subprogram's functional impact that drives an impact across all outage scenarios.[23] The intersections that permit for a quantifiable reduction in CMI are coded with dots. The intersections that do not permit a quantifiable CMI reduction, but are significant and qualitative in nature, are coded with a character know as a double-tilde (≈). Only the quantifiable CMI reductions (dots) are used to derive a monetary benefit (i.e., an avoided outage-related cost) by applying VoLL techniques. (Sometimes the term Value of Service is also used.)

Table 3 accounts for impacts that may be significant, but it also may be hard to quantify the CMI impacts. Often this relates to the challenges of quantifying the reduction. An example (as shown) is that a more reliable and high-speed network with newer SCADA and relays will improve system restoration (reduce outage duration, or resiliency).[24]

Table 3 also includes a coding of whether the impact of the subprogram is a reduction in the frequency or the duration of outage events. It is possible that the technology, and related functionality, accomplishes both. For example, the use of more reclosers to segment the 13 kV circuits provides a storm hardening benefit as the number of extended outages is reduced for some customers. Refer to *Appendix B – ES II Electric* Subprogram Details, for more detailed discussion of the impact.

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[23] All outage scenarios include all three categorized events: Sustained Interruption, Blue Sky events; Major Events (excluding Sandy); and Major Events (Sandy).

[24] PSE&G estimates an additional impact outside of CMI. These are cost reductions related to outages because, if total major storm event durations are reduced, total labor costs to restore the system are reduced. The cause of this impact is the communication, software, and analytical capabilities that help identify outage locations and help to more efficiently plan and dispatch the outage restoration work. This additional impact is described in *Appendix B – ES II Electric Subprogram Details.*

Table 3 Benefit Matrix Extract – CMI Related Impacts

Benefit Mapping -- Relationship of Impact to Benefit Type			CMI-related Impacts					
			(Sustained Interruption, Blue Sky)		Major Events (Excluding Sandy)		Major Events (Sandy)	
			Reliability		System Hardening	System Resiliency	System Hardening	System Resiliency
Sub-Programs	No.	Impact (requires statement involving concrete consequences)	Outage Reduction - Frequency	Outage Reduction - Duration	Outage Reduction - Frequency	Outage Reduction - Duration	Outage Reduction - Frequency	Outage Reduction - Duration
			C	D	E	F	G	H
Substation	Station Flood and Storm Surge Mitigation Project							
Substation	SF1	Bring stations into compliance with recommended flood hazard standards (per updated FEMA flood zone designations)			•		•	
Substation	SF3	Avoided emergency repair work due to fewer 'run to failure' equipment failures in substation	•					
Substation	Substation Upgrades 26/4 kV Stations Project							
Substation	SU2	Avoided emergency repair work due to fewer 'run to failure' equipment failures in substation	•					
Outside Plant Higher Design and Construction	Spacer Cable Project							
Outside Plant Higher Design and Construction	SP1	Improved conductor performance during major events (rain, wind, snow, ice loading etc.)			•		•	
Outside Plant Higher Design and Construction	SP2	Improved conductor performance during day to day operations	•					
Contingency Reconfiguration Strategies	Increased Sectionalization Project							
Contingency Reconfiguration Strategies	IS2	Reduced outage footprint on 4kV circuits and feeder ties	•		•		♒	
Contingency Reconfiguration Strategies	IS3	Reduced outage footprint on 13kV circuits	•		•		♒	
Contingency Reconfiguration Strategies	IS6	Reduced outage footprint on 13kV circuits - branch recloser	•		♒		♒	
Contingency Reconfiguration Strategies	Reclosing Devices							
Contingency Reconfiguration Strategies	FS3	Reduced outage footprint - reclosing device	•		♒		♒	
Grid Modernization	Advanced Distribution Management System (ADMS) Project							
Grid Modernization	AD4	More reliable communications and new ADMS will improve data collection and visualization during all scenarios to improve safety, reduce operations cost, and reduce outage durations.		♒		•		♒

The intersections of the subprogram subparts with quantifiable CMI reduction impacts are displayed in Table 4.

Table 4 Annual Estimated CMI Reduction by Subprogram Subpart and Impact

Benefit Mapping -- Relationship of Impact to Benefit Type			CMI-related Impacts					
			(Sustained Interruption, Blue Sky)		Major Events (Excluding Sandy)		Major Events (Sandy)	
			Reliability		System Hardening	System Resiliency	System Hardening	System Resiliency
Sub-Programs	No.	Impact (requires statement involving concrete consequences)	Outage Reduction - Frequency	Outage Reduction - Duration	Outage Reduction - Frequency	Outage Reduction - Duration	Outage Reduction - Frequency	Outage Reduction - Duration
			C	D	E	F	G	H
Substation	Station Flood and Storm Surge Mitigation Project							
	SF1	Bring stations into compliance with recommended flood hazard standards (per updated FEMA flood zone designations)			21,690,405		62,535,973	
	SF3	Avoided emergency repair work due to fewer 'run to failure' equipment failures in substation	270,490					
	Substation Upgrades 26/4 kV Stations Project							
	SU2	Avoided emergency repair work due to fewer 'run to failure' equipment failures in substation	676,224					
Outside Plant Higher Design and Construction	Spacer Cable Project							
	SP1	Improved conductor performance during major events (rain, wind, snow, ice loading etc.)			25,359,968		116,784,050	
	SP2	Improved conductor performance during day to day operations	2,710,428					
Contingency Reconfiguration Strategies	Increased Sectionalization Project							
	IS2	Reduced outage footprint on 4kV circuits and feeder ties	2,364,231		8,819,338		♒	
	IS3	Reduced outage footprint on 13kV circuits	8,683,860		32,629,600		♒	
	IS6	Reduced outage footprint on 13kV circuits - branch recloser	697,747		♒		♒	
	Reclosing Devices							
	FS3	Reduced outage footprint - reclosing device	3,933,420		♒		♒	
Grid Modernization	Advanced Distribution Management System (ADMS) Project							
	AD4	More reliable communications and new ADMS will improve data collection and visualization during all scenarios to improve safety, reduce operations cost, and reduce outage durations.		♒		15,902,591		♒

Figure 5 provides a summary tally of these effects (excluding the effects related to Superstorm Sandy) for Year 2025 (first full year of benefit realization) within the forecast period. Because the cost-benefit analysis takes the past seven years of actual experience and averages it to estimate a yearly rate, this figure is an approximation of average yearly effects that reflect actual recent historical experience. This method is consistent with the assumption that, putting aside Superstorm Sandy, the actual storm intensities in the future will most likely be as volatile as they have been in this past period, which we find reasonable. Figure 5 captures average intensities (and reductions) as applied in the cost-benefit analysis as a way to develop estimates of effects over the approximately 20 year forecast period.

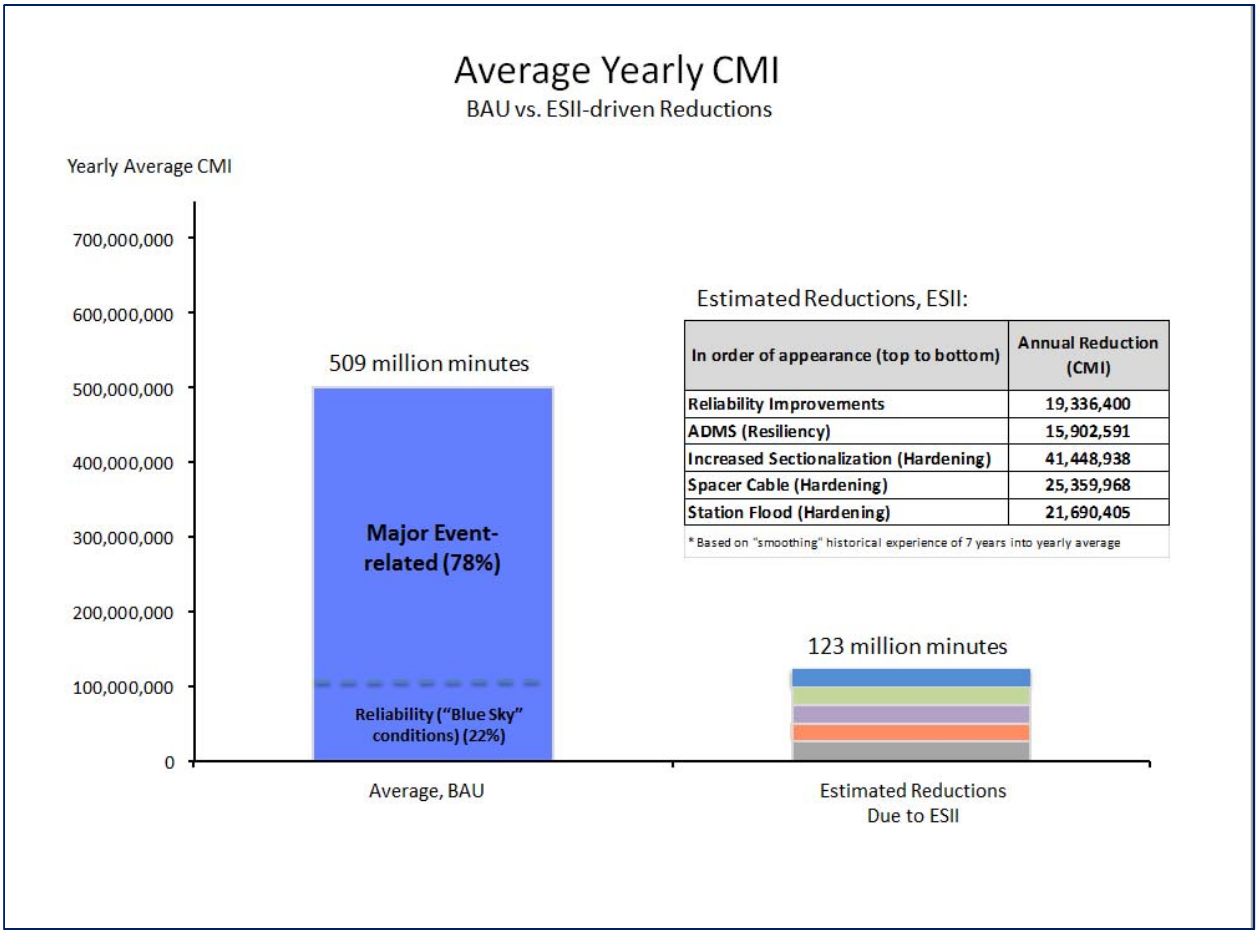

Figure 5 Total Average Annual CMI Under BAU and CMI Reduction Under ES II (Year 2025)

Figure 5 excludes Superstorm Sandy, as noted previously. Major events are broken down into two types of major events for impact analysis, called "Major Events (excluding Sandy)" and "Major Events (Sandy; catastrophic)." This further refinement of "major events" is because Superstorm Sandy increased outage minutes dramatically.[25] In fact, from 2012 to 2016 the cumulative total of all outage minutes is approximately 2 billion excluding Superstorm Sandy, whereas Superstorm Sandy separately caused nearly 10 billion in outage minutes. In addition, PSE&G notes that the underlying outage data related to Superstorm Sandy are less detailed due to the nature and scale of

[25] This approach of separating of high impact, low frequency outages was originally recommended in IEEE 1366-2003, which was formalized in IEEE 1366-2012.

the event and the data being collected at the time the storm occurred. This warrants extra steps in assessing the additional impacts of this superstorm. The set-aside for analysis purposes of Superstorm Sandy provides for a much more conservative assessment of the subprogram impacts.

Black & Veatch further estimates that the ES II Electric Program will also reduce CMI in a major event such as Sandy. These reductions are explored within the sensitivity analysis, which is contained in the section titled *Sensitivity Analyses.*

Resiliency Versus Hardening Impacts

Table 3, Table 4, and Figure 5, encapsulate the CMI reductions, including those related to resiliency improvements. Resiliency refers to PSE&G's ability to recover quickly from damage to any of its facilities' components or to any of the external systems PSE&G depends upon. Resiliency measures do not prevent damage; rather, they enable electric facilities to continue operating despite damage and/or promote a rapid return to normal operations when damages and outages do occur.[26] The ES II Electric Program improves PSE&G's ability to improve restoration times (positive resiliency impacts) through the Grid Modernization Subprogram and Contingency Reconfiguration Subprogram.

System hardening is defined as physical changes to PSE&G's electric infrastructure to make it less susceptible to storm damage, such as high winds, flooding, or flying debris that could occur during all outage scenarios. Hardening improves the durability and stability of distribution infrastructure, allowing it to withstand the impacts of severe weather events with reduced damage.[27] As summarized in Table 3 and Table 4, the ES II Electric Program includes various "physical changes" to the electric infrastructure that reduce susceptibility to storm damage, such as new poles and spacer cable, substation equipment, and communications equipment.

REDUCTION IN OUTAGE TIMES DUE TO NEW ADMS CAPABILITIES

The ADMS and communications network will provide PSE&G with the means to reduce the time it takes to restore the system after a Major Event. Commensurate with this reduction in restoration management costs, restoring the system sooner will mean that total customer outage durations are reduced. This will lead to additional CMI impacts and VoLL benefits. Refer to *Appendix B – ES II Electric Subprogram Details* for an explanation of the ADMS-driving benefits.

TRANSLATING CMI INTO VALUE

At the core of the cost-benefit analysis is the translation of the CMI reductions into value as experienced by PSE&G customers. The cost-benefit analysis assumes that customers will realize value because outage events will be reduced due to the ES II Program, and the many costs, damages and inconveniences associated with outages will be avoided. Translating the outage reductions into lost economic value requires care in the recognition of different levels and types of impacts. As a backdrop to the approach used by Black & Veatch, it is useful to set out some of the underpinnings of how to consider the impacts and (avoided) costs that may be applied to a cost-benefit analysis for this type of utility infrastructure investment. Additionally, as described earlier, Black & Veatch

[26] Edison Electric Institute, "Before and After the Storm – Update March 2014", pg. 1, retrieved on December 18, 2017 from
http://www.eei.org/issuesandpolicy/electricreliability/mutualassistance/Documents/BeforeandAftertheStorm.pdf
[27] Ibid.

uses *reliability* and *resiliency* to orient the reader to outage conditions related to different time scales.

Conceptual Considerations

Unlike in a purely competitive market, improving the reliability and resiliency of a utility's electric delivery system is challenging since there is no referenceable market. It is difficult to observe the price consumers would be willing to pay to avoid outages because there are not easily available substitutes consumers can select under short notices. Over time they *will* adapt, but understanding how customers value sustained improvements to the overall reliability of the electric grid is an important area of policy research.

Economists agree that the value customers perceive in reliability is tied to the outage costs (and harm and inconveniences) they avoid, but outage costs are not always easy to identify. When power is not available residential customers and businesses incur many *direct* and *indirect* impacts. A direct cost might be spoilage in a restaurant refrigerator. Indirect costs are impacts induced by the direct impacts. In a resiliency-scale event, for example, there would be *wide ranging* impacts encompassing worker productivity, direct customer costs for supplies, delays to projects under construction, emergency-related costs to local governments, accidents and injuries, and lower tax and fee revenues (due to a decline in economic activity), just to name a few.

Customers and businesses also face additional costs both in the short term and long term. Short-term costs are often understood as damage costs. Some customers might seek out long-term alternatives (e.g., consider moving if service is very poor during reliability-scale events and/or resiliency-scale events). The long-term costs are often forms of adaptive behaviors to avoid the outage risk in the future (such as installing a backup generator for an electricity customer who determines losing power is no longer acceptable). These can also be considered mitigation costs that help avoid the damage in the future.

For outages, it is also relevant to expand the impacts to beyond just observable costs. Some of the impacts are quantifiable in monetary terms, and hence, economic in nature; whereas, other impacts reflect social impacts tied to convenience, personal safety, pain and suffering, security, and other less tangible, but very real, values to the customer. Outage impacts are also characterized by *externalities*, which can be either positive or negative. Externalities are impacts incurred by others not party to the economic transaction. For example, an outage event may disrupt an airport and cause supply chain disruptions for manufacturers far outside the immediate region. This is a form of negative "network externalities"; it is beyond the influence of the manufacturer suffering the damage.

The foregoing information is provided to set a context for why assessing a monetary value to CMI reductions requires care. The structure of many of the outage cost types and attributes are summarized in Table 5. This information is taken from the literature on power system disruptions. It represents one of many ways that economists describe outage costs.

Table 5 Structure of Damage and Mitigation Costs[28]

PRIVATE INDIVIDUALS			ECONOMY (INDUSTRY, COMMERCIAL USERS)		
Damage Costs		Mitigation Costs	Damage Costs		Mitigation Costs
Direct	Indirect		Direct	Indirect	
Restrictions on activities Lost leisure, stress Financial costs Damage to premises and real estate Food spoilage Data loss Health and safety aspects.	Restrictions on acquisition of goods Costs for other private individuals and companies	Procurement of standby generators, batteries, etc. Investments in grid construction via charges (network tariffs)	Opportunity costs of idle resources. Lost profits. Production holdups and restart times. Adverse effects and damage to capital goods Data loss	Delayed deliveries along the value chain. Damage for consumers if the company produces an end product. Cost/benefits for some manufacturers. Health and safety aspects.	Procurement of standby generators, batteries, etc. Investments in grid construction via charges (network tariffs)

Value of Lost Load (VoLL) Reliability Factors

To translate the CMI reductions into value improvements, Black & Veatch applies a set of factors that relate customer class, outage durations, and load assumptions to economic value. These factors – which pertain to reliability-scale events -- have been developed for the specific purpose of estimating the value to customers of power outages. The economic losses associated with these factors are referred to as the Value of Lost Load, or VoLL.

These factors are shown in Table 6, and were originally published in the "Updated Value of Service Reliability Estimate for Electric Utility Customers in the United States." The Lawrence Berkeley National Laboratory (LBNL) under contract with the Department of Energy developed this report.[29] The cost-benefit analysis utilizes the cost per event factors in Table 6 based upon customer class. Black & Veatch finds that these factors have been widely cited and often applied.[30]

The VoLL factors reflect a microeconomic viewpoint, one that aims to capture the direct and privately borne costs of consumers and businesses facing outage events. The bearing on direct and privately borne costs is important: customers experience many types of costs, and suffer many forms of inconvenience and harm during and because of outages, and these impacts are not well or completely accounted for in the VoLL factors. *Therefore, additional direct and indirect costs, as well*

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[28] Schroder, T. and W. Kuckshinrichs, "Value of Lost Load: An Efficient Economic Indicator for Power Supply Security?", Frontiers in Energy Research, Cross Mark. December 24, 2015. Page 3.
[29] Sullivan, Schellenberg, and Blundell in collaboration with Nexant. Lawrence Berkeley National Laboratory (LBNL-6941E). Performed as part of DOE Contract No. DE-AC02-05CH11231. January 2015. Available online from http://emp.lbl.gov/sites/all/files/lbnl-6941e.pdf.
[30] PSE&G applied earlier versions of these factors in its Energy Strong I petition.

as inconveniences, and harms, represent additional impacts not included in the VoLL factors. One outage study, in fact, estimates that indirect costs can exceed direct costs by a large factor.[31]

Table 6 VoLL Factors (For Reliability) per Event, Average kW and Unserved kWh (U.S.2013$) by Duration and Customer Class[32]

CUSTOMER CLASS AND COSTS	INTERRUPTION DURATION					
	MOMENTARY	30 MINUTES	1 HOUR	4 HOURS	8 HOURS	16 HOURS
Medium and Large C&I (Over 50,000 Annual kWh)						
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per Average kW	$15.90	$18.70	$21.80	$48.40	$103.20	$203.00
Cost per Unserved kWh	$190.70	$37.40	$21.80	$12.10	$12.90	$12.70
Small C&I (Under 50,000 Annual kWh)						
Cost per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Average kW	$187.90	$237.00	$295.00	$857.10	$2,138.10	$4,128.30
Cost per Unserved kWh	$2,254.60	$474.10	$295.00	$214.30	$267.30	$258.00
Residential						
Cost per Event	$3.90	$4.50	$5.10	$9.50	$17.20	$32.40
Cost per Average kW	$2.60	$2.90	$3.30	$6.20	$11.30	$21.20
Cost per Unserved kWh	$30.90	$5.90	$3.30	$1.60	$1.40	$1.30

In order to apply the VoLL factors to the estimated CMI reductions, Black & Veatch makes the following observations:

- The VoLL factors represent weighted average and predicted values from the LBNL-6941Ereport. Black & Veatch used the weighted average values (as shown in Table ES-1 of the report) because they address seasonality and time of day variables.[33]

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[31] A reliability study conducted for Pacific Gas & Electric of a potential major electricity outage in downtown San Francisco found that indirect costs of the outage to businesses ranged from 50 percent to two times the size of the direct costs to business, according to testimony provided by Pacific Gas & Electric representatives before the California Public Utility Commission. Refer to Pacific Gas & Electric's Opening Brief, Application No. 12-12-004 (E 39 E), Page 12, which addresses its Application for Authorization to Construct a 230 kV Transmission Project. The study is referred to as "Downtown San Francisco Long Duration Outage Cost Study", prepared by Dr. Michael Sullivan of Freeman, Sullivan & Co.

[32] Sullivan, Schellenberg, and Blundell in collaboration with Nexant, "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States", Table ES-1, page xii.

[33] "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States", page xiii. The distribution of future interruptions by season and time of day is obviously unknown. The approach taken by Black & Veatch respects the weighted averages for these considerations embedded in the VoLL factors.

- The VoLL factors take into account differences in value amongst customer classes, as indicated by Table 6. For example, there is a break point at 50,000 kWh annual consumption. Black & Veatch has applied overall customer mix assumptions to each subprogram.
- The CMI impacts estimated for each subprogram have resolution to the sub-hour. For example, CMI reduction calculation estimates appear as 2.4 or 6.2 hours, etc. To determine VoLL impacts, the CMI values are rounded up or down to the nearest 1/2 hour and linearly interpolated between the values shown in Table 6.
- The VoLL factors are adjusted for inflationary impacts. The factors in Table 6 are expressed in 2013 dollars. Accordingly, a 2.1 percent annual adjustment is applied to the VoLL factors from 2013 through the forecast period.
- Black & Veatch additionally observes that the VoLL factors being used are mainly based on data and studies conducted in Western, Midwestern and Southern states.[34] Black & Veatch believes a specific application of the underlying regression model that supports the VoLL factors in Table 6 would yield higher VoLL factors when addressing northeast energy prices and conditions.

VoLL Factors Applied to Outages Exceeding 16 Hours

Care is needed in applying the VoLL *reliability*-scale factors to *resiliency*-scale events. In fact, study authors of the VoLL factors caution on the direct application of the factors shown in in Table 6 to longer events.[35] However, there are many strong reasons to believe that VoLL impacts increase with outage duration, as indicated by the trend of the data in Table 6 as outage durations increase. The question addressed by Black & Veatch for purposes of this cost-benefit analysis is by what degree do the outage costs increase with duration, and what is the basis for making claims of this increase. Based on a balancing of considerations discussed in this section, and supported in *Appendix K – VoLL Factors Applied to Resiliency-scaled Events*, Black & Veatch believes it is reasonable for the cost benefit model to apply the 16 hours VoLL factors shown in Table 6 to outages greater than 16 hours. This is a significant – and conservative -- assumption for the cost-benefit analysis.

ADDITIONAL OUTAGE-RELATED IMPACTS

There are many additional costs that are not fully accounted for within the VoLL estimate. While the VoLL concept seeks out individual customer preferences and tries to identify customers' "willingness to pay" to secure greater energy security, it is not feasible to include all direct and indirect costs, or externalities, that result from the outage event, especially an extended one. A major disruption, for example, will impair public safety and may result in accidents and injuries. Outages place additional unfunded burdens on local government. Major construction activities may be disrupted and delayed. Major storms can also depress economic output well beyond the duration of the outage itself, as businesses and consumers recover from the outage. Additionally, customers may engage in long-term behaviors to mitigate future outage risks (such as purchasing stand-by generators), and they may also suffer long-term losses such as higher taxes and insurance costs. These are just some examples of the impacts of major events.

[34] Ibid, pg. 48.
[35] Ibid, pg. 17.

Table 7 reviews additional impact areas beyond those subsumed within the VoLL value estimates.

Table 7 Examples of Additional Impacts and Costs Incurred by Customers Due to Outages

IMPACT	DESCRIPTION
Public Safety-Related Costs	Outage events can lead to accidents, injuries, sickness, and death.
Additional Long-Term Economic Activity	Some economic impacts can linger for many weeks and months beyond the outage event itself if the outage causes long-term damage to businesses and infrastructure.
Long-Term Costs for Public Service Activities	Local responders, critical care facilities, and public safety government entities will incur additional costs to address traffic control, emergency services, and security. These costs will have to be made up in the form of increased tax levies or fees.
Direct Utility Costs to Complete Service Restoration	The utility incurs direct costs to safely restore its electric system. The cost-benefit analysis provides estimates of some of these avoided costs assuming ES II Electric Program storm hardening and resiliency measures.
Value of Delay in Utility Capital Programs	A major outage most likely suspends normal capital investment work, thereby deferring any benefits associated with these programs until they can be resumed.
Temporary Housing Costs	Customers will require temporary housing and support costs for homes that may be without heat or utilities if the outage is prolonged. For example, elevator-dependent buildings may be difficult to live in until power is restored.
Out of Area Business Activity	Businesses outside of the area may be impacted as their supply chains are disrupted due to an outage event.
Long-Term Customer Costs	Utility bills and insurance premiums may increase. Government fees and taxes may increase to cover storm-related costs.

In short, the VoLL concept is an effective tool to help address the value lost during an outage event but does not capture all potential direct and indirect impacts of the outage event over the long term.

THE IMPORTANCE OF A COMMUNICATIONS NETWORK TO THE ES II ELECTRIC PROGRAM

The ES II Program includes the Grid Modernization Subprogram comprised of two subparts. The Communication Network Subpart will replace an aging communications network. The ADMS Subpart will put in place new back office tools and software capabilities to manage grid assets and functions. These are very important components of the ES II Program.

PSE&G presently uses a combination of communication networks to support the operations and maintenance of the distribution system. Plain old telephone service (POTS) lines support SCADA communications to reclosers and multiprotocol label switching (MPLS) circuits support SCADA communications to substations. In addition to these provider-based communication circuits, PSE&G has been evaluating an alternative private fiber network to serve its operations centers and substations. The number of devices PSE&G expects to connect to these networks exceeds ten thousand endpoints. For a list of endpoints refer to the description section in Appendix B under Subprogram B-4 – Grid Modernization (Subpart 2 – Communication Network). This type of communication is commonly referred to as "machine-to-machine" communications,[36] and it has significantly different characteristics than consumer cell phone or business internet communications.[37]

The network PSE&G selects will support a variety of ADMS and SCADA applications. (For a list of these applications, refer to Appendix B, Subprogram B-4 – Grid Modernization (Subpart 1 – ADMS). Many of these applications require a communication network that supports fast installation (of new endpoints), high reliability, high bandwidth, low latency, and security. To meet these needs PSE&G anticipates building and operating its own network versus relying on public carriers. The Communication Network subpart of the Grid Modernization Subprogram includes adding fiber connectivity (to improve communications reliability with alternate paths) and a wireless mesh network in other areas.

PSE&G plans to expand its existing private High Speed Network (HSN) to support the required bandwidth. For machine-to-machine communications using its current carriers, costs could quickly become prohibitive. The fundamental characteristic of electric utility application communications is that the traffic is far from predictable, and it is difficult to estimate. Data traffic will spike whenever there is an outage. These "bursty", unpredictable traffic patterns could result in unpredictable costs. Low latency is also a requirement of the HSN, and it too drives costs. As devices start using up more bandwidth, network congestion results, which increases latency.[38]

PSE&G believes that it can expand its existing private network to support its growing bandwidth and low latency requirements. With its own network, all aspects of the network performance will be within PSE&G's control and not subject to third party supplier constraints. This includes meeting growing security requirements, including New Jersey regulatory requirements.[39] With its own internal network, PSE&G can monitor and control the *complete* network and not have to rely on external providers to meet its requirements or put in place mitigations.

BENEFIT ESTIMATE RESULTS

As described in the previous sections, the benefit estimates included in the cost-benefit analysis can be considered in a number of different ways. Table 8 shows the benefit estimate results in a way that reflects the organization of *Appendix A – Benefit Matrix,* which includes the following:

- Separating utility operating cost reductions from VoLL.

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[36] Machine-to-machine communications are defined for this report as communication initiated and maintained with very limited human involvement. For example, SCADA to RTU communication is machine-to-machine communication.
[37] Cell phones typically have voice and data plans, where the calls and applications using these plans are infrequently critical communications when compared with utility-based communications that provide situational awareness during normal and abnormal operating conditions. Business internet connections can support a variety of business needs, some of which are often viewed as critical to the business and may also be machine-to-machine communications.
[38] Network congestion and latency can be compared to highway traffic, which will typically move about freely without adversely impacting the travel time from point A to point B (latency). As the traffic increases during rush hours, or other periods of high use, the highway becomes congested, and the travel time from point A to point B increases.
[39] In 2016, the New Jersey BPU adopted cybersecurity regulations in docket A016030196 available online at http://www.nj.gov/bpu/pdf/boardorders/2016/20160318/3-18-16-6A.pdf.

- Further separating cost reductions into day-to-day cost reductions and those cost reductions that are the result of an outage reduction.
- Further separating VoLL into reliability, system hardening, and system resiliency benefits.

VoLL represents over 87 percent of the overall benefit value, and cost reductions represent approximately 13 percent.

Table 8 shows the benefit estimate results by benefit area.

Table 8 Benefit Estimate Results by Benefit Area ($1,000s, Nominal. 20 Year)

$USD Nominal (1,000's)	Cost Reductions – Day to Day	Cost Reductions – Outage Related	Outage (VoLL) - Reportable - Reliability	Outage (VoLL) – Major Events - Hardening	Outage (VoLL) – Major Events - Resiliency	Total
Total	$526,005.5	$8,799.2	$1,053,405.5	$2,027,777.9	$501,900.3	$4,117,888.5

Additionally, Figure 6 shows the time-phased benefit impacts, which largely begin in Year 6 (2024) once all ES II Electric Program subprograms are completed. In reality, benefits will phase in as projects are completed. A 2.1 percent annual escalation factor is applied to the benefit stream.[40]

[40] From December 2016 to December 2017, the Consumer Price Index for All Urban Consumers (CPI-U) rose 2.1 percent. Over the same 12-month period the previous year, the index also increased 2.1 percent, following a 0.7-percent increase from December 2014 to December 2015. Refer to https://www.bls.gov/opub/ted/2018/consumer-price-index-2017-in-review.htm.

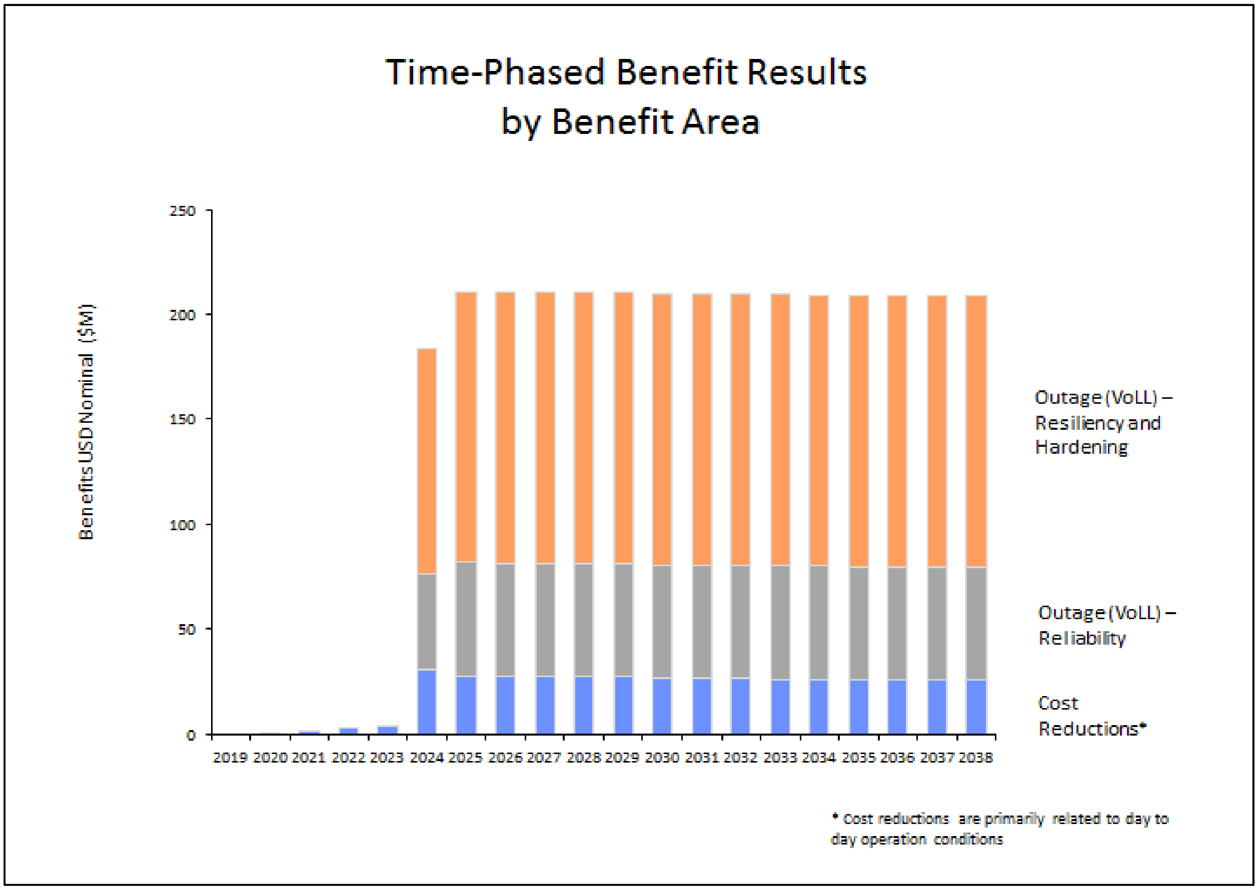

Figure 6 Time-Phased Benefit Estimate Results by Benefit Area

While Figure 6 shows a steady benefit level, this is largely due to applying the past 7 years of historical storm data as a yearly average rate in the forecast period. It is more likely that Major Events would be episodic and more extreme (and the benefits would track this more volatile pattern). Figure 6 is based on benefits that assume the same level of storm intensity as actually experienced by PSE&G customers (excluding Superstorm Sandy), as an *average* condition.

BENEFIT RESULTS FOR SUBPROGRAMS

Table 9 further divides the benefit estimate results into each subprogram and related subparts. Observations derived from and comments to further explain the results of this table include the following:

- The Station Flood and Storm Surge Mitigation and Substation Upgrades 69/4kV or 26/4kV Stations subprogram subparts include similar reliability-based VoLL, due to upgrades to the Class C substations.[41] However, the Station Flood and Storm Surge Mitigation subprogram also includes an additional VoLL impact due to the reduction in the risk of substation flooding events.
- The Increased Sectionalization subprogram subpart contributes significantly to the overall ES II Electric Program's benefits. This subprogram subpart includes converting all existing two

[41] The Station Flood and Storm Surge Mitigation Subprogram includes six Class C substations (in addition to other types of substations), while the Substation Upgrades 26/4 kV Stations includes 15 substations, which are all Class C substations.

section overhead 13 kV circuits to three section circuits along with adding circuit sectionalization to 4kV circuits that currently does not exist.

- VoLL related to reduced outage duration in major events (resiliency) for the branch reclosers within the Increased Sectionalization Subpart and for reclosing devices within the Reclosing Devices Subpart of the Contingency Reconfiguration Strategies subprogram are not quantified in the benefit estimates. Branch reclosers do in fact provide a benefit in major storm events related to reduced outage duration by reducing outages, providing status and enabling remote operation; however, the basis for quantifying the benefit is historical outage data for reclosers and fuses. The outage data is difficult to correlate because of the nature of nested outages,[42] so the benefit was not quantified. This treatment adds conservatism to the cost-benefit model results.

Table 9 20 Year Benefit Results by Subprogram and Subpart ($1,000s)

Subprogram (Subparts)	Cost Reductions – Day to Day	Cost Reductions – Outage Related	Outage (VoLL) - Reportable - Reliability	Outage (VoLL) – Major Events - Hardening	Outage (VoLL) – Major Events - Resiliency	Total
Subprogram: Substation						
Station Flood and Storm Surge Mitigation	$118,835.6	$3,283.3	$10,599.6	$206,456.4	$0.0	$339,174.9
Substation Upgrades 26/4 kV Stations	$297,089.0	$0.0	$26,499.0	$0.0	$0.0	$323,588.0
Subprogram: Outside Plant Higher Design and Construction Standards						
Spacer Cable	$0.0	$1,600.9	$137,657.3	$821,097.2	$0.0	$960,355.5
Subprogram: Contingency Reconfiguration						
Increased Sectionalization	$0.0	$254.1	$772,161.6	$1,000,224.2	$0.0	$1,772,639.9
Reclosing Devices	$0.0	$3,660.9	$106,488.0	$0.0	$0.0	$110,148.9
Subprogram: Grid Modernization						
Advanced Distribution Management System (ADMS)	$16,724.1	$0.0	$0.0	$0.0	$501,900.3	$518,624.5
Communication Network	$93,356.8	$0.0	$0.0	$0.0	$0.0	$93,356.8
Total	**$526,005.5**	**$8,799.2**	**$1,053,405.5**	**$2,027,777.9**	**$501,900.3**	**$4,117,888.5**

QUALITATIVE BENEFITS

The above benefit estimates do not consider the additional value added by benefits that are identified as qualitative in nature.

- The VoLL is an estimation tool that values outage events within certain parameters of duration extent. As it pertains to Major Events of significant outage duration, there are many other direct

[42] A nested outage is when a fuse operates along with an upstream recloser. While the recloser reports its status via SCADA, a fuse operation depends upon customers calling in to report an outage. Even when this happens, PSE&G procedures are to restore the mainline first and then create another job for the blown fuses. The outage causing the fuse operation may or may not be the same cause as the recloser operation.

and indirect costs that are not reflected in VoLL. These have not been monetized and included in the cost-benefit analysis.

- The ES II Electric Program investments will reduce risks to the system beyond storm-related events; for example, the substation upgrades reduce the risk of failure of old and aging equipment.
- ES II Program Investments support advanced grid functions, such as supporting DERs, whose use will grow.
- The high-speed communications network will be put in place to support devices such as DERs and capacitor controls.[43] The combination of the high speed network with the ADMS applications provides a platform that will position PSE&G to be able to monitor, secure, interact with, and support the distribution grid as grid operating complexity grows.
- Due to the communications network and its interconnection with other devices, PSE&G operators will have much more information about system performance in outage conditions than currently available, and this will help restore the system more quickly and safely. This impact is not included in all subprogram estimates.
- The subprograms will improve the safety of the system during all conditions. There will be fewer hazardous conditions that pose safety risks to employees and customers. There will be fewer damage locations on overhead conductors, fewer downed wires and poles, and generally safer work conditions in and around substations.
- Through the ES II Electric Program, PSE&G will dramatically improve its ability to address the systemic obsolescence risk of aging assets. This will allow PSE&G to devote less time toward system maintenance (essentially work-around activities) and more time devoted to helping the grid deliver more value to the customer.

FUTURE PROGRAM SUPPORT

There are several ways that the ES II Electric Program will support PSE&G's future programs. These intersections are identified on Figure 7, which is extracted from the Benefit Matrix provided in *Appendix A – Benefit Matrix*.

[43] For a more complete list of devices, refer to the list under Appendix B, *Subprogram B-4 – Grid Modernization (Subpart 2 – Communication Network.*

Benefit Mapping -- Relationship of Impact to Benefit Type					Other
					Other
Sub-Programs	No.	Area (Short Hand)	Impact (requires statement involving concrete consequences)	Driver of the Impact	Future Program Support
					J
Substation	Station Flood and Storm Surge Mitigation Project				
	SF6	Flood	Increased data and other capabilities that could support future data collection requirements caused by significant hosting of DER	Substation upgrades provide new microprocessor-based relays and SCADA.	♒
	Substation Upgrades 26/4 kV Stations Project				
	SU5	Upgrade	Increased data and other capabilities that could support future data collection requirements caused by significant hosting of DER	Substation upgrades provide new microprocessor-based relays and SCADA.	♒
Grid Modernization	Advanced Distribution Management System (ADMS) Project				
	AD6	HSN+ADMS	High speed network and ADMS will be able to support future applications, such as smart grid, smart city, and DER programs	Build out and operation of high speed nework and installation of new ADMS	♒

Figure 7 ES II Support of Future Programs

Cost-Benefit Analysis Results

Black & Veatch estimates that the ES II Electric Program will reduce PSE&G costs (both capital and annual O&M expense), improve system reliability, and lower system risk associated with major storm events, thereby resulting in a more hardened system with greater resiliency. Reducing the outage frequency and duration can be further valued in terms of VoLL, a measure of how customers and businesses perceive the value of improved system reliability, hardening, and resiliency. The estimated costs and benefits, and the resulting benefit-to-cost ratio, are presented in Table 10.

Table 10 Benefit Results and Benefit-Cost-Ratio, by Subprogram (2019-2038)

Subprogram	Costs ($1,000s)			Benefits ($1,000s)			Ratio
	ES II Investment Cost (A)	Additional ES II Support Cost (B)	Total 20 Year Cost Estimate (C) = (A) + (B)	Cost Reductions (D)	Avoided Outage Costs –VoLL (E)	Total Monetized Benefits (F) = (D) + (E)	Simple Benefit-Cost Factor (G) = (F) / (C)
Substation	$906,000.0	$0.0	$906,000.0	$419,207.9	$243,555.0	$662,762.9	0.7
Outside Plant, Higher Design and Construction Standards	$345,000.0	$0.0	$345,000.0	$1,600.9	$958,754.5	$960,355.5	2.8
Contingency Reconfiguration Strategies	$145,000.0	$0.0	$145,000.0	$3,915.0	$1,878,873.9	$1,882,788.9	13.0
Grid Modernization	$107,000.0	$27,226.2	$134,226.2	$110,080.9	$501,900.3	$611,981.3	4.6
Total	**$1,503,000.0**	**$27,226.2**	**$1,530,226.2**	**$534,804.7**	**$3,583,083.7**	**$4,117,888.5**	**2.7**

Of the benefit values identified in Table 10, a significant percentage (87 percent) is associated with the value to customers of reducing outage events. Approximately 71 percent is associated with reducing the effects of major storm events, and 29 percent is related to day-to-day outage events. Outages examined within the cost-benefit analysis range in duration from a momentary outage (brief) to upwards of days in duration.[44] Moreover, 13 percent of total benefit value ($535M) is

[44] As noted earlier, VoLL is a measure of directly borne costs, and does not account for many indirect costs, externalities, and social welfare impacts. Additionally, Black & Veatch limits the outage duration reduction estimates due to limits in published VoLL factors. These facts tend to make the analysis conservative. Additionally, as explored in this Report, it is challenging to value improvements to reliability, hardening, or resiliency. This is due in part to the fact that electrical system attributes are not fungible in the short term; customers do not have easily accessible alternatives when electricity is not available. To address this challenge, economists have developed ways to measure a customer's "willingness to pay" for unserved electricity during outages. These measures – and published VoLL factors – are applied to the ES II Electric Program cost-benefit analysis to derive the estimates shown in Table 1.

associated with the value of reducing operating costs during all operating conditions (during outages or otherwise). Importantly, the Superstorm Sandy impacts are not included in the Table 10 results.

The cost-benefit analysis results can be expressed in several ways. As shown, a simple comparison of costs and benefits reveals that for the entire ES II Electric Program, monetized benefits exceed costs by $2.6B, resulting in a benefit-to-cost ratio of 2.7 over the approximately 20-year period. Additionally, the net present value (NPV) of the benefit and cost impacts is $526M, using a discount factor of 6.9 percent, which aligns with the weighted average cost of capital (WACC) PSE&G utilized in its January 12, 2018 base rate case filing. Figure 8 depicts the approximately 20-year nominal and present value cost and benefit results.

Figure 8 depicts the approximately 20-year nominal and present value cost and benefit results. Note that there is additional value associated with avoiding the indirect costs and other impacts caused by outage events; these are not captured in the monetized benefit value displayed in Figure 8. Nor are the additional benefits related to reducing Superstorm Sandy-scaled effects.

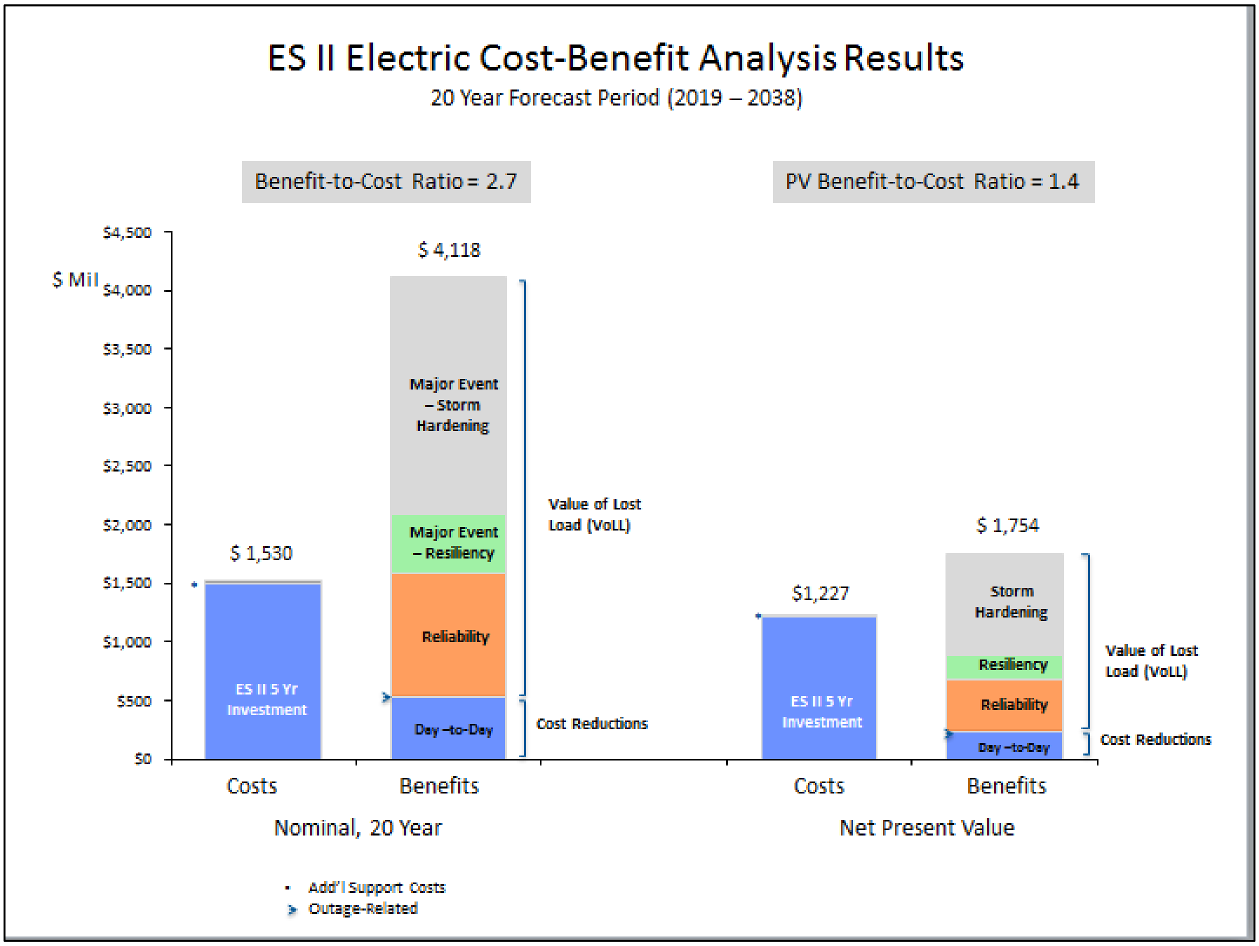

Figure 8 ES II Electric Program Costs and Monetized Benefits (excludes Superstorm Sandy)

Black & Veatch emphasizes that the above cost-benefit analysis results are limited to those benefits that can be quantified and monetized. The results do not consider the additional value added by benefits that are identified as qualitative in nature. This report has identified many, including improved safety, support for future grid operations, improved communications reliability and security, and enhanced asset management capabilities (through advanced control systems and analytics).

In Black & Veatch's view, the analysis is conservative for at least seven reasons.

1. The analysis is limited to an approximately 20 year forecast period, whereas many of the ES II investments are expected to be in service for many decades, well beyond the benefit forecast period. The mitigation benefits provided by the ES II Electric Program are provided on a continuous, 24 hour x 365-day basis over 50 or more years.

2. The base case results exclude outage data covering the region's experience during Superstorm Sandy, which hit the area with tremendous severity during October 2012.[45] The impact of including this storm into the analysis is described in the next section.

3. The major outage event benefits are focused to VoLL estimates, but there are additional indirect effects experienced during major events that are not included in VoLL. The analysis recognizes but does not monetize several very important qualitative benefits, such as safety, and many indirect outage-related costs.

4. The analysis ignores the "ramping in" of benefits during the ES II investment period, instead relying on the assumption that the benefits largely start to accrue in Year 6.

5. The ES II Program includes the build out of an advanced communications and distribution management system, which positions PSE&G to create additional value as grid functions evolve through mandate or independent market forces. This value is not monetized in the cost-benefit analysis results.

6. The ES II Electric Program capital creates additional flexibility for PSE&G to direct its base capital spending in other priority areas that otherwise might be deferred.

7. The analysis ignores the effects of growth in customers, load served, or the economy.

Sensitivity Analyses

Several sensitivities have been developed to explore the range of impacts related to key input variables and assumptions. Table 11 explains the key variables that are scrutinized for the purposes of sensitivity analyses. The sensitivity analysis results for the items shown in Table 11 are documented in *Appendix J – Sensitivity Analyses Results*

Table 11 Sensitivity Analyses

VARIABLE	DESCRIPTION	SENSITIVITY ADJUSTMENT/ APPROACH
Inclusion of Superstorm Sandy	Superstorm Sandy is treated as a sensitivity analysis because the	Superstorm Sandy data are applied in the following way to create a sensitivity result:

[45] By way of comparison, the PSE&G experienced a total of 2 billion of CMI over the past seven years as part of major events, excluding Superstorm Sandy. Superstorm Sandy itself contributed 9.8 billion CMI separately. Black & Veatch believes it is appropriate to address Superstorm Sandy in a sensitivity analysis due in part to the severity of this event, the length of circuit and substation outages that resulted, and the potential error of performing simple linear extrapolations of reliability-scaled outage impact factors to long, major outage events.

VARIABLE	DESCRIPTION	SENSITIVITY ADJUSTMENT/ APPROACH
	historical outage data is less refined and it creates difficulties applying specific outage reduction arguments to the data (as done for the Major Events). At the same time, Superstorm Sandy was hugely impactful by nearly a factor of 10, and should not be ignored.	Substation Flood: Based on Superstorm Sandy average substation flood outage duration due to flood, avoided VoLL and O&M costs calculated assuming all 16 substations flood to the flood elevations published by the Federal Emergency Management Agency (FEMA)[46], with 9 of the 16 substation flooding to the level experienced during Sandy (based on 9 of the 22 substations (~60 percent) that flooded during 2010 – 2016 were flooded during Superstorm Sandy) Spacer Cable: For selected circuits, on a circuit by circuit basis, average historical duration and CI per event for Superstorm Sandy was utilized to calculate avoided VoLL and O&M costs calculated based on event reduction factor of 2.56 times. Contingency Reconfiguration: Due to the difficulties in applying the specific outage reduction impacts to the data, impacts not considered. Although this analysis was not conducted, this subprogram would likely provide some level of benefit in an event of the level of Superstorm Sandy.
Increase in the Capital Costs Experienced as Part of ES II Electric Program Implementation	Increases in the capital costs of the ES II Electric Program will increase and delay any break-even point for return on benefit value.	Evaluate a 10 percent increase and decrease in capital costs.
Recognize the Exclusion of the "Ramp In" of Benefit Value	The core case ignores the additional benefit value created during the ES II Program investment period, as the projects are completed and the systems installed and commissioned.	Evaluate the potential impact of including a ramp in of benefit value.
Escalation Factor	Cost and benefit factors are assumed to change and inflate over time as the value to customers tracks nominal dollar changes within the general economy.	Evaluate inflation rates different than selected 2.1%. Evaluate 0% (no inflation adjustment) and 4% (modest level of yearly inflation).
Impact of System Growth in Either	This is a potentially very important factor but is subject to undue	N/A

[46]Information about the advisory based flood elevations and maps are available on the FEMA website at http://www.region2coastal.com/sandy/abfe

VARIABLE	DESCRIPTION	SENSITIVITY ADJUSTMENT/ APPROACH
Customers or Loads	speculation. It is possible that load growth is positive or negative, depending on energy efficiency, for example. Alternatively, demand for new appliances and grid services such as electric vehicles and battery storage may change the nature of electricity value and patterns of use. The cost-benefit study does not consider these effects and elects, rather, to assume no changes over time.	
Changes to the VoLL Factors	Changes to VoLL factors could be driven by many factors, including load growth (above). It can also be driven by the contribution of electricity services to economic output. As electricity becomes more valuable, the loss of it becomes more damaging.	A range of VoLL % adjustments have been evaluated. See Figure 9.

The most impactful sensitivities are Superstorm Sandy and the VoLL factors. The effects of these two sensitivities are summarized below. Figure 9 shows the change to the benefit-to-cost ratio of the analysis results over 20 years. VoLL factors are adjusted from the assumed values (at 0 percent). Superstorm Sandy estimated effects are also shown.

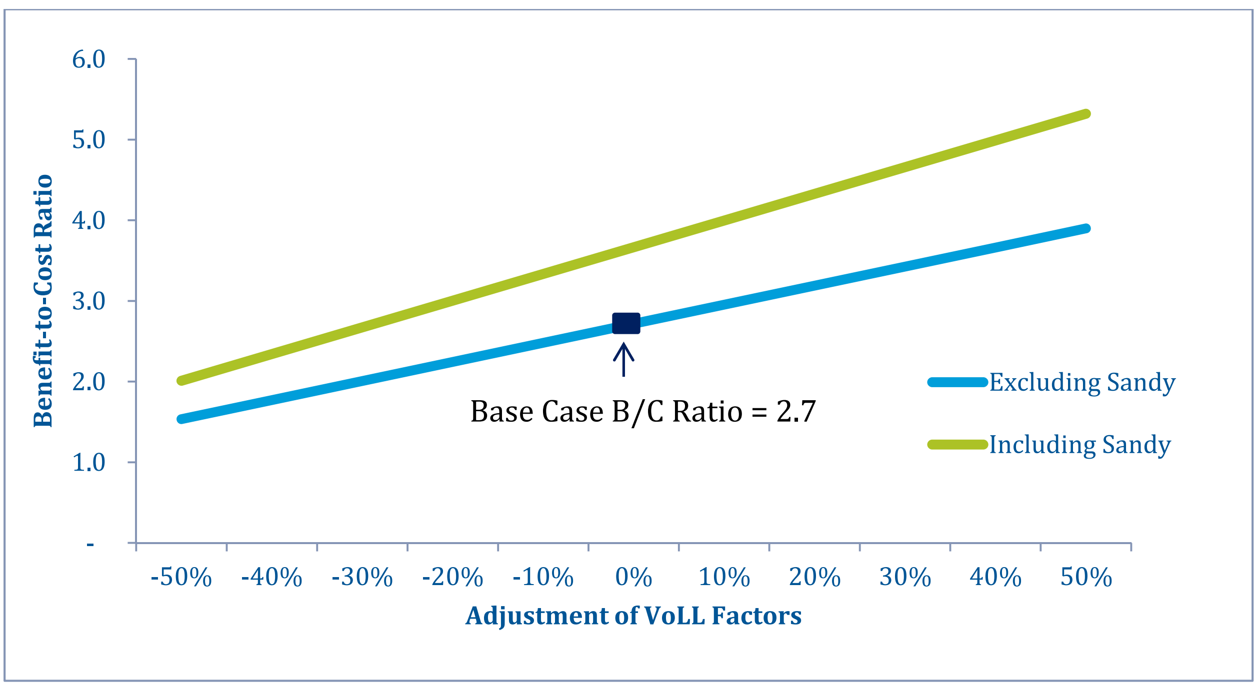

Figure 9 ES II Electric Program: Sensitivity Analyses

Conclusions

PSE&G has constructed its ES II Electric Program with goals aimed at improving system reliability, hardening, and resiliency across all outage conditions. Leveraging actual historical outage data from the recent past (2010 through 2016) – combined with estimates of operating cost reductions tied to aging assets and fewer outage conditions – Black & Veatch conservatively estimates beneficial value exceeding costs by a factor of 2.7 over an approximately 20 year period. This estimate places a large emphasis on how reducing the duration and frequency of outages provides customers with significant value in both day-to-day circumstances as well as during major storm events. Furthermore, the benefit estimates are tied to a disciplined review of the planned technologies, their associated functionalities, and the intermediate impacts required to achieve the benefits.

The cost-benefit analysis is premised on a straightforward assumption that the average rate of intensity of the past seven years of outage experience will continue throughout the approximately 20 year forecast period.

Black & Veatch also describes many additional areas where the analysis is conservative. These include limiting the analysis to an approximately 20 year forecast (much shorter than the life of the ES II Program assets), exclusion of Superstorm Sandy experience, not estimating many direct and indirect costs (that are not embedded in VoLL factors), largely ignoring benefit achievement in years prior to Year 6, not factoring in the support of future grid requirements (such as DER support), and not including growth in customer or load effects.

Including Superstorm Sandy level impacts raises the benefit-to-cost ratio to 3.6, an increase of nearly 40 percent. Extending the forecast period to 40 years (reflecting the long service life of the substations and spacer cable, for example) raises the benefit-to-cost ratio to 7.4, an increase of a factor of 2.7. Assuming both raises the benefit-to-cost ratio to 10.1. These benefit-to-cost ratios are shown on Figure 10.

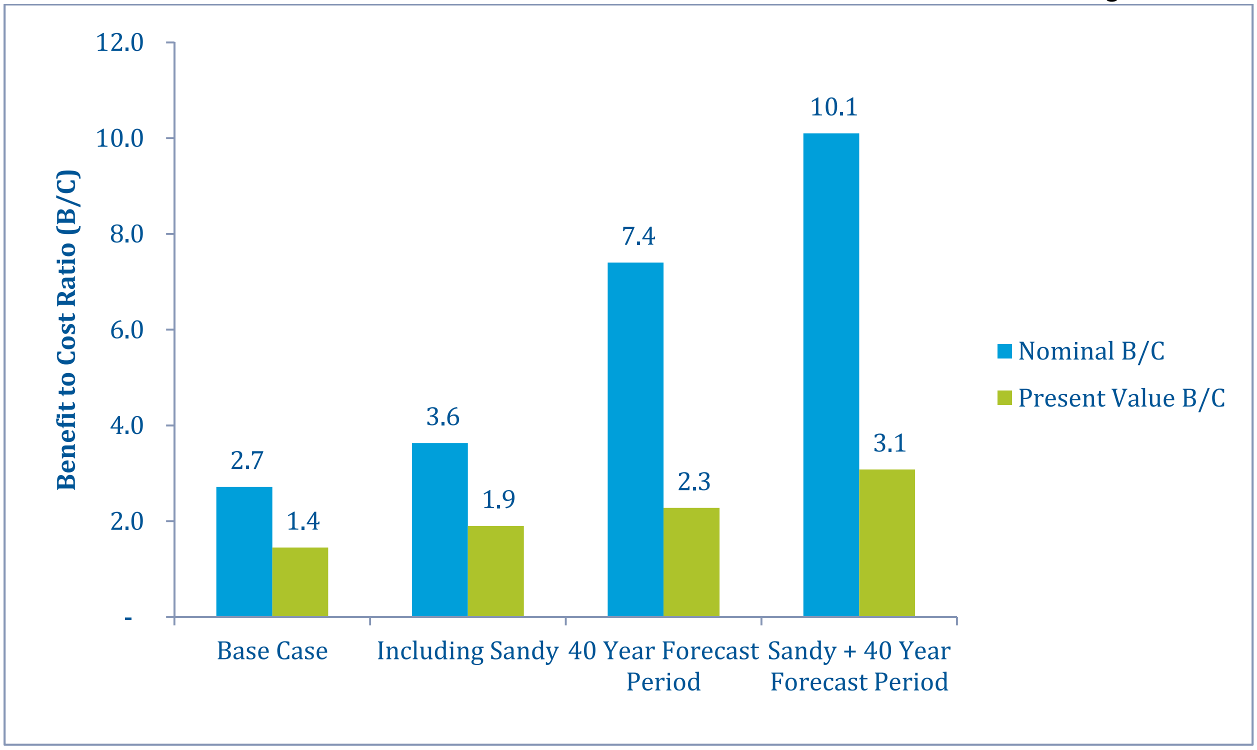

Figure 10 Comparison of Base Case to Select Sensitivity Analyses: Benefit to Cost Ratio

The strictly monetary benefit-to-cost ratio, by its nature, also ignores consideration of many significant and important qualitative benefits, such as reduction in overall risk and improvement in safety that will be created through the ES II Electric Program investments.

Finally, Black & Veatch believes that the cost-benefit analysis – and especially the discrete estimate of a specific monetary benefit-to-cost ratio -- is one of several inputs to decision makers about the merits of the ES II Electric Program, but it is not dispositive by itself. For example, a significant portion of the PSE&G investment is guided by important asset and risk management findings that are guided by a range of criteria, including safety and environmental performance, and which help address the chronic and long-term effects of aging equipment and run-to-failure conditions.

Appendix A – Benefit Matrix

Benefit Mapping -- Relationship of Impact to Benefit Type				Cost Related Impacts		CMI-related Impacts								Other		
				Non-Outage Related	Outage Related	(Sustained Interruption, Blue Sky)		Major Events (Excluding Sandy)		Major Events (Sandy)		Other		
						Reliability		System Hardening	System Resiliency	System Hardening	System Resiliency			
Sub-Programs	No.	Impact (requires statement involving concrete consequences)	Driver of the Impact	Reduced / Avoided O&M and/or CapEx	Reduced / Avoided O&M and/or CapEx	Outage Reduction - Frequency	Outage Reduction - Duration	Outage Reduction - Frequency	Outage Reduction - Duration	Outage Reduction - Frequency	Outage Reduction - Duration	Safety or Compliance Related	Future Program Support	Other
				A	B	C	D	E	F	G	H	I	J	K
Substation	Station Flood and Storm Surge Mitigation													
	SF1	Reduced risk of flood-related outages for the upgraded substations	Bring substations into compliance with the advisory FEMA post-Superstorm Sandy flood elevations and the flood elevation requirements established by the NJDEP Flood Hazard Rules, codified at N.J.A.C. 7:13		•			•		•		♒		
	SF2	Bring substations into compliance with with current, modern building standards	Upgrading buildings reduces safety risks									♒		
	SF3	Reductions in emergency repair work due to fewer “run to failure” equipment conditions in the substations	Substation upgrades eliminate old and aging equipment that causes failures and must be repaired under emergency conditions		♒	•						♒		
	SF4	Avoided corrective maintenance due to aging equipment in substation (non-catastrophic, or is not outage-related)	The substation upgrades eliminate the old and aging equipment requiring corrective maintenance	•								♒		
	SF5	Faster outage restoration times	Substation upgrades eliminate old and aging equipment by providing microprocessor-based remote terminal units (RTUs) and relays that support improved situational awareness				♒		♒		♒	♒		
	SF6	Increased data and other capabilities that could support future data collection requirements caused by significant hosting of DER	Substation upgrades provide new microprocessor-based relays and SCADA.										♒	
	SF7	Reduction in future base capital expenditures	Accelerating substation rebuilds as part of ES II	•										
	Substation Upgrades 26/4 kV Stations													
	SU1	Bring substations into compliance with with current, modern building standards	Upgrading buildings reduces safety risks									♒		
	SU2	Reductions in emergency repair work due to fewer “run to failure” equipment conditions in the substations	Substation upgrades eliminate old and aging equipment that causes failures and must be repaired under emergency conditions		•	•						♒		
	SU3	Avoided corrective maintenance due to aging equipment in substation (non-catastrophic, or is not outage-related)	The substation upgrades eliminate the old and aging equipment requiring corrective maintenance	•								♒		
	SU4	Faster outage restoration times	Substation upgrades eliminate old and aging equipment by providing microprocessor-based remote terminal units (RTUs) and relays that support improved situational awareness				♒		♒		♒	♒		
	SU5	New microprocessor-based relays and SCADA increase data provision and other capabilities that could support future data collection requirements caused by significant hosting of DER	Substation upgrades provide new microprocessor-based relays and SCADA.										♒	
	SU6	Reduction in future base capital expenditures	Accelerating substation rebuilds as part of ES II	•										

Benefit Mapping -- Relationship of Impact to Benefit Type				Cost Related Impacts		CMI-related Impacts								Other		
				Non-Outage Related	Outage Related	(Sustained Interruption, Blue Sky)		Major Events (Excluding Sandy)		Major Events (Sandy)		Other				
						Reliability		System Hardening	System Resiliency	System Hardening	System Resiliency					
Sub-Programs	No.	Impact (requires statement involving concrete consequences)	Driver of the Impact	Reduced / Avoided O&M and/or CapEx	Reduced / Avoided O&M and/or CapEx	Outage Reduction - Frequency	Outage Reduction - Duration	Outage Reduction - Frequency	Outage Reduction - Duration	Outage Reduction - Frequency	Outage Reduction - Duration	Safety or Compliance Related	Future Program Support	Other		
				A	B	C	D	E	F	G	H	I	J	K		
Spacer Cable																
Outside Plant Higher Design and Construction Standards	SP1	Improved conductor performance during major events (rain, wind, snow, ice loading etc.)	Installation of spacer cable results in stronger conductors that reduce energized conductors falling on ground		•			•		•		≈				
	SP2	Improved conductor performance during day to day operations	Installation of spacer cable results in stronger conductors that reduce energized conductors falling on ground		•	•						≈				
	SP3	Deferral of conductor replacement on 4kV; fewer conductor repairs; less vegetation management	Installation and use of spacer cable allows for deferral of some pole and conductor replacement costs and some avoided repair conditions	≈												
Increased Sectionalization																
Contingency Reconfiguration Strategies	IS1	Reduced O&M to locate and resolve outage locations because smaller feeder sections decrease patrol and investigation time	Operation of reclosers (including incremental new) with ADMS and high speed network		≈											
	IS2	Reduced outage footprint on 4kV circuits and feeder ties	Installation of new reclosers provides greater segmentation and some customers avoid an extended outage			•		•		≈						
	IS3	Reduced outage footprint on 13kV circuits	Installation of new reclosers provides greater segmentation and some customers avoid an extended outage			•		•		≈						
	IS4	Reduced O&M to investigate and resolve nested outages	Installation and use of branch reclosers at three-phase fused branch circuits		≈											
	IS5	Reduced O&M in avoided truck roll as there is a reduced need to investigate and resolve blown fuse with a branch recloser	Installation and use of branch reclosers at three-phase fused branch circuits		•											
	IS6	Reduced outage footprint on 13kV circuits	Installation and use of branch reclosers at three-phase fused branch circuits cause customers on circuit branch to avoid an extended outage			•		≈		≈						
	IS7	Improves (reduces) the time to restore system after outage	Installation and use of branch reclosers at three-phase fused branch circuits				≈		≈		≈					
Reclosing Devices																
	FS1	Reduced O&M to investigate and resolve nested outages	Reclosing devices with upstream recloser operation are communicated to SCADA		≈									Addressed elsewhere		
	FS2	Reduced O&M in avoided truck roll as there is a reduced need to investigate and resolve blown fuses with reclosing devices	Installation and use of reclosing devices on single and two-phase branch circuits		•											
	FS3	Reclosing devices cause a percentage of permanent outages to only be momentary outages	Installation and use of reclosing devices at single and two-phase fused branch circuits cause customers on circuit branch to avoid an extended outage			•		≈		≈						
	FS4	Improves (reduces) the time to restore system after outage	Installation and use of reclosing devices on single and two-phase branch circuits		≈		≈		≈		≈					

Benefit Mapping -- Relationship of Impact to Benefit Type				Cost Related Impacts		CMI-related Impacts						Other		
				Non-Outage Related	Outage Related	(Sustained Interruption, Blue Sky) Reliability		Major Events (Excluding Sandy)		Major Events (Sandy)		Other		
								System Hardening	System Resiliency	System Hardening	System Resiliency			
Sub-Programs	No.	Impact (requires statement involving concrete consequences)	Driver of the Impact	Reduced / Avoided O&M and/or CapEx	Reduced / Avoided O&M and/or CapEx	Outage Reduction - Frequency	Outage Reduction - Duration	Outage Reduction - Frequency	Outage Reduction - Duration	Outage Reduction - Frequency	Outage Reduction - Duration	Safety or Compliance Related	Future Program Support	Other
				A	B	C	D	E	F	G	H	I	J	K
Grid Modernization	**Advanced Distribution Management System (ADMS)**													
	AD1	Improved understanding of electrical asset damage	Post event analytics in ADMS from reclosing devices											≈
	AD2	Reduction in the # of trips and the length of trips to investigate outages	ADMS provides geographic visualization tools to help troubleshoot locations, combined with new connected devices on network.		≈									Addressed elsewhere
	AD3	Reduction in mutual aid costs during very large events	ADMS provides geographic visualization tools to help troubleshoot locations, combined with new connected devices on network.		≈				≈					Addressed elsewhere
	AD4	More reliable communications will improve data collection to improve safety, reduce operations cost, and reduce outage durations	ADMS provides tools requiring up-to-date data that will help crews work more safely and efficiently	≈	≈		≈		•		≈	≈		
	AD5	Reduced O&M expense to locate and resolve nested outages	Improved information with new reclosers and reclosing devices to resolve nested outages		≈									Addressed elsewhere
	AD6	The high-speed network and ADMS will be able to support future applications, such as DER installations	the network will be built out and the ADMS will be installed										≈	
	AD7	Avoided upgrade on legacy OMS (one time savings)	Installation of new ADMS with integrated OMS	•										
	AD8	Elimination of maintenance costs for the existing OMS.	Installation of new ADMS with integrated OMS	•										
	Communication Network													
	HS1	Reduction in telco monthly charges - legacy (substations and reclosers)	Phase out of Plain Old Telephone Service (POTS) lines with the ramp in of new HSN	•										
	HS2	Reduction in telco POTS line maintenance costs (existing reclosers, new reclosers, and reclosing devices)	POTS lines will be phased out with the ramp in of new high-speed network	•										
	HS3	Reduction in transition costs to telco fiber (recurring upgrade cycles)	Ramp in of HSN as alternative to telco fiber	•										
	HS4	Reduction in substation POTS line O&M costs	Ramp in of HSN as alternative to telco fiber	≈										
	HS5	Elimination of routine maintenance related to telco fiber	Ramp in of HSN as alternative to telco fiber	•										

Legend:

• (green)	- Monetary benefit derived from PSE&G data and inputs	≈	- Qualitative benefit, difficult to monetize
• (yellow)	- Monetary benefit derived from CMI reduction and VoLL calculation	(blank)	- Not applicable; no significant impact or benefit
Addressed elsewhere	- Benefit included in another subprogram		

Appendix B – ES II Electric Subprogram Details

The ES II Electric Program is comprised of four major subprograms whose details are described in this appendix. Each subprogram is comprised of one or more subparts.

SUBPROGRAM B-1 - SUBSTATION (SUBPART 1 – STATION FLOOD AND STORM SURGE MITIGATION)

There are two Subparts to the Substation Subprogram. This Subpart addresses substation rebuilds to address both lifecycle risks and flood hazards.

DESCRIPTION

The Station Flood and Storm Surge Mitigation Subpart emerges from PSE&G's internal studies and confirmations to identify substations within the Federal Emergency Management Agency (FEMA) preliminary flood elevations designations.[47] The studies included field surveys, site inspections to confirm critical equipment, and development of office-level estimates including contingency estimates.

The Station Flood and Storm Surge Mitigation Subprogram complies with the guidance from the State of New Jersey concerning FEMA post-Superstorm Sandy flood elevations and the flood elevation requirements, which are established by the New Jersey Department of Environmental Protection (NJDEP) Flood Hazard Rules, codified at N.J.A.C. 7:13.

PSE&G has identified 21 substations that have major equipment below the base flood elevations "plus one foot". Five of these substations (Homestead, North Avenue, North Bergen, Penhorn, and Newport) are being raised as part of PSE&G's base capital program in part to facilitate PJM's Regional Transmission Expansion Plan (RTEP) projects[48] impacting these locations. The remaining 16 substations with equipment below the base flood elevations "plus one foot" are included in the ES II Program as to address Flood and Storm Surge hazards.

Consistent with PSE&G's experience in the ESI implementation, PSE&G has compared the alternatives of raising or eliminating substations based on the cost effectiveness of the available solutions. In general, 4 kV substations with low customer counts and/or low peak loads are the best candidates to eliminate, generally in conjunction with a 13 kV circuit upgrade. This is consistent with what has been done with three ESI Program substations (Garfield Place, River Edge, and Bayway 4 kV). The current proposed substations and recommended alternatives included in ES II Program are identified in Table 12:

[47] Information about the advisory based flood elevations and maps are available on the FEMA website at www.region2coastal.com/sandy/abfe.

[48] RTEP transmission projects are projects that are part of the PJM Independent System Operator planning process that identifies necessary transmission system upgrades and enhancements in PJM's region to provide for the operational, economic and reliability requirements of the transmission system and provide appropriate service to customers.

Table 12 List of Substations Proposed for Flood Mitigation

SUBSTATION NAME	STATION CLASS	RECOMMENDATION
Meadow Road	H	Raise
Leonia Substation	H	Raise
Kingsland Substation	H	Raise
Ridgefield 13 kV	H	Raise
Ridgefield 4 kV	C	Eliminate
Hasbrouck Heights Substation	C	Raise
Academy Street Substation	C	Raise
Woodlynne Substation	C	Raise
Toney's Brook Substation	C	Raise
Clay Street Substation	A	Raise
Waverly Substation	A	Raise
State Street Substation	A	Raise
Orange Valley Substation	C	Raise
Market Street Substation	A	Eliminate
Lakeside Avenue Substation	A	Raise
Constable Hook Substation	Unit	Raise

Where a recommended alternative is defined as "Raise," the scope of the work under the ES II Electric Program will be to install new, elevated 13 kV switchgear (Class H substations) or 4 kV switchgear (Class C and Class A substations) a minimum of one foot above the published flood levels. The work typically involves multiple steps to complete, as contingencies need to be put in place to maintain N-1 redundancy for customers served through the use of mobile transformers or other means. N-1 refers to system reliability requirements when losing certain transmission or distribution capacity where Components (N) have at least one independent backup component (1). For the substations where the recommended alternative is defined as "Eliminate," the scope of work includes conversion of 4 kV to 13 kV operation at an adjacent Class H substation. This alternative is only used where capacity for the load is available at one or more other substations.

GOALS AND OBJECTIVES

This subprogram is aimed at protecting customers served by these substations from outages due to flood events while also reducing overall risk by installing modern equipment. The goals are in concert and aligned with the goals of the "life-cycle" Substation Subprogram, *but add additional mitigation value* directed at addressing the flood hazards at these stations. Please refer to the Goals and Objectives section of the Substation Upgrades 26/4 kV Stations Subpart for further discussion of the key considerations of risk reduction related to the "lifecycle programs" achieved by installing modern equipment in the substations. Also, refer to *Appendix A – Benefit Matrix* for delineation of specific benefit attributes.

DESIGN BASIS

The projects that make up this Subpart will comply with the advised FEMA post-Superstorm Sandy flood elevations and the flood elevation requirements established by the NJDEP Flood Hazard Rules, codified at N.J.A.C. 7:13. Additionally, consistent with the substation lifecycle subprogram, PSE&G has standardized designs for all switchgear and unit substations. Old switchgear will not be re-used as relocating the switchgear is cost prohibitive and, in the case of 4kV substations, the equipment has generally reached the end of its useful life. Equipment that is removed will be returned to stock when the equipment is judged to have remaining useful life.

ALTERNATIVES

Elimination of substations was considered, but was only recommended in instances where elimination was cost-efficient and capacity[49] was available. Installation of flood walls or temporary flood measures such as sandbags at these substations was not considered to be a viable solution because of potential floodwater infiltration through ducts and conduits.[50]

ENERGY STRONG II DEPENDENCIES AND PRECEDENCES

There are no major dependencies (that impose implementation risks) with our parts of the ES II Program. There may be some circuits from these substations that are targeted elsewhere, but those circumstances are not considered a major dependency. For several substations, a parallel 69kV upgrade of the 26 kV high side will be completed in conjunction with the lower voltage upgrade. The approval and funding of these 69 kV upgrades are not part of the ES II Electric Program.

ENERGY STRONG I ALIGNMENT

The original ESI approved program was limited to substations that had experienced water intrusion in the past. It was noted in the original filing that PSE&G would also review and identify other substations that could benefit from flood and/or storm surge mitigation, utilizing the newly defined FEMA advisory based flood elevations. This ES II Program Subpart is the result of those studies and confirmations of impact on critical substation facilities.

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[49] The maximum capability of a substation to supply a given level of energy at any point in time and is typically determined from an analysis of substation configuration, load carrying capacity of its associated equipment (transformers, breakers, conductors, etc.), contingency plans (the ability of nearby substations to pick up some portion of the load under emergency conditions), reserve margins, and other factors.

[50] As addressed in ES1, floodwalls can be a good tool in some situations. Other factors in addition to potential water infiltration through ducts and conduits and the underground facilities that must be moved, circumvented, or modified are the size of the property involved; concerns regarding egress/ingress from station; previous experience obtaining variances and permits; effectiveness; recurring maintenance; impact of waves requiring robust designs; and the cumulative system impact of multiple floodwalls needing attention during a storm event. Refer to http://www.state.nj.us/rpa/docs/recent/PUBLIC%20VERSION%20Salamone%20Appendix%20Part%20B.pdf.

RISKS OF SUCCESSFUL IMPLEMENTATION

Each substation re-build (or elimination) is a stand-alone project. Based upon previously completed substation upgrade projects, the most significant risks for the successful implementation at each substation typically include permitting, possible need for property to facilitate the project, and maintaining customer electrical supply service throughout the project's duration. For any substations that are eliminated, availability of construction resources common to other Subprograms and/or Subparts will need to be evaluated.

COSTS AND ASSUMPTIONS

PSE&G has developed cost estimates for each substation, consistent with standing internal practices, and consistent with practices applied as part of the original Energy Strong Program. As part of ES II, costs are defined in part on actual experience obtained through ESI implementation. Moreover, PSE&G has experience with the type of equipment purchases and installation costs for each substation. The associated cost estimates (which include contingency) and project sequencing during construction are site-specific. The PSE&G estimates used in this cost-benefit analysis are identical to those in Mr. Gray's testimony.

BENEFITS

The Station Flood and Storm Surge Mitigation effort has the following benefits (as identified in *Appendix A – Benefit Matrix*):

1. Bring substations into compliance with the advisory FEMA post-Superstorm Sandy flood elevations and the flood elevation requirements established by the NJDEP Flood Hazard Rules, codified at N.J.A.C. 7:13 (SF1). This results in reduced risk of flood-related outages for the upgraded substations (which is hardening benefit). The SF1 benefits claimed are as follows:

   a. Operations – Reduced/Avoided O&M and/or Capital Expenditures (SF1-B). The upgraded substations will reduce flood risk, which avoids the historical average cost of the flood repair work (as seen by operations) in both O&M and capital expenditures (CapEx).

   b. Outage Reduction – Frequency under major events (excluding Sandy) (hardening) (SF1-E). The upgraded substations will reduce the flood risk; this assumption is used to compute the avoided customer minutes of interruption (CMI) based on historical average flood impacts.

   c. Outage Reduction – Frequency under major events (Superstorm Sandy) (hardening) (SF1-G). The upgraded substations will reduce the flood risk.

   d. Safety and Compliance Related (SF1-I). The upgraded substations will be constructed to the latest design standards that meet current FEMA post-Superstorm Sandy flood elevations and the flood elevation requirements established by the NJDEP Flood Hazard Rules, codified at N.J.A.C. 7:13. Avoiding a flooded substation avoids safety issues associated with hazardous conditions during the flood and also assessing and repairing damaged equipment, which are difficult to monetize, so this benefit is qualitative.

The remaining benefits claimed (SF2-SF7) are identical to those claimed by the Substation Upgrades 26/4 kV Stations Subpart of the Substation Subprogram (SU1-SU6) because both upgrade the substations to new equipment and standards. Please refer to that Subpart benefit section for discussion of the remaining benefits.

FUNCTIONAL REQUIREMENTS TO ACHIEVE BENEFIT

PSE&G will require a robust communication connection to the upgraded substation, which may depend upon the timing of the Communication Network Subpart of the Grid Modernization Subprogram (e.g., some substations may not have existing SCADA or some existing SCADA circuits may require more bandwidth and improved reliability). This will be addressed on a case-by-case basis.

BUSINESS PROCESS CHANGES TO ACHIEVE BENEFITS

Minimal business process changes are expected to achieve benefits because PSE&G currently has the required construction standards and training to ensure the workforce is familiar with the construction and operation of newly constructed substations.

BENEFIT: METRICS, KEY ASSUMPTIONS, AND CALCULATIONS

Benefit calculations are based upon avoiding a future flood event and using VOLL to monetize the event. During Superstorm Sandy and Irene, a typical flooded substation experienced approximately a 3-day outage. The number of customers supplied by each substation subject to upgrade as part of ES II is known. Additionally, the 4 kV substations generally do not have alternative supplies because the substation only has radial circuits; therefore, all customers supplied by the 4 kV substations are assumed to experience an outage as the result of a flood event. On the other hand, the 13 kV substations have ties to external circuits; however, many tie back to the same substation and thus all customers supplied by the 13 kV substations are assumed to experience an outage as the result of a flood event.

The benefit calculations also include estimates for avoided repair costs, leveraging historical average flood event repair costs to estimate avoided costs resulting from a flood event.

The Class C substations within this Subpart are also exposed to the same catastrophic equipment failures as are discussed within the Substation Upgrades 26/4 kV Stations Subpart. Please refer to the Benefit: Metrics, Key Assumptions, and Calculations discussion in the Substation Upgrades 26/4 kV Stations for the remaining benefits.

The Station Flood and Storm Surge Mitigation effort has the following benefit calculations (as identified in *Appendix A – Benefit Matrix*):

1. Bring substations into compliance with the advisory FEMA post- Sandy flood elevations and the flood elevation requirements established by the NJDEP Flood Hazard Rules, codified at N.J.A.C. 7:13 (SF1). The SF1 benefits are calculated as follows:
    a. Operations – Reduced/Avoided O&M and/or Capital Expenditures (SF1-B). The benefit is calculated as the avoided historical average cost of the flood repair work (as seen by

operations) in both O&M and CapEx. Refer to the Benefits assumptions section for an explanation of the specific assumptions for how this reduced risk is translated into avoided costs. Per the use of the Risk-based Lifecycle Model, the value associated with the risk avoidance is related to the application of the definition of a base flood[51] to the upgraded substations.

b. Outage Reduction – Frequency under major events (excluding Sandy) (hardening) (SF1-E). This benefit calculation computes in customer minutes of interruption (CMI) based on historical average flood impacts. This result is monetized using VoLL based upon customer type and outage duration.

c. Outage Reduction – Frequency under major events (Sandy) (hardening) (SF1-G). This benefit calculation computes CMI based on the Sandy flood impacts. This result is monetized using VoLL based upon customer type and outage duration.

d. Safety and Compliance Related (SF1-I). This benefit is qualitative so there is no benefit calculation.

The remaining benefit calculations (SF2-SF7) are identical to those calculations in the Substation Upgrades 26/4 kV Stations Subpart of the Substation Subprogram (SU1-SU6). Please refer to that Subpart benefit section for calculation of the remaining benefits.

[51] A base flood has a 1 percent chance of being equaled or exceeded in any given year. This is the regulatory standard also referred to as the 100-year flood. The base flood is the national standard used by the National Flood Insurance Program (NFIP) and all federal agencies for the purposes of requiring the purchase of flood insurance and regulating new development. Base Flood Elevations (BFEs) are typically shown on Flood Insurance Rate Maps (FIRMs). Definition retrieved from https://www.fema.gov/base-flood on December 11, 2017.

BENEFIT REALIZATION SCHEDULE

In addition to reducing the risk of major outages caused by storm surges, non-major storm related improvements are also expected and will be realized upon operation of the rebuilt raised station. However, from a timing perspective, the cost-benefit analysis assumes that no benefits will be realized until after Year 5 (completion of the entire set of Station Flood and Storm Surge Mitigation rebuilds).

Because storm-related benefits are dependent on severe weather activity, the benefits (tied to outages for major event versus sustained interruption events) are separated out. Moreover, the benefit calculation assumes that there is a probability of flood events in the future as follows:

- Whether the flood event occurs is uncertain, but based on actual experience during the past seven years, PSE&G experienced damage to substations from flooding, which created multi-day outages.
- For purposes of the cost-benefit analysis, the benefit computations assume that each substation included in this subprogram subpart will, if left at its current elevation, flood once during the approximately 20-year forecast period. Furthermore, this rate of flooding is divided between the Major Event data both with and without Superstorm Sandy, as around 60 percent of the substations that flooded during the past seven years occurred during Superstorm Sandy. An average was created to simulate an equivalent level of flooding on a per year average for both the Major Events without Superstorm Sandy and Major Events with Superstorm Sandy.

INCREMENTAL COSTS TO ACHIEVE BENEFIT

There are minimal incremental costs to achieve these benefits because preventative maintenance programs are the same regardless of age. The resources PSE&G devotes to substation maintenance will also be devoted to new substations. (Notwithstanding this, the cost-benefit analysis takes into account the avoided costs due to substation outages due to aging equipment, but this is a unique area of cost occurrence. The reference here is to normal day-to-day maintenance activities).

BUSINESS AS USUAL SCENARIO

The BAU scenario continues with the unabated risk of flood events, and continued level of equipment failures and corrective maintenance related to old and aging equipment (refer to the related Substation Upgrades 26/4 kV Stations Subpart of the Substation Subprogram).

SUBPROGRAM B-1 - SUBSTATION (SUBPART 2 – STATION UPGRADES 26/4KV STATIONS)

There are two Subparts to the Substation Subprogram. This Subpart addresses substation rebuilds to address lifecycle risks.

DESCRIPTION

PSE&G proposes to replace or retire substations with 4 kV assets that are either at or near the end of their useful life. There are 95 substations with 4 kV assets that warrant inclusion in the program, 11 of which are part of the Station Flood and Storm Surge Mitigation Subprogram subpart. Class A/B substation designs have 4 kV facilities in a masonry building and substations were constructed between 1903 and 1952. Class C substations have all facilities outdoors with 4 kV equipment in metal-clad switchgear, and substations were constructed between 1938 and 1976. A breakdown of these substations is below:

- Class A/B substations
  - Number of substations - 34
  - Average age – 92 years

Total Customers Served: 269,622

- Class C substations
  - Number of substations - 50
  - Average age – 62 years

Total Customers Served: 234,001

The majority of the 26 kV and/or 4 kV equipment in these substations is the original equipment installed at the time the substations were constructed. PSE&G has evaluated these substations to determine if the substation is still required or if the substation's circuits can be cost effectively converted to 13 kV operations.

Black & Veatch (under a separate effort from the ES II Electric Program) and PSE&G collaborated in conducting a study of asset demographics, failure curves, and risk scoring for all its Distribution Assets , which helped PSE&G identify substations to be included in this Subpart.

Using the Risk Model and expert engineering knowledge and tools, the PSE&G team developed the Substation Upgrades 26/4 kV Stations Subprogram. The model also quantified the risk reduction achieved by replacing complete substations of particular classes, such as the A, B, and C substations. The risk reduction achieved by these substation replacement programs was compared to a 'business as usual' scenario (as a baseline) to arrive at the relative risk reduction. Utilizing the Risk Model in this manner provided PSE&G a tool to develop the life-cycle aspects of ES II that cost effectively reduces its overall system risk.

Based on risk scoring, the substations that supply 13 kV circuits generate lower risk scores due to the substation design, configuration, and age. This aligns with the analysis performed on three substations in the ESI program (Garfield Place, River Edge, and Bayway 26/4 kV). The 4kV substations with low customer counts and/or low peak loads are the best candidates to eliminate with a 13 kV circuit upgrade. For substations that must remain, PSE&G will prioritize Class C substations for replacement, because the 4 kV equipment is outdoor metal-clad switchgear and is exposed to the elements. Due to the antiquated (circa 1940s) design and condition of the 4 kV equipment in the Class C substations, PSE&G is proposing that this equipment be completely replaced with modern insulation, equipment, and protection schemes as part of this effort.

The proposed list of substations shown in Table 13 are upgrades that eliminate old and aging equipment whose age is a direct causative factor leading to sustained interruption events. For example, Class C substations have a history of substation shutdowns related to the age, condition, and design of the facilities; whereas, Class H substations have a lower likelihood of substation shutdowns due to the improved substation design that, for many faults and/or failures inside the substation, automatically isolates the impacted equipment and automatically transfers load to backup/secondary sources to limit any outage. In 2013, PSE&G had nine Class C substations trip out in a single day, including two substation fires, due to a severe temperature inversion that caused condensation inside the switchgear. Another example is water infiltration inside equipment during storms where during driving rain conditions water enters the bus duct and can cause tracking and flash-overs.

Table 13 List of Substations Proposed for Upgrade

SUBSTATION NAME	SUBSTATION CLASS	RECOMMENDATION
WOODBURY	C	Upgrade 4 kV
PLAINFIELD	C	Upgrade 4 kV
SPRING VALLEY RD	C	Upgrade 4 kV
MOUNT HOLLY	C	Upgrade 4 kV
MCLEAN BLVD	C	Upgrade 4 kV
PARAMUS	C	Upgrade 4 kV
WARREN POINT	C	Upgrade 4 kV
HAMILTON	C	Upgrade 4 kV
TEANECK	C	Upgrade 4 kV
FRONT STREET	C	Upgrade 4 kV
TONNELLE AVENUE	C	Upgrade 4 kV
GREAT NOTCH	C	Upgrade 4 kV
DUMONT	C	Upgrade 4 kV
40TH ST	C	Upgrade 4 kV
TOTOWA	C	Upgrade 4kV

The scope for each individual substation will generally include the installation of new 4 kV switchgear with the substation supporting both the original switchgear and the new equipment until all circuits can be cut over. Once all circuits are cut over, the original equipment will be removed from service. Each project typically involves multiple steps to complete as contingencies need to be put in place to maintain N-1 redundancy for customers served through the use of mobile transformers or other means. The equipment to be upgraded will primarily be the 4 kV equipment as in most cases the 26 kV equipment has already been, or is in the process of being, upgraded to 69 kV as part of a separate transmission project, outside of ES II. Equipment that is removed will be returned to stock when the equipment is judged to have remaining useful life.

GOALS AND OBJECTIVES

Installing modern equipment will reduce overall risk. Key considerations are as follows:

1. Improved operational performance through greatly improved protection and insulation.
2. Improved worker safety because new equipment avoids hazardous equipment failures caused by old and aging equipment.
3. Elimination of catastrophic failure due to design limitations. PSE&G has three recent examples of catastrophic failures whose root cause was condensation due to extreme temperature/humidity swings: a substation transformer failure in January 2014; a substation transformer/breaker cubicle fire in November 2013; and a substation transformer/breaker cubicle fire in January 2014.
4. Elimination of substation shutdowns during heavy rain or significant temperature fluctuations. Historical outage data for 2010 through 2016 show that on average, Class C substations experience 3.8 shutdowns per year, many of which are related to such rain or temperature fluctuations.
5. Avoidance of ongoing replacement costs of equipment that fails in service.

DESIGN BASIS

PSE&G has standardized designs for all switchgear. The work will be essentially the same as the Station Flood and Storm Surge Mitigation Subprogram with the exception that new installations will not be elevated.

ALTERNATIVES

PSE&G considered the elimination of substations, but this strategy is only recommended where cost is efficient and substation capacity was available.

Maintenance of existing equipment:

1. In order to clean the switchgear bus (which is a major cause of many outage and repair issues), the substation must be off-loaded resulting in O&M costs and reliability risks due to limited external capacity. This is not feasible in many cases.
2. Coatings have been installed on Class C substations to help reduce water infiltration during heavy rain events.

PSE&G is in the process of eliminating five substations as part of its base capital plan.

ENERGY STRONG II DEPENDENCIES AND PRECEDENCES

Refer to the dependencies and precedence in the Station Floods and Storm Surge Mitigation Subprogram.

ENERGY STRONG I ALIGNMENT

This life-cycle Subprogram is new for ES II. It is the next important logical step in PSE&G's long-term asset management strategy and effort to reduce its overall system risk associated with aging substation performance.

RISKS OF SUCCESSFUL IMPLEMENTATION

Each substation is essentially a stand-alone project. The risks for the successful implementation at each substation generally include permitting, possible need for property to facilitate the project, and maintaining customer service throughout the project. Another risk is the number of active substation projects in a division at one time. Work must be spread out to limit potential reliability impacts on the system.

COSTS AND ASSUMPTIONS

Cost estimates are generally based on the experience of ESI. PSE&G has experience with the equipment costs related to the project. The contingency and project phases and associated costs, however, are very site specific. Cost estimates are currently based on assuming a 50 percent risk and contingency value on top of the construction estimates. The PSE&G estimates used in this cost-benefit analysis are identical to those in Mr. Gray's testimony.

BENEFITS

This Subpart has the following benefits (as identified in *Appendix A – Benefit Matrix*):

1. Upgraded substations will be in conformance with current, modern building standards (SU1-I and SF2-I). Upgrading these buildings, especially the brick buildings at Class A/B substations, reduces safety risks, which are difficult to monetize; this benefit is qualitative.

2. Reductions in emergency repair work due to fewer "run to failure" equipment conditions in the substations (SU2 and SF3). The substation upgrades eliminate old and aging equipment that causes failures and must be repaired under emergency conditions. The benefits claimed are as follows:

   a. Operations - Reduced/Avoided O&M and/or CapEx (SU2-B and SF3-B). Fewer emergency repairs reduces the associated total annual cost as seen by operations in O&M and CapEx. The reduction in emergency repairs is difficult to monetize; this benefit is qualitative.

   b. Outage Reduction – Frequency for sustained interruption events (SU2-C and SF3-C). The upgraded substations will avoid an outage to perform the emergency repairs.

   c. Safety or Compliance Related (SU2-I and SF3-I). Reducing the occurrence of emergency repairs will reduce the number of employee hours spent working on equipment, which reduces the exposure of trained and qualified employees to nonetheless potentially hazardous conditions. These safety benefits are difficult to monetize, so this benefit is qualitative.

3. Avoidance of corrective maintenance due to aging equipment in substation (non-catastrophic, or is not outage-related) (SU3 and SF4). The benefits claimed are as follows:

   a. Reduced/Avoided O&M and/or CapEx (SU3-A and SF4-A). The substation upgrades eliminate the old and aging equipment requiring corrective maintenance.

   b. Safety or Compliance Related (SU3-I and SF4-I). Reducing the occurrence of maintenance will reduce the number of employee hours spent working on equipment, which reduces the exposure of trained and qualified employees to nonetheless potentially hazardous conditions. These safety benefits are difficult to monetize, so this benefit is qualitative.

4. Faster outage restoration times because of newer SCADA and relays (resiliency) under all outage scenarios (SU4 and SF5). The substation upgrades eliminate old and aging equipment by providing microprocessor-based remote terminal units (RTUs) and relays that support improved situational awareness. The benefits claimed are as follows:

   a. Outage Reduction – Duration, under all scenarios (SU4-D, SU4-F, SU4-H, SF5-D, SF5-F, and SF5-H). Installation of new microprocessor-based RTUs and relays improve situational awareness by providing data intended to support the shortening of outage restoration processes with respect to damage assessment and efficiency of outage restoration work preparation. This improvement is difficult to monetize, so this benefit is qualitative.

   b. Safety or Compliance Related (SU4-I and SF5-I). An improved understanding of equipment damage improves associated safety issues during outage restoration that can impede restoration procedures. This improvement is difficult to monetize, so this benefit is qualitative.

5. New microprocessor-based relays and SCADA increase data provision and other capabilities (i.e., remote access, real-time monitoring, flexible settings/configuration, etc.) that could support future data collection requirements caused by significant hosting of DER (SU5 and SF6). By meeting the future data requirements with already installed relays and SCADA, future costs for supporting DER could be avoided. This benefit is difficult to monetize, so this benefit is qualitative.

6. PSE&G will reduce future base capital expenditures by accelerating substation rebuilds as part of ES II. This is a Reduced / Avoided O&M and/or CapEx benefit.

FUNCTIONAL REQUIREMENTS TO ACHIEVE BENEFIT

PSE&G will require a robust communication connection to the upgraded substations, which may depend upon the timing of the Communication Network Subpart of the Grid Modernization Subprogram (e.g., some substations may not have existing SCADA or some existing SCADA circuits may require more bandwidth and improved reliability). This will be addressed on a case-by-case basis.

BUSINESS PROCESS CHANGES TO ACHIEVE BENEFIT

Minimal business process changes are expected to achieve benefit because PSE&G currently has the required construction standards and training to ensure the workforce is familiar with the construction and operation of newly constructed substations.

BENEFIT: METRICS, KEY ASSUMPTIONS, AND CALCULATIONS

This Subpart calculates benefits (as identified in *Appendix A – Benefit Matrix*) as follows:

1. Upgraded substations will be in conformance with current, building standards (SU1-I and SF2-I). This benefit is qualitative so there is no benefit calculation.
2. Reductions in emergency repair work due to fewer "run to failure" equipment conditions in the substations (SU2 and SF3). The benefits are calculated as follows:
   a. Safety or Compliance Related (SU2-I and SF3-I). This benefit is qualitative so there is no benefit calculation.
   b. Operations - Reduced/Avoided O&M and/or CapEx (SU2-B and SF3-B). The benefit is calculated based upon the reduction in the population of equipment being repaired and its associated historical equipment failure rate and the failure rate of the population of new equipment being installed.
   c. Outage Reduction – Frequency for sustained interruption events (SU2-C and SF3-C). A catastrophic equipment failure can lead to a significant outage (even a substation shutdown of over 24 hours). The SU2-C benefit calculation uses historical data to calculate the average duration of a substation equipment failure and associated CMI that is monetized using VoLL based upon customer type and outage duration. The number of customers supplied by each substation is known. For 4 kV substations, there generally are no alternative supplies as these are radial; therefore, all customers supplied by the 4 kV substations are assumed to experience an outage as the result of an equipment failure. The calculation is based upon the avoidance of the historical average substation equipment failure outage as average CMI and is monetized using VoLL based upon customer type and outage duration.
3. Avoidance of corrective maintenance due to aging equipment in substation (non-catastrophic, or is not outage-related) (SU3 and SF4). The benefits claimed are as follows:
   a. Reduced/Avoided O&M and/or CapEx (SU3-A and SF4-A). The benefit calculation uses historical corrective maintenance costs to estimate avoided costs due to failures and uses a likelihood of failure curve to inform an assumption of increasing corrective maintenance costs in the future. The benefit is calculated based upon the reduction in the population of equipment requiring maintenance and its associated historical maintenance rate and the maintenance rate of the population of new equipment being installed.
   b. Safety or Compliance Related (SU3-I and SF4-I). This benefit is qualitative so there is no benefit calculation.

4. Faster outage restoration times because of newer SCADA and relays (resiliency) under all outage scenarios (SU4 and SF5). The benefits are calculated as follows:
   a. Outage Duration Reduction, under all outage scenarios (SU4-D, SU4-F, SU4-H, SF5-D, SF5-F, and SF5-H). This benefit is qualitative so there is no benefit calculation.
   b. Safety or Compliance Related (SU4-I and SF5-I). This benefit is qualitative so there is no benefit calculation.
5. New microprocessor-based relays and SCADA increase data provision and other capabilities that could support future data collection requirements caused by significant hosting of DER (SU5 and SF6). This benefit is qualitative so there is no benefit calculation.
6. PSE&G will reduce future base capital expenditures by accelerating substation rebuilds as part of ES II, reducing future revenue requirement demands associated with these substations (SU6 and SF7). PSE&G has estimated that it will replace 12 of the Class C substations over the approximately 20 year forecast period under the BAU scenario, at a rate of approximately one substation rebuild every 18 months. By accelerating the Class C substation investment as part of the ES II Electric Program, in effect customers are relieved of this specific cost burden (and aging asset risk and exposure) as the costs under BAU form the basis of revenue requirement.

BENEFIT REALIZATION SCHEDULE

Benefits are expected and will be realized upon installation of the new elevated switchgear and as circuits are cut over on an individual basis. However, the cost-benefit analysis assumes that no benefits will be realized until after Year 5.

INCREMENTAL COSTS TO ACHIEVE BENEFIT

There are minimal incremental costs to achieve benefit because preventative maintenance programs are the same regardless of age.

BUSINESS AS USUAL SCENARIO

The BAU scenario is the continued increased risk of equipment failure due to age and antiquated design. Substations that cannot be eliminated require a significant capital investment and without an accelerated program will remain in service for multiple years to come.

SUBPROGRAM B-2 – OUTSIDE PLANT HIGHER DESIGN AND CONSTRUCTION STANDARDS (SUBPART 1 – SPACER CABLE)

This Subprogram has only one subpart, the Spacer Cable Subpart.

DESCRIPTION

PSE&G proposes to convert existing open wire construction on 13 kV and 4 kV circuits to spacer cable. The construction change consists of replacement of cross-arm open wire construction with a more compact spacer cable configuration. Approximately 47 percent of PSE&G's overhead 13 kV and 4 kV mainline electrical system is composed of wires installed on crossarms with an underbuilt neutral wire. A spacer cable system is composed of rugged tree wire, compacted into a bundle with a steel cable support and overall shield wire (instead of an underbuilt neutral that is installed below the cross-arm where secondary cables are also typically installed). It is resistant to tree and limb damage because of its high strength and smaller profile. On a crossarm, approximately an 8 foot wide span of 13 kV open wire is exposed compared to approximately 18 inches on spacer cable.

The Spacer Cable Subpart will upgrade approximately 500 miles of circuits. As part of this effort, PSE&G proposes to replace approximately 7,100 inadequate poles with additional storm guying (as required) along these circuits. The pole replacements will target smaller diameter poles that are greater than 30 years of age. The spacer cable upgrades require that poles are replaced where pole tops cannot support spacer construction. In addition, by replacing poles with larger diameter (Class 2) poles, the strength of the pole will be increased significantly. A structural analysis of typical pole configurations and additional consideration for pole age shows that the replacement of a typical 40 foot Class 4 (smaller diameter) pole with a Class 2 pole result in an overall strength gain of 53 percent.

PSE&G will also enhance storm guying for the poles along these circuits. Pole guying refers to the use of cables and earth embedded anchors to strengthen poles and support an overhead electrical distribution system. The tension on guy wires from wind forces and tree impact will significantly reduce the shear and bending forces on a pole line. Appropriate placement of additional pole guys would reduce overall storm damage significantly by increasing pole strength and reducing cascading pole failures. This is required where spacer cable is being installed as the additional strength of the conductor construction (steel messenger) will typically hold up large trees provided the supporting poles are of sufficient strength. The additional strength provided by pole upgrades and storm guying aligns with the needs for upgrading to spacer cable.

GOALS AND OBJECTIVES

One goal of this subprogram is improved performance during storms. PSE&G has analyzed the performance of spacer cable on its system during major storm events and has found that on a per mile basis spacer cable had 60 percent to 500 percent fewer damage locations attributed to tree contacts that caused customer interruptions, as compared with crossarm construction.

Fewer damage locations will result in fewer outages and faster restoration of service. This is due to the smaller profile and the presence of a steel support cable that supplies additional strength and protects the conductors from tree contacts. PSE&G experience has shown that vegetation-related damage accounts for up to 80 percent of damage during a storm event; this reduction in damage will have significant hardening benefits for customers for all types during storm events.

Better overvoltage protection is also obtained by the installation of shield wire, offering protection from lightning strikes that are also more prevalent during storm conditions.

DESIGN BASIS

The Subprogram will include the replacement of three-phase open wire construction with spacer cable. The work is standard and each installation will include design work specific to each location, including pole replacement and guying. Poles will be replaced as required (along with guying) to meet new design standards that support the new conductor arrangement on the poles. This includes modifications to the circuit layout drawings and GIS.

ALTERNATIVES

There are no obvious alternatives for this subprogram.

ENERGY STRONG II DEPENDENCIES AND PRECEDENCES

This subprogram is standalone.

ENERGY STRONG I ALIGNMENT

This subprogram was not performed during ESI.

RISKS OF SUCCESSFUL IMPLEMENTATION

Primary risks associated with this subprogram are resource constraints that could impede schedule performance. This risk can be mitigated by contracting work with outside contractors.

COSTS AND ASSUMPTIONS

Included in the cost is the engineering and installation of the spacer cable along with the costs associated with approximately 7,100 pole replacements and guying. Cost estimates are derived from previously completed spacer cable installations and pole replacements. The PSE&G cost estimates used in this cost-benefit analysis are identical to those in Mr. Gray's testimony.

BENEFITS

The Outside Plant Higher Design and Construction Standards Subprogram has the following benefits (as summarized in *Appendix A – Benefit Matrix):*

1. Improved conductor performance during major events (rain, wind, snow, ice loading, etc.) (SP1). Installation of spacer cable results in stronger conductors that reduce energized conductors falling on ground. This results in the following benefits:

   a. Operations – Reduced/Avoided O&M and/or CapEx during major events (with and without Superstorm Sandy)(hardening) (SP1-B). Spacer cable will reduce the occurrence of damage events related to vegetation during major storms because of the strength of the spacer cable and replaced poles and guying. Costs will be reduced based upon historical averages of tree repair costs (O&M and CapEx) and the outage event reduction factor per circuit segment associated with major events (minus Superstorm Sandy) and major events (Superstorm Sandy).

   b. Outage Reduction – Frequency, under major events (excluding Sandy) (hardening) (SP1-E) and under major events (Superstorm Sandy) (SP1-G). Spacer cable will reduce the occurrence of damage events related to vegetation during major storms (excluding Sandy) because of the strength of the spacer cable and replaced poles and guying. The historical outage data is reduced by a reduction factor per circuit segment associated with major storms excluding Superstorm Sandy avoids CMI and is monetized using VoLL based upon customer type and outage duration.

   c. Safety or Compliance Related (SP1-I). Spacer cable will reduce the occurrence of downed conductors because of the strength of the spacer cable and replaced poles and guying. Avoiding downed conductors prevents associated safety hazards, which are difficult to monetize, so this benefit is qualitative.

2. Improved conductor performance during day-to-day operations (SP2). This results in the following benefits:

   a. Operations – Reduced/Avoided O&M and/or CapEx during day to day operations (SP2-B). This benefit is similar in nature to the benefit SP1-B, except under day-to-day operations.

   b. Outage Reduction – Frequency, under day to day operations (SP2-C). This benefit is similar in nature to the benefit under SP1-E and SP1-G, except under day-to-day operations.

3. Deferral of conductor replacement on 4 kV, fewer conductor repairs, and less vegetation management (SP3). Installation and use of spacer cable allows for deferral of some pole and conductor replacement costs and some avoided repair conditions (SP3-A). This benefit

applies to Normal Operations – Reduced/Avoided O&M and/or CapEx, but is difficult to quantify, and therefore is claimed as a qualitative benefit.

Note that PSE&G considered impacts to vegetation management and pole inspection. Impacts to vegetation management were seen as negligible so as to not be qualitative. The impact to pole inspection was also seen as minimal so as to not be qualitative because the quantity of poles being replaced is small when compared to the total pole population.

FUNCTIONAL REQUIREMENTS TO ACHIEVE BENEFIT

None.

BUSINESS PROCESS CHANGES TO ACHIEVE BENEFIT

Minimal business process changes to achieve benefit are expected because PSE&G currently has the required construction standards and training to ensure the workforce is familiar with the construction and operation of spacer cable.

BENEFIT: METRICS, KEY ASSUMPTIONS, AND CALCULATIONS

This Subpart calculates benefits (as identified in *Appendix A – Benefit Matrix*) using an event reduction factor that is developed using historical system outage data (number of events) for already installed spacer cable (that is similar in construction to the spacer cable being installed) versus outage data (number of events) for open wire. Based on historical system outage data showing the better performance of spacer cable during major storm events as compared to open wire, the installation of spacer cable is assumed to result in an outage event reduction factor for major events (excluding Superstorm Sandy), for major events (such as Superstorm Sandy), and similarly under day-to-day operations. The benefits for this Subpart are calculated as follows:

1. Improved conductor performance during major events (SP1). The benefits are calculated as follows:

    a. Operations – Reduced/Avoided O&M and/or CapEx during major events (with and without Superstorm Sandy)(hardening) (SP1-B). The SP1-B benefit is calculated by using the outage event reduction factor for spacer cable performance compared to three-phase open/bare wire under all outage scenarios. To develop O&M and CapEx dollars under all outage scenarios, each outage event reduction factor is used to reduce an assumed future annual number of events, which is then multiplied by the historical average tree repair costs under all outage scenarios.

    b. Outage Reduction – Frequency, under major events (excluding Sandy) (hardening) (SP1-E) and under major events (Superstorm Sandy) (SP1-G). The SP1-E and SP1-G benefits are calculated based upon the reduction in CMI. The outage event reduction factor is applied to the historical annual average CMI per event on a per circuit segment basis to calculate an assumed future annual CMI that is monetized using VoLL based upon customer type and average outage duration. For major events, it is assumed that the level of storms experienced during the previous 7 years within PSE&G's service territory (2010 through 2016) will reoccur over the 20-year cost-benefit analysis period, thereby reducing the assumed annual CMI associated with major events.

c. Safety or Compliance Related (SP1-I). This benefit is qualitative so there is no benefit calculation.

2. Improved conductor performance during day-to-day operations (SP2). The benefits are calculated as follows:
    a. Operations – Reduced/Avoided O&M and/or CapEx during day to day operations (SP2-B). The calculation of this benefit is similar to the calculation in SP1-B.
    b. Outage Reduction – Frequency, under day to day operations (SP2-C). The calculation of this benefit is similar to the calculation in SP1-E and SP1-G.
    c. Safety or Compliance Related (SP2-I). This benefit is qualitative so there is no benefit calculation.
3. Deferral of conductor replacement on 4 kV, fewer conductor repairs, and less vegetation management (SP3). This benefit is qualitative so there is no benefit calculation.

BENEFIT REALIZATION SCHEDULE

Benefits are expected and can be realized upon spacer cable and pole installation. However, the cost-benefit analysis assumes that no benefits will be realized until after Year 5.

INCREMENTAL COSTS TO ACHIEVE BENEFIT

This is direct replacement of existing infrastructure, and thus, there will not be any incremental costs to achieve the benefit. (This refers to the potential for incremental operating costs).

BUSINESS AS USUAL SCENARIO

The BAU scenario is that circuit performance will continue in the same pattern as recent same as historical performance.

SUBPROGRAM B-3 – CONTINGENCY RECONFIGURATION STRATEGIES (SUBPART 1 – INCREASED SECTIONALIZATION)

There are two Subparts to the Contingency Reconfiguration Strategies Subprogram. This Subpart addresses the installation of spacer cable.

DESCRIPTION

PSE&G proposes to increase sectionalizing on its circuits to increase system hardening and resiliency as follows:

1. Convert all existing two-section overhead 13 kV circuits to three-section circuits. PSE&G currently has a total of 1,050 13 kV distribution circuits, of which approximately 690 circuits have been identified as candidates to have additional feeder reclosers installed. Two approaches will be used: either installing an additional recloser in either the first or second segment when one of those segments has a larger number of customers or installing two new reclosers that create two new segments with more equally distributed customers in each segment that can not be accomplished by using the existing recloser locations. Reclosers that are removed will be returned to stock when the equipment is judged to have remaining useful life.
2. Enhance overhead 4 kV radial circuits with a recloser to create two sections and reduce the number of customers impacted by an outage. PSE&G currently has a total of 1,316 4 kV distribution circuits, of which approximately 500 have been selected to have an additional section added.
3. Replace three-phase branches with and without fuses with branch reclosers that will avoid extended interruptions for faults of a transient nature that still cause a fuse to operate. PSE&G currently has over 20,000 three-phase branch fuse installations with varying degrees of outage performance, of which approximately 100 have been selected to have branch reclosers installed.
4. Create overhead 4 kV circuit ties by installing reclosers so service can be restored from an alternative source in the event of an outage.

GOALS AND OBJECTIVES

The overall objective is to reduce the number of customers affected by extended outages caused by distribution circuit faults (hardening).

The additional sections and branch reclosers will also provide added flexibility to restore customers during storm restoration (resiliency).

DESIGN BASIS

The design basis is the installation of distribution reclosers mounted on distribution poles utilizing existing PSE&G standards. Although the work is standard, each installation will include design work specific to each location, which includes modifications to the circuit layout drawings, GIS, communications, and Distribution SCADA system.

ALTERNATIVES

None.

ENERGY STRONG II DEPENDENCIES AND PRECEDENCES

This Subpart is dependent on the Communication Network Subprogram because the installation of the reclosers is contingent upon the ability to reliably communicate with the devices. Communications is required to monitor and operate the device remotely, to set the device up for live-line work, and to gather loading information.

ENERGY STRONG I ALIGNMENT

This Subpart is similar and well aligned with the ESI Contingency Reconfiguration program (both install new distribution reclosers). The ESI filing, however, focused specifically on critical customer restorations. The focus here is on improving the reliability of a broader number of customers (including both critical and non-critical) through outage avoidance (hardening) and shorter restoration times (resiliency).

RISKS OF SUCCESSFUL IMPLEMENTATION

There are no substantive risks associated with this Subpart beyond the dependence of a reliable communication infrastructure described earlier.

COSTS AND ASSUMPTIONS

Costs for this Subpart are based upon historical cost data that PSE&G has gathered through installation of a large number of reclosers in recent years. The cost estimate includes equipment, associated communication hardware, initial engineering/layout work, installation, testing and SCADA interface work. The PSE&G estimates used in this cost-benefit analysis are identical to those in Mr. Gray's testimony.

BENEFITS

This Subpart has the following benefits (as summarized in *Appendix A – Benefit Matrix*):

1. Reduced O&M to locate and resolve outage locations because smaller feeder sections decrease patrol and investigation time (IS1-B). This decrease in O&M expense is a benefit categorized as Operations – Reduced/Avoided O&M and/or CapEx. It is difficult to quantify the exact reduction because the reduction in locating the damage will vary based upon fault type and location[52]. In addition, while the benefit applies to all outage scenarios, it is negligible under blue sky events because comparatively less time is spent than on optimizing, prioritizing, and scheduling crews for field work. During both major event scenarios, the benefit in the field work to locate and resolve outage locations becomes a small proportion of the outage duration that now includes a substantial effort in optimizing, prioritizing, and scheduling crews for field work (i.e., an improvement of several minutes in the time locating the damage is relatively small compared to several hours it takes to dispatch a crew to the job). Therefore, this benefit is difficult to monetize for all outage scenarios and this benefit is qualitative.

2. Reduced outage footprint on 4 kV circuits and feeder ties. This impact is driven by installation of new reclosers that adds segmentation, fault isolation on a shorter segment, and with the addition of a feeder tie, an alternate source becomes available. This results in the following benefits (IS2):

    a. Outage Reduction – Frequency under reliability (IS2-C). Additional reclosers and feeder ties will reduce the number of customers seeing an extended outage under normal operating conditions when it is typical for damage to be locally isolated.

    b. Outage Reduction – Frequency under major events (excluding Sandy) (hardening) (IS2-E). Additional reclosers and feeder ties will reduce the number of customers seeing an extended outage under major events (excluding Sandy) when damage is more widespread, but still relatively localized.

    c. Outage Reduction – Frequency under major events (Sandy; catastrophic) (hardening) (IS2-G). Additional reclosers and feeder ties will be less effective during major catastrophic events because damage is more widespread and not locally isolated. This reduces the impact reclosers and feeder ties will have and makes the benefit more difficult to quantify, so this benefit is qualitative.

3. Reduced outage footprint on 13 kV circuits. This impact is similar to Item 2 above, except that the 13 kV circuits already have circuit ties. This results in the following benefits (IS3):

    a. Outage Reduction – Frequency under reliability (IS3-C). Similar to 4 kV benefit IS2-C because circuit ties are already available.

    b. Outage Reduction – Frequency under major events (excluding Sandy) (hardening) (IS3-

[52] The reduced time is further augmented by the operation of reclosers in combination with the ADMS (from the ADMS Subpart of the Grid Modernization Subprogram) capabilities to provide a geographic view of outages, and the HSN (from the Communication Network Subpart of the Grid Modernization Subprogram) that enable the communications with the recloser.

E). Similar to 4 kV benefit IS2-E because circuit ties are already available.

c. Outage Reduction – Frequency under major events (Sandy; catastrophic) (hardening) (IS3-G). Similar to 4 kV benefit IS2-G, this is a qualitative benefit.

4. Reduced O&M to investigate and resolve nested outages (IS4). This impact is driven by the installation of branch reclosers to replace the three-phase fuses on branch circuits. In this case, under all outage scenarios, an unknown nested outage is replaced with a known nested outage when a branch recloser operates in coordination with upstream devices. It is difficult to determine from the historical data the exact number of nested outages because fuse and recloser operations may not be correlated in the outage data. This makes the benefit more difficult to quantify and the benefit is qualitative.

5. Reduced O&M in avoided field trips as there is a reduced need to investigate and resolve blown fuse with a branch recloser (IS5-B). This impact is driven by the installation and use of branch reclosers at three-phase fused branch circuits. This benefit is only quantified under sustained interruption and major events (excluding Sandy) because blown fuse events are not normally investigated during major catastrophic events because of the widespread nature of the damage where most blown fuses are addressed during the restoration work by crews already in the field.

6. Reduced outage footprint on 13 kV circuits (IS6). This impact is driven by the installation and use of branch reclosers at three-phase fused branch circuits that cause customers on that circuit branch to avoid an extended outage.

   a. Outage Reduction – Frequency under reliability (hardening) (IS6-C). Branch reclosers will change the outage seen by impacted customers from an extended outage to a momentary outage under normal operating conditions when it is typical for damage to be locally isolated to that branch.

   b. Outage Reduction – Frequency under major events (excluding Sandy) (hardening) (IS6-E). Branch reclosers will change the outage seen by impacted customers from an extended outage to a momentary outage under major events (excluding Sandy) when damage is more widespread, but still relatively localized to that branch. However, due to nested outages on branch circuits, it is difficult to quantify the impact. This benefit is qualitative.

   c. Outage Reduction – Frequency under major events (Sandy; catastrophic) (hardening) (IS6-G). Branch reclosers will be more effective than fuses during major events (Sandy; catastrophic) and change the outage seen by impacted customers from an extended outage to a momentary outage. However, due to nested outages on branch circuits, it is difficult to quantify the impact. This benefit is qualitative.

7. Improved (reduced) the time to restore system after outage (resiliency) (IS7-D, IS7-F, and IS7-H). Branch reclosers are enabled with communications, allowing remote setup for work under all outage scenarios and reducing the occurrence of nested outages under all outage scenarios. This benefit is difficult to monetize, so this benefit is qualitative for all outage scenarios.

FUNCTIONAL REQUIREMENTS TO ACHIEVE BENEFIT

This Subpart relies on the PSE&G owned and operated HSN (via the Communication Network Subpart of the Grid Modernization Subprogram) that supports full SCADA communication and operation of reclosers to achieve the benefits.

BUSINESS PROCESS CHANGES TO ACHIEVE BENEFIT

Minimal business process changes are expected in order to achieve benefit because there is existing communication to reclosers today. While that communication technology will change from a POTS line to a wireless network, the Communication Network Subprogram will address any of those business process change requirements.

BENEFIT: METRICS, KEY ASSUMPTIONS, AND CALCULATIONS

This Subpart of the Contingency Reconfiguration Strategies Subprogram has benefits (summarized in *Appendix A – Benefit Matrix*) that are calculated as follows:

1. Reduced O&M to locate and resolve outage locations because smaller feeder sections decrease patrol and investigation times (IS1-B). It is difficult to quantify the exact reduction because the reduction will vary based upon fault type and location. This benefit is qualitative so there is no benefit calculation.

2. Reduced outage footprint on 4 kV circuits and feeder ties (IS2). The benefits are calculated as follows:

    a. Outage Reduction – Frequency under reliability (IS2-C). Using the number of customers on the circuit segment where the recloser is installed (with assumed customer split between residential, commercial, and industrial), average outage duration per sustained interruption event on that segment, and assumption that the average reduction of the customers impacted by any type of damage to overhead circuit by 25 percent per event without a feeder tie and 50 percent with a feeder tie, CMI is calculated and is monetized using VoLL based upon customer type and outage duration.

    b. Outage Reduction – Frequency under major events (excluding Sandy) (hardening) (IS2-E). Using the number of customers on the circuit segment where the recloser is installed (with assumed customer split between residential, commercial, and industrial), average outage duration per major event (excluding Sandy) on that segment, and assumption that the average reduction of the customers impacted by any type of damage to overhead circuit by 25 percent per event without a feeder tie and 50 percent with a feeder tie, CMI is calculated and is monetized using VoLL based upon customer type and outage duration. For major events, it is assumed that the level of storms experienced during the previous seven years (excluding Sandy) within PSE&G's service territory (2010-2016) will reoccur over the 20 year cost-benefit analysis period, thereby reducing the assumed annual CMI improvement associated with major events by approximately 50 percent.

    c. Outage Reduction – Frequency under major events (Sandy; catastrophic) (hardening)

(IS3-G). This benefit is qualitative so there is no benefit calculation.

3. Reduced outage footprint on 13 kV circuits. The benefit calculation is similar to those calculated in IS2, except that the 13 kV circuits already have circuit ties. The benefits are calculated as follows:

    a. Outage Reduction – Frequency under reliability (IS3-C). This calculation is similar to the IS2-C calculation, except that the tie recloser will exist, so the 50 percent impact is used in the calculation.

    b. Outage Reduction – Frequency under major events (excluding Sandy) (hardening) (IS3-E). This calculation is similar to the IS2-E calculation.

    c. Outage Reduction – Frequency under major events (Sandy; catastrophic) (hardening). This benefit is qualitative so there is no benefit calculation.

4. Reduced O&M to investigate and resolve nested outages (IS4). This benefit is qualitative so there is no benefit calculation.

5. Reduced O&M in avoided field trips as there is a reduced need to investigate and resolve a blown fuse with a branch recloser (IS5-B). The benefit is calculated only for major events (excluding Sandy) (as also indicated by VoLL calculation in IS6 below). Sustained interruption impacts (blue sky) are negligible. Major catastrophic event impacts have extensive damage where reclosers have historically shown minimal impact because there is widespread equipment damage. For all outage scenarios, the calculation uses historical data indicating an average rate for successful reclosing to estimate how successful a branch recloser could be in restoring service in each scenario (e.g., "Branch Recloser Reportable Outage Improvement Factor", "Branch Recloser Major Events Outage Improvement Factor", and "Branch Recloser Major Events - Sandy outage Improvement Factor"). An assumed future annual number of outages are reduced and then multiplied by the historical average field trip cost.

6. Reduced outage footprint on 13 kV circuits (IS6). The benefits are calculated as follows:

    a. Outage Reduction – Frequency under reliability (IS6-C). Using the number of customers on the circuit segment where the branch recloser is installed (with assumed customer split between residential, commercial, and industrial), the average outage minutes per blown fuse as a sustained interruption event on that segment, and the reduction factor used in the IS5 benefit calculation applies, CMI is calculated and is monetized using VoLL based upon customer type and outage duration.

    b. Outage Reduction – Frequency under major events (excluding Sandy) (hardening) (IS6-E). This benefit is qualitative so there is no benefit calculation.

    c. Outage Reduction – Frequency under major events (Sandy; catastrophic) (hardening) (IS6-G). This benefit is qualitative so there is no benefit calculation.

7. Improves (reduces) the time to restore system after outage (resiliency) (IS7-D, IS7-F, and IS7-H). These benefits are qualitative so there is no benefit calculation.

BENEFIT REALIZATION SCHEDULE

Benefits are independent for each circuit and will be realized immediately after installation of each recloser. However, the cost-benefit analysis assumes that no benefits will be realized until after Year 5 (completion of the entire Increased Sectionalization Subpart of the Contingency Reconfiguration Strategies Subprogram).

INCREMENTAL COSTS TO ACHIEVE BENEFIT

Each recloser will have annual ongoing incremental O&M associated with it. Currently, minimal preventive maintenance is performed on these devices, but there will be incidental continuing maintenance associated with the new installation. These additional incidental costs are not known at this time, but are not expected to be significant.

BUSINESS AS USUAL SCENARIO

The BAU scenario is that customers will continue to see a similar number of outages with similar durations and experienced historically.

SUBPROGRAM B-3 – CONTINGENCY RECONFIGURATION STRATEGIES (SUBPART 2 – RECLOSING DEVICES)

There are two Subparts to the Contingency Reconfiguration Strategies Subprogram. This Subpart addresses the installation of reclosing devices.

DESCRIPTION

PSE&G uses primary fuses on branches off the mainline of a circuit in an effort to limit the customers affected by a fault/outage event on that branch. While this limits the outage to a smaller area, the customers impacted will experience an extended outage. When these outages occur, PSE&G does not receive any automated indication of the outage and must wait for a customer to report the outage. Once an outage is identified, a lineman is dispatched to identify the problem, perform any needed repairs, and replace the fuse to restore power.

PSE&G proposes to install single phase devices in line with fuses on single and two-phase branch lines that currently have only fuses and require customer calls and/or field inspections to understand if customers are out of power or restored. The reclosing devices will be pole-mounted and will trip and reclose in the event of a fault on the branch line. They are SCADA enabled via a small, pole-mounted communication cabinet, capable of providing information on successful reclosing events and power status at their location. This will provide an immediate indication of events. For example, momentary or extended outages are automatically reported, without the need for a customer contact. With these capabilities, the reclosing devices will provide both hardening and resiliency benefits.

GOALS AND OBJECTIVES

Reduction of customer outage extensions on upgraded branches (hardening) and reduction of outage duration (resiliency).

DESIGN BASIS

PSE&G currently does not have any of these devices installed; therefore, some work is required to develop a construction standard and training to ensure the workforce is familiar with the construction and operation of the reclosing devices.

ALTERNATIVES

No alternatives.

ENERGY STRONG II DEPENDENCIES AND PRECEDENCES

The reclosing devices require a communication network so that sensor data is communicated to SCADA. Each reclosing device is contingent on the completion of the PSE&G owned and operated HSN (via the Communication Network Subpart of the Grid Modernization Subprogram).

ENERGY STRONG I ALIGNMENT

None.

RISKS OF SUCCESSFUL IMPLEMENTATION

This solution requires a communication network in order to drive and secure the impacts (that drive the benefits). Therefore, a cost-effective communication network is a clear dependency. A risk of successful implementation of the Subprogram is that these communication connections are numerous and could be delayed.

COSTS AND ASSUMPTIONS

The design and installation cost estimates are based on PSE&G internal estimates of labor to install primary devices, configure the SCADA system, and provide the communications. The PSE&G estimates used in this cost-benefit analysis are identical to those in Mr. Gray's testimony.

BENEFITS

This Subpart of the Contingency Reconfiguration Strategies Subprogram has the following benefits (as summarized in *Appendix A – Benefit Matrix*):

1. Reduced O&M to locate and resolve nested outage locations because reclosing devices with upstream recloser operation are communicated to SCADA (FS1). The reduced time is caused by the operation of reclosing devices in combination with the ADMS (from the ADMS Subpart of the Grid Modernization Subprogram) capabilities to provide a geographic view of outages, and the HSN (from the Communication Network Subpart of the Grid Modernization Subprogram) that enable the communications with the reclosing devices. It is difficult to quantify the exact reduction because the reduction will vary based upon fault type and location. This decrease in O&M expense is a benefit categorized as Operations – Reduced/ Avoided O&M and/or CapEx and is difficult to monetize, so this benefit is qualitative.
2. Reduced O&M in avoided field trips as there is a reduced need to investigate and resolve blown fuses with reclosing devices (FS2-B). This impact is driven by the installation and use of reclosing devices at non three-phase fused branch circuits. This benefit is only quantified under sustained interruption event and major events (excluding Sandy) because blown fuse events are not normally investigated during major events (Sandy; catastrophic); the widespread nature of the damage where most blown fuses are addressed during the restoration work is because of the number of crews in the field. Reclosing devices will be more selective than fuses and lockout only on permanent faults that will be investigated.
3. Reclosing devices cause a percentage of permanent outages to only be momentary outages, improving performance during storms by reducing the number of extended outages. This impact is driven by the installation and use of reclosing devices at non three-phase fused branch circuits that cause customers on that circuit branch to avoid an extended outage.

a. Outage Reduction – Frequency under reliability (FS3-C). Reclosing devices will change outage seen by impacted customers from an extended outage to a momentary outage under normal operating conditions when it is typical for damage to be locally isolated to that branch.

b. Outage Reduction – Frequency under major events (excluding Sandy) (hardening) (FS3-E). Reclosing devices will change the outage seen by impacted customers from an extended outage to a momentary outage under major events (excluding Sandy) when damage is more widespread, but still relatively localized to that branch. However, due to nested outages on branch circuits, it is difficult to quantify the impact. This benefit is qualitative.

c. Outage Reduction – Frequency under major events (Sandy; catastrophic) (hardening) (FS3-G). Reclosing devices will be more effective than fuses during major events (Sandy; catastrophic) and change the outage seen by impacted customers from an extended outage to a momentary outage. However, due to nested outages on branch circuits, it is difficult to quantify the impact. This benefit is qualitative.

4. Improved (reduced) the time to restore system after outage (resiliency) (FS4-B, FS4-D, FS4-F, and FS4-H). Reclosing devices are enabled with communications, raising the visibility of nested outages and reducing the occurrence of nested outages under all outage scenarios. This benefit is difficult to monetize for all three scenarios, along with O&M costs, so this benefit is qualitative.

FUNCTIONAL REQUIREMENTS TO ACHIEVE BENEFIT

In order to achieve benefit, a PSE&G owned and operated HSN (via the Communication Network Subpart of the Grid Modernization Subprogram) is required to support full SCADA communication with the reclosing devices.

BUSINESS PROCESS CHANGES TO ACHIEVE BENEFIT

PSE&G currently does not have any of these devices on the network so there will be some work required to develop a construction standard and training to ensure the workforce is familiar with the construction and operation this device.

BENEFIT: METRICS, KEY ASSUMPTIONS, AND CALCULATIONS

This Subpart of the Contingency Reconfiguration Strategies has benefits (summarized in *Appendix A – Benefit Matrix*) that are calculated as follows:

1. Reduced O&M to locate and resolve nested outage locations because reclosing devices with upstream recloser operation are communicated to SCADA (FS1). This benefit is qualitative so there is no benefit calculation.

2. Reduced O&M in avoided field trips as there is a reduced need to investigate and resolve blown fuses with reclosing devices (FS2-B). The benefit is calculated by applying a similar reduction factor used in the IS5 benefit calculation (“Reclosing Device Reportable Outage

Improvement Factor", "Reclosing Device Major Events Outage Improvement Factor", and "Reclosing Device Major Events - Sandy Outage Improvement Factor") to the historical number of events on a per circuit segment basis to calculate an assumed future annual number of events that is multiplied by the historical average field trip cost.

3. Reclosing devices cause a percentage of permanent outages to only be momentary outages, improving performance during storms by reducing the number of extended outages (FS3). The benefits are calculated as follows:

   a. Outage Reduction – Frequency under reliability (FS3-C). Using the number of customers on the circuit segment where the reclosing device is installed (with assumed customer split between residential, commercial, and industrial), the average outage minutes per blown fuse as a sustained interruption event on that segment, and the reduction factor used in the FS2-B benefit calculation applies, CMI is calculated and is monetized using VoLL based upon customer type and outage duration.

   b. Outage Reduction – Frequency under major events (excluding Sandy) (hardening) (FS3-E). This benefit is qualitative so there is no benefit calculation.

   c. Outage Reduction – Frequency under major events (Sandy; catastrophic) (hardening) (FS3-G). This benefit is qualitative so there is no benefit calculation.

4. Improved (reduced) the time to restore system after outage (resiliency) (FS4-B, FS4-D, FS4-F, and FS4-H). This benefit is qualitative so there is no benefit calculation.

BENEFIT REALIZATION SCHEDULE

Benefits are independent for each circuit and will be realized immediately after installation of each reclosing device. However, the cost-benefit analysis assumes that no benefits will be realized until after Year 5 (completion of the entire Reclosing Device Subpart of the Contingency Reconfiguration Strategies Subprogram).

INCREMENTAL COSTS TO ACHIEVE BENEFIT

The reclosing devices are new devices and will require qualified personnel to monitor them and coordinate maintenance and repair (device failure, premature battery failure as described below, etc.). PSE&G believes that existing resources will be able to perform these maintenance activities and therefore no incremental costs are identified at this time. There will also be repair costs associated with any failures of the reclosing devices. These additional repair costs are not known at this time, but these costs are not expected to be significant.

The new reclosing devices are normally powered by energy extracted (or scavenged) from line current by the reclosing device. The communications module in the reclosing device includes a battery to provide power to run the communications module radio and to manually operate the reclosing device when the line current is off. The reclosing device battery is of the lithium-manganese dioxide type, not rechargeable, and lasts for up to 10 years. Another standard battery is also included in the communication cabinet. If an automatic battery test indicates the batteries are exhausted, then the batteries should be replaced as soon as possible. For the reclosing device, replacement of the battery requires replacement of the reclosing device's communication module. Battery maintenance was not included in the estimate but will be part of the final maintenance plan. The final vendor solution will drive battery life considerations.

BUSINESS AS USUAL SCENARIO

The BAU scenario is that customers will continue to receive extended outages at a rate similar to historical because of a branch fuse operation.

SUBPROGRAM B-4 – GRID MODERNIZATION (SUBPART 1 – ADMS)

There are two Subparts to the Grid Modernization Subprogram. This Subpart addresses the installation of a new ADMS.

DESCRIPTION

PSE&G proposes to build upon the successful implementation of the new, centralized SCADA system and implement an ADMS. The new ADMS will improve data integration and provide powerful tools that will provide resiliency benefits. To accomplish this, the new ADMS depends on a high-speed network for communications as part of the Communication Network Subpart of the Grid Modernization Subprogram.

The ADMS will incorporate SCADA data sources, such as outage information, gained from substations, reclosing devices, and potential future deployment of Smart Meters and AMI. The ADMS will also include an integrated OMS that will replace the existing, stand-alone OMS. The new ADMS will assimilate data from the existing GIS. The new ADMS will also include SCADA functionality for real-time monitoring and control of the distribution grid, including fault-related data, from many more new devices. Future support of DER could also increase the data requirements from many existing and new devices. This increased reliance on SCADA functionality is not possible without a reliable, high-speed network for communications to the substations and reclosing devices, which is provided by the Communication Network Subpart of the Grid Modernization Subprogram.

The ADMS will include powerful tools for analysis and visualization in one system. The ADMS will provide a single user interface for more efficient management and analysis of outage data through an integrated OMS, other data integrations, and geographic view of all integrated outage data and damage locations that are not currently available in the existing OMS or GIS system In addition, the ADMS will include tools for dynamic visualization supporting incident management to assist in damage location identification. The new ADMS will display in real-time the confirmed damage locations on a map, current status (confirmed, assigned, etc.), and relate the damage locations to groups of outage incidents. Providing this information will significantly improve damage assessment time by providing a geographic or spatial view of the incoming outage data, eliminating duplicate assignments, and simplifying analysis that will increase the speed of restoration.

The ADMS will include an advanced system architecture, including the hardware and network to address redundancy, failover, backup, etc., as well as support for migrating to cloud-based architecture and distributed data center.

The ADMS will also enhance security through a common security architecture with standards, tools, and processes that can be utilized to meet security requirements for today and in the future across the entire system. Because the ADMS includes an integrated OMS, there could be less need for maintaining, updating, and managing data models, interfaces, and training programs.

Also included are the integrations between the OMS and GIS systems that will associate plant damage to its geographical location and relate it with trouble incidents; enable customers to provide information about damage, including pictures; develop an optimized work plan to improve work prioritization and provide predictive Estimated Time of Restoration; develop new and simplified storm management applications for our internal mobile crews; develop a mutual aid field application; and enhance storm management analytics, visualization, and reporting. Efficient use of mutual aid workers is critical for restoration work during major events because typically the number of crews is double or more of the existing workforce, and efficient work identification, prioritization, and assignment to crews requires additional tools for storm restoration.

GOALS AND OBJECTIVES

PSE&G goals and objectives for this subprogram is to reduce outage management risk, improve customer communications and satisfaction, shorten customer outage durations, and support next generation grid applications. As the grid of the future evolves into a more complex network to support the increasing deployment of reclosing devices[53], increased penetration of DER, and power flows from multiple sources and directions, the ADMS will serve as the intelligent system to manage this next generation grid.

DESIGN BASIS

The ADMS will include the following:

1. A detailed electrical model of the distribution system for use in real-time and study mode and for supporting "as-operated" modeling functions.
2. A set of distribution network applications supporting outage management including: distribution topology processor and switch order management.
3. User interface (UI) functionality comprising tabular displays and pop-ups for configuring ADMS functions and displaying solutions results.
4. A full function distribution operator training system (DOTS) with realistic simulation of the power system and dynamic modeling of active devices and their controllers and advanced fault modeling capability.

Where applicable, ADMS functions will run in the following modes:

1. Real-time – Applications have access to real-time SCADA telemetry and generally operate on the current state of the network defined by the real-time instance of the network model.
2. Study Mode – Users can evaluate various hypothetical system conditions using private study instances of the network model and ADMS applications without affecting real-time operations.

[53] Reclosing devices are deployed in Subprogram B-3 – Contingency Reconfiguration Strategies (Subpart 2 – Reclosing Devices).

Outage Management System

1. Base OMS functions.
2. Declaring and tracking named storms, including storm type/level, areas affected, start/end times, etc.
3. Set up mutual aid crews in OMS for purposes of work assignments.
4. Storm estimated time of restoration (ETR) calculation including global, local, and outage ETRs based on damage assessment.
5. Dynamic storm outage priority calculation based on confirmed damage reporting.
6. Support development of system-generated optimal restoration plans.
7. Enables “manual overrides” where suboptimal activities are mandated (e.g., emergency or political requests).
8. Support storm reports and dashboards.
9. Switch order management for set up for work.

Damage Assessment

Incorporate a suite of tools to manage the overall damage assessment process from dispatch and lookup through restoration efforts including functions to:

1. Identify predicted damage locations (areas to patrol), areas complete, and forecast areas to go.
2. Ensure efficient completion of damage assessment activities and minimize duplication.
3. Support predicted and confirmed damage.
4. Tools to support damage assessment personnel: dispatchers, leads, and crews.
5. Create damage jobs based on outages as well as manually from police and fire calls.
6. Application for damage assessment dispatchers to assign work based upon geography.
7. Record damage information related to actual GIS based features of outside plant equipment.
8. Support grouping multiple damage locations for each outage.
    a. Damage type, quantity, hazard, etc.
    b. Includes qualified reports from social media and crowdsourcing.
9. Damage data QA.
10. Aggregate damage by outage, feeder, substation, etc.
11. Overall damage assessment dashboard and status reports.

Situational Awareness System (SA)

1. Map view of system with as-operated network model.
2. Weather overlay.
3. View of outage locations, crew locations, and hazards.
4. View of customer calls and crowdsource/social media reports.
5. Damage assessment jobs and polygons.
6. Damage assessment totals by area.
7. Storm management dashboard including mobile application.

ADMS/Storm Management Training Simulator

1. DOTS including function to play back historical storms.

Architecture

1. Additional servers and other hardware required.
2. High availability/resilient design consistent with current system architecture.

ALTERNATIVES

The alternative is to maintain the use of the existing manual, off-line processes to enable distribution management functions. This will limit PSE&G's ability to effectively manage the increasing complexity of the distribution grid. Keeping the existing discrete distribution management applications and a separate OMS will inhibit the ability to prevent and quickly respond to customer outages. PSE&G will also not be able to effectively support the integration of battery storage and increased penetration of DERs.

ENERGY STRONG II DEPENDENCIES AND PRECEDENCES

The ADMS relies on the high-speed network for communication with substations and field devices as part of the Communication Network Subpart of the Grid Modernization Subprogram. The additional distributed automation (DA) devices deployed as part of ESI and ES II will provide even more value when they are part of an ADMS.

ENERGY STRONG I ALIGNMENT

The ADMS implementation builds upon the successful deployment of the new centralized SCADA system that was part of the ESI filing.

RISKS OF SUCCESSFUL IMPLEMENTATION

One identified risk is contractor delays during implementation, such as could arise from missing scheduled dates to deliver on functional requirements due to delays in specifying and/or testing the functions. To mitigate this risk, PSE&G will continue using a structured process for technology projects and follow project management best practices.

COSTS AND ASSUMPTIONS

The cost estimates are based on historical experience and vendor quotes. The costs include application licenses, hardware, vendor services, and internal labor.

The costs also include estimates of the expected ongoing O&M costs to support the ADMS into the future, such as licensing costs and internal IT costs.

BENEFITS

The ADMS Subpart of the Grid Modernization Subprogram has the following benefits (as summarized in *Appendix A – Benefit Matrix):*

1. The ADMS will improve understanding of electrical asset damage because of post event analytics in ADMS from the reclosing devices installed as part of the Reclosing Devices Subpart of the Contingency Reconfiguration Strategies Subprogram (AD1-K). This benefit is based on an initial assessment of the reclosing device technology and ADMS analytics. This is a qualitative benefit until experience is gained with the implementation and how the improved data can further PSE&G's understanding of equipment damage.

2. Reduction in the number of trips and the length of trips to investigate outages (AD2-B) because the ADMS provides geographic visualization tools to help troubleshoot locations, combined with new connected devices on network (AD2-K). The AD2-B benefit is an Operations - Reduced/Avoided O&M and/or CapEx benefit during sustained interruption events (reliability). The ADMS will have improved data for analysis, enabling PSE&G to better track the event where it occurred. In addition, PSE&G expects improvements in their POR process, where a more exact location and description for the outage can be logged for future analysis. These impacts are difficult to quantify, so this benefit is qualitative.

3. Reduction in mutual aid costs during very large events because the ADMS provides geographic visualization tools to help troubleshoot locations (AD3-B and AD3-F), combined with new devices on connected to the HSN (AD3-K). The AD3-B benefit is categorized as Operations - Reduced/Avoided O&M and/or CapEx. Efficient use of mutual aid workers is critical for restoration work during major events because typically the number of crews is double or more of the existing workforce. Efficient work identification, prioritization, and assignment to crews shortens the outage duration (AD3-F) and will allow a reduction in the time mutual aid crews are on site. These impacts are difficult to quantify, so these benefits are qualitative.

4. More reliable communications will improve data collection to improve safety, reduce operations cost, and reduce outage durations because the ADMS provides tools requiring

up-to-date data that will help crews work more safely and efficiently (AD4), has the following benefits:

a. Normal Operations - Reduced/Avoided O&M and/or CapEx (AD4-A). Up-to-date data feeding the new ADMS tools will improve situational awareness of the grid and improve work setup, remote operation of equipment, remote confirmation of equipment status, and other efficiencies during normal operations. Improving the efficiency of normal operations is an avoided O&M benefit this is difficult to monetize, so this benefit is qualitative.

b. Outage Operations - Reduced/Avoided O&M and/or CapEx (AD4-B). Up-to-date data feeding the new ADMS tools will improve situational awareness of the outage and improve work setup, remote operation of equipment, remote confirmation of equipment status, and other efficiencies during outage operations. Improving the efficiency of outage operations is an avoided O&M benefit; this is difficult to monetize, so this benefit is qualitative.

c. Outage Reduction – Duration, under Blue Sky and Major Event (Sandy) scenarios (AD4-D, and AD4-H). With working more efficiently during outages (refer to item c above), reductions in customer outage durations are expected. The expected impact is difficult to monetize under blue sky events because outages are typically not widespread. Under major events like Sandy, damage will be widespread and historical data from Sandy does not provide a solid basis to perform reduction calculations. These benefits are therefore qualitative

d. Outage Reduction – Duration, under major events (AD4-F). With working more efficiently during outages (refer to the description in item c above), reductions in customer outage durations are expected based upon previous experience during major events (excluding Sandy). The new ADMS has tools that allow efficient work identification, prioritization, and assignment to crews, reducing outage duration.

e. Safety or Compliance Related (AD4-I). Up-to-date data feeding the new ADMS tools will improve situational awareness of hazards that can adversely impact field work. Avoiding hazardous conditions and their associated safety issues are difficult to monetize, so this benefit is qualitative.

5. There will be reduced O&M expense to locate and resolve nested outages because of improved information being collected from new reclosers and reclosing devices installed in the Contingency Reconfiguration Strategies Subprogram (AD5-B). With fewer fuses, there will be fewer time consuming nested outages to analyze in operations, and with more reclosing devices and reclosers communicating with SCADA, more field data will be available to operations (AD5-K) during outages to improve situational awareness of the outages and improve work setup, remote operation of equipment, remote confirmation of equipment status, and other efficiencies during outage analysis. It is difficult to quantify the efficiency gained in operations, so this benefit is difficult to monetize and is qualitative.

6. The high-speed network and ADMS will be able to support future applications, such as DER installations because the network will be built out and the ADMS will be installed (AD6-J). It is difficult to quantify the impact of future applications and support, making

this benefit difficult to monetize and, therefore, is qualitative.

7. Avoided upgrade of legacy OMS (one time savings) because of the installation of a new ADMS with integrated OMS (AD7-A). This is an avoided O&M cost under Normal Operations --Reduced/Avoided O&M and/or CapEx. PSE&G expects to avoid one upgrade of the legacy OMS because the new ADMS has an integrated OMS that will replace the existing OMS. This is only one time because the ADMS costs include future upgrades of that system, so it is reasonable to assume only a single upgrade of the legacy OMS will be avoided.

8. Elimination of annual maintenance costs for the existing OMS because of a new ADMS with integrated OMS (AD8-A). This is an avoided O&M cost under Normal Operations -- Reduced/Avoided O&M and/or CapEx.

FUNCTIONAL REQUIREMENTS TO ACHIEVE BENEFIT

PSE&G owned and operated high-speed network (via Communication Network Subpart of the Grid Modernization Subprogram) that supports full SCADA communication and operation of reclosing devices, reclosers, and substations.

BUSINESS PROCESS CHANGES TO ACHIEVE BENEFIT

Additional training on new capabilities and streamlined process for damage assessment.

BENEFIT: METRICS, KEY ASSUMPTIONS, AND CALCULATIONS

The ADMS Subpart of the Grid Modernization Subprogram has benefits (summarized in *Appendix A – Benefit Matrix*) that are calculated as follows:

1. The ADMS will improve understanding of electrical asset damage (AD1-K). This benefit is qualitative so there is no benefit calculation.

2. Reduction in the number of trips and the length of trips to investigate outages (AD2-B). This benefit is qualitative so there is no benefit calculation.

3. Reduction in mutual aid costs (AD3). These benefits (AD3-B and AD3-F) are qualitative so there is no benefit calculation.

4. More reliable communications will improve data collection to improve safety, reduce operations cost, and reduce outage durations because the ADMS provides tools requiring up-to-date data that will help crews work more safely and efficiently (AD4). The benefits are calculated as follows:

    a. Normal Operations - Reduced/Avoided O&M and/or CapEx (AD4-A). This benefit is qualitative so there is no benefit calculation.

    b. Outage Operations - Reduced/Avoided O&M and/or CapEx (AD4-B). This benefit is qualitative so there is no benefit calculation.

    c. Outage Reduction – Duration, under Blue Sky and Major Events (Sandy) scenarios (AD4-

D and AD4-H). These benefits are qualitative so there is no benefit calculation.

d. Outage Reduction – Duration, under Major Events (excluding Sandy) (AD4-F). This benefit is calculated based upon data available from a storm that occurred on June 23, 2015. The calculation leverages the Spacer Cable Subpart first, by reducing the number of outages that occurred on open wire construction due to tree and vegetation issues. Circuits with storm outages and in the Spacer Cable subpart are removed from the outage data. Some of the remaining outages that are similar in nature are addressed more quickly, in part because there are fewer outages to be addressed, but also because the new ADMS has tools that allow efficient work identification, prioritization, and assignment to crews. Similar outages are then reduced in duration because they are started sooner. The reduction in CMI is calculated and rounded down so as to be a conservative estimate based upon actual storm data. The CMI is then monetized using VoLL based upon customer type and outage duration.

e. Safety or Compliance Related (AD4-I). Up-to-date data feeding the new ADMS tools will improve situational awareness of hazards that can adversely impact field work. This benefit is qualitative so there is no benefit calculation.

5. Reduced O&M expense to locate and resolve nested outages (AD5-B). This benefit is qualitative so there is no benefit calculation.

6. The high-speed network and ADMS will be able to support future applications, such as DER programs (AD6-J). This benefit is qualitative so there is no benefit calculation.

7. Avoided upgrade on legacy OMS (one time savings) (AD7-A). The benefit is estimated by PSE&G based on historical upgrade costs.

8. Elimination of annual maintenance costs for the existing OMS (AD8-A). The benefit is estimated by PSE&G based on historical actual annual maintenance costs.

BENEFIT REALIZATION SCHEDULE

Benefits are independent for each circuit and will be realized immediately after installation of the ADMS along with each reclosing device and recloser. However, the cost-benefit analysis assumes that no benefits will be realized until after Year 5.

INCREMENTAL COSTS TO ACHIEVE BENEFIT

Incremental ongoing O&M costs for the ADMS include vendor annual maintenance fees and annual PSE&G IT support. Incremental costs for the annual O&M costs for the ADMS addition are based on a budgetary quote from a potential vendor. Incremental costs for the annual PSEG IT costs for the ADMS addition are estimated.

BUSINESS AS USUAL SCENARIO

The business as usual scenario is described in the section above on alternatives.

SUBPROGRAM B-4 – GRID MODERNIZATION (SUBPART 2 – COMMUNICATION NETWORK)

There are two Subparts to the Grid Modernization Subprogram. This Subpart addresses the installation of a new communication network.

DESCRIPTION

PSE&G proposes to create a high-speed network comprised of a new wireless network connected to new and existing fiber-optic cable infrastructure at PSE&G substations. When constructed, the high-speed network will allow PSE&G to eliminate the existing and future use of dedicated telecommunication circuits (POTS lines and MPLS circuits) for remote communication to both PSE&G and POTS lines to customer equipment. PSE&G envisions potential equipment/locations will be connected to the new high-speed network, such as the following:

1. Capacitors (8,600+).
2. Fault line indicators.
3. Power quality monitors (160+).
4. Network protectors (4,300+).
5. Distribution generation communication.
6. Substation transformer and breaker monitoring equipment.

As part of the high-speed network, the overall wireless network will be designed to provide coverage for all existing reclosers on the system (approximately 2,500 reclosers) to facilitate both system and customer equipment communication moving forward. The wireless network will be private and secured based on regulatory requirements to ensure PSE&G's capability to monitor and control the distribution system. Once devices are connected to the wireless network, the monitoring and control functions will be via the new ADMS (installed as part of the Grid Modernization Subprogram). The wireless network will expand PSE&G's communication capabilities to the edge of the grid or closer to their electric customers, allowing the integration of new devices that can support further reliability enhancements as well as DER, demand response, electric vehicles, and/or energy efficiency in the future.

The communication network Subpart of the Grid Modernization Subprogram will also install fiber-optic cable to approximately 31 distribution substations not currently on the PSE&G transmission fiber system to provide the backbone communication system for the wireless network. Also included is the connection of approximately 133 substations with existing fiber at the substation. The transmission fiber system is already constructed and will provide the backbone for the majority of communications and provide significant storm hardening benefits by being installed on transmission right-of-way steel towers in right of way cleared of vegetation. PSE&G substations will be the connection points for the high-speed pole-mounted wireless network that will be installed for communication to PSE&G and customer equipment.

Conversion of the existing communications for PSE&G reclosers to the wireless network is also included, as these are the critical devices for PSE&G's existing and future circuit automation system. The existing POTS line communication system is presently being upgraded by Verizon to fiber as well. The new reclosers and reclosing devices installed in Contingency Reconfiguration Strategies Subprogram will also utilize the new wireless network. The exact wireless network design and technology will be dependent on the vendor, who will be selected through a competitive bidding process.

Finally, installation of an additional fiber connection to each electric operations center is included, which will further enhance reliable communications.

GOALS AND OBJECTIVES

Construct a secure high-speed network across the PSE&G electric service territory to enable communications with a broad range of electric distribution field assets and customer equipment. Reliability, redundancy, and resilience are key characteristics of the desired communication platform. Required capabilities of this network include high-bandwidth data transmission, minimal latency, industry standard data encryption and authentication, complete privacy, and the ability to prioritize communications traffic based on hierarchical classification.

The electric distribution industry is trending to implement more "smart" devices across the electric network to better monitor, operate, and heal the grid. These devices require secure, reliable, and resilient communication. The current legacy POTS line communication infrastructure is increasingly becoming the weak link in implementing new smart technologies for several reasons, including the ongoing cost per connection and aging technology, which the provider is replacing POTS lines with fiber. This will eliminate the concerns and position PSE&G to implement additional DA solutions to better serve customers as opportunities arise.

DESIGN BASIS

PSE&G recently commissioned a solely owned and operated fiber-optic communication network connecting electric distribution substations to the corporate network and SCADA. Additional fiber-optic cable would be installed to other distribution substations to expand the "backbone" of the network based on those previously completed designs.

A wireless network will be designed based on standards that PSE&G will develop and will be consistent with industry standard implementation for wireless network design, construction, testing, and commissioning.

ALTERNATIVES

The business as usual scenario described in detail below is the considered alternative.

ENERGY STRONG II DEPENDENCIES AND PRECEDENTS

This subprogram is not dependent upon other subprograms; however, other subprograms or their individual portions will depend on implementation of the high-speed network as noted in their related sections, specifically the new reclosers and reclosing devices installed in the Contingency Reconfiguration Strategies Subprogram.

ENERGY STRONG I ALIGNMENT

None.

RISKS OF SUCCESSFUL IMPLEMENTATION

As noted above, there are several other subprograms and/or portions of subprograms that will leverage the new high-speed network, specifically new reclosers and reclosing devices. The risk is that the communication network will not be ready for some locations. To minimize this risk, PSE&G will coordinate these installations according to the implementation of the new wireless communication network and fiber-optic cable installation (as required) or connection (as required). While this may slightly delay the initial installation of these devices, it will ensure that the communication network is ready before locations require communications.

COSTS AND ASSUMPTIONS

Design and installation costs are based on historical costs of similar installations and internal estimates for unit costs and installation rates. The cost estimates include materials, labor, and support staff costs for network design, as-built (or field markup print [FMP]), traffic control, and mobilization. The costs have been estimated as follows:

1. Initial capital investment. These are PSE&G's estimates for installing the HSN including wireless network and recloser costs, fiber installation, and substation fiber cutover costs.

2. Warranty. PSE&G estimates this cost based upon the existing ECNet[54] contract costs for support and warranty on a per device basis applied to the total estimated number of devices on the new wireless network.

3. Maintenance. PSE&G estimates this cost based upon the historical ECNet failure rate and maintenance costs on the ECNet failures applied to the total estimated number of devices on the new wireless network.

4. NOC Charges & Maintenance. PSE&G estimates this cost based upon the historical NOC charges and maintenance, accounting for transmission stations being split off the distribution portion.

5. Additional NOC & Maintenance.

[54] The Energy Communication Network (ECNet) is comprised of meters, networks, and back office systems. Established around 2014, ECNet provides PSE&G metering services for the largest commercial and industrial customers. ECNet is owned by PSE&G but is operated and managed by a third party. PSE&G installs the meters, poles, and routers, as well as performs any IT work.

Additional operation and maintenance costs. PSE&G estimates this cost to cover any other HSN operation and maintenance costs not otherwise included.

BENEFITS

The Communication Network Subprogram has the following benefits (as summarized in *Appendix A – Benefit Matrix):*

1. Reduction in telco monthly charges – legacy (substations and reclosers) (HS1-A). The POTS lines will be phased out with the ramp in of new high-speed network. This is a Normal Operations - Reduced/Avoided O&M and/or CapEx benefit.
2. Reduction in telco POTS line related maintenance costs (existing reclosers, new reclosers, and reclosing devices) (HS2-A). The POTS lines will be phased out with the ramp in of new high-speed network. This is a Normal Operations - Reduced/Avoided O&M and/or CapEx benefit.
3. Reduction in transition costs to telco fiber under telco's transition from copper lines to fiber (recurring upgrade cycles) (HS3-A). The ramp in of the high-speed network is an alternative to telco fiber. These are high-speed network avoided O&M costs. This is a Normal Operations - Reduced/Avoided O&M and/or CapEx benefit.
4. Reduced substation POTS line O&M costs (HS4-A). The ramp in of high-speed network is an alternative to telco fiber. This is a Normal Operations - Reduced/Avoided O&M and/or CapEx benefit. PSE&G has historical substation MPLS circuit maintenance costs. The reliability of the MPLS circuits is known as compared to the existing fiber network from 8 months of available data, but unlike the recloser POTS lines, the costs associated with MPLS outages are not specifically quantified due to limited repair data. This benefit is therefore qualitative.
5. Elimination of routine maintenance related to telco fiber (HS5-A). The ramp in of high-speed network is an alternative to telco fiber. This is a Normal Operations - Reduced/Avoided O&M and/or CapEx benefit.

FUNCTIONAL REQUIREMENTS TO ACHIEVE BENEFIT

None.

BUSINESS PROCESS CHANGES TO ACHIEVE BENEFIT

A support organization is already in place for the monitoring and repair of fiber-optic cable. PSE&G will have to leverage existing organizations that support communication networks (L&G, Radio) to support the new wireless network. PSE&G includes estimated operation and maintenance costs based upon their experience with their existing internal communication networks.

BENEFIT: METRICS, KEY ASSUMPTIONS, AND CALCULATIONS

The Communication Network Subprogram benefits (*Appendix A – Benefit Matrix*) are calculated as follows:

1. Reduction in telco monthly charges – legacy (substations and reclosers) (HS1-A). This benefit is calculated based on the following and are likely conservative:

    a. Historical average of telco monthly costs for current reclosers. The estimated monthly POTS line cost for reclosers is calculated based on the historical average of all recloser POTS line monthly costs as shown in Table 14. Note that historical average POTS line costs have been tabulated for substations and the master substation, but are not included because the impact of the high-speed network on these lines has not been specifically determined. The impact on the total estimated cost is that it underestimates the costs and so is likely conservative.

    b. Historical average of telco monthly costs for current substation MPLS circuits. The estimated monthly MPLS cost for substations is calculated based on the historical average of all substation MPLS monthly costs as shown in Table 15.

Table 14 POTS Line Estimated Monthly Costs

TYPE	AVAILABLE MATCHING PHONE NUMBERS	AVG. MONTHLY PER LINE COST	ESTIMATED ANNUAL PER LINE COST	TOTAL ESTIMATED ANNUAL COSTS
New Reclosing Devices (w/ ES II)	3,282	$20.12	$241.44	$792,406
New Reclosers (w/ ES II)	1,190	$20.12	$241.44	$287,314
Current Reclosers	2,033	$20.12	$241.44	$490,848
Total	**6,505**			**$1,570,567**

Table 15 Estimated Monthly MPLS Circuit Charges

DESCRIPTION	COUNT	ESTIMATED MONTHLY PER CIRCUIT COST	ESTIMATED ANNUAL PER LINE COST	TOTAL ESTIMATED ANNUAL COSTS
Distribution Substation MPLS Circuits	164	439	$5,268	$863,952
Total	**181**			**$863,952**

2. Reduction in telco POTS line related maintenance costs (existing reclosers, new reclosers, and reclosing devices) (HS2-A). This is a Normal Operations - Reduced/Avoided O&M and/or CapEx benefit that is calculated as follows:

    a. Historical average PSE&G monthly maintenance costs related to a typical POTS line on existing reclosers. This cost is estimated by PSE&G based on historical costs associated with troubleshooting and fixing communication failures at reclosers and assuming a similar failure rate will continue. PSE&G has documented the recloser POTS line performance history between October 23, 2016, and December 8, 2017, as shown in Table 16. Communication failures are grouped into two types. Type 1 failures are resolved with one field visit, with work done on field equipment and potentially on the SCADA master. Historically, these have typically taken approximately 6 hours of effort, and are 25 percent of all failures. Type 2 failures include multiple site visits and extended follow up with Verizon. These historically take approximately 10 hours of effort, and are 75 percent of all failures.

Table 16 Recloser POTS Line Historical Performance

TOTAL FAILURES	TOTAL DAYS	TYPE 1 FAILURES	TYPE 2 FAILURES	AVERAGE FAILURES /DAY
1,524	411	381	1,143	3.71

b. The average PSE&G monthly maintenance costs for a typical POTS line on reclosing devices is calculated using the historical average monthly cost for existing reclosers.

c. Historical average PSE&G monthly maintenance costs for a typical POTS line on new reclosers is calculated using the same average monthly cost for existing reclosers.

3. Reduction in transition costs to telco fiber (recurring upgrade cycles) (HS3-A). These are high-speed network avoided O&M costs. Verizon is in the process of upgrading existing POTS lines to its fiber network in a small local area with no coordination with and limited notification of PSE&G. While this work is completed by Verizon, there are some upgrade costs that PSE&G must bear to complete the upgrade. This recently started at the end of 2017 and PSE&G has estimated the costs based on their limited experience. Verizon covers all costs for their upgraded equipment, so PSE&G costs are associated with making the new connection to the provided equipment. By installing a completely independent communication network, PSE&G will avoid the estimated upgrade costs shown in Table 17. For estimating the benefit, all existing recloser POTS lines are assumed to be replaced over ten years following ramp-up of 22 installations in 2018. For the ten year period from 2019 through 2028, 203 locations are estimated to be upgraded annually at an estimated annual cost of approximately $766,009 as shown in Table 17.

Table 17 Estimated PSE&G Costs to Upgrade Recloser POTS Lines to Fiber

RESOURCE	ESTIMATED COST PER LOCATION	LOCATION S	TOTAL ESTIMATED HOURS	TOTAL ESTIMATED COST*
UT Total	$2,309	203	4,060	$468,635
IT Total	$1,465	203	1,814	$297,374
Total				**$766,009**

*Differences due to rounding

4. Reduction in substation POTS line O&M costs (HS4-A). This benefit is qualitative so there is no benefit calculation.

5. Elimination of routine maintenance associated with telco fiber (HS5-A). This is a Normal

Operations - Reduced/Avoided O&M and/or CapEx benefit due to ramp in of the HSN as alternative to telco fiber. Since Verizon POTS to fiber conversions have just started and there is no historical data to use, the maintenance cost is estimated based upon the historical MPLS failures for 144 substations over 8 months as shown in Table 18 using the average cost of fixing a recloser POTS failure.

Table 18 2017 (8 Months) MPLS Circuit Historical Performance

DESCRIPTION	TFI	MPLS	ANNUAL FAILURE ESTIMATE
Total Unplanned Outages[55]	0	48	72
No. of Stations with Unplanned Outages	0	24	N/A
Cumulative Unplanned Outage Time (hours)	0	680	N/A

BENEFIT REALIZATION SCHEDULE

Once the new wireless network is operating with sufficient redundancy, existing reclosers will be migrated from the legacy communication network to the new wireless network. Design, construction, testing, commissioning, and validating the high-speed network is currently forecasted to take 4 to 5 years that will yield incremental O&M savings as new devices are connected to the wireless network and substations are converted from MPLS to PSE&G fiber.

[55] Unplanned outages can be caused by problems located anywhere between the RTU to Verizon's equipment and circuits.

INCREMENTAL COSTS TO ACHIEVE BENEFIT

The high-speed network is an expansion of the existing fiber-optic network and installation of a new wireless network. These expanded and new systems will require qualified personnel and modified business processes adapted to the new wireless network to monitor the network and coordinate maintenance and repair. PSE&G estimates two new resources are required, whose incremental costs are estimated based on a project lead resource.

In addition to the new resources, the new high-speed network will require the following:

1. PSE&G maintenance costs. These costs are estimated by PSE&G based on the historical ECNet failure cost, assuming that the new wireless network will have similar performance.

2. PSE&G ENT support costs. These costs are estimated by PSE&G based on the ECNet contract.

3. Warranty costs. These costs are estimated by PSE&G based on the ECNet contract.

4. NOC charges and maintenance. These costs are estimated by PSE&G based on historical costs, separated into two costs, one for sites where distribution will be split from the transmission network and another for only distribution substations based on similar historical costs.

Battery maintenance was not included in the estimate but will be part of the final maintenance plan. The final vendor solution will drive battery life considerations.

The new wireless network will also include licensing costs estimated as a total license fee every 10 years (not including streetlight-mounted equipment) (depending on whether the selected technology is licensed or not). The license fee is estimated based on a standard license fee for an estimated number of locations.

BUSINESS AS USUAL SCENARIO

The business as usual scenario is using Verizon services to support the communications to substations, reclosers, and reclosing devices. These services are in transition by Verizon as noted herein.

Appendix C – Key Assumptions Table

SUBPROGRAM/ ELEMENT	DESCRIPTION	ASSUMPTIONS	SOURCE
General			
Nominal Dollar Reference	The cost-benefit analysis is based on nominal dollars, assuming a base year of 2018. The first year of escalation adjustment is 2019. The rate is applied as a compounded factor.	n/a	
Escalation - Avoided O&M Costs	The avoided costs are subject to escalation adjustment.	2.1%	Bureau of Labor Statistics (BLS) previous 2 years Consumer Price Index for All Urban Consumers increase
Discount Rate	Discount rate utilized in net present value (NPV) calculations.	6.9%	PSE&G
Customer Growth (and load growth)	Growth in the number of electric customers may impact load growth. Load growth may also decline with efficiency improvements. Additionally, load can grow due to increased demand for such appliances as electric vehicles. The cost-benefit model does not attempt to speculate on these changes, and hold customer counts and load assumptions constant.	No customer growth assumed	PSE&G
Forecast Period	ES II Program is assumed to be implemented starting in 2019 and conclude in early 2024. An additional forecast period of approximately 15 years extends beyond this initial investment period.	2019 – 2038	B&V

VoLL			
VoLL Factors	Value customers place on utility service disruptions and system reliability for events under 16 hours, for each residential, commercial, and industrial customer classes.	Utilized "cost per event" factors from LBNL-6941e, June 2015. Values interpolated to the 1/2 hour	Lawrence Berkeley National Laboratory.
	Value customers place on utility service disruptions and system integrity for event over 16 hours; the cost-benefit analysis, however, caps the values at the 16 hour reliability threshold.	Utilized "cost per event" factors from LBNL-6941e, June 2015. Capped at 16 hours.	Lawrence Berkeley National Laboratory.
VoLL Escalation	The source data shown in Table 6 is in 2013 dollars. While the LBNL-6941e report provides several limitations to the study[56], there is no recommendation or other guidance on how to adjust the 2013 dollars to future years. The related Interruption Cost Estimate (ICE) Calculator (referenced in the LBNL-6941e report) uses a 2% "expected annual inflation rate" input to estimate the value of reliability over a specified number of years, which is similar to rate of 2.1 percent applied to VoLL escalation in this cost-benefit analysis. The input is used to increase the calculated value over the study years, which start in the current year.	2.1%	BLS previous 2 years Consumer Price Index for All Urban Consumers increase
Customer Distribution	The VoLL factors require consideration for un-served load, which varies by customer type. In fact, the VoLL factors are unique for residential, small commercial and industrial (C&I) and large C&I. The cost-benefit analysis therefore, apportions the number of customers interrupted to customer classes.	Residential = 85.9% Small C&I = 13.2% Med/Large C&I = 0.4%	PSE&G
Station Flood and Storm Surge Mitigation			
Scope	Raising 14 substations and eliminating two substations.		PSE&G
Implementation Cost	$432M		PSE&G

[56] LBNL-6941E, page xiv.

New Incremental Recurring Capital to Maintain[57]	This is direct replacement or elimination of existing infrastructure and thus there will not be any incremental recurring costs.	None	PSE&G
New Incremental Recurring O&M to Maintain	This is direct replacement or elimination of existing infrastructure and thus there will not be any incremental recurring costs.	None	PSE&G
Avoided Flood Scenario	To drive out the benefits associated with each identified substation, avoided flood events are assumed.	In order to keep the cost-benefit analysis aligned to PSE&G's recent past experience, the analysis assumes each substation floods once during the 20 year forecast period.	PSE&G
Avoided Repair Cost per Flood Event	The assumed avoided number of flood events (based on the Avoided Flood Scenario) is multiplied by an assumed per event repair cost.	$360,000	PSE&G
Annual Class C Substation Failure Rate	The Class C substations have historical suffered a high rate of equipment failures. The cost-benefit analysis applies a historical failure rate to assume an annual average number of Class C substation failures that will be avoided by the upgrade.	4.8%	PSE&G
Rate of Increase in Annual Class C Substation Failure Rate	Based on the current age and condition of the substations and comparing the age of these facilities to industry average lives, PSE&G anticipates that failures will increase as the facilities continue to age.	Based on likelihood of failure curve	PSE&G
Avoided Annual O&M Corrective Maintenance	Annual per Class C substation O&M costs spent on corrective maintenance due to the age and condition of the substations, which is not required for new substations.	$9,000	PSE&G
Avoided Annual Capital Corrective Maintenance	Annual per Class C substation capital costs spent on corrective maintenance due to the age and condition of the substations, which is not required for new substations.	$93,000	PSE&G

[57] Care is needed in interpreting these statements. Incremental support costs are similar for the existing assets that are being removed, unless a specific benefit value is claimed. The effort is to isolate on new incremental costs that are not reflected in revenue requirement today.

Substation Upgrades 26/4kV Stations			
Scope	Upgrading 4 kV switchgear for 16 Class C substations		PSE&G
Implementation Cost	$478M		PSE&G
Incremental Recurring Capital to Maintain	This is direct replacement or elimination of existing infrastructure and thus there will not be any incremental recurring costs.	None	PSE&G
Incremental Recurring O&M to Maintain	This is direct replacement or elimination of existing infrastructure and thus there will not be any incremental recurring costs.	None	PSE&G
Annual Class C Substation Failure Rate	The Class C substations have historical suffered a high rate of equipment failures. The cost-benefit analysis applies a historical failure rate to assume an annual average number of Class C substation failures that will be avoided by the upgrade.	4.8%	PSE&G
Rate of Increase in Annual Class C Substation Failure Rate	Based on the current age and condition of the substations and comparing the age of these facilities to industry average lives, PSE&G anticipates that failures will increase as the facilities continue to age.	Based on likelihood of failure curve	PSE&G
Avoided Annual O&M Corrective Maintenance	Annual per Class C substation O&M costs spent on corrective maintenance due to the age and condition of the substations, which is not required for new substations.	$9,000	PSE&G
Avoided Annual Capital Corrective Maintenance	Annual per Class C substation capital costs spent on corrective maintenance due to the age and condition of the substations, which is not required for new substations.	$93,000	PSE&G
Spacer Cable			
Scope	Upgrading approximately 500 miles of circuits with open wire construction to spacer cable and associated pole upgrades.		PSE&G
Implementation Cost	$341M		PSE&G
Incremental Recurring Capital to Maintain	This is direct replacement of existing infrastructure and will not have any incremental recurring costs.	None	PSE&G

Incremental Recurring O&M to Maintain	This is direct replacement of existing infrastructure and will not have any incremental recurring costs.	None	PSE&G
Sustained Interruption Event Reduction Factor	Spacer cable reduces the occurrence of damage events related to vegetation because of the increased strength of the spacer cable and replaced poles and guying. Historical spacer cable performance was compared to openwire performance during Hurricane Irene, Halloween snowstorm, and the 2010 Nor'easter to determine factor.	2.56 times fewer events	PSE&G
Major Events (excluding Sandy) Outage Reduction Factor	Spacer cable reduces the occurrence of damage events. Historical spacer cable performance was compared to openwire performance during Hurricane Irene, Halloween Snowstorm, and the 2010 Nor'easter to determine factor.	2.56 times fewer events	PSE&G
Major Events (Sandy) Outage Reduction Factors	Spacer cable reduces the occurrence of damage events. Historical spacer cable performance was compared to openwire performance during Hurricane Irene, Halloween Snowstorm, and the 2010 Nor'easter to determine factor.	2.56 times fewer events	PSE&G
Avoided Repair Cost per Event	Spacer cable reduces the occurrence of damage events. The assumed reduced number of annual events (based on above outage reduction factors) is multiplied by an assumed per event repair cost.	$1,000	PSE&G
Increased Sectionalization			
Scope	Installation of reclosers on approximately 690 13 kV circuits and 500 4 kV circuits and installation of approximately 100 branch reclosers.		PSE&G
Implementation Cost	$100M		PSE&G

Incremental Recurring Capital to Maintain	Each recloser will have incidental annual ongoing incremental O&M associated with it.	As explained in report these are not known at this time, but PSE&G does not expect them to be significant. Based on other programs they may or may not be new and incremental.	PSE&G
Incremental Recurring O&M to Maintain	Each recloser will have incidental annual ongoing incremental O&M associated with it.	As explained in report these are not known at this time, but PSE&G does not expect them to be significant. Based on other programs they may or may not be new and incremental.	PSE&G
13 kV Sustained Interruption Event Reduction Factor	Average reduction in the percentage of customers on a circuit impacted by any type of damage to overhead circuit, due to installation of recloser.	50%	PSE&G
13 kV Major Events (excluding Sandy) Outage Reduction Factor	Average reduction in the percentage of customers on a circuit impacted by any type of damage to overhead circuit, due to installation of recloser.	50%	PSE&G
4 kV Sustained Interruption Event Reduction Factor	Average reduction in the percentage of customers on a circuit impacted by any type of damage to overhead circuit, due to installation of recloser.	25%	PSE&G
13 kV Major Events (excluding Sandy) Outage Reduction Factor	Average reduction in the percentage of customers on a circuit impacted by any type of damage to overhead circuit, due to installation of recloser.	25%	PSE&G
Branch Recloser Outage Reduction Factor	Average reduction in the percentage of customers on a circuit impacted by any type of damage to overhead circuit, due to installation of recloser.	50%	PSE&G
Average Avoided Field Trip Cost per Event	Branch reclosers reduce the number of events that require a field trip to resolve a blown fuse. The assumed reduced number of annual events (based on above outage reduction factor) is multiplied by an assumed per event field trip cost.	$500	PSE&G
Reclosing Devices			

Scope	Installation of over 3,200 reclosing devices		PSE&G
Implementation Cost	$45M		PSE&G
Incremental Recurring Capital to Maintain	Recurring capital costs may include replacements of equipment due to failures.	These costs have not be identified or estimated at this time. These costs are not known at this time, but PSE&G does not expect them to be significant. Based on other programs they may or may not be new and incremental.	PSE&G
Incremental Recurring O&M to Maintain	PSE&G will incur recurring O&M costs for labor to replace equipment due to failures.	These costs have not be identified or estimated at this time. These costs are not known at this time, but PSE&G does not expect them to be significant. Based on other programs they may or may not be new and incremental.	PSE&G
Sustained Interruption Event Reduction Factor	Average reduction in the percentage of customers on a circuit impacted by any type of damage to overhead circuit, due to installation of reclosing devices.	50%	PSE&G
Average Avoided Field Trip Cost per Event	Reclosing devices reduce the number of events, which require a field trip to resolve a blown fuse. The assumed reduced number of annual events (based on above outage reduction factor) is multiplied by an assumed per event field trip cost.	$500	PSE&G
ADMS			
Scope	Implementation of an ADMS		PSE&G
Implementation Cost	$35M		PSE&G
Incremental Recurring Capital to Maintain	No incremental recurring capital above and beyond the BAU case were identified.	None	PSE&G
Incremental Recurring O&M to Maintain	Incremental ongoing O&M costs for the ADMS include vendor annual maintenance fees and annual PSE&G IT support.	Total ~ $450,000 per Year	PSE&G

Annual Avoided OMS O&M	Because the new ADMS will include an integrated OMS, the annual maintenance costs for the existing OMS will be avoided.	$450,000 per Year	PSE&G
One-Time Avoided OMS Upgrade	Because the new ADMS will include an integrated OMS, PSE&G expects to avoid one upgrade of the legacy OMS because the new ADMS has an integrated OMS.	$7M	PSE&G
Communication Network			
Scope	High-speed network comprised of a new wireless network connected to new and existing fiber-optic cable infrastructure at PSE&G substations.		PSE&G
Implementation Cost	$78M		PSE&G
Incremental Recurring Capital to Maintain	No incremental recurring capital above and beyond the BAU case was identified. System asset life assumed 20 years for purposes of this estimate.	None	PSE&G
Incremental Recurring O&M to Maintain	• PSE&G maintenance costs. • Warranty costs. • NOC charges and maintenance. • Field maintenance.	Total ~ $800,000 per Year	PSE&G
Reduction in Telco Monthly Charges	Due to the phase out of POTS lines with the ramp in of the new high-speed network, the telco line charges to existing reclosers and reclosers and the reclosing devices proposed under their respective ES II subprograms will be avoided.	Total ~ $2.4M per Year	PSE&G
Reduction in Telco Land Line Maintenance Costs	Due to the phase out of POTS lines with the ramp in of the new high-speed network, the maintenance costs for existing reclosers and reclosers and the reclosing devices proposed under their respective ES II subprograms will be avoided.	Total ~ $2.0M per Year, phased out as telco fiber installed in BAU case	PSE&G

Reduction in Transition Costs to Telco Fiber	PSEG's public carrier is upgrading the existing POTS lines to fiber service that requires PSE&G to make a new connection to the public carrier provided equipment. Due to the phase out of POTS lines with the ramp in of the new high-speed network, this connection cost will be avoided.	Total ~ $766,000 per Year, for 10 years until all existing POTs lines replaced	PSE&G
Elimination of routine maintenance of telco fiber	Due to the phase out of POTS lines with the ramp in of the new high-speed network, the maintenance cost for telco fiber installed in BAU scenario will be avoided.	Total ~ $1.5M per Year, phased in as telco fiber installed in BAU case	PSE&G

Appendix D – Historical Outage Data Applied to Benefit Estimates

SUBPROGRAM SUBPARTS	HOW HAS OUTAGE DATA BEEN UTILIZED FOR BENEFIT ESTIMATE?
Substation Flood and Storm Surge Mitigation	**Sustained Interruption**: Number of annual average historical Class C substation failures used to estimate annual failure rate. Annual failure rate applied to the identified Class C substations (6) to estimate annual number of substation failures. Average historical per event duration utilized to calculate annual VoLL based on estimated annual number of substation failures determined above. Estimated annual number of substation failures determined above also used to determine O&M cost reductions due to avoided substation failures. **Major Event (excluding Superstorm Sandy)**: Based on Hurricane Irene flood outage data and average historical outage duration due to flood, annual VoLL calculated based on: - All 16 substations assumed to flood in BAU case in 20 year forecast period. - 7 of the total 16 substations assumed to flood to level experienced during Irene (and therefore included in analysis), based on 9 of the 22 substations (~40%) that flooded during 2010 – 2016 contributed to Irene Above assumption of number of substations to flood used to determine O&M cost reductions due to avoided substation floods. **Major Event (Superstorm Sandy) (for sensitivity analysis)**: Based on Superstorm Sandy flood outage data and average historical outage duration due to flood, annual VoLL calculated based on: - All 16 substations assumed to flood in BAU case in 20 year forecast period. - 9 of the total 16 substations assumed to flood to level experienced during Sandy (and therefore included only in sensitivity), based on 9 of the 22 substations (~60%) that flooded during 2010 – 2016 contributed to Sandy Above assumption of number of substations to flood used to determine O&M cost reductions due to avoided substation floods. Estimated annual number of substation failures determined above also used to determine O&M cost reductions due to avoided substation failures.

SUBPROGRAM SUBPARTS	HOW HAS OUTAGE DATA BEEN UTILIZED FOR BENEFIT ESTIMATE?
Substation Upgrades 26/4 kV Stations	**<u>Sustained Interruption</u>:** Number of annual average historical Class C substation failures used to estimate annual failure rate. Annual failure rate applied to the identified Class C substations (15) to estimate annual number of substation failures. Furthermore, average historical per event duration utilized to calculate annual VoLL based on estimated annual number of substation failures determined above. Estimated annual number of substation failures determined above also used to determine O&M cost reductions due to avoided substation failures.
Spacer Cable	**<u>Sustained Interruption</u>:** For selected circuits, on a circuit by circuit basis, average historical duration, and CI per event for ***sustained interruption*** events utilized to calculate VoLL based on: - Annual average number of events by circuit reduced by 2.56 times. - 2.56 factor determined by comparing average performance of open wire cable to spacer cable during (a) Halloween Snowstorm, (b) Hurricane Irene, and (c) 2010 Nor'easter and utilizing result. Estimated annual number of outage events reduced determined as described above also used to determine O&M cost reductions due to avoided field trips and repairs. **<u>Major Event (excluding Superstorm Sandy)</u>:** For selected circuits, on a circuit by circuit basis, average historical duration, and CI per event for ***major events (excluding Superstorm Sandy)*** utilized to calculate VoLL based on: - Annual average number of events by circuit reduced by 2.56 times. - 2.56 factor determined by comparing average performance of open wire cable to spacer cable during (a) Halloween Snowstorm, b) Hurricane Irene, and c) 2010 Nor'easter and utilizing result Estimated annual number of outage events reduced determined as described above also used to determine O&M cost reductions due to avoided field trips and repairs. **<u>Major Event (Superstorm Sandy) (for sensitivity)</u>:** For selected circuits, on a circuit by circuit basis, average historical duration, and CI per event for ***Superstorm Sandy*** utilized to calculate VoLL based on: - Annual average number of events by circuit reduced by 2.56 times. - 2.56 factor determined by comparing average performance of open wire cable to spacer cable during (a) Halloween Snowstorm, b) Hurricane Irene, and c) 2010 Nor'easter and utilizing result Estimated annual number of outage events reduced determined as described above also used to determine O&M cost reductions due to avoided field trips and repairs.

<table>
<tr><th>SUBPROGRAM SUBPARTS</th><th>HOW HAS OUTAGE DATA BEEN UTILIZED FOR BENEFIT ESTIMATE?</th></tr>
<tr><td>Increased Sectionalization</td><td><u>Sustained Interruption</u>:
For selected circuits, on a circuit by circuit basis (section by section basis for 13 kV reclosers), average historical duration, and CI per event for sustained interruption events utilized to calculate VoLL based on:
- Annual average number of events by circuit reduced by 50% for 13 kV reclosers and branch reclosers and 25% for 4 kV reclosers.
- Reduction factor determined by historical 2010-2016 data showing recloser success rate at 67% for all events and assuming conservative 50%.

Estimated annual number of outage events reduced for branch reclosers determined as described above also used to determine O&M cost reductions due to avoided field trips and repairs.

<u>Major Event (excluding Superstorm Sandy)</u>:
For selected circuits, on a circuit by circuit basis (section by section basis for 13 kV reclosers), average historical duration, and CI per event for major events (excluding Superstorm Sandy) utilized to calculate VoLL based on:
- Annual average number of events by circuit reduced by 50% for 13 kV reclosers and 25% for 4 kV reclosers.
- Reduction factor determined by historical 2010-2016 data showing recloser success rate at 67% for all events and assuming conservative 50%.</td></tr>
<tr><td>Reclosing Devices</td><td><u>Sustained Interruption</u>:
For selected circuits, on a circuit by circuit basis, average historical duration, and CI per event for sustained interruption events utilized to calculate VoLL based on:
- Annual average number of events by circuit reduced by 50%.
- Reduction factor determined by IEEE data indicating reclosing can be successful up to 85-90% of the time and assuming conservative 50%.

Estimated annual number of outage events reduced determined as described above also used to determine O&M cost reductions due to avoided field trips and repairs.</td></tr>
<tr><td>ADMS</td><td><u>Major Event</u>:
Historical annual major event CMI used to calculate VoLL based on:
- Reduction in major event duration of 5%</td></tr>
<tr><td>Communication Network</td><td><u>Telco Phone Line Maintenance</u>:
Historical annual average recloser communication failure rate used to determine avoided phone line maintenance costs associated with ES II scenario

Historical annual average MPLS communication failure rate used to determine avoided telco maintenance costs associated with ES II scenario</td></tr>
</table>

Appendix E – Incremental Support Costs

SUBPROGRAMS - SUBPARTS	DESCRIPTION / BASIS OF ESTIMATE
Substation Flood and Storm Surge Mitigation	This is direct replacement or elimination of existing infrastructure and, thus, there will not be any incremental recurring costs.
Substation Upgrades 26/4 kV Stations	This is direct replacement or elimination of existing infrastructure and, thus, there will not be any incremental recurring costs.
Spacer Cable	This is direct replacement or elimination of existing infrastructure and, thus, there will not be any incremental recurring costs.
Increased Sectionalization	Each recloser will have incidental annual ongoing O&M associated with it. PSE&G does not expect these costs to be significant at this time.
Reclosing Devices	The reclosing devices are new devices and will require qualified personnel to monitor them and coordinate maintenance and repair (device failure, premature battery failure as described below, etc.). PSE&G believes that existing resources will be able to perform these maintenance activities and therefore no incremental costs are identified at this time. There will also be repair costs associated with any failures of the reclosing devices. These additional repair costs are not known at this time, but these costs are not expected to be significant.
ADMS	Incremental ongoing O&M costs include vendor annual software maintenance fees and annual internal PSE&G IT support. Incremental costs are based upon a budgetary quote from a potential vendor.
Communication Network	• PSE&G estimates two resources are required to monitor the network and coordinate maintenance and repair. • Additionally, the new high-speed network will require: • Maintenance costs. These costs are estimated by PSE&G based upon the historical ECNet failure cost, assuming that the new wireless network will have similar performance. • PSE&G EC ENT support costs. These costs are estimated by PSE&G based upon the ECNet contract. • Warranty. These costs are estimated by PSE&G based upon the ECNet contract. • NOC charges and maintenance.[58] These costs are estimated by PSE&G based upon historical costs, separated into two costs, one for sites where distribution will be split from the transmission network and another for only distribution substations based upon similar historical costs.

[58] NOC refers to Network Operating Center.

Appendix F – Substation Avoided Base Capital Activity Levels

ES II Investment Period (also extends into early 2024)

	Total, 5 years	Total, 20 years	1 2019	2 2020	3 2021	4 2022	5 2023	6 2024	7 2025	8 2026	9 2027	10 2028	11 2029	12 2030	13 2031	14 2032	15 2033	16 2034	17 2035	18 2036	19 2037	20 2038
BAU Completion Rate	*2*	*12*	0.00	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67
ES II: Completion Rate	*21*	*21*	0.00	5.00	6.00	5.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Difference	*19*	*9*	*0*	*5*	*5*	*4*	*5*	*-1*	*-1*	*0*	*-1*	*-1*	*0*	*-1*	*-1*	*0*	*-1*	*-1*	*0*	*-1*	*-1*	*0*
Cumulative Difference			*0*	*5*	*10*	*14*	*19*	*18*	*17*	*17*	*16*	*15*	*15*	*14*	*13*	*13*	*12*	*11*	*11*	*10*	*9*	*9*

Appendix G – Total Cost Forecast

Costs ($1,000's)	20 Yr Sum - Total	20 Yr Sum - Capital	20 Yr Sum - O&M	5 Year Period Total	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
I. Hardening, Resiliency, and Lifecycle																								
Station Flood Mitigation																								
Initial Capital Investment	428,000.0	428,000.0	-	428,000.0	8,560.0	107,000.0	192,600.0	94,160.0	25,680.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
No Incremental Additional Ongoing O&M Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Substation Upgrades 26/4kV Stations																								
Initial Capital Investment	478,000.0	478,000.0	-	478,000.0	9,560.0	119,500.0	215,100.0	105,160.0	28,680.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
No Incremental Additional Ongoing O&M Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal, Hardening, Resiliency, and Lifecycle	**906,000.0**	**906,000.0**	**0.0**	**906,000.0**	**18,120.0**	**226,500.0**	**407,700.0**	**199,320.0**	**54,360.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
II. Hardening and Resiliency																								
Spacer Cable																								
Initial Capital Investment	345,000.0	345,000.0	-	341,550.0	13,800.0	69,000.0	86,250.0	86,250.0	86,250.0	3,450.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
No Incremental Additional Ongoing O&M Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Increased Sectionalization																								
Initial Capital Investment	100,000.0	100,000.0	-	99,000.0	4,000.0	20,000.0	25,000.0	25,000.0	25,000.0	1,000.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Minimal Incremental Additional Ogoing O&M (not quantified)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Reclosing Devices																								
Initial Capital Investment	45,000.0	45,000.0	-	44,550.0	1,800.0	9,000.0	11,250.0	11,250.0	11,250.0	450.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Minimal Incremental Additional Ogoing O&M (not quantified)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal, Hardening and Resiliency	**490,000.0**	**490,000.0**	**0.0**	**485,100.0**	**19,600.0**	**98,000.0**	**122,500.0**	**122,500.0**	**122,500.0**	**4,900.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
III. Technology																								
Advanced Distribution Management System (ADMS)																								
Initial Capital Investment	35,000.0	35,000.0	-	35,000.0	1,400.0	7,000.0	8,750.0	8,750.0	9,100.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vendor Ongoing Annual Support for ADMS	6,267.3	-	6,267.3	472.8	-	-	75.1	156.5	241.2	329.5	339.8	347.0	354.3	361.7	369.3	377.1	385.0	393.1	401.3	409.7	418.3	427.1	436.1	445.3
PSE&G IT Ongoing Annual Support for ADMS	3,133.7	-	3,133.7	236.4	-	-	37.5	78.2	120.6	164.8	169.9	173.5	177.1	180.9	184.6	188.5	192.5	196.5	200.7	204.9	209.2	213.6	218.0	222.6
Communication Network																								
Initial Capital Investment	72,000.0	72,000.0	-	71,280.0	2,880.0	14,400.0	18,000.0	18,000.0	18,000.0	720.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Warranty	4,178.2	-	4,178.2	315.2	-	-	50.0	104.3	160.8	219.7	226.6	231.3	236.2	241.1	246.2	251.4	256.6	262.0	267.5	273.2	278.9	284.8	290.7	296.8
Maintenance	2,611.4	-	2,611.4	197.0	-	-	31.3	65.2	100.5	137.3	141.6	144.6	147.6	150.7	153.9	157.1	160.4	163.8	167.2	170.7	174.3	178.0	181.7	185.5
NOC Charges & Maintenance	2,089.1	-	2,089.1	157.6	-	-	25.0	52.2	80.4	109.8	113.3	115.7	118.1	120.6	123.1	125.7	128.3	131.0	133.8	136.6	139.4	142.4	145.4	148.4
Additional NOC & Maintenance	1,253.5	-	1,253.5	94.6	-	-	15.0	31.3	48.2	65.9	68.0	69.4	70.9	72.3	73.9	75.4	77.0	78.6	80.3	81.9	83.7	85.4	87.2	89.1
Field Maintenance	7,693.1	-	7,693.1	1,508.6	160.0	326.7	333.6	340.6	347.7	355.0	362.5	370.1	377.9	385.8	393.9	402.2	410.6	419.3	428.1	437.1	446.2	455.6	465.2	474.9
Subtotal, Technology	**134,226.2**	**107,000.0**	**27,226.2**	**109,262.0**	**4,440.0**	**21,726.7**	**27,317.5**	**27,578.2**	**28,199.6**	**2,102.1**	**1,421.7**	**1,451.5**	**1,482.0**	**1,513.1**	**1,544.9**	**1,577.3**	**1,610.5**	**1,644.3**	**1,678.8**	**1,714.1**	**1,750.1**	**1,786.8**	**1,824.3**	**1,862.7**
Annual Total	**1,530,226.2**	**1,503,000.0**	**27,226.2**	**1,500,362.0**	**42,160.0**	**346,226.7**	**557,517.5**	**349,398.2**	**205,059.6**	**7,002.1**	**1,421.7**	**1,451.5**	**1,482.0**	**1,513.1**	**1,544.9**	**1,577.3**	**1,610.5**	**1,644.3**	**1,678.8**	**1,714.1**	**1,750.1**	**1,786.8**	**1,824.3**	**1,862.7**
Summary of Costs by Subprogram (Nominal Values)																								
Subtotal, Substation	906,000.0	906,000.0	0.0	906,000.0	18,120.0	226,500.0	407,700.0	199,320.0	54,360.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal, Outside Plant Higher Design and Construction Standards	345,000.0	345,000.0	0.0	341,550.0	13,800.0	69,000.0	86,250.0	86,250.0	86,250.0	3,450.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal, Contingency Reconfiguration Strategies	145,000.0	145,000.0	0.0	143,550.0	5,800.0	29,000.0	36,250.0	36,250.0	36,250.0	1,450.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal, Grid Modernization	134,226.2	107,000.0	27,226.2	109,262.0	4,440.0	21,726.7	27,317.5	27,578.2	28,199.6	2,102.1	1,421.7	1,451.5	1,482.0	1,513.1	1,544.9	1,577.3	1,610.5	1,644.3	1,678.8	1,714.1	1,750.1	1,786.8	1,824.3	1,862.7
Annual Total	**1,530,226.2**	**1,503,000.0**	**27,226.2**	**1,500,362.0**	**42,160.0**	**346,226.7**	**557,517.5**	**349,398.2**	**205,059.6**	**7,002.1**	**1,421.7**	**1,451.5**	**1,482.0**	**1,513.1**	**1,544.9**	**1,577.3**	**1,610.5**	**1,644.3**	**1,678.8**	**1,714.1**	**1,750.1**	**1,786.8**	**1,824.3**	**1,862.7**
Summary of Costs by Subpart (Nominal Values)																								
Subtotal, Station Flood and Storm Surge Mitigation	428,000.0	428,000.0	0.0	428,000.0	8,560.0	107,000.0	192,600.0	94,160.0	25,680.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal, Substation Upgrades 26/4 kV Stations	478,000.0	478,000.0	0.0	478,000.0	9,560.0	119,500.0	215,100.0	105,160.0	28,680.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal, Spacer Cable	345,000.0	345,000.0	0.0	341,550.0	13,800.0	69,000.0	86,250.0	86,250.0	86,250.0	3,450.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal, Increased Sectionalization	100,000.0	100,000.0	0.0	99,000.0	4,000.0	20,000.0	25,000.0	25,000.0	25,000.0	1,000.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal, Reclosing Devices	45,000.0	45,000.0	0.0	44,550.0	1,800.0	9,000.0	11,250.0	11,250.0	11,250.0	450.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal, Advanced Distribution Management System (ADMS)	44,401.0	35,000.0	9,401.0	35,709.1	1,400.0	7,000.0	8,862.6	8,984.7	9,461.9	494.3	509.8	520.5	531.4	542.6	553.9	565.6	577.5	589.6	602.0	614.6	627.5	640.7	654.1	667.9
Subtotal, Communication Network	89,825.2	72,000.0	17,825.2	73,552.9	3,040.0	14,726.7	18,454.9	18,593.5	18,737.7	1,607.8	911.9	931.1	950.6	970.6	991.0	1,011.8	1,033.0	1,054.7	1,076.9	1,099.5	1,122.6	1,146.1	1,170.2	1,194.8
Annual Total	**1,530,226.2**	**1,503,000.0**	**27,226.2**	**1,500,362.0**	**42,160.0**	**346,226.7**	**557,517.5**	**349,398.2**	**205,059.6**	**7,002.1**	**1,421.7**	**1,451.5**	**1,482.0**	**1,513.1**	**1,544.9**	**1,577.3**	**1,610.5**	**1,644.3**	**1,678.8**	**1,714.1**	**1,750.1**	**1,786.8**	**1,824.3**	**1,862.7**

Appendix H – Benefit Estimate Forecast

Benefits ($1,000's)	Benefit ID	Total 20 Year Benefits	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
O&M Benefits																						
Bring substations into compliance with the advisory FEMA post-Superstorm Sandy flood elevations and the flood elevation requirements established by the NJDEP Flood Hazard Rules, codified at N.J.A.C. 7:13	SF1-B	2,987.8	0.0	0.0	0.0	0.0	0.0	144.3	176.8	180.5	184.3	188.2	192.1	196.2	200.3	204.5	208.8	213.2	217.7	222.2	226.9	231.7
Avoidance of corrective maintenance due to aging equipment in substation (non-catastrophic, or is not outage-related)	SF4-A	567.1	0.0	0.0	0.0	0.0	0.0	38.1	44.9	44.1	43.2	42.2	41.2	40.1	38.9	37.7	36.4	35.1	33.6	32.1	30.5	28.9
Avoidance of corrective maintenance due to aging equipment in substation (non-catastrophic, or is not outage-related)	SU3-A	1,417.6	0.0	0.0	0.0	0.0	0.0	95.3	112.4	110.2	107.9	105.5	102.9	100.2	97.3	94.3	91.1	87.7	84.1	80.3	76.3	72.2
Improved conductor performance during major events (rain, wind, snow, ice loading etc)	SP1-B	743.5	0.0	0.0	0.0	0.0	0.0	35.9	44.0	44.9	45.9	46.8	47.8	48.8	49.8	50.9	52.0	53.0	54.2	55.3	56.5	57.6
Improved conductor performance during day to day operations	SP2-B	857.5	0.0	0.0	0.0	0.0	0.0	41.4	50.7	51.8	52.9	54.0	55.1	56.3	57.5	58.7	59.9	61.2	62.5	63.8	65.1	66.5
Reduced O&M in avoided truck roll as there is a reduced need to investigate and resolve blown fuse with branch recloser	IS5-B	254.1	0.0	0.0	0.0	0.0	0.0	12.3	15.0	15.4	15.7	16.0	16.3	16.7	17.0	17.4	17.8	18.1	18.5	18.9	19.3	19.7
Reduced O&M in avoided truck roll as there is a reduced need to investigate and resolve blown fuses with reclosing devices	FS2-B	3,660.9	0.0	0.0	0.0	0.0	0.0	176.8	216.7	221.2	225.8	230.6	235.4	240.4	245.4	250.6	255.8	261.2	266.7	272.3	278.0	283.9
Elimination of maintenance costs for the existing OMS	AD8-A	8,794.5	0.0	0.0	0.0	0.0	0.0	424.8	520.5	531.4	542.6	553.9	565.6	577.5	589.6	602.0	614.6	627.5	640.7	654.1	667.9	681.9
Reduction in telco monthly charges - legacy (substations and reclosers)	HS1-A	52,029.3	0.0	101.5	621.9	1,296.3	1,998.8	2,730.3	2,815.7	2,874.9	2,935.2	2,996.9	3,059.8	3,124.1	3,189.7	3,256.7	3,325.1	3,394.9	3,466.2	3,539.0	3,613.3	3,689.2
Reduction in telco POTS line maintenance costs (existing reclosers, new reclosers, and reclosing devices)	HS2-A	7,603.5	0.0	84.9	467.9	866.9	1,169.6	1,383.2	1,176.9	961.3	736.1	501.0	255.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reduction in transition costs to telco fiber (recurring upgrade cycles)	HS3-A	6,751.9	0.0	31.9	195.7	407.9	628.9	867.7	886.0	904.6	923.6	943.0	962.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Elimination of routine maintenance related to telco fiber	HS5-A	26,972.0	0.0	0.0	39.0	162.8	376.5	692.6	883.9	1,083.0	1,290.0	1,505.2	1,728.9	1,961.4	2,002.6	2,044.6	2,087.6	2,131.4	2,176.2	2,221.9	2,268.5	2,316.2
Subtotal, O&M Benefits		**112,639.7**	**0.0**	**218.3**	**1,324.4**	**2,733.9**	**4,173.8**	**6,642.7**	**6,943.5**	**7,023.2**	**7,103.2**	**7,183.4**	**7,263.9**	**6,361.6**	**6,488.2**	**6,617.3**	**6,749.0**	**6,883.3**	**7,020.2**	**7,159.9**	**7,302.3**	**7,447.6**
Capital Benefits																						
Bring substations into compliance with the advisory FEMA post-Superstorm Sandy flood elevations and the flood elevation requirements established by the NJDEP Flood Hazard Rules, codified at N.J.A.C. 7:13	SF1-B	295.5	0.0	0.0	0.0	0.0	0.0	14.3	17.5	17.9	18.2	18.6	19.0	19.4	19.8	20.2	20.7	21.1	21.5	22.0	22.4	22.9
Avoidance of corrective maintenance due to aging equipment in substation (non-catastrophic, or is not outage-related)	SF4-A	6,592.1	0.0	0.0	0.0	0.0	0.0	443.1	522.4	512.5	501.9	490.6	478.7	466.0	452.6	438.4	423.4	407.6	390.9	373.4	354.9	335.5
Avoidance of corrective maintenance due to aging equipment in substation (non-catastrophic, or is not outage-related)	SU3-A	16,480.1	0.0	0.0	0.0	0.0	0.0	1,107.9	1,306.1	1,281.3	1,254.8	1,226.6	1,196.7	1,165.0	1,131.4	1,096.0	1,058.5	1,019.0	977.3	933.5	887.3	838.9
Reduction in future base capital expenditures	SF7-A	111,676.5	0.0	0.0	0.0	0.0	0.0	5,394.3	6,609.1	6,747.9	6,889.6	7,034.3	7,182.0	7,332.8	7,486.8	7,644.0	7,804.6	7,968.4	8,135.8	8,306.6	8,481.1	8,659.2
Reduction in future base capital expenditures	SU6-A	279,191.2	0.0	0.0	0.0	0.0	0.0	13,485.8	16,522.7	16,869.7	17,224.0	17,585.7	17,955.0	18,332.0	18,717.0	19,110.1	19,511.4	19,921.1	20,339.5	20,766.6	21,202.7	21,648.0
Avoided upgrade on legacy OMS (one time savings)	AD7-A	7,929.6	0.0	0.0	0.0	0.0	0.0	7,929.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal, Capital Benefits		**422,165.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**28,374.9**	**24,977.9**	**25,429.2**	**25,888.5**	**26,355.8**	**26,831.4**	**27,315.3**	**27,807.7**	**28,308.7**	**28,818.5**	**29,337.2**	**29,865.0**	**30,402.1**	**30,948.5**	**31,504.4**
Value of Lost Load Benefits																						
Bring substations into compliance with the advisory FEMA post-Superstorm Sandy flood elevations and the flood elevation requirements established by the NJDEP Flood Hazard Rules, codified at N.J.A.C. 7:13	SF1-E	206,456.4	0.0	0.0	0.0	0.0	0.0	9,972.4	12,218.2	12,474.8	12,736.8	13,004.3	13,277.4	13,556.2	13,840.9	14,131.5	14,428.3	14,731.3	15,040.6	15,356.5	15,679.0	16,008.2
Reductions in emergency repair work due to fewer "run to failure" equipment conditions in the substations	SF3-C	10,599.6	0.0	0.0	0.0	0.0	0.0	512.0	627.3	640.5	653.9	667.6	681.7	696.0	710.6	725.5	740.8	756.3	772.2	788.4	805.0	821.9
Reductions in emergency repair work due to fewer "run to failure" equipment conditions in the substations	SU2-C	26,499.0	0.0	0.0	0.0	0.0	0.0	1,280.0	1,568.2	1,601.2	1,634.8	1,669.1	1,704.2	1,740.0	1,776.5	1,813.8	1,851.9	1,890.8	1,930.5	1,971.0	2,012.4	2,054.7
Improved conductor performance during major events (rain, wind, snow, ice loading etc)	SP1-E	821,097.2	0.0	0.0	0.0	0.0	0.0	39,661.4	48,593.1	49,613.6	50,655.5	51,719.2	52,805.4	53,914.3	55,046.5	56,202.4	57,382.7	58,587.7	59,818.1	61,074.2	62,356.8	63,666.3
Improved conductor performance during day to day operations	SP2-C	137,657.3	0.0	0.0	0.0	0.0	0.0	6,649.2	8,146.7	8,317.7	8,492.4	8,670.8	8,852.8	9,038.7	9,228.6	9,422.4	9,620.2	9,822.3	10,028.5	10,239.1	10,454.1	10,673.7
Reduced outage footprint on 4kV circuits and feeder ties	IS2-C	143,860.1	0.0	0.0	0.0	0.0	0.0	6,948.9	8,513.7	8,692.5	8,875.1	9,061.5	9,251.7	9,446.0	9,644.4	9,846.9	10,053.7	10,264.8	10,480.4	10,700.5	10,925.2	11,154.6
Reduced outage footprint on 4kV circuits and feeder ties	IS2-E	218,997.9	0.0	0.0	0.0	0.0	0.0	10,578.2	12,960.5	13,232.6	13,510.5	13,794.2	14,083.9	14,379.7	14,681.6	14,990.0	15,304.7	15,626.1	15,954.3	16,289.3	16,631.4	16,980.7
Reduced outage footprint on 13kV circuits	IS3-C	598,797.3	0.0	0.0	0.0	0.0	0.0	28,923.7	35,437.3	36,181.5	36,941.3	37,717.0	38,509.1	39,317.8	40,143.4	40,986.5	41,847.2	42,726.0	43,623.2	44,539.3	45,474.6	46,429.6
Reduced outage footprint on 13kV circuits	IS3-E	781,226.4	0.0	0.0	0.0	0.0	0.0	37,735.5	46,233.6	47,204.5	48,195.8	49,207.9	50,241.2	51,296.3	52,373.5	53,473.4	54,596.3	55,742.8	56,913.4	58,108.6	59,328.9	60,574.8
Reduced outage footprint on 13kV circuits - branch recloser	IS6-C	29,504.2	0.0	0.0	0.0	0.0	0.0	1,425.1	1,746.1	1,782.7	1,820.2	1,858.4	1,897.4	1,937.3	1,978.0	2,019.5	2,061.9	2,105.2	2,149.4	2,194.6	2,240.6	2,287.7
Reclosing devices cause a percentage of permanent outages to only be momentary outages	FS3-C	106,488.0	0.0	0.0	0.0	0.0	0.0	5,143.7	6,302.0	6,434.4	6,569.5	6,707.5	6,848.3	6,992.1	7,139.0	7,288.9	7,442.0	7,598.2	7,757.8	7,920.7	8,087.0	8,256.9
More reliable communications will improve data collection to improve safety, reduce operations cost, and reduce outage durations	AD4-F	501,900.3	0.0	0.0	0.0	0.0	0.0	24,243.3	29,702.8	30,326.6	30,963.4	31,613.7	32,277.6	32,955.4	33,647.5	34,354.1	35,075.5	35,812.1	36,564.1	37,332.0	38,116.0	38,916.4
Subtotal, Value of Lost Load Benefits		**3,583,083.7**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**173,073.4**	**212,049.5**	**216,502.6**	**221,049.1**	**225,691.2**	**230,430.7**	**235,269.7**	**240,210.4**	**245,254.8**	**250,405.2**	**255,663.7**	**261,032.6**	**266,514.3**	**272,111.1**	**277,825.4**
Value of Lost Load Benefits - Sandy																						
Bring substations into compliance with the advisory FEMA post-Superstorm Sandy flood elevations and the flood elevation requirements esta	SF1-G	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Improved conductor performance during major events (rain, wind, snow, ice loading etc)	SP1-G	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal, Value of Lost Load Benefits - Sandy		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Overall Total		**4,117,888.5**	**0.0**	**218.3**	**1,324.4**	**2,733.9**	**4,173.8**	**208,091.1**	**243,970.9**	**248,955.0**	**254,040.8**	**259,230.4**	**264,525.9**	**268,946.6**	**274,506.2**	**280,180.8**	**285,972.6**	**291,884.2**	**297,917.9**	**304,076.3**	**310,361.9**	**316,777.5**

Benefits ($1,000's)	Total 20 Year Benefits	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Summary of Benefits by Category (Nominal Values)																					
Subtotal, Cost Reductions – Day to Day	526,005.5	0.0	218.3	1,324.4	2,733.9	4,173.8	34,592.7	31,400.7	31,920.7	32,448.8	32,985.0	33,529.4	33,099.1	33,705.9	34,323.7	34,952.5	35,592.6	36,244.2	36,907.5	37,582.6	38,269.8
Subtotal, Cost Reductions – Outage Related	8,799.2	0.0	0.0	0.0	0.0	0.0	425.0	520.7	531.7	542.8	554.2	565.9	577.8	589.9	602.3	614.9	627.8	641.0	654.5	668.2	682.3
Subtotal, Outage (VoLL) - Reportable - Reliability	1,053,405.5	0.0	0.0	0.0	0.0	0.0	50,882.6	62,341.3	63,650.5	64,987.1	66,351.9	67,745.3	69,167.9	70,620.4	72,103.5	73,617.6	75,163.6	76,742.1	78,353.6	79,999.1	81,679.0
Subtotal, Outage (VoLL) – Major Events - Hardening	2,027,777.9	0.0	0.0	0.0	0.0	0.0	97,947.6	120,005.4	122,525.5	125,098.5	127,725.6	130,407.9	133,146.4	135,942.5	138,797.3	141,712.0	144,688.0	147,726.4	150,828.7	153,996.1	157,230.0
Subtotal, Outage (VoLL) – Major Events - Resiliency	501,900.3	0.0	0.0	0.0	0.0	0.0	24,243.3	29,702.8	30,326.6	30,963.4	31,613.7	32,277.6	32,955.4	33,647.5	34,354.1	35,075.5	35,812.1	36,564.1	37,332.0	38,116.0	38,916.4
Annual Total	**4,117,888.5**	**0.0**	**218.3**	**1,324.4**	**2,733.9**	**4,173.8**	**208,091.1**	**243,970.9**	**248,955.0**	**254,040.8**	**259,230.4**	**264,525.9**	**268,946.6**	**274,506.2**	**280,180.8**	**285,972.6**	**291,884.2**	**297,917.9**	**304,076.3**	**310,361.9**	**316,777.5**
Summary of Benefits by Subprogram (Nominal Values)																					
Subtotal, Substation	662,762.9	0.0	0.0	0.0	0.0	0.0	32,487.5	39,725.8	40,480.5	41,249.4	42,032.8	42,830.8	43,643.9	44,472.2	45,316.0	46,175.7	47,051.5	47,943.7	48,852.6	49,778.6	50,721.9
Subtotal, Outside Plant Higher Design and Construction Standards	960,355.5	0.0	0.0	0.0	0.0	0.0	46,388.0	56,834.5	58,028.1	59,246.7	60,490.8	61,761.1	63,058.1	64,382.4	65,734.4	67,114.8	68,524.2	69,963.2	71,432.5	72,932.5	74,464.1
Subtotal, Contingency Reconfiguration Strategies	1,882,788.9	0.0	0.0	0.0	0.0	0.0	90,944.2	111,424.8	113,764.8	116,153.8	118,593.0	121,083.5	123,626.3	126,222.4	128,873.1	131,579.4	134,342.6	137,163.8	140,044.2	142,985.1	145,987.8
Subtotal, Grid Modernization	611,981.3	0.0	218.3	1,324.4	2,733.9	4,173.8	38,271.4	35,985.8	36,681.7	37,390.9	38,113.7	38,850.4	38,618.3	39,429.3	40,257.3	41,102.7	41,965.9	42,847.2	43,746.9	44,665.6	45,603.6
Annual Total	**4,117,888.5**	**0.0**	**218.3**	**1,324.4**	**2,733.9**	**4,173.8**	**208,091.1**	**243,970.9**	**248,955.0**	**254,040.8**	**259,230.4**	**264,525.9**	**268,946.6**	**274,506.2**	**280,180.8**	**285,972.6**	**291,884.2**	**297,917.9**	**304,076.3**	**310,361.9**	**316,777.5**
Summary of Benefits by Subpart (Nominal Values)																					
Subtotal, Station Flood and Storm Surge Mitigation	339,174.9	0.0	0.0	0.0	0.0	0.0	16,518.6	20,216.3	20,618.2	21,027.9	21,445.8	21,872.0	22,306.7	22,749.9	23,201.9	23,662.9	24,133.0	24,612.4	25,101.3	25,599.8	26,108.3
Subtotal, Substation Upgrades 26/4 kV Stations	323,588.0	0.0	0.0	0.0	0.0	0.0	15,968.9	19,509.4	19,862.4	20,221.5	20,586.9	20,958.8	21,337.2	21,722.3	22,114.1	22,512.8	22,918.5	23,331.3	23,751.4	24,178.8	24,613.6
Subtotal, Spacer Cable	960,355.5	0.0	0.0	0.0	0.0	0.0	46,388.0	56,834.5	58,028.1	59,246.7	60,490.8	61,761.1	63,058.1	64,382.4	65,734.4	67,114.8	68,524.2	69,963.2	71,432.5	72,932.5	74,464.1
Subtotal, Increased Sectionalization	1,772,639.9	0.0	0.0	0.0	0.0	0.0	85,623.7	104,906.1	107,109.2	109,358.5	111,655.0	113,999.7	116,393.7	118,838.0	121,333.6	123,881.6	126,483.1	129,139.3	131,851.2	134,620.1	137,447.1
Subtotal, Reclosing Devices	110,148.9	0.0	0.0	0.0	0.0	0.0	5,320.5	6,518.7	6,655.6	6,795.4	6,938.1	7,083.8	7,232.5	7,384.4	7,539.5	7,697.8	7,859.5	8,024.5	8,193.0	8,365.1	8,540.7
Subtotal, Communication Network	518,624.5	0.0	218.3	1,324.4	2,733.9	4,173.8	5,673.8	5,762.5	5,823.7	5,884.9	5,946.1	6,007.3	5,085.5	5,192.3	5,301.3	5,412.6	5,526.3	5,642.3	5,760.8	5,881.8	6,005.3
Subtotal, Advanced Distribution Management System (ADMS)	93,356.8	0.0	0.0	0.0	0.0	0.0	32,597.7	30,223.3	30,858.0	31,506.0	32,167.6	32,843.2	33,532.9	34,237.0	34,956.0	35,690.1	36,439.6	37,204.8	37,986.1	38,783.8	39,598.3
Annual Total	**4,117,888.5**	**0.0**	**218.3**	**1,324.4**	**2,733.9**	**4,173.8**	**208,091.1**	**243,970.9**	**248,955.0**	**254,040.8**	**259,230.4**	**264,525.9**	**268,946.6**	**274,506.2**	**280,180.8**	**285,972.6**	**291,884.2**	**297,917.9**	**304,076.3**	**310,361.9**	**316,777.5**

Appendix I – Estimate of Results (Dashboard View)

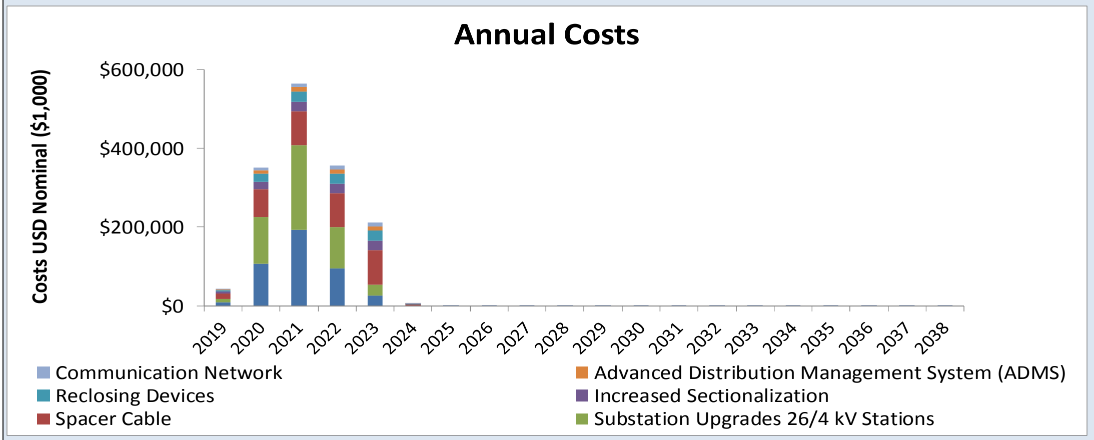
PSEG Energy Strong II Electric Cost-Benefit Analysis
RESULTS DASHBOARD
Jun 5, 2018

COSTS

Summary:

$USD Nominal (1,000's)	ESII 5 Year Investment Cost	ESII Support Cost	Total 20 Year Cost Estimate
Station Flood and Storm Surge Mitigation	$ 428,000.0	$ -	$ 428,000.0
Substation Upgrades 26/4 kV Stations	$ 478,000.0	$ -	$ 478,000.0
Spacer Cable	$ 345,000.0	$ -	$ 345,000.0
Increased Sectionalization	$ 100,000.0	$ -	$ 100,000.0
Reclosing Devices	$ 45,000.0	$ -	$ 45,000.0
Advanced Distribution Management System (ADMS)	$ 35,000.0	$ 9,401.0	$ 44,401.0
Communication Network	$ 72,000.0	$ 17,825.2	$ 89,825.2
Total	**$ 1,503,000.0**	**$ 27,226.2**	**$ 1,530,226.2**

Cost Profile:

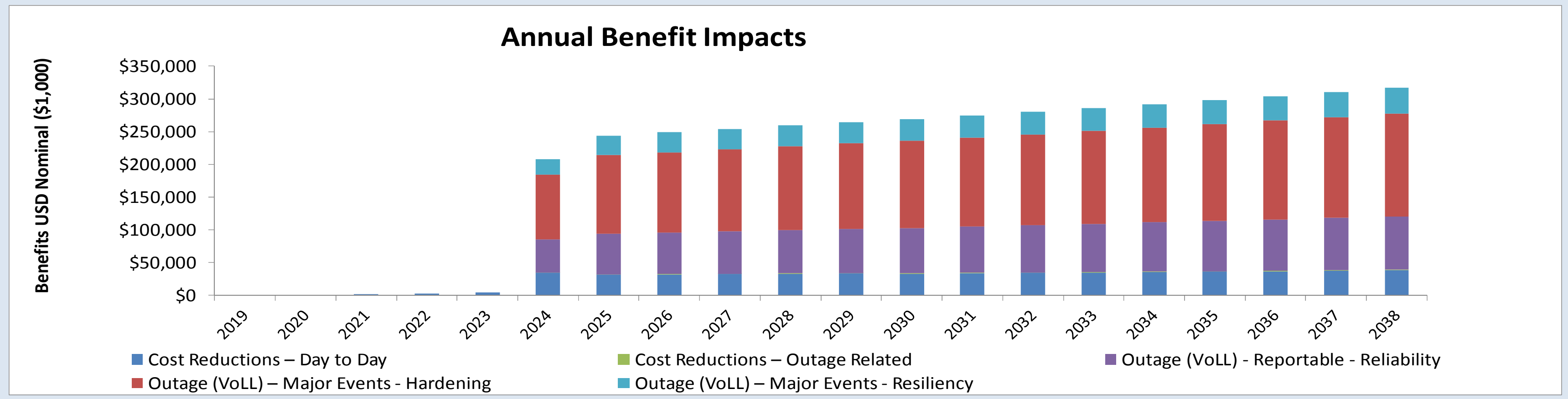


BENEFITS

Summary:

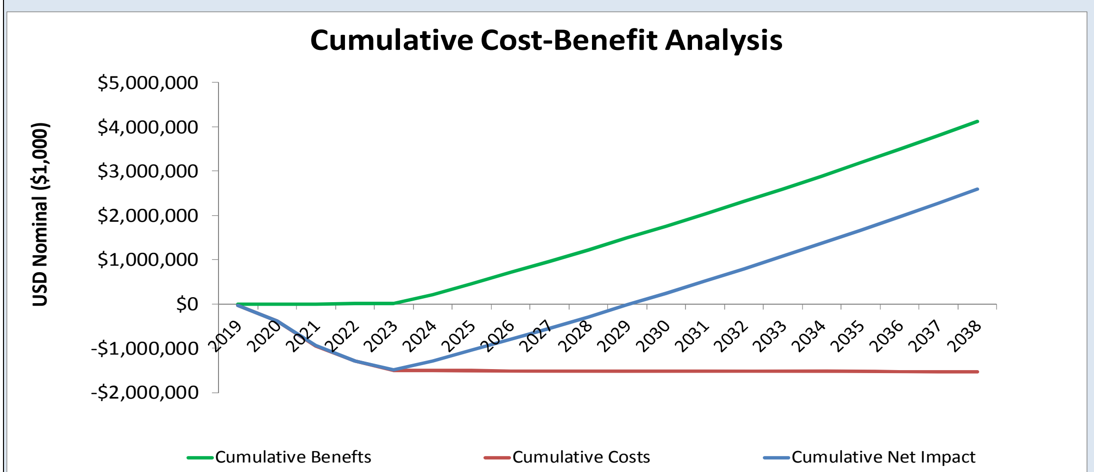
$USD Nominal (1,000's)	Cost Reductions – Day to Day	Cost Reductions – Outage Related	Outage (VoLL) - Reportable - Reliability	Outage (VoLL) – Major Events - Hardening	Outage (VoLL) – Major Events - Resiliency	Total
Station Flood and Storm Surge Mitigation	$ 118,835.6	$ 3,283.3	$ 10,599.6	$ 206,456.4	$ -	**$ 339,174.9**
Substation Upgrades 26/4 kV Stations	$ 297,089.0	$ -	$ 26,499.0	$ -	$ -	**$ 323,588.0**
Spacer Cable	$ -	$ 1,600.9	$ 137,657.3	$ 821,097.2	$ -	**$ 960,355.5**
Increased Sectionalization	$ -	$ 254.1	$ 772,161.6	$ 1,000,224.2	$ -	**$ 1,772,639.9**
Reclosing Devices	$ -	$ 3,660.9	$ 106,488.0	$ -	$ -	**$ 110,148.9**
Advanced Distribution Management System (ADMS)	$ 16,724.1	$ -	$ -	$ -	$ 501,900.3	**$ 518,624.5**
Communication Network	$ 93,356.8	$ -	$ -	$ -	$ -	**$ 93,356.8**
Total	**$ 526,005.5**	**$ 8,799.2**	**$ 1,053,405.5**	**$ 2,027,777.9**	**$ 501,900.3**	**$ 4,117,888.5**

Benefit Profile:



COST-BENEFIT ANALYSIS

Cost-Benefits Profile:



Cost-Benefits Metrics:

Subprogram	Subprogram Costs (2019 – 2038) (a)	Cost Reductions (2019 – 2038) (b)	Avoided Outage Costs - VoLL (2019 – 2038) (c)	Total Monetized Benefits (d) = (b) + (c)	Simple Benefit-Cost Factor (e) = (d) / (a)	Simple Payback Period (from 2019)	Net Present Value (6.9%)
Station Flood and Storm Surge Mitigation	$ 428,000.0	$ 122,118.9	$ 217,056.0	$ 339,174.9	0.8	N/A	(205,697.7)
Substation Upgrades 26/4 kV Stations	$ 478,000.0	$ 297,089.0	$ 26,499.0	$ 323,588.0	0.7	N/A	(252,884.6)
Spacer Cable	$ 345,000.0	$ 1,600.9	$ 958,754.5	$ 960,355.5	2.8	11.0	133,433.6
Increased Sectionalization	$ 100,000.0	$ 254.1	$ 1,772,385.9	$ 1,772,639.9	17.7	6.1	672,680.4
Reclosing Devices	$ 45,000.0	$ 3,660.9	$ 106,488.0	$ 110,148.9	2.4	11.8	10,991.3
Advanced Distribution Management System (ADMS)	$ 44,401.0	$ 16,724.1	$ 501,900.3	$ 518,624.5	11.7	10.1	11,517.2
Communication Network	$ 89,825.2	$ 93,356.8	$ -	$ 93,356.8	1.0	7.4	156,380.9
Total – All Subprograms	**$ 1,530,226.2**	**$ 534,804.7**	**$ 3,583,083.7**	**$ 4,117,888.5**	**2.7**	**11.1**	**526,421.0**

Appendix J – Sensitivity Analyses Results

Include Superstorm Sandy

Subprogram Subpart	20 Year Costs	20 Year Cost Reductions	VoLL	Total Benefits	B/C Ratio	% Change in B/C Factor
Substation Flood and Storm Surge Mitigation	$428,000.0	$126,348.2	$482,499.9	$608,848.2	1.4	79.5%
Substation Upgrades 26/4kV Stations	$478,000.0	$297,089.0	$26,499.0	$323,588.0	0.7	0.0%
Spacer Cable	$345,000.0	$1,956.5	$2,126,074.4	$2,128,030.9	6.2	121.6%
Increased Sectionalization	$100,000.0	$254.1	$1,772,385.9	$1,772,639.9	17.7	0.0%
Reclosing Devices	$45,000.0	$3,660.9	$106,488.0	$110,148.9	2.4	0.0%
ADMS	$44,401.0	$16,724.1	$501,900.3	$518,624.5	11.7	0.0%
Communication Network	$89,825.2	$93,356.8	$0.0	$93,356.8	1.0	0.0%
Total	**$1,530,226.2**	**$539,389.7**	**$5,015,847.6**	**$5,555,237.2**	**3.6**	**34.9%**

10% Increase in Capital Costs

Subprogram Subpart	20 Year Costs	20 Year Cost Reductions	VoLL	Total Benefits	B/C Ratio	% Change in B/C Factor
Substation Flood and Storm Surge Mitigation	$470,800.0	$122,118.9	$217,056.0	$339,174.9	0.7	-9.1%
Substation Upgrades 26/4kV Stations	$525,800.0	$297,089.0	$26,499.0	$323,588.0	0.6	-9.1%
Spacer Cable	$379,500.0	$1,600.9	$958,754.5	$960,355.5	2.5	-9.1%
Increased Sectionalization	$110,000.0	$254.1	$1,772,385.9	$1,772,639.9	16.1	-9.1%
Reclosing Devices	$49,500.0	$3,660.9	$106,488.0	$110,148.9	2.2	-9.1%
ADMS	$47,901.0	$16,724.1	$501,900.3	$518,624.5	10.8	-7.3%
Communication Network	$97,025.2	$93,356.8	$0.0	$93,356.8	1.0	-7.4%
Total	**$1,680,526.2**	**$534,804.7**	**$3,583,083.7**	**$4,117,888.5**	**2.5**	**-8.9%**

10% Decrease in Capital Costs

Subprogram Subpart	20 Year Costs	20 Year Cost Reductions	VoLL	Total Benefits	B/C Ratio	% Change in B/C Factor
Substation Flood and Storm Surge Mitigation	$385,200.0	$122,118.9	$217,056.0	$339,174.9	0.9	11.1%
Substation Upgrades 26/4kV Stations	$430,200.0	$297,089.0	$26,499.0	$323,588.0	0.8	11.1%
Spacer Cable	$310,500.0	$1,600.9	$958,754.5	$960,355.5	3.1	11.1%
Increased Sectionalization	$90,000.0	$254.1	$1,772,385.9	$1,772,639.9	19.7	11.1%
Reclosing Devices	$40,500.0	$3,660.9	$106,488.0	$110,148.9	2.7	11.1%
ADMS	$40,901.0	$16,724.1	$501,900.3	$518,624.5	12.7	8.6%
Communication Network	$82,625.2	$93,356.8	$0.0	$93,356.8	1.1	8.7%
Total	**$1,379,926.2**	**$534,804.7**	**$3,583,083.7**	**$4,117,888.5**	**3.0**	**10.9%**

Ramp-In of Benefits

Subprogram Subpart	20 Year Costs	20 Year Cost Reductions	VoLL	Total Benefits	B/C Ratio	% Change in B/C Factor
Substation Flood and Storm Surge Mitigation	$428,000.0	$149,725.8	$242,883.0	$392,608.7	0.9	15.8%
Substation Upgrades 26/4kV Stations	$478,000.0	$365,130.8	$29,732.8	$394,863.6	0.8	22.0%
Spacer Cable	$345,000.0	$1,750.7	$1,048,437.8	$1,050,188.5	3.0	9.4%
Increased Sectionalization	$100,000.0	$277.8	$1,938,177.5	$1,938,455.3	19.4	9.4%
Reclosing Devices	$45,000.0	$4,003.3	$116,449.1	$120,452.4	2.7	9.4%
ADMS	$44,401.0	$17,551.9	$549,139.7	$566,691.6	12.8	9.3%
Communication Network	$89,825.2	$93,356.8	$0.0	$93,356.8	1.0	0.0%
Total	**$1,530,226.2**	**$631,797.1**	**$3,924,819.9**	**$4,556,617.0**	**3.0**	**10.7%**

VoLL Escalation = 0.0%

Subprogram Subpart	20 Year Costs	20 Year Cost Reductions	VoLL	Total Benefits	B/C Ratio	% Change in B/C Factor
Substation Flood and Storm Surge Mitigation	$428,000.0	$122,118.9	$148,484.8	$270,603.7	0.6	-20.2%
Substation Upgrades 26/4kV Stations	$478,000.0	$297,089.0	$18,127.6	$315,216.6	0.7	-2.6%
Spacer Cable	$345,000.0	$1,600.9	$655,869.8	$657,470.8	1.9	-31.5%
Increased Sectionalization	$100,000.0	$254.1	$1,212,463.1	$1,212,717.1	12.1	-31.6%
Reclosing Devices	$45,000.0	$3,660.9	$72,846.9	$76,507.8	1.7	-30.5%
ADMS	$44,401.0	$16,724.1	$343,342.6	$360,066.8	8.1	-30.6%
Communication Network	$89,825.2	$93,356.8	$0.0	$93,356.8	1.0	0.0%
Total	**$1,530,226.2**	**$534,804.7**	**$2,451,134.8**	**$2,985,939.5**	**2.0**	**-27.5%**

VoLL Escalation = 4.0%

Subprogram Subpart	20 Year Costs	20 Year Cost Reductions	VoLL	Total Benefits	B/C Ratio	% Change in B/C Factor
Substation Flood and Storm Surge Mitigation	$428,000.0	$122,118.9	$306,000.3	$428,119.2	1.0	26.2%
Substation Upgrades 26/4kV Stations	$478,000.0	$297,089.0	$37,357.6	$334,446.6	0.7	3.4%
Spacer Cable	$345,000.0	$1,600.9	$1,351,629.1	$1,353,230.1	3.9	40.9%
Increased Sectionalization	$100,000.0	$254.1	$2,498,667.1	$2,498,921.2	25.0	41.0%
Reclosing Devices	$45,000.0	$3,660.9	$150,124.3	$153,785.2	3.4	39.6%
ADMS	$44,401.0	$16,724.1	$707,567.0	$724,291.2	16.3	39.7%
Communication Network	$89,825.2	$93,356.8	$0.0	$93,356.8	1.0	0.0%
Total	**$1,530,226.2**	**$534,804.7**	**$5,051,345.5**	**$5,586,150.3**	**3.7**	**35.7%**

Appendix K – VoLL Factors Applied to Resiliency-scaled Events

Care is needed in applying the VoLL *reliability*-scale factors to *resiliency*-scale events. Based on a balancing of considerations Black & Veatch believes it is reasonable for the cost benefit model to **apply the 16 hours VoLL factors to outages greater than 16 hours**. This appendix provides additional support for this assumption.

- As outage durations increase, customer impacts increase. The *nature* of impacts also changes when comparing shorter-term and long-term outages. Customer behaviors also change in response to the severity of the event.
- The relationship between duration and impacts may not be linear, and there may be declining marginal impacts. This means extrapolating the reliability factors for VoLL in a linear fashion may overstate VoLL.
- One recent study of a power outage in New York City explains that the value of unserved load on a kWh basis is $89/person/day. (This compares to the residential VoLL factor in Table 6 of $32.40 per 16-hour event.) The study then puts this into the context of the VoLL reliability factors. "To place these in the context of reliability impacts, this translates into $0.29/kWh unserved." This is further explained as being "at the lower range of VoLLs estimated for electric outage of 12 hours."[59]
- The LBNL-6943e study reports VoLL values for durations of 30 minutes, 4 hours, 8 hours, and 16 hours (refer to the headings shown in Table 6). Other tables and figures further breakdown these summary values between the hours of 0 and 16, where visual inspection shows a linear relationship between the hours shown.[60] Based on this information, Black & Veatch has applied a linear relationship for the values shown in Table 6 for interpolation purposes.
- Because PSE&G's historical outage data show outage durations not conforming to the headings shown in Table 6, picking the lowest heading would underestimate the benefit and picking the highest value would overestimate the benefit. For example, if the actual historical outage data show an average duration of 147 minutes, using the VoLL value for 60 minutes in Table 6 will underestimate the benefit and using the value for 240 hours in Table 6 will overstate the benefit. The cost benefit model uses the closest half hour increment to 147 minutes based upon Microsoft Excel's rounding function.
- The VoLL factors published in LBNL-6943e stop at 16 hours. PSE&G historical outage data, on the other hand, indicate outage durations often exceed 16 hours. Therefore, an approach is necessary to valuing these longer outages.
- Taking into account many factors, Black & Veatch believes it is reasonable for the cost benefit evaluation here to apply the values shown at 16 hours (per LBNL-6941e) to outages greater than 16 hours (up to 72 hours). In effect, the Black & Veatch approach is conservative in that it applies the 16-hour value for outages exceeding 16 hours. Black & Veatch's reasoning is that outage impact costs continue to grow as outage durations extend in time.

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[59] EPRI. "Measuring the Value of Electric System Resiliency. A Review of Outage Cost Surveys and Natural Disaster Impact Study Methods." 3002009670. Pages 5-17.
[60] Ibid, refer to Figure 3-1 on page 30, Figure 3-2 on page 32, Figure 4-1 on page 38, Figure 4-2 on page 40, Figure 5-1 on page 45, Figure 5-2 on page 47, and Figure 5-3 on page 47.

- As the durations increase the direct and indirect costs and impacts also grow. This is particularly true since long duration events on individual circuits are commonly associated with major storm events affecting an entire area.
- The study explains that the values apply to "relatively short power interruptions of up to 24 hours at most."[61] This is due in part because of "the relatively few number of observations beyond 12 hours." Therefore, what happens between 16 and 24 hours is not specifically addressed. The study does note, however, that in "planning for long duration power interruptions of 24 hours or more, the nature of costs change and the indirect, spillover effects to the greater economy must be considered", with a reference to a single study covering durations between 24 hours and 7 weeks.[62] The single study that is referenced was not obtained by Black & Veatch.
- PSE&G historical outage data indicates outage durations can exceed 16 hours and an approach is necessary to valuing these longer outages. Black & Veatch believes it is reasonable for the cost benefit model to apply the values shown at 16 hours to outages greater than 16 hours (up to 72 hours is included).

The LBNL-6943e study indicates that location is a limitation of the study. "No data were available from the northeast/mid-Atlantic region,"[63] which includes New Jersey. "The absence of interruption cost information for the northeast/mid-Atlantic region is particularly troublesome because of the unique population density and economic intensity of that region" and it is "unknown whether, when weather and customer compositions are controlled, the average interruption costs from this region are different than those in other parts of the country."[64] The study does not recommend a method to account for this difference. The cost benefit model includes a factor ("Northeast Region Multiplier") that allows VoLL values to be modified based upon the specified value. A value of 1 leaves the VoLL values unchanged.

Even with a good classification system, in the circumstance of a resiliency-scale outage, there are many factors that influence the degree of destructiveness and harm that is caused (and the resulting cost impacts). Factors include the location and geographic extent of the event, its duration, the time of year, weather conditions, the extent to which other utility services are also impacted, and the types of customers potentially affected. The resulting costs are also influenced by the effectiveness of the response of local government, emergency responders, critical care facilities, and utilities, all of whom are reacting to the emergency conditions brought on by the outage event and helping to protect public safety. Outage costs that are incurred are also highly sensitive to the nature of the businesses affected and the degree of choice and flexibility businesses and their customers have in responding to the event.[65]

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[61] Ibid, page xiv.
[62] Ibid, page 17.
[63] Ibid, page xiv.
[64] Ibid, page 48.
[65] Efforts are made to evaluate outage costs after major events and to use this information as a basis for future consideration, so there is a good understanding of the kinds of impacts that occur during outages. However, such post hoc approaches (referred to as black out studies) do not remove the value measurement challenges associated with an event. Additionally, outage events are infrequent, they are often unique to the particular utility and location, and they are costly to analyze. These are some of the primary reasons why other valuation estimation methods are pursued.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF THE
COST-BENEFIT ANALYSIS PANEL
ENERGY STRONG II PROGRAM - GAS

Q. Please introduce the members of the Cost-Benefit Panel, Energy Strong II Program – Gas (the "ESII-Gas CBA Panel" or "Panel").

A. The witnesses comprising the ESII-Gas CBA Panel are Krystal Richart, Russell A. Feingold, and Andrew L. Trump.

Q. Ms. Richart, please state your name and business address.

A. My name is Krystal R. Richart, and my business address is 11401 Lamar Avenue Overland Park, KS 66211.

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

A. I am a Manager employed by Black & Veatch Management Consulting, LLC ("Black & Veatch").

Q. Please describe your educational background and business experience.

A. The information is provided in Schedule-BV-ESII-GAS-1.

Q. Mr. Feingold, please state your name and business address.

A. My name is Russell A. Feingold, and my business address is 2525 Lindenwood Drive Wexford, Pennsylvania 15090.

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

A. I am a Vice President at Black & Veatch and lead its Rates & Regulatory Practice.

Q. Please describe your educational background and business experience.

A. The information is provided in Schedule-BV-ESII-GAS-2.

Q. Mr. Trump, please state your name and business address.

A. My name is Andrew L. Trump, and my business address is 832 Media Line Road, Newtown Square, Pennsylvania.

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

A. I am a Director employed by Black & Veatch.

Q. Please describe your educational background and business experience.

A. The information is provided in Schedule-BV-ESII-GAS-3.

Q. Mr. Nushart, please state your name and business address.

A. My name is Michael J. Nushart, and my business address is 11401 Lamar Avenue, Overland Park, KS 66211.

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

A. I am a Principal Consultant employed by Black & Veatch.

Q. Please describe your educational background and business experience.

A. The information is provided in Schedule-BV-ESII-GAS-4.

Q. What is the purpose of the Panel's testimony?

A. The Panel is sponsoring the cost-benefit analysis of the gas portion of the Energy Strong II ("ES II") program. Our full report ("Report") is provided in Schedule-BV-ESII-GAS-5.

Q. What does your Report entail?

A. As explained in our Report and in other parts of PSE&G's direct testimony, ES II has two subprograms: the Curtailment Resiliency Subprogram and the Metering & Regulating

("M&R") Upgrade Subprogram. The Curtailment Resiliency Subprogram is comprised of six infrastructure projects that will reinforce PSE&G's gas distribution system to address the risk of a major supply disruption from the interstate pipeline system. The M&R Upgrade Subprogram consists of rebuilding seven of PSE&G's existing M&R stations to bring them into conformance with current design standards and, in the case of two stations, reduce the risk of flooding, which could occur during heavy storm surges.

Our project team examined the specific investments and a variety of supporting data and information related to these Subprograms to develop a cost-benefit analysis. In this analysis, the costs are based on the estimated infrastructure project costs provided by PSE&G. In addition, Black & Veatch did extensive work with the data and facts related to these investments to identify and, where possible, quantify and monetize the benefits provided by these investments. It also identified benefits that could not be quantified and thus are characterized as qualitative in nature.

Q. Please describe the quantification of benefits.

A. Our project team, under the assumptions of the analysis, estimated quantitative and monetized benefits of approximately $1,136 million, or a ratio of quantifiable benefits-to-costs of 1.1 considering all projects in the gas portion of ES II. In addition, as noted above, the study identified many important qualitative benefits, which were difficult to quantify and monetize.

Q. How did Black & Veatch develop a quantification of the benefits?

A. The quantified benefits principally come from the Curtailment Resiliency Subprogram. Black & Veatch compared a "business as usual" ("BAU") scenario, in which

PSE&G is assumed to operate without the ES II program, to PSE&G's system operation with the ES II gas investments completed and in place. For each of these scenarios we assumed a situation where PSE&G experiences a 100% service interruption ("outage") for 10 days on a major interstate pipeline system that interconnects with the PSE&G gas distribution system.[1] During the outage we assumed a persistent 30 degree Fahrenheit average daily temperature. This outage event leads to an extended restoration period, which is required to safely restore PSE&G's gas system and re-establish gas delivery service to the impacted PSE&G customers. With this assumption embedded in both scenarios it is then possible compared the scenarios and estimate the incremental differences to the PSE&G system and its customers.

Q. Is the assumed interstate pipeline outage duration of 10 days reasonable?

A. Yes. An outage of this nature is assumed to be a low probability, high consequence event, which all hope will never occur. Nevertheless, based on gas outages we have researched, including the recent non-heating season interstate gas pipeline curtailment PSE&G experienced in 2016, we believe this is a reasonable outage duration to assume for this analysis.

Q. Please explain how you quantified the benefits from these assumptions.

A. As mentioned, the benefits that accrue to the system are determined by comparing the BAU and ES II scenarios. If the outage occurs, the BAU scenario experiences the outage impacts, whereas the ES II scenario avoids them. This gives rise to several differences related to costs and customer impacts. To analyze this outage and quantify the benefits

[1] The outage event is assumed to occur on the Texas Eastern Transmission system (owned and operated by Enbridge Inc.), which is one of PSE&G's largest interstate pipeline suppliers of natural gas.

through this comparison, Black & Veatch analyzed data that indicated that under this outage, under BAU (i.e., without ES II), it would take PSE&G 30 days to restore gas service to 95 percent of its customers once the interstate pipeline is repaired.[2] In contrast, with the ES II investment scenario, there would be no outages, because the six projects comprising PSE&G's Curtailment Resiliency Subprogram would enable PSE&G to supplement gas deliveries from alternative interstate pipeline suppliers by moving these supplies across its gas distribution system in reaction to the outage.

Based on this difference in outcomes between the two scenarios, we estimated, to the extent possible, the value of lost load ("VoLL") and other direct costs involved in the outage. Thus, the quantified benefits derived by the ES II investments are largely associated with the VoLL estimates. Under BAU customers experience the outage, whereas under the ES II scenario, the outage is avoided. Therefore, VoLL expresses the value customers impute to the loss (or retention under ES II) of the gas they normally consume. We also identified additional benefits related to the outage avoidance that are difficult to quantify and that are not included in the VoLL estimates.

Q. What are the difficult to quantify benefits of the M&R Upgrade Subprogram?

A. Upgrading the M&R stations will provide PSE&G many qualitative benefits compared to continued reliance on existing, old stations. The upgraded stations will conform with current design standards, which will lead to several operating and environmental benefits. PSE&G will also avoid certain capital costs related to these stations in future years.

[2] An additional 33 days are necessary to restore the remaining 5% of customers. As documented in our Report, PSE&G's actions to restore its gas distribution system after a major outage event represents a complex and expensive undertaking involving hundreds of utility workers for many weeks.

Q. What does your study show?

A. The ES II Gas Program as a whole shows quantified benefits in excess of the costs of the program by a ratio of 1.1. This ratio understates the overall value by not incorporating the qualitative (unquantified) benefits of the program. In the case of the M&R Upgrade Subprogram, our analysis shows only modest quantitative benefits, which reflect the future costs that are avoided by PSE&G. Additionally, qualitative benefits are associated with reducing flood risk and improving station performance and design. For the Curtailment Resiliency Subprogram, the benefits are related to the modeled single outage event occurrence of a specific nature and duration; in fact the ES II investments will provide on-going outage mitigation benefits over many decades of expected service life of these assets, and over all operating conditions.

Q. What types of qualitative benefits have been identified for the M&R Upgrade Subprogram?

A. Upgrading the M&R substations will provide several qualitative benefits. The stations will be brought into conformance with PSE&G's current design standards, helping to improve operating and environmental performance of these stations. Noise levels will be reduced through improved layout, materials, and building structural materials. For two stations, flooding risks will be abated (which could in some flooding circumstances result in an outage condition). The new stations will result in the elimination of upstream relief valves, and the installation of a second regulator run without monitor regulators, therefore simplifying the layout. Other equipment such as scrubbers and heaters will be evaluated for potential replacement if they are at risk of wearing out. For all the stations, obsolete, hard to find and difficult to repair equipment will be replaced, thereby ensuring that old equipment and parts do not cause undue maintenance problems in the future, or raise station reliability risks.

Q. What should one conclude from your Analysis?

A. The analysis provides a cost-benefit analysis of the gas portion of the proposed ES II Program and supports the PSE&G decision to pursue the ES II Gas Program.

Q. Does this complete the Panel's testimony?

A. Yes.

Krystal R. Richart, P.E., MBA

Krystal Richart is currently a project manager in Black & Veatch's management consulting business. She holds a Bachelor of Science in Industrial and Management Systems Engineering from the University of Nebraska and a Master of Business Administration with a concentration in Finance from the University of Kansas. She is also a licensed Professional Engineer of Industrial Engineering.

Ms. Richart has nine years of experience in project controls, estimating, and various management consulting projects at Black & Veatch. Her past experience includes extensive planning and scheduling experience including expertise in both Microsoft Project and Primavera products, costs control as well as experience in the preparation of opinions of probable construction cost. Ms. Richart's experience in Black & Veatch's management consulting business includes independent engineering technical due diligence for conventional energy, renewable energy, transmission lines, wind, and desalination plants.

PROJECT EXPERIENCE

Confidential Clients; Conventional-Fired Plants/Portfolios Independent Engineering; United States; 2014-2018

Manager - Black & Veatch. Ms. Richart has provided independent engineering services in support of various potential acquisitions/sales/refinancing of portfolios of power generation assets or plants in the United States. Ms. Richart's responsibilities have included due diligence of asset characteristics, condition assessment, performance review, operations and maintenance review, review of major agreements and analysis of financial projections, with responsibilities varying by project. Ms. Richart has managed or participated in conducting independent engineering services on over 47 GW of conventional assets.

Confidential Client; Wind Portfolio Independent Engineering; United States; 2016-2016

Consultant - Black & Veatch. Ms. Richart has provided independent engineering services in support of the potential sale of a portfolio of wind assets in the United States. Ms. Richart's responsibilities included performance review, review of major agreements, and analysis of operating cost projections.

PROJECT MANAGER

Expertise:
Cost Controls; Data Analysis and Presentation; Planning and Scheduling; Project Management; Technical Due Diligence

Education

Masters, Business Administration, Finance, University of Kansas, 2011, United States

Bachelor of Science, Industrial Engineering, University of Nebraska - Lincoln, 2008, United States

Professional Registration

Certification, Krystal R. Richart, Industrial, E-14519, Nebraska, United States, 2012

Total Years of Experience

10

Black & Veatch Years of Experience

10

Confidential Client; Charrua-Ancoa Transmission Project; Chile; 2015-2015

Consultant - Black & Veatch. Analyzed the project schedule and the terms of the engineering, procurement and construction (EPC) contract for reasonableness, use of industry best practices, and consistency to identify potential areas and magnitudes of schedule delay risk for an approximately 200 km 500 kV transmission line.

Confidential Client; Wisconsin Utility Plant Independent Engineer; Madison, Wisconsin, United States; 2014-2015

Consultant - Black & Veatch. Senior analyst for independent engineering services in support of a potential sale of assets in Wisconsin. Collected and analyzed historical operating data, assisted in development of operating projections, and participated in site visits.

Confidential Client; Interchile Transmission Project; Chile; 2014-2015

Consultant - Black & Veatch. Analyzed the project schedule and the terms of the engineering, procurement and construction contracts for reasonableness, use of industry best practices, and consistency to identify potential areas and magnitudes of schedule delay risk for an approximately 1,000 kilometer (km) 500/220 kV transmission line.

Sewerage and Water Board of New Orleans; Annual Report on Operations; New Orleans, Louisiana, United States; 2015-2015

Consultant - Black & Veatch. Consultant assisting in the preparation of the 2014 annual report on operations for water, wastewater and storm drainage utilities, including evaluation of management, operations, financing and compliance with bond covenants.

Washington Suburban Sanitation Commission; FY2017 Executive Asset Management Plan Alternatives Evaluation; Laurel, Maryland, United States; 2015-2015

Senior Analyst - Black & Veatch. Senior analyst for alternatives evaluation to support WSSC in the development of their 2017 Enterprise Asset Management Plan Business Case. Effort included developing forecasted 30 year capital plans optimizing on level of service, risk, and cost.

BHP Billiton; Escondida Water Supply; Antofagasta, Chile; 2011-2014

Lead Planner - Black & Veatch. Lead Planner, assisted in preparation of a study level resource-loaded, quantity-loaded engineering, procurement and construction (EPC) schedule for the purpose of validating the proposed project timeline and assisting the client in obtaining project funding. Assisted in preparation of the baseline engineering and procurement portions of the EPC schedule and identification of contractual key performance indicators (KPIs).

Led schedule and cost control functions on an EPC project with over a $100 million total professional services fee, ensuring that the engineering documents and procurement services were delivered to support construction and planned KPI metrics were achieved. Developed, prepared and presented schedule and cost reports to clients, management, and team members, identifying trends and variances.

Analyzed schedule and cost deviations from plan to determine and forecast project variations and developed recovery plans, when necessary. Analyzed the EPC schedule to determine contractual milestones for suppliers. Evaluated supplier bids for conformance to required schedule and identified risks within the proposal schedule. Evaluated suppliers' baseline and monthly schedule updates for conformance to schedule requirements and contractual milestones.

Johnson County Wastewater; Mill Creek Regional Effluent Tunnel; Johnson County, Kansas, United States; 2010-2014

Project Controls - Black & Veatch. Helped to create a cost-loaded, logic driven schedule of design activities. Performed cost control functions and earned value analysis. Performed reviews of the contractor's P6 schedule to evaluate progress and performance, to assist in evaluation of pay applications, and to provide the client an estimate of the contractor's cash flows.

Irvine Ranch Water District; Biosolids & Energy Recovery Facilities Project; Irvine, California, United States; 2010-2013

Project Controls - Black & Veatch. Created a logic-driven schedule of design activities which progressed on a monthly basis. Performed cost control functions including production of cost reports, earned value analysis, production of cost forecasts, and trend management.

Various Clients; Cost Estimating Experience; United States; 2008-2013

Estimator - Black & Veatch. Ms. Richart's cost estimating experience includes assistance in creating engineering opinion of probable construction costs, including the following responsibilities:

○ Performed takeoffs from drawings and specifications to develop

quantities to use in the opinion of probable construction cost.
○ Assisted in the development of the estimate's work breakdown structure and reporting format.
○ Used the Timberline estimating tool to apply location-appropriate productivity rates and material costs to quantities in order to develop direct costs.
○ Assisted in identification and proper application of markups to achieve appropriate indirect costs.

These responsibilities were performed on a number projects. Below is a representative list of the types of projects estimated:

○ San Diego County Water Authority | San Vicente Dam Raise, Lakeside, California | 2009 – 2010
○ Irvine Ranch Water District | Biosolids & Energy Recovery Facilities Project; Irvine, California |2010-2013
○ Reading, PA | Reading Wastewater Treatment Plant, Reading, Pennsylvania | 2008-2009
○ Orange County Water District | Initial Expansion of the Groundwater Replenishment System; Orange County, California |2009 – 2010

Orange County Water District; Initial Expansion of the Groundwater Replenishment System; Orange County, California, United States; 2009-2010

Project Controls - Black & Veatch. Helped to create a logic-driven schedule of design activities that were progressed on a monthly basis. Analyzed the schedule to identify areas of potential impact and modified the schedule when scope changes affected the baseline schedule.

Developed a deliverables-based, earned value management system used to report progress internally and to create monthly progress reports to the client.

American Structurepoint; East Chicago Water Treatment Plant; Indiana, United States; 2009-2010

Project Controls - Black & Veatch. Created a cost loaded, logic-driven schedule of detailed design activities including subcontract responsibilities and vendor deliverables.

Modesto Irrigation District; Domestic Water Project – Phase 2, Plant Expansion CM Services; Modesto, California, United States; 2009-2009

Project Controls - Black & Veatch. Performed schedule reviews of contractor's Primavera schedule to ensure the contractor properly maintained the schedule and to identify areas of concern. Evaluated the impacts on the schedule's critical path and checked for conformance to the contract schedule specifications.

City of Reading; Reading Wastewater Treatment Plant; Pennsylvania, United States; 2008-2009

Project Controls - Black & Veatch. Created a detailed logic-driven Primavera schedule of design activities to be performed in multiple offices around the world. Created a work breakdown structure used to create various reports for submittal to client staff.

Russell A. Feingold

Mr. Feingold is an experienced, officer-level management consultant with a broad range of project and managerial experience involving gas, electric, and water utilities. Specializing in the energy and utilities industries, he has advised energy clients pertaining to costing and pricing, competitive market analysis, rate case and regulatory planning and policy development, innovative ratemaking concepts, gas supply planning and procurement issues, strategic business planning, merger and acquisition analysis, regulatory due diligence, corporate restructuring, new product and service development, load research and demand forecasting studies, and market planning. He has prepared and presented expert testimony submitted to the FERC, and several state and provincial regulatory commissions dealing with the costing, pricing, and marketing of gas and electric utility services.

PROJECT EXPERIENCE

Utility Ratemaking and Regulatory Policy Analysis

Mr. Feingold is a nationally recognized expert in all elements of utility costing, pricing and regulatory requirements. He has participated in numerous projects for gas and electric utilities and has extensive experience in a broad range of utility ratemaking issues, including:

- Fully allocated and marginal cost studies;
- Rate design, strategic and market-based pricing;
- Service and rate unbundling;
- Innovative rates for distributed generation (DG) customers
- Revenue sharing;
- Revenue decoupling, weather normalization and other automatic adjustment rate mechanisms;
- Infrastructure cost recovery mechanisms;
- Incentive ratemaking and Performance-Based Regulation (PBR); and
- End-user bypass and energy regulation analysis.

He has worked closely with a number of gas and electric utilities to develop the conceptual underpinnings, regulatory evidence and related filings, and has provided expert testimonial support for the implementation of various automatic adjustment rate mechanisms to address variability of energy sales (revenue decoupling) and the timely recovery of costs associated with infrastructure replacement, uncollectible accounts expense and energy efficiency and conservation programs for utility end-use customers.

He has assisted clients in the evaluation and development of PBR approaches to replace traditional cost-based regulation. In particular, he has worked with:

- A combination utility to develop gas and electric price cap mechanisms for its distribution businesses;

VICE PRESIDENT, RATE & REGULATORY SERVICES LEAD

Specialization:
Utility Ratemaking and Regulatory Policy Analysis, Utility Costing and Pricing, Rate Case Management, Competitive Market Analysis, Strategic Business Planning, Corporate Restructuring, New Product and Service Development, Energy Litigation Support, Expert Testimony

Education
- Polytechnic Institute of New York University, MS Financial Management, 1977.
- Washington University, St. Louis, BS Electrical Engineering, 1973.

Professional Associations
- American Gas Association, Financial Associate Member
- Member, State Affairs Committee of the American Gas Association
- Member, Energy Bar Association
- Member, Energy Bar Association Electricity and Natural Gas Regulation Committees
- Member, Institute of Electrical and Electronic Engineers

Year Career Started
1973

Year Started with B&V
2007

- A Canadian combination utility to provide strategic, developmental, and litigation support for the implementation of two PBR plans and the related performance indicators and targets.
- A Canadian gas utility to provide strategic and issue-oriented support for development and implementation of a "second generation" PBR plan;
- An Eastern gas utility to evaluate and develop a performance-based Purchased Gas Adjustment (PGA) mechanism;
- A Midwestern gas utility to develop performance-based gas procurement measures for use in conjunction with the filing of performance-based PGA mechanisms before state regulators; and
- A Midwestern electric utility to evaluate and develop a price cap mechanism to be applied to each of its classes of service.

For a Northeastern gas utility, Mr. Feingold directed an effort to develop the activity-based cost support for a wide range of unbundled services in conjunction with establishing a residential pilot program permitting all customers the opportunity to purchase all or any part of their energy requirements on a competitive basis from third-party suppliers.

Mr. Feingold was responsible for conducting an in-depth analysis of the current gas rates and services for a Midwestern gas utility. He developed an appropriate pricing structure for the utility's unbundled gas transportation and storage services and assisted in establishing a longer-range pricing strategy for all utility services with support provided through the presentation of expert testimony. This assignment is typical of Mr. Feingold's work in the utility rate design and analysis area.

Interstate Natural Gas Pipeline Ratemaking and Regulation

Mr. Feingold has worked on numerous ratemaking and regulatory projects on behalf of major natural gas shippers involving interstate natural gas pipeline companies regulated by the Federal Energy Regulatory Commission in the U.S. and the National Energy Board in Canada. These projects have addressed a wide variety of issues, including:

- Revenue requirements;
- Cost allocation methods
- Rate design and competitive pricing;
- Service and rate unbundling;
- Sales forecasting analyses;
- Revenue sharing methods;
- Fuel cost recovery and fuel tracker mechanisms; and
- Expert testimony and energy litigation support.

Gas Supply Planning and Procurement

Mr. Feingold has conducted numerous studies related to gas supply procurement and planning for local distribution companies and combination utilities. These studies have analyzed a wide range of issues, including the availability and cost of future supplies; evaluation of alternate gas supply and deliverability resources; gas supply planning, procurement and management processes of a utility; supply reliability and peak day/winter season capacity levels; and the appropriateness of a capacity reserve margin.

Additionally, he has been involved in gas supply modeling activities related to least-cost planning and the evaluation of transportation project alternatives. Mr. Feingold has provided these services to various local distribution companies, including three Midwestern gas utilities, a Western gas and electric utility, a Southern gas utility, a Midwestern gas and electric utility, an Eastern gas and electric utility and a Midwestern gas utility.

Mr. Feingold worked with numerous gas distribution utilities to analyze and support through expert testimony their design day demand and capacity requirements before utility regulators. These included South Jersey Gas Company, Equitable Gas Company, Dominion Peoples and Dominion East Ohio and PG Energy.

On behalf of the Gas Research Institute (GRI), Mr. Feingold directed a comprehensive study to evaluate the future role of peak-shaving in gas utility operations. The objective of the study was to:

- Evaluate the role of peak-shaving supplies in relation to storage and deliverability within the larger context of the evolving demand profile in the natural gas industry;
- Determine peak-shaving costs;
- Summarize trends in utility decision practices that influence the value of peak-shaving supplies;
- Assess the opportunity to realize synergies with utility peak-shaving and new-end uses, such as power generation and transportation;
- Project future demand for peak-shaving supplies; and
- Isolate any issues or barriers to increasing the benefit of utilization of peak-shaving supplies and identify any R&D opportunities.

Mr. Feingold has also advised electric utility clients on the procurement of gas supply and interstate capacity resources for use in electric generation, including Nevada Power Company and an Eastern combination utility.

Expert Testimony and Litigation Support

Mr. Feingold has presented expert testimony before the following regulatory bodies:

- Federal Energy Regulatory Commission
- National Energy Board of Canada
- Arkansas Public Service Commission
- British Columbia Utilities Commission (Canada)
- California Public Utilities Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Georgia Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Iowa Utilities Board
- Kentucky Public Service Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Public Utilities
- Michigan Public Service Commission
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- Nebraska Public Service Commission
- New Hampshire Public Utilities Commission
- New Jersey Board of Public Utilities
- New Mexico Public Regulation Commission
- New York Public Service Commission
- North Carolina Utilities Commission
- North Dakota Public Service Commission
- Public Utilities Commission of Ohio
- Oklahoma Corporation Commission
- Ontario Energy Board (Canada)
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Philadelphia Gas Commission
- Régie de l'Énergie Quebec (Canada)
- South Dakota Public Utilities Commission
- Tennessee Regulatory Authority
- Utah Public Service Commission
- Vermont Public Service Board
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission
- Wyoming Public Service Commission

Andrew Lewis Trump

Mr. Trump has extensive experience working with utility and energy organizations in areas of business development, licensing, and capital planning. He has a broad understanding of North American energy markets, experience leading business development licensing activities for a major North American merchant power plant developer, and expertise in capital planning associated with Smart Grid and Smart Metering. Particular areas of influence and experience include: project finance and capital planning in complex regulated energy markets. Mr. Trump has supported utility clients in:

○ Overall account leadership to the business team in the creation of smart grid infrastructure strategy, business cases, capital spending plans, cost recovery plans, and project evaluations

○ Capital planning and investment strategy updates, including progress-to-date audits and assessments. Metric plan development.

○ Leadership and responsibility for teams of expert witnesses in complex electric utility regulatory licensing and capital project approval proceedings

○ Preparation and delivery of testimony to regulatory agencies in areas of power plant development and smart metering

○ Creation and delivery of detailed financial analysis to support smart metering and generation project valuation (project finance)

○ Comprehensive sourcing (supply chain) team leadership and support, including procurement strategy, contracting process management, RFP development, pricing evaluations, and contract negotiations support (facilitation, negotiation lead, pricing and value analysis, contract development)

Mr. Trump has experience representing merchant power station and electrical transmission projects and rulemaking matters before decision makers at the California Public Utility Commission (CPUC), the California Energy Commission (CEC), the California Environmental Protection Agency, the California Coastal Commission, the California State Lands Commission, various regional California Regional Water Quality Control Boards, the South Coast Air Quality Management District, and the California Air Resources Board. He has authored and provided testimony and technical and feasibility reports in central power station development projects, and has led teams of expert witnesses in these matters before the CEC and other authorizing agencies in both formal hearings and public workshop settings.

Since 2008, Mr. Trump has applied his regulatory experience in the above matters to grid modernization and utility capital planning. He has

DIRECTOR

Expertise:
AMI; Capital Planning; Grid Modernization; Regulatory Initiatives; Smart Grid

Education
Master of Arts, Public Policy, Regulatory Affairs, George Mason University, 2010, United States
Certificate, Project Management, Risk, University of California Berkeley, 2000, United States
Bachelor of Arts, Physical Sciences, Harvard University, 1984, United States

Total Years of Experience
16.1

Black & Veatch Years of Experience
5.8

Office Location
Pennsylvania, USA: United States

represented clients in regulatory affairs on smart metering issues and capital planning, authoring and supporting testimony for utility executives, speaking at hearings, helping to create meaningful regulatory strategies for their smart metering projects, preparing analysis used in proceedings, and presenting at public workshops.

Mr. Trump's background includes positions with Duke Energy (Director, Project Development and Licensing), Schlumberger/CellNet Data Systems (Director, Business Development), California Environmental Associates (Senior Consultant), and Bain & Company (Associate). He also spent two years working in Malawi, Africa working on rural water infrastructure projects.

PROJECT EXPERIENCE

Vectren Corporation; Smart Meter Plan; Indiana, United States; 2016

Consultant - Black & Veatch. Mr. Trump provided strategy consulting services for the development of a comprehensive Smart Meter Plan.

New Jersey Natural Gas; Strategy Consulting; New Jersey, United States; 2016

Consulting - Black & Veatch. Mr. Trump provided strategy consulting services in support and development of the Company's cost benefit evaluation of a $175M natural gas pipeline line expansion project.

California American Water; Consulting Services; California, United States; 2016

Consultant - Black & Veatch. Mr. Trump provided strategy consulting services in support and development of the Company's smart meter regulatory initiative.

City Public Service (CPS); Smart Grid Business Case; Texas, United States; 2014-2016

Consultant - Black & Veatch. Mr. Trump provided leadership and expertise in the development of grid modernization Business Case and project valuation.

Commonwealth Edison (ComEd, subsidiary of Exelon); Smart Meter Business Case; Illinois, United States; 2011-2016

Consultant - Black & Veatch. Mr. Trump provided leadership in the development of ComEd's Smart Meter Business Case and project valuation.

PECO (subsidiary of Exelon); Smart Metering Business Case and Smart Metering Plan; Pennsylvania, United States; 2009-2014

Consultant - Black & Veatch. Mr. Trump provided strategy consulting services in support and development of the company's Smart Metering Business Case and Smart Metering Plan (pursuant to PA Act 129) filed with the Pennsylvania Public Utilities Commission, developing the business case financial model used to assess project economics.

Southern Maryland Electric Cooperative; Smart Meter and Demand Response Plan; Maryland, United States; 2010-2012

Consultant - Black & Veatch. Mr. Trump provided strategy consulting services leading to the development of a comprehensive Smart Meter and Demand Response Plan. He led the development of the company's financial business case, authored materials used for hearings, and represented the utility before the Commission.

Central Louisiana Electric Co-Op (CLECO) Power LLC; Smart Meter Business Case; Louisiana, United States; 2010

Consultant -. Mr. Trump led an engagement resulting in the development of a preliminary CLECO's Smart Meter Business Case and project valuation.

Pepco Holdings, Inc.; AMI Business Case; United States; 2009-2010

Consultant -. Mr. Trump developed key updates to the company's AMI Business Case financial models. He developed the strategy for RFP solicitation, led the evaluation of vendor commercial responses including the evaluation of pricing, and led various parts of the company's negotiation efforts leading to smart meter service contracts, including the development of key contract elements such as warranty, performance measures and incentive structures.

Baltimore Gas & Electric (BGE); MDMS Business Case; Maryland, United States; 2009-2010

Consultant -. Mr. Trump developed BGE's AMI Business Case financial model and RFP commercial and pricing tools, and led the evaluation of vendor pricing. He facilitated and supported BGE's evaluation of vendor proposals, and facilitated vendor negotiations in several areas of the AMI initiative. He also provided guidance and oversight of the cost and operational benefit models used to support BGE's regulatory filings.

San Diego Gas and Electric; AMI Business Case; California, United States; 2008

Consultant -. Mr. Trump developed key updates to the company's AMI Business Case financial models. He developed the strategy for RFP solicitation and led the evaluation of vendor community commercial responses including the evaluation of pricing.

Michael J Nushart

Mike Nushart brings more than four decades of natural gas industry experience and provides data-driven Pipeline Integrity Management and code compliance expertise with a focus on data definition, acquisition, integration and, analysis.

Experience includes 32 years of direct utility management of gas distribution and transmission, construction, operations, and maintenance with special emphasis on cost effective code compliance and system safety and reliability. Subsequent to a successful utility career, the skills acquired have been applied to a consultancy that has assisted other LDC operators in achieving improved pipeline integrity, cost savings and efficiencies.

PROJECT EXPERIENCE

CPS Energy; Follow-On Compliance Consulting; San Antonio, Texas, United States; 2017-2017

Principal Consultant - Compliance - Black & Veatch. This engagement provided compliance subject matter expertise in the re-write of a single Control Room Management Plan and procedures covering two control rooms. It also included the development of a recommendation for functional consolidation of the two control rooms and advised client management on the potential compliance and economic impacts of candidate operating models. Developed Criterion-Referenced Instructional Design-based training curriculum for Gas Controllers and drafted training roadmap with corporate Training and Development staff.
Guided the development of a compliance tracking system and provided work type and periodicity framework.
Conducted assessment of current state data processes required for Pipeline Integrity Management and developed a recommendation for an improvement plan.

PRINCIPAL CONSULTANT

Expertise:

Asset Management; Control Room Management Compliance; Gas Transmission and Distribution Construction; Gas Transmission and Distribution Operations and Maintenance; Pipeline Integrity Management; Pipeline Radiographic Testing; Pipeline Safety; Pipeline Safety Code Compliance; Underground Gas Storage Compliance; Work and Asset Management

Education

Certificate, Pipeline Safety Seminar, U. S. Department of Transportation - Transportation Safety Institute, 1989, United States

Certificate, Preparatory for Welding Inspectors, American Welding Society, 1984, United States

Certificate, D1.1 Steel Code Clinic, American Welding Society, 1984, United States

Certificate, Weld Quality and Inspection, Metals Engineering Institute - American Society for Metals, 1979, United States

Certificate, SNT-TC-1A Radiographer, NDT Level II, American Society for Nondestructive Testing - DuPont, 1974, United States

Certificate, Underground Pipe Installation, University of Wisconsin, 1972, United States

Total Years of Experience

49.4

Black & Veatch Years of Experience

1

Professional Associations

CPS Energy; ISO 55001 Asset Management & Gas Operations Assessment; San Antonio, Texas, United States; 2017-2017

Principal Consultant Gas T&D SME - Black & Veatch. Conducted the ISO 55001 Asset Management assessment and a review of transmission and distribution operations. The principal focus was on asset data management as it relates to pipeline integrity management. The project also included examining external compliance documentation and developing recommendations for improvement.

The team conducted interviews and document review required by ISO 55000 with the addition of questions and discussion to evaluate gas operations. Particular emphasis areas were asset integrity management and compliance safety, code compliance, Gas Control, dispatching, outsourcing, organizational structure, and workforce utilization.

Significant accomplishments on engagement:
Participated in and conducted assessment interviews for ISO 55001 and related operations functions.
Authored Operations Review Summary document including improvement recommendations.
Authored detailed assessment review of external compliance findings documentation including corresponding improvement recommendations.
Assisted team in the development of key initiatives work plan for Roadmap.

Consolidated Edison; Gas Technology Business Case and Roadmap; New York, New York, United States; 2015-2015

Gas Industry Subject Matter Expert and Enterprise Asset Management Consultant - Computer Sciences Corporation - SubK. The project focus was to evaluate and augment a previous phase 0 report and develop a business case and roadmap document in preparation for the implementation of a work and asset management system. Special emphasis areas were public safety, code compliance, and workforce utilization.
Major accomplishments on engagement:
Authored Case for Action, Current State - Functional and Compliance Issues and Recommendations, Future State Operating Model, and Gap Analysis sections of the business case.
Conducted and documented Gap Analysis
Developed key initiatives work plan for Roadmap

American Gas Association Best Practices Benchmarking - Utility Representative
American Welding Society - Member
American Society for Nondestructive Testing - Member

Language Capabilities

Office Location

, New Mexico, USA: United States

Piedmont Natural Gas; Operations Assets and System Integrity (OASIS); Charlotte, North Carolina, United States; 2013-2014

Gas Industry Subject Matter Expert and Enterprise Asset Management Consultant - Piedmont Natural Gas - SubK. The project focus was on electronic data capture in support of code compliance and pipeline integrity management.
Major accomplishments on engagement:
Conducted Gap Analysis
Facilitated business rules definition and documentation
Designed Transmission Integrity Management Program functions for work and asset management incorporation
Provided gas industry subject matter expertise to system design, build and, system integration testing teams
Designed user acceptance testing scenarios

Piedmont Natural Gas; Operations Assets and System Integrity (OASIS); Charlotte, North Carolina, United States; 2011-2013

Gas Industry Subject Matter Expert and Enterprise Asset Management Consultant - Computer Sciences Corporation - SubK. The project focus was on electronic data capture in support of code compliance and pipeline integrity management.
Major accomplishments on engagement:
Conducted Current State Assessment
Facilitated Future State workshops
Conducted Gap Analysis
Facilitated System Design Labs
Facilitated business rules definition and documentation
Provided gas industry subject matter expertise to system design, build and, system integration testing teams

AGLR; Merger Acquisition Transition and Integration – AGLR/NUI; Elizabeth, New Jersey, United States; 2004-2005

Project Manager - Questas Consulting. Project Manager for the transition and integration planning for the acquisition of NUI Corporation by AGLR facilitated the development of detailed plans for integrating three gas distribution companies in three eastern states into the operations of the acquiring company. Plans included a methodology for the implementation of the business model used by the acquiring holding company. Key processes addressed include:
Business Development/Finance/Administration: Incoming Calls, Billing Collections/Accounting
Data Transfer: Bill Printing, Collections, Gas Accounting, Financials, IT Infrastructure/ Systems, Communication, Sales of storage capacity
Field Operations: Distribution/Pipeline Operations/Storage and Brine Operations
Gas Supply, Preventive Maintenance and Inspections, Damage Prevention/Assessment, Emergency Response, Corrective Maintenance and Repair, Investigate Leaks/Leak Surveys, Maintenance of Meters and Regulators, Meter Reading, Operation Support, Fleet, Safety and Training, Corrosion, Warehousing, Gas Operations (Pressure Control/Gas Control, SCADA/Telemetry, Pipeline and Storage Contracts, Forecasting, Measurement) Compliance Audit.

AGLR; Merger Acquisition Transition and Integration – AGLR/Virginia Natural Gas; Norfolk, Virginia, United States; 2001-2001

Process Specialist - Tier Consulting - SubK. Led and facilitated teams in integration methodology after the acquisition of an east coast gas distribution company by a large southeast holding company. Focus areas were Field Customer Service operations including field, back office and, dispatch, Engineering and Construction, Operations and Maintenance functions, Workforce Utilization and Operational Metrics.

Atlanta Gas Light; Process Improvement Facilitation – Atlanta Gas Light; Atlanta, Georgia, United States; 2000-2000

Process Specialist - Facilitator - HCA Consulting. Led and facilitated teams focusing on quality and cost improvement in damage prevention and workforce utilization.

PRESENTATIONS & PUBLICATIONS

. "Method and Apparatus for Anterior and Posterior Mobilization of the Human Ankle." United States Patent 7,297,091 B2. November 2007

ENERGY STRONG II GAS PROGRAM

Cost-Benefit Analysis

B&V PROJECT NO. 197382

PREPARED FOR

Public Service Electric and Gas Company (PSE&G)

8 JUNE 2018

BLACK & VEATCH

Foreword

Public Service Electric and Gas Company (PSE&G) has requested that Black & Veatch Management Consulting, LLC ("Black & Veatch") conduct a cost-benefit analysis for the subprograms and projects comprising the natural gas delivery system portion of its Energy Strong II Program (ES II Gas Program or Program). This Program is being proposed by PSE&G in its petition to the New Jersey Board of Public Utilities (BPU). A newly-enacted rule[1] identifies "any applicable cost-benefit analysis for each project" as part of the minimum filing requirements of any Infrastructure Investment Program (IIP) petition to the BPU.

To fulfill this regulatory requirement, a Black & Veatch project team obtained information and data to evaluate the costs and benefits of the ES II Gas Program. The Black & Veatch staff reviewed the current Energy Strong Program (ES I Program) that has been approved by the BPU, the various components of the proposed ES II Gas Program, identified and gathered data and assumptions to apply to the current analysis effort, and reviewed study results and conclusions. This Report describes this effort for PSE&G's proposed ES II Gas Program and related Subprograms. A companion report has been prepared for PSE&G's proposed ES II Electric Program.

For this effort, PSE&G provided cost estimates to Black & Veatch to use for the ES II Gas Program investments within this cost-benefit analysis. Black & Veatch then led a process to identify and describe the quantitative and qualitative benefits of the ES II Gas Program projects, estimate monetary values for these benefits where possible, and provide analytic and policy-oriented support for PSE&G's filing, specifically in support of its provision of appropriate cost-benefit estimates for the ES II gas investments.

The evaluators for this effort are:

ES II Gas Program
Russell Feingold
Michael Nushart
Krystal Richart
Andrew Trump

[1] See New Jersey Administrative Code, sections 14:3-2A, 50 N.J.R. 630(a).

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Executive Summary

Public Service Electric & Gas Company (PSE&G) is seeking approval from the New Jersey Board of Public Utilities (BPU) for the gas portion of its Energy Strong II Program (ES II Gas Program) for hardening and improving the resiliency of PSE&G's natural gas delivery system. The capital expenditure estimated by PSE&G for this five-year Program is approximately $1.0B. PSE&G has aligned the Program to the BPU's Infrastructure Investment Program (IIP) rule, the purpose of which is to improve utility system reliability, resiliency, and/or safety, and with PSE&G's core objective of providing safe and adequate service to its 1.8M gas customers. The five-year investment period begins in 2019.

This report documents the cost-benefit analysis of the ES II Gas Program, consistent with the newly-enacted BPU IIP rule. The cost and benefit estimates are organized based on the two PSE&G proposed gas subprograms. The Curtailment Resiliency Subprogram is comprised of six projects that will reinforce PSE&G's gas distribution system and further protect the system from the risk of a major supply disruption originating upstream of the PSE&G gas distribution system on the interstate pipeline system.[2] These individual projects work together to support the system should a supply disruption occur. The Metering & Regulating (M&R) Upgrade Subprogram consists of rebuilding seven of PSE&G's existing M&R stations to address their growing physical obsolescence and, in the case of two, flood hazards, thus bringing all seven into conformance with modern design practices. Appendix A - Detailed Characteristics of PSE&G's ES II Gas Subprograms provides additional information on the Curtailment Resiliency Subprogram and M&R Upgrade Subprogram.

PSE&G's Curtailment Resiliency Subprogram

Black & Veatch estimates that the quantifiable and monetized benefits of PSE&G's proposed Curtailment Resiliency Subprogram exceed direct investment costs of $863M by a factor of 1.3, in simple nominal dollar terms. This conclusion is based on Black & Veatch's detailed analysis of a specific gas outage scenario on one of the interstate pipeline systems interconnecting to the PSE&G's gas distribution system and impacting approximately 177,132 customers (and approximately 435,500 people) located within the region.

To analyze this scenario Black & Veatch assumed one outage event occurs during the winter with a 10-day duration at an average daily temperature of 30^0F. This is followed by 30 days to restore gas service to 95 percent of PSE&G's customers.[3] While this outage represents a low probability event, it is based on realistic assumptions in light of our review of gas outage events that have occurred around the country in recent years. The benefit values estimate the significant value to the impacted customers of avoiding the direct costs of this event over its entire duration. Specifically, the six projects comprising PSE&G's Curtailment Resiliency Subprogram enable it to quickly supplement gas deliveries from alternative interstate pipeline suppliers, moving these supplies across its gas distribution system in reaction to major upstream outages. This reduces the extent and duration of the outage, mitigating its costs and harmful effects.

[2] In the specific analysis described in this report, the outage event is assumed to occur on the Texas Eastern Transmission system (owned and operated by Enbridge Inc.), which is one of PSE&G's largest interstate pipeline suppliers of natural gas.

[3] An additional 33 days are necessary to restore all customers. As documented in this report, PSE&G's actions to restore its gas distribution system after a major outage event represent a complex and expensive undertaking involving hundreds of utility workers for many weeks.

The benefit-to-cost ratio of 1.3 includes (as the numerator) the identified and estimated monetary benefits associated with avoiding the severe consequences of this outage event, divided by the Curtailment Resiliency Subprogram investment costs.[4] This benefit-to-cost ratio *excludes* many qualitative benefits, and the additional value associated with mitigating outage risks over the many decades during which the planned infrastructure will be in service.

Table 1 summarizes PSE&G's estimates of the number of firm customers that would avoid a curtailment of gas service under the modeled outage scenario, assuming completion of PSE&G's proposed Curtailment Resiliency Subprogram infrastructure investments.[5] Black & Veatch applies these results as input variables in its cost-benefit analysis.

Table 1 Summary Results of PSE&G's Gas Outage Scenario Analysis: Outages Avoided

GAS SYSTEM CONDITION	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	TOTAL
	Number of Firm Gas Customers That Lose Service In the Outage Event			
Customer Outages Avoided With ES II Curtailment Resiliency Subprogram	162,500	13,000	1,632	177,132

Figure 1 summarizes the results of the cost-benefit analysis in monetary and qualitative terms.

[4] For purposes of risk communication, Black & Veatch's computation of a benefit-to-cost ratio is simplified without consideration of a specific timeframe or discount factor. In fact, the investment costs would be spread over many years (as many as 60), as the assets have long physical and economic lives. Through the utility ratemaking process, customers will be exposed to a fraction of the $863M investment costs on a yearly basis. Secondly, the mitigation benefits are provided on a constant and continuous basis.

[5] All interruptible customers are 100% curtailed during the gas outage event. No additional load curtailment -- as prescribed in PSE&G's Gas Emergency Procedures and NJAC Title 14, Chapter 29 -- was considered for this assessment.

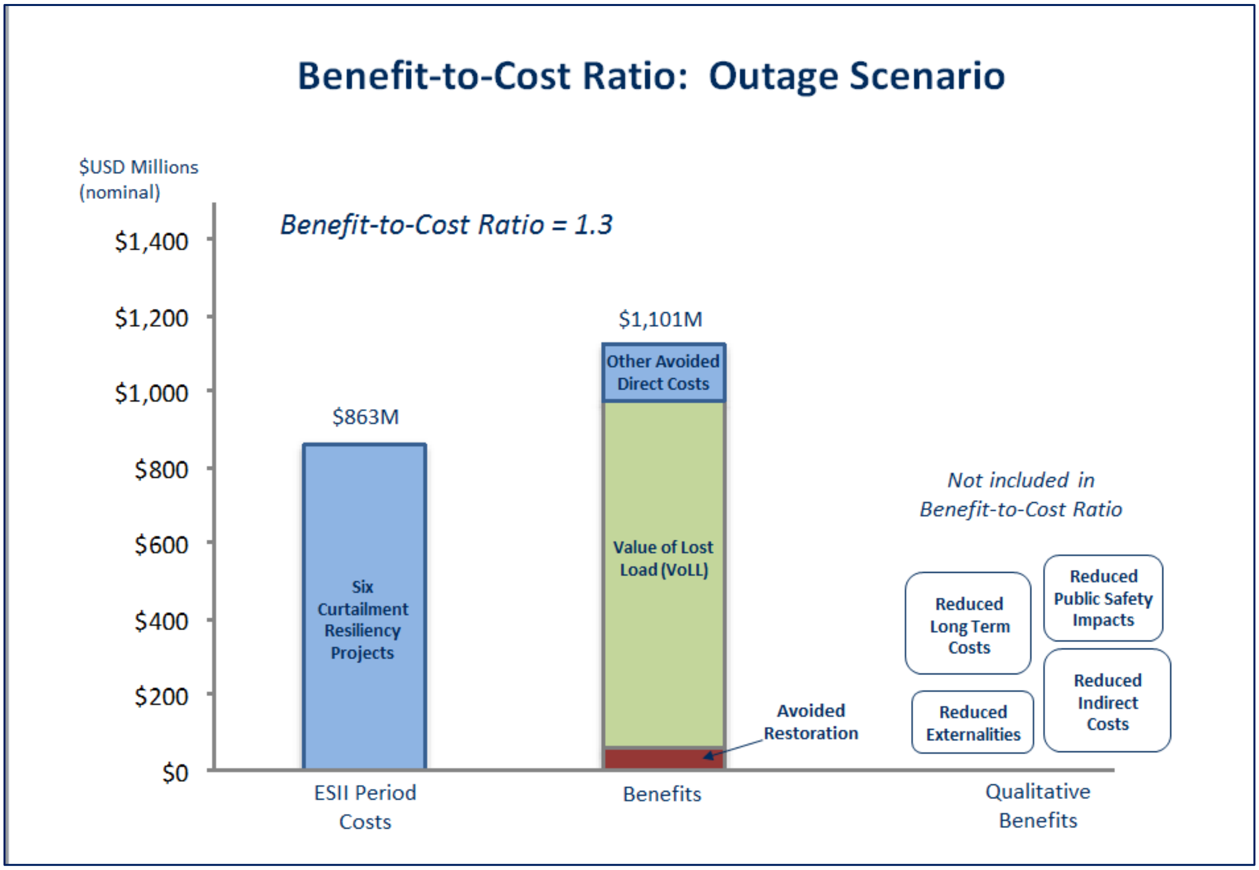


Figure 1 Benefit-to-Cost Ratio for the Curtailment Resiliency Subprogram

PSE&G's M&R Upgrade Subprogram

The M&R station upgrades proposed by PSE&G – estimated as $136M of direct investment during the five-year period – are justified on several cost-beneficial grounds when including the role of qualitative as well as quantified monetary benefits.

- First, a wide range of qualitative benefits is identified within this cost-benefit analysis. These provide a first stage of justification for PSE&G's M&R station upgrade needs. These benefits include eliminating the hazard related to flooding, (and the associated risk that a flooding event could take two of the M&R stations out of service). [6] Qualitative benefits also include those associated with the building of a new station conforming to current design practices. A new station will be equipped with: increased overpressure protection, reduced noise levels (due to new equipment, piping layout and materials used in the building envelop), newer equipment less prone to maintenance problems, modern cathodic protection systems, improved coatings, and better pipe protection systems throughout.

- Second, based on PSE&G's expectations of the need to rebuild three of these facilities (Camden, East Rutherford, and Central,) as part of its base capital spending plan over the next 20 years (in the absence of the ES II Program), Black & Veatch's cost-benefit analysis

[6] See the Direct Testimony of Wade M. Miller, PSE&G's Director – Gas Transmission and Distribution Engineering, for a description of the M&R Upgrade Subprogram and asset risk evaluation process.

recognizes the *avoided* costs that result due to the ES II Gas Program. Future spending associated with these stations will be reduced because of the replacement of these three stations under the ES II Gas Program.

- Third, PSE&G has identified the various risk reduction benefits associated with these stations as part of its lifecycle- and asset risk assessment.[7]

In summary, Black and Veatch's study indicates that the M&R stations slated for replacement are old, are increasingly difficult to maintain due to aging equipment, do not conform to current design practices and, for two of the M&R stations (Camden and East Rutherford), are at elevations below FEMA flood protection standards, thus posing an outage risk in the event of a major flood. Black and Veatch's analysis supports the conclusion that it is prudent to further harden and upgrade PSE&G's gas distribution system by replacing these seven M&R stations as part of the ES II Gas Program before there is an imminent hazard or an actual outage event, and before corrective maintenance requirements become challenging to address.[8]

Context for PSE&G's Resiliency Initiatives

PSE&G's resiliency initiatives are being proposed at a time of considerable interest and attention by gas distribution utilities, interstate gas pipeline companies, utility regulators, other market participants, and public/governmental officials in addressing natural gas resiliency issues and needs.[9]

In New Jersey, the BPU held a discussion-based tabletop exercise[10] on June 13, 2017, for the purpose of creating a dialogue and to exercise certain protocols between the natural gas sector and state/federal partners addressing a hypothetical natural gas supply shortage and/or outage. The exercise, called *NJ Pilot Light 2017*, was also completed to further evaluate the natural gas sector's resiliency during a natural gas outage on a 30-degree day. The exercise was partially modeled in relation to an April 2016 incident involving an interstate natural gas supply disruption caused by pipeline failure and subsequent emergency repairs to the system owned and operated by Enbridge Inc. (Enbridge) in Pennsylvania. This event (and others) is described in greater detail later in this report.

As a threshold matter, it is universally accepted and recognized in the energy industry that a gas utility is obligated to ensure that its natural gas system is resilient, reliable, and sufficiently reinforced to provide uninterrupted gas service to its firm customers during extreme weather conditions (i.e., design day temperatures) upon which its gas delivery system is designed. However, there are times when the particular circumstances faced by a gas utility are unplanned and extreme

[7] Ibid, pages 4-5 and page 10.

[8] Appreciating the impacts of increased corrective maintenance is difficult when inspecting individual assets and/or projects. Rather, it is the cumulative impacts of corrective maintenance over many types of assets that erode the ability of the utility to maintain overall system reliability within a fixed capital budget.

[9] See for example, *Assessment of the Adequacy of Natural Gas Pipeline Capacity in the Northeast United States*, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability Energy Infrastructure Modeling and Analysis Division (November 2013*); Implications of Disruption to Natural Gas Deliverability, Analysis of the Ability of the Natural Gas Market to Withstand Loss of Pipeline Capacity, Summary of All Project Reports,* U.S. Department of Energy, sponsored by the U.S. DOE Office of Electricity Delivery & Energy Reliability (September 2008); and the American Gas Association's Workshop materials on *Natural Gas Resiliency* (April 29, 2014).

[10] A tabletop exercise is a meeting of key personnel to discuss a simulated emergency situation in an informal setting.

in nature, creating operational problems that can cause a loss of gas service to a portion of its customer base. These circumstances can be created by either natural or human actions, or a combination of both. While gas outage events experienced by gas utilities may be perceived as infrequent in layman's terms, they do occur. The risk of an upstream natural gas supply outage forms the underlying justification for the PSE&G Curtailment Resiliency Subprogram.

Cost-Benefit Methodology

To perform the cost-benefit analysis for the outage scenario, Black & Veatch explored a wide range of effects of a gas curtailment. This included conducting a detailed assessment of the extensive work that would be necessary to restore PSE&G's gas distribution system after an outage event. Moreover, Black & Veatch identifies both quantitative and qualitative benefits related to the outage event. Benefits include both: (a) the estimated value PSE&G customers place on *avoiding* the direct costs created by the outage event, in terms of Value of Lost Load (VoLL); and (b) other direct costs, indirect costs, and other impacts resulting from the outage.

To keep the analysis straightforward, one outage event is assumed. The benefits of avoiding the impacts of this outage are compared to the investment costs of PSE&G's proposed Curtailment Resiliency Subprogram. Moreover, Black & Veatch has not attempted to identify or quantify effects of multiple outage events (varying temperature and duration assumptions, for example) so as to mathematically compute expected values; we do not believe this would be the most reasonable way to conduct this analysis of a low probability but high consequence event. Rather, Black & Veatch believes that exploring a single outage event using a reasonable set of assumptions and conditions provides more meaningful guidance to decision makers, better portraying the nature and consequences of an outage event, the scale of activities associated with restoring the system, the magnitude of the resulting direct and indirect costs and the potential harm that could result in such a circumstance.

Conclusions

Measured against the single specific outage scenario evaluated by Black & Veatch, the Curtailment Resiliency Subprogram yields quantifiable monetary benefits in excess of the investment costs. Black & Veatch believes that this outage scenario is a reasonable one, and depicts the nature and scale of impacts for this kind of low probability and high consequence event. Many qualitative benefits are also identified in addition to the monetized benefits. For the M&R station upgrades, the cost-benefit analysis identifies and describes a benefit-to-cost ratio of 0.3, reflecting the limited quantifiable monetary benefits associated with avoiding future base capital spending (associated with the replacement of three of these stations over the foreseeable future). Notwithstanding this result, there are asset risk management and other qualitative benefits that support the M&R Upgrade Subprogram.

Combining the quantifiable benefits of both Subprograms yields an ES II Gas Program benefit-to-cost ratio of 1.1, as summarized in Figure 2. Black & Veatch notes that the Program investments within both Subprograms have long expected useful physical and economic lives, and thus will provide gas distribution system protection benefits on a continuous basis far into the future. This enduring and "always on" aspect of these investments in providing risk reduction benefits is not reflected in the benefit-to-cost ratio.

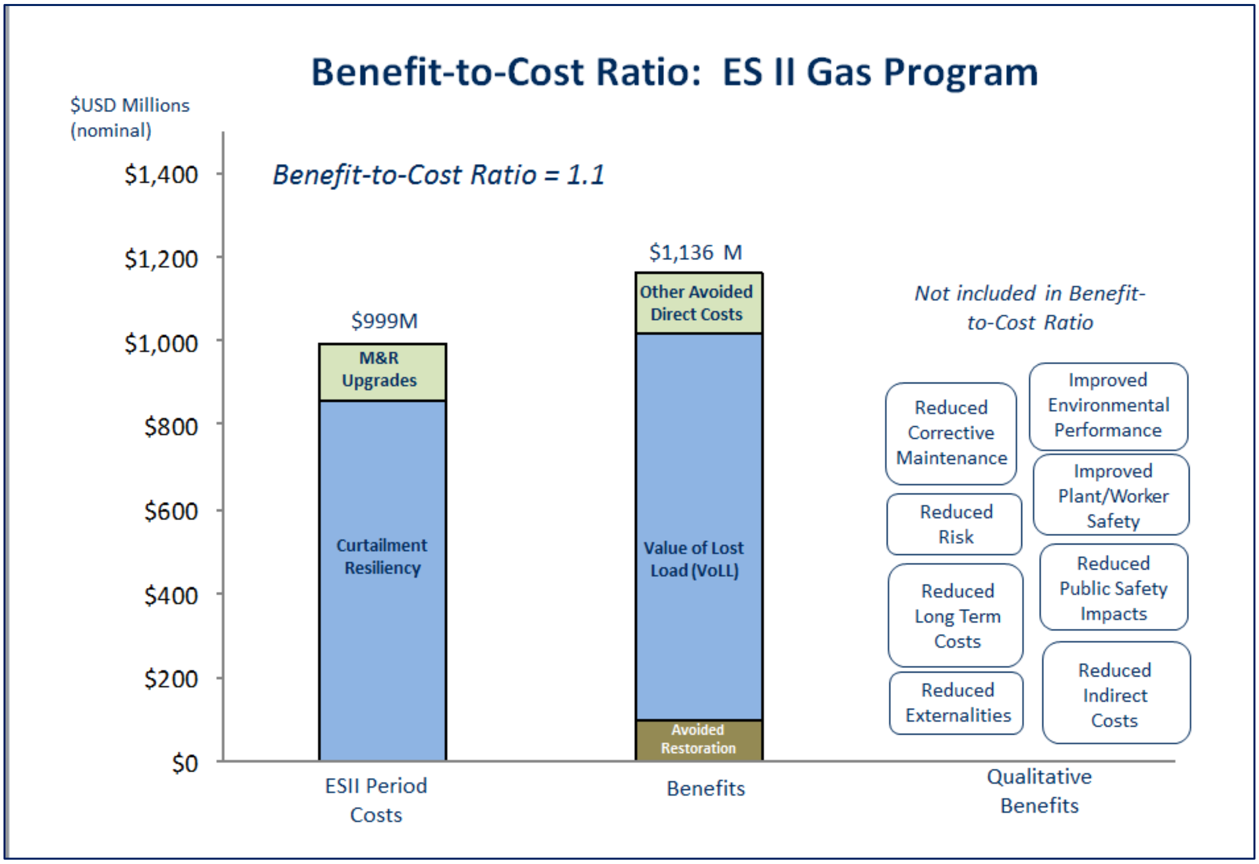


Figure 2 Benefit-to-Cost Ratio for the ES II Gas Program

The results of the cost-benefit analysis conducted by Black & Veatch are consistent with the IIP rule regarding the provision of information on costs and benefits. The results reflect an estimate of specific, quantifiable and monetized benefits in relation to investment costs, using reasonable assumptions. Additionally, as is appropriate in a cost-benefit analysis, the results also include reliance on many significant yet hard to quantify and/or monetize benefits, as depicted in Figure 2, even though these qualitative benefits can not be formally included within the benefit-to-cost ratio.

Introduction

This report documents the cost-benefit analysis for PSE&G's ES II Gas Program, consistent with newly-enacted BPU IIP regulations related to the improvement of utility system reliability, resiliency, and/or safety. This five year, $1.0B program is aligned with both (a) the broader BPU Infrastructure Investment Program (IIP) rule, the purpose of which is to improve utility system reliability, resiliency, and/or safety, and (b) PSE&G's core objective of providing safe and adequate service to its 1.8M gas customers. The five-year investment period begins in 2019.

Context for the Focus on Resiliency

Recent events have heightened the awareness by gas distribution utilities such as PSE&G of the risks of interstate pipeline system curtailments. PSE&G concluded that it was necessary and appropriate to reevaluate the resiliency of its gas system in recognition of certain recent curtailments on the interstate pipeline system. Of particular note is the recent unplanned gas outage incident in the vicinity of Delmont, Pennsylvania on the Texas Eastern Gas Transmission, L.P. (Texas Eastern) system, which occurred April 29, 2016. This outage had a direct impact on PSE&G's natural gas operations.[11]

PSE&G's Curtailment Resiliency Subprogram

The Curtailment Resiliency Subprogram is comprised of six projects that will reinforce PSE&G's gas distribution system and further protect it from the risk of a major supply disruption. This risk is related to a disruption *upstream* of the PSE&G gas distribution system and on the interstate pipeline system owned by other companies.[12]

The six projects have an estimated investment cost of $863M over a five-year period. PSE&G designed these six projects to support continued service to firm gas customers[13] to the maximum extent possible in the event of a major gas outage on any one of the interstate pipeline systems serving PSE&G (which are upstream of its various city gate delivery points). Depending on the location and nature of the upstream outage event, some combination of these new PSE&G facilities would operate to reroute available gas supplies from other interstate pipelines serving PSE&G in a way to reduce or eliminate the gas service impact that would otherwise ensue.

Five distribution projects in PSE&G's Curtailment Resiliency Subprogram are designed to address specific areas of its service territory served primarily by one pipeline. In the event of an outage, PSE&G can transport gas from an alternative pipeline into these areas. As a result, these projects enable PSE&G to move large volumes of gas across areas of its service territory in ways that cannot be accomplished today, ensuring continued gas service to these identified areas. The sixth project is aimed at maintaining a supplemental supply of LNG on PSE&G's system, thus providing *additional* support when contracted gas supplies cannot be obtained on the interstate pipeline systems.

[11] As described by PSE&G in the Direct Testimony of Wade M. Miller at pages 3-4.
[12] As described in this report, the outage event that is applied to the outage scenario and forms the basis of the monetization of benefits is assumed to occur on the Texas Eastern system (owned and operated by Enbridge Inc.), which is one of PSE&G's largest interstate pipeline suppliers of natural gas.
[13] Firm service is the highest quality sales or transportation service offered to customers by a gas distribution utility, such as PSE&G, that anticipates no planned interruption. With the loss of gas deliverability from an interstate pipeline, firm service would be the last gas service curtailed by the gas distribution utility, with service to the residential class considered to be the highest priority category, which means residential customers would be the last group to be curtailed.

Together, these six projects will provide enhanced supply resiliency to PSE&G's gas distribution system at times of high customer demand while standing ready to mitigate the effects of gas outages on the interstate pipeline systems supplying PSE&G.

M&R Upgrade Subprogram

The M&R Upgrade Subprogram consists of rebuilding seven of PSE&G's existing M&R stations to address their growing risk of being technically outdated and, in the case of two, flood hazards, thus bringing all seven into conformance with current design practices and building standards. The seven projects have an estimated investment cost of $136M over the 5-year period. All seven upgrades functionally rebuild and replace the existing M&R stations at their current locations. Due to the condition of three of these stations, PSE&G estimates that it will have to replace them as part of its normal base capital spending over the next 15-20 years. All of the station upgrades are justified on the grounds of overall risk reduction benefits, as well as on a wide range of qualitative benefits, which are enumerated in this analysis. The structures and much of the equipment in these stations are old, and pose a risk to the continued safe and reliable operation of the gas distribution system. Two of the replacements are further justified by the fact that they reside within flood hazard areas.

Focus on Safety

Improving safety for customers and employees alike is also an overarching goal of the ES II Gas Program. Both Subprograms lower the risk that customers will experience gas supply disruptions (and therefore the harm that can result due to these disruptions). The M&R upgrades replace very old structures with equipment that is prone to break down and difficult to repair. Upgrading M&R stations improve public safety by eliminating upstream relief valves that release gas into the atmosphere in the case the maximum allowable operating pressure (MAOP) of the station is exceeded, provides improved noise abatement measures by installing regulator stations in new buildings reducing the noise to surrounding areas, and reduces the number of methane release points. Personnel safety is improved due to the M&R site being laid out in a manner that allows personnel easy access to O&M activities and the new building which will house the regulation equipment will be built to current building codes.

DEFINITIONS

While resiliency is of significant interest to electric, gas and water utility planners, there is no consensus on its definition. Moreover, the terms *reliability*, *resiliency*, and *hardening* all tend to converge in their meanings when used to discuss improving utility infrastructure. To assist in describing the benefits of PSE&G's Curtailment Resiliency Subprogram, Black & Veatch offers the following observations regarding use of these terms.

Resiliency

Infrastructure resiliency is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event. Another view of resiliency is provided in a recent Sandia Lab report in which it defines resiliency as "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents."[14] The Sandia Report also emphasizes that the focus of resiliency is on **high-consequence, low-probability** events.

These concepts are built into a more specific meaning for purposes of the Black & Veatch cost-benefit analysis: *gas supply resiliency* more specifically relates to the ability of a gas distribution utility such as PSE&G to continue to provide gas service to its firm customers under a reduction or termination of service by one or more interstate pipelines that supply it. Such events are referred to in this analysis as "curtailment" of service. Curtailment is specifically defined as the loss of normally expected gas deliveries as a consequence of supply or transportation interruptions. A curtailment can relate to either: (1) unplanned, high gas demand requirements from shippers; or (2) a pipeline or equipment failure. Furthermore, a *demand*-related curtailment is typically a result of widespread severe cold causing increased gas demands by customers that cannot be met with available gas supplies. A curtailment related to pipeline or equipment *failure* is typically the result of a pipeline rupture or loss of compression or storage facilities.

Reliability

For a gas distribution utility such as PSE&G, reliability is simply the continued ability to meet the natural gas needs of end-use customers, at the customers' desired level of service quality, even when events reduce the amount of available natural gas. While not the driver of its ES II Gas Subprograms, PSE&G must engage in reliability-focused activities, such as re-light activities, as a consequence of outage events, and as part of the gas system restoration process.

Hardening

In the Staff Report on Electricity Markets and Reliability issued by the U.S. Department of Energy,[15] the concept of hardening was defined as follows:

> Hardening of an asset or system refers to physically changing infrastructure to make it less susceptible to damage. Hardening improves the durability and stability of an energy structure, making it better able to withstand the impacts of hurricanes, weather events or attacks.[16]

In the case of PSE&G's M&R Upgrade Subprogram, and particularly related to flood hazards, PSE&G is hardening these assets. However, Black & Veatch notes that it is not uncommon to include hardening as part of total system resiliency.

NJ PILOT LIGHT 2017

Recently, gas distribution utilities, interstate gas pipeline companies, utility regulators, other market participants, and public/governmental officials have shown considerable interest in addressing natural gas resiliency issues and needs.[17] In fact, in New Jersey, the BPU held a

[14] Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States, Sandia Report SAND2014-18019, September 2014, Sandia National Laboratories.
[15] Staff Report to the Secretary on Electricity Markets and Reliability, U.S. Department of Energy, August 2017. Available at: http://www.sandia.gov/search/index.html?q=Conceptual+framework+2014&x=0&y=0
[16] Ibid, p. 63.
[17] For example, refer to *Assessment of the Adequacy of Natural Gas Pipeline Capacity in the Northeast United States*, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability Energy Infrastructure Modeling and Analysis Division (November 2013*); Implications of Disruption to Natural Gas Deliverability, Analysis of the Ability of the Natural Gas Market to Withstand Loss of Pipeline Capacity, Summary of All Project Reports,*

discussion-based tabletop exercise[18] on June 13, 2017, for the purpose of creating a dialogue and to exercise certain protocols between the natural gas sector and state/federal partners addressing a hypothetical natural gas supply shortage and/or outage. The exercise, *NJ Pilot Light 2017*, was also developed to further evaluate the natural gas sector's resiliency during a natural gas outage on a 30 degree day. The exercise was to some extent modeled after a recent incident in April 2016 involving a natural gas supply disruption caused by pipeline failure and subsequent emergency repairs to the system owned and operated by (Enbridge) in Pennsylvania (described in greater detail elsewhere in this Report).

This set of workshops identified several PSE&G utility strengths related to responding to such an event, including a mature mutual aid sector; social media capabilities to convey timely and accurate information to customers; and a strong understanding of the Incident Command System,[19] as well as a strong underground pipeline hazard prevention program ("call before you dig"), which recognizes the high risk third party excavators, builders, and others pose to causing damage to PSE&G's underground pipelines. Furthermore, the workshop's After Action Report/Improvement Plan[20] concludes that one of the "primary areas for improvement" is "identification of diverse natural gas supplies and interconnection to multiple interstate sources can improve resilience in the natural gas sector."[21]

As a threshold matter, it is universally accepted and recognized in the energy industry that a gas utility is obligated to ensure that its natural gas system is able to provide uninterrupted gas service to its *firm* customers during the extreme weather conditions (i.e., design day temperatures) upon which its gas delivery system is designed. However, there are times when the particular circumstances faced by a gas utility are unplanned and extreme in nature, creating operational challenges that can cause a loss of gas service to a portion of its customer base. These circumstances can be created by either natural or human actions, or a combination of both.

EXAMPLES OF MAJOR NATURAL GAS OUTAGE EVENTS

While gas outage events experienced by gas utilities may be infrequent, they do occur. Some examples of major natural gas outage events are described in Appendix B - Examples of Major Natural Gas Outage Events. These include:

- On October 11, 2017, Texas Eastern which is owned and operated by Enbridge Inc., declared a force majeure on an unplanned gas outage that occurred at its Berne Compressor Station in Eastern Ohio.

U.S. Department of Energy, sponsored by the U.S. DOE Office of Electricity Delivery & Energy Reliability (September 2008); and the American Gas Association's Workshop materials on *Natural Gas Resiliency* (April 29, 2014).

[18] A tabletop exercise is a meeting of key personnel to discuss a simulated emergency situation in an informal setting.

[19] The Incident Command System (ICM) is a standardized on-scene emergency management concept associated with the National Incident Management System which is designed to allow its users (generally incident managers) to adopt an integrated organizational structure equal to the complexity and demands of single or multiple incidents without being hindered by jurisdictional boundaries.

[20] NJ Pilot Light 2017, After Action Report/Improvement Plan (Redacted Version), New Jersey Board of Public Utilities, Division of Reliability and Security, dated August 25, 2017.

[21] Ibid, Executive Summary, p. 8.

- On October 1, 2017, a 30-inch gas pipeline of Southern California Gas Company (SoCalGas) exploded in Newberry Springs, California, and a second line was also damaged. The shutdown of the two pipelines meant that SoCalGas lost the ability to ship about 0.8 Bcf per day into the region.

- Texas Eastern also experienced a force majeure event on April 29, 2016, due to an unplanned outage downstream of its Delmont Compressor Station in Delmont, Pennsylvania. Some level of curtailment persisted due to this event for a total of 6 months.[22]

- In May 2010, a delivery station served by Florida Gas Transmission (FGT) that delivers natural gas to the Jupiter and North Palm Beach County areas of TECO Peoples Gas experienced a loss in pressure that impacted the ability of TECO Peoples Gas to serve approximately 10,500 gas customers.[23]

Although gas outages are infrequent, their impacts can be significant under extreme conditions. In fact, it is in part due to the significant harm that can follow these events that gas distribution systems are engineered to high levels of reliability and risk avoidance.

DESIGN PRINCIPLES OF THE COST-BENEFIT APPROACH

In conducting a cost-benefit analysis, there are many choices that need to be made concerning how to make the analysis as meaningful and relevant as possible in order to provide guidance to decision makers. For purposes of the Curtailment Resiliency Subprogram, Black & Veatch first developed a robust understanding of how PSE&G approached constructing this subprogram with its aim to address the risk of upstream pipeline outages. This involved developing an understanding of how the six underlying projects support PSE&G's gas distribution system under differing conditions of temperature, duration, and operating conditions.

As part of this effort, Black & Veatch provided additional context for outages, through researching examples of recent gas outages on the interstate pipeline systems and associated utility response activities. Black & Veatch also explored the nature of response activities, from start (initial notice of an outage) to finish (full restoration) so as to generate a reasonable estimate of the length of time and the costs involved to restore PSE&G's gas distribution system under certain conditions and assumptions.

As a consequence of this fact-finding, Black & Veatch has recommended the following premises to PSE&G, as adopted in this report, for purposes of preparing a cost-benefit analysis, and thereby helping to demonstrate the value of the Subprogram:

1. The PSE&G gas distribution system risk related to an upstream gas supply system outage event is best framed in terms of the direct and indirect costs and other impacts to PSE&G's customers during, and as a consequence of, the outage event. These impacts are directly

[22] Fortunately, this unplanned outage did not occur during the winter heating season, but it bears repeating that gas supply disruptions are not theoretical events. If the curtailment on Texas Eastern had occurred on a mid-winter day with an average daily temperature of 5ºF (i.e., PSE&G's design day), it is possible that PSE&G may have eventually curtailed firm gas service to potentially more than 400,000 customers. Under this gas outage situation, PSE&G may have initially interrupted gas service to more than 250,000 firm customers and potentially more than 400,000 firm customers as the initial curtailment continued and locally-held peak shaving supplies were depleted.
[23] For details of this gas outage event and the required gas service restoration efforts, see the daily press releases issued by TECO Peoples Gas on May 18, 2010 through May 23, 2010.

proportional to the number of customers impacted, the length of time they are without gas service, and the temperature conditions throughout the outage. Black & Veatch applies Value of Lost Load (VoLL) concepts and factors to support these cost impact estimates.

2. The cost-benefit analysis must accommodate (either computationally or qualitatively) the fact that there are many possible conditions (variables) that uniquely form an outage event scenario. These involve: upstream pipeline outage assumptions, curtailment duration, temperature conditions persisting throughout the event, the capacity of and operational decisions about utilization of peak shave resources, availability of substitute firm gas supply, and labor resources needed to restore the system once the curtailment has ended.

3. The cost-benefit analysis results should also recognize the fact that PSE&G's Curtailment Resiliency Subprogram infrastructure will provide mitigation benefits over many decades, and that there is risk of multiple outage events on different interstate pipeline systems over these many decades.

4. Attempting to describe all of the possibilities under an outage event scenario is not practical or reasonably feasible. Additionally, describing the benefit impacts in terms of mathematically derived *expected values* does not provide meaningful guidance to decision makers because the enormity of the impacts of any single event is not well communicated within the result.[24]

5. What is more meaningful for decision makers in Black & Veatch's view is to identify a specific outage event that represents a reasonable set of conditions, is feasible to identify and describe, and clearly demonstrates the function and value of the investments, thereby permitting an estimate of the full range of impacts associated with this event. Black & Veatch also believes the gas outage scenario should be guided by similar events that have occurred in the past.

6. With such a single point estimate and result, sensitivities can be used to explore how differing conditions influence these results, either lowering or raising value as input variables are adjusted (e.g., how do lower temperatures or a different outage duration influence the cost-benefit results ?).

7. By treating the outage event risk as a discrete event and scenario -- and by comparing the resulting benefits to the five-year investment costs – a simple benefit-to-cost ratio can be computed on nominal dollar terms.

8. Since costs are, in fact, spread out over many decades through the normal utility ratemaking process -- and the benefits are received in full for any single outage avoided – the simple benefit-to-cost ratio helps frame the insurance aspect of the yearly cost burden to customers. Customers, in effect, are asked to invest yearly through the rates process a fraction of the ES II Subprogram cost to avoid on a continuous basis -- and over many decades -- the enormity of costs, inconvenience and harm that would result should an outage occur.

The cost-benefit analysis presented herein rigorously applies these premises to the Curtailment Resiliency Subprogram evaluation.

[24] This is an underlying challenge of applying cost benefit techniques to low probability and high consequence events.

UPSTREAM OUTAGE EVENT RISK

The concepts of risk and uncertainty are central to the cost-benefit analysis for the ES II Gas Program and to the Curtailment Resiliency Subprogram, in particular. Risk is the measure of the likelihood (or probability) and the potential consequences (impacts or hazards) of uncertain future events.

The cost-benefit analysis does not speculate on the specific nature of upstream outage events. Outages *do* occur for many reasons. Rather, the cost-benefit analysis evaluates the range of potential impacts of a major gas outage event on one of the interstate gas pipeline systems serving PSE&G's gas distribution system. Both quantified and monetized impacts are identified, as are qualitative impacts (which are difficult to quantify), such as the impacts to public safety.

The cost-benefit analysis also does not attempt to assign a specific level of probability to the outage event, except to note it is best characterized as a high-consequence, low-probability event. Furthermore, the gas outage scenario is assumed to occur during the months when gas demands are growing due to increased space heating requirements (i.e., during cold temperature periods when the availability of gas for heating purposes is a greater necessity for customers). A modest duration of 10 days is assumed for the interstate pipeline system outage event, although the time to restore the PSE&G system is many days longer. Taking this approach, Black & Veatch believes the cost-benefit analysis respects the challenges broadly acknowledged in the community in evaluating resiliency type investments, while providing a reasonable cost-benefit result to serve the purposes of the IIP rule.

The energy utility industry acknowledges that there are significant challenges in properly assessing resiliency investments. Black & Veatch observes that some of the urgency around resiliency investments and evaluation techniques has been driven by perceptions of new risk levels brought on by long term climate change and other emerging risk factors. Similarly, technological and lifestyle developments have led to an increase in society's dependence on the continuous availability of reliable electric and gas utility service, to support heating, lighting, communications, the flow of cyber information, and other indispensable elements of our daily, public life.

From the industry's perspective, there is growing concern about and interest in enhanced resiliency. In addition, new technologies, market arrangements, and data analytics provide an increased set of options to understand and address risks. However, there are no standardized frameworks for assessing resiliency levels, including specific cost-benefit techniques, making it difficult to determine optimal levels of investment or of establishing the relative merits of various alternative pathways.[25] As EPRI concludes:

> The scale and risk characteristics of… high-impact, low frequency risks… can be very challenging to analyze. Moreover, there is no unifying perspective or framework for cost-benefit analysis of resiliency efforts, though there is much interest in advancing the state-of-the-art.[26]

[25] Electric Power Research Institute (EPRI). *Electric Power System Resiliency: Challenges and Opportunities*, Rep. 3002007376. February 2016, p. 45. https://www.epri.com/#/pages/product/000000003002007376/. Many of EPRI's observations concerning resiliency valuation challenges pertain to both gas and electric sectors.
[26] Ibid.

Black & Veatch acknowledges these challenges. Moreover, it acknowledges that traditional approaches of evaluating the value of investments in low probability circumstances sometimes involve expected value techniques where models are established to try to identify and value a full range of potential scenarios and their outcomes. As noted earlier, Black & Veatch does not believe this provides meaningful guidance, as the enormity of the impacts that could result can be undervalued.

Figure 3 has been prepared to explain different phases of the outage event in conceptual terms. The *Gas Outage Event* refers to the upstream gas supply pipeline event. The *Restoration Period* covers PSE&G's efforts to restore the system after the outage event has concluded. The *Curtailment Period* is intended to represent the entire length of time customers experience a loss of gas service. These terms – Outage Event, Restoration Period, and Curtailment Period – are used in describing the scenario.

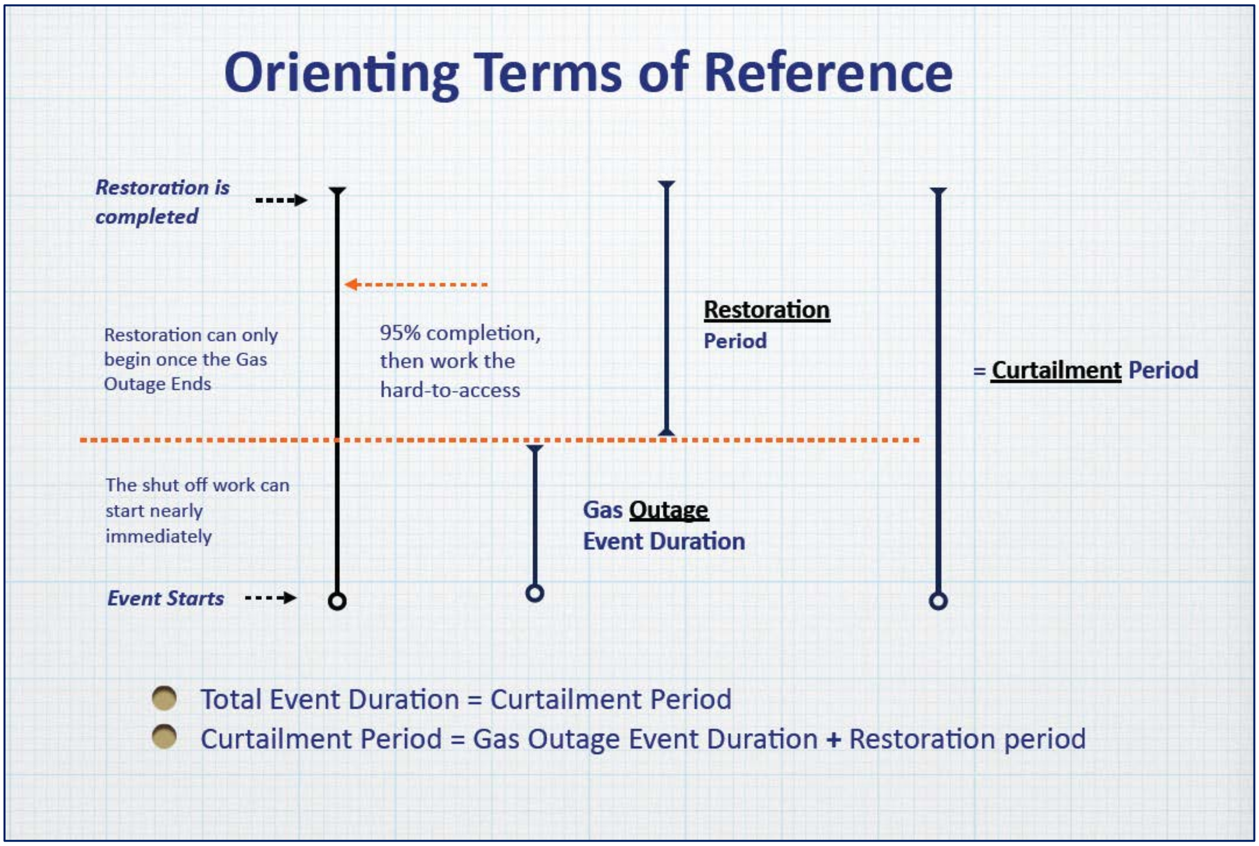


Figure 3 Outage Event Terminology

Multiple-Day Gas Outage Event

In light of the premises enumerated earlier, and in particular those established in items 2 and 5, Black & Veatch recommended the following characteristics of the outage event scenario, for purposes of applying them to the cost-benefit analysis for the Curtailment Resiliency Subprogram:[27]

[27] See Figure 3 for an explanation of the key terms referred to in this section.

- Assume: Gas outage event duration of ten (10) days. This is the time period during which the particular interstate pipeline system is out of service. PSE&G would not have any advanced notice of this event, and would not know for many hours the specific circumstances of the incident, or any estimate of the time to repair the system and restore service.

- Following this event, PSE&G would work to shut down and secure the distribution system affected by the gas outage. This work begins nearly immediately. It is necessary to secure (i.e. physically isolate) the affected portion distribution system and thereby shut off gas service to customers prior to any effort to restore service.

- Once the Gas Outage Event has ended, PSE&G would begin the restoration work. The duration of the restoration period is a specific output of the Black & Veatch evaluation effort and is based on many inputs about outage event circumstances and PSE&G labor resources.

- An average daily temperature of 30^0F was assumed throughout the duration of the curtailment period. By way of comparison, the range of average daily temperatures during the winter months of December through February in Newark, New Jersey has been: 30^0F - 44^0F in December, 24^0F - 39^0F in January, and 27^0F - 42^0F in February.[28] These ranges provide the *normal* minimum and maximum temperatures based on weather data collected from 1981 to 2010 by the US National Climatic Data Center, part of the National Oceanic and Atmospheric Administration (NOAA).[29] Additionally, according to data compiled by NOAA for the Liberty International Airport temperatures from 1981 to 2010, for the 90-day period December 1 to February 28, the average minimum achieved temperatures have been less than 30^0F on 79 of these days. While daily temperatures fluctuate, it is common that during these months temperatures will range below 30^0F.[30]

- The gas outage occurs on the Texas Eastern/Algonquin Gas Transmission (Algonquin) interstate pipeline systems (one of PSE&G's largest interstate pipeline suppliers). These systems are part of the larger Enbridge interstate pipeline system.

- The gas outage occurs outside of, and upstream of, the state of New Jersey.

- Third-party supplies will be curtailed by PSE&G, consistent with the amounts they would have delivered on Texas Eastern.

- All other interstate pipeline systems with facilities within New Jersey are operable and have the ability to flow the required gas volumes within PSE&G's current contract limits, including third-party supplies.

- PSE&G's existing LNG and Liquid Propane Gas (LPG) peak shaving supplies and its proposed new LNG facility are all utilized starting on Day 1 of the gas outage, and are fully depleted by the end of Day 15. Storage volumes are assumed to be full at the beginning of the outage period.

[28] U.S. Climate Data for Newark, New Jersey available at: https://www.usclimatedata.com/climate/newark/new-jersey/united-states/usnj0355.
[29] This information is provided by Weather.com. It references data provided by the NOAA. Data is available at: https://www.currentresults.com/Weather/New-Jersey/temperature-january.php.
[30] This information is gathered from data available at NOAA: https://www.ncdc.noaa.gov/cdo-web/.

Black & Veatch believes the 10-day Gas Outage Event duration is reasonable, and reflects recent gas outage experiences on other interstate pipeline systems. Moreover, this outage event includes support from PSE&G's new LNG plant proposed under the ES II Curtailment Resiliency Subprogram, operating in conjunction with PSE&G's existing peak shaving plants.[31]

Summary Results of the Gas Outage Event

The results of PSE&G's gas outage analysis conducted under Black & Veatch's gas outage scenario are formalized around two specific conditions (or scenarios): (1) the Business-as-Usual (BAU) scenario which estimates the gas outages that would occur <u>without</u> the inclusion of the ES II Curtailment Resiliency Subprogram investments; and (2) the ES II scenario which estimates the number of gas outages that would occur <u>with</u> the inclusion of the ES II Curtailment Resiliency Subprogram investments. The resulting difference between these two scenarios represents the number of customer outages that would be <u>avoided</u> as a result of the Curtailment Resiliency Subprogram investments.

Under the BAU scenario, PSE&G estimates that 177,132 gas customers would lose firm gas service under the above described gas outage scenario. Under the ES II scenario, no customers would lose firm gas service.[32]

As explained in further detail later in this report, the initial gas outage causes a loss of firm gas service to approximately 129,000 gas customers. By the end of Day 4 of the Curtailment Period, this amount grows to 177,132 firm gas customers. The two step result is due to the depletion of local supplemental supplies that support the outage area.

COST-BENEFIT ANALYSIS METHODOLOGY FOR THE M&R UPGRADE SUBPROGRAM

The M&R station upgrades proposed by PSE&G are justified on several cost-beneficial grounds. PSE&G has identified the various risk reduction benefits associated with M&R station replacement based on the lifecycle of these stations and the station asset risk evaluations.[33] Support for these lifecycle risks is not reflected in Black & Veatch's cost-benefit analysis.

The focus of the cost-benefit analysis in relation to the M&R stations has been mainly to identify all of the qualitative benefits that result from the station upgrades. The benefits include flood-related, outage hazard reduction benefits for two of the seven M&R stations. The cost-benefit analysis also recognizes the avoided costs provided by the ES II Gas Program in relation to three of these stations, and performs a present value calculation for these avoided costs.

[31] As explored in the sensitivity analyses, the proposed LNG plant provides valuable support to PSE&G's gas distribution system for an additional two days during a gas outage of longer duration once its peak shaving resources are fully depleted. The specific extent of this support is also a function of the Curtailment Period duration, and the specific decisions that PSE&G makes on how to dispatch each of these facilities.

[32] All interruptible customers are 100% curtailed during the gas outage event. No additional load curtailment -- as prescribed in PSE&G's Gas Emergency Procedures and NJAC Title 14, Chapter 29 -- was considered for this assessment.

[33] The direct testimony of Wade Miller describes PSE&G's evaluation of these M&R stations. "The purpose is to modernize M&R Station designs, reduce the likelihood and consequence of equipment failure, and, in two of the seven stations, harden against flooding events. PSE&G has analyzed asset demographics, failure curves, and risk scoring for all its M&R assets, similar to its efforts in PSE&G's electric distribution assets."

Company Profile and PSE&G's Gas System Operational Needs

COMPANY/CORPORATE DESCRIPTION

PSE&G is a combined electric and natural gas distribution company that provides regulated retail natural gas services to approximately 1.8M residential, commercial and industrial customers. PSE&G currently serves nearly three quarters of New Jersey's population (with a state population of approximately 8.8M inhabitants[34]) in a service area consisting of a 2,600 square mile diagonal corridor across the state from Bergen to Gloucester Counties and in more than 300 urban, suburban and rural communities, including New Jersey's six largest cities. PSE&G is regulated by the BPU.

PSE&G is one of four major natural gas utilities operating in the state of New Jersey (Figure 4). The other natural gas utilities in New Jersey are:

- Elizabethtown Gas (an AGL Resources Company).
- New Jersey Natural Gas Company (New Jersey Natural Gas).
- South Jersey Gas Company (South Jersey Gas).

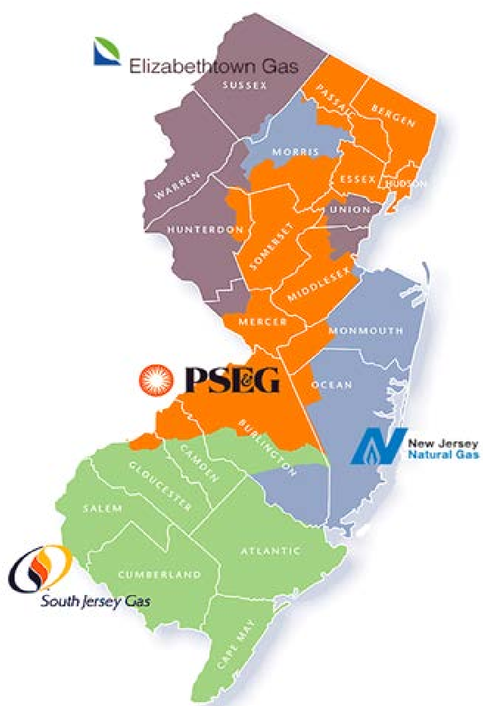


Figure 4 Natural Gas Utilities Operating in New Jersey

[34] Source is the 2010 US Census. https://www.census.gov/2010census/popmap/ipmtext.php?fl=34.

PSE&G'S GAS SYSTEM

As of December 31, 2016, PSE&G's gas system includes more than 17,800 miles of gas mains, 12 gas distribution headquarters, two sub-headquarters, and one meter shop serving all of its gas territory in New Jersey. In addition, PSE&G operates 58 natural gas metering and regulating stations of which 22 are located on property owned by customers or interstate pipeline companies and are operated under lease, easement or other similar arrangement. In some instances, the interstate pipeline companies own portions of the M&R station facilities. PSE&G also owns and contracts to use certain peak shaving facilities.

PSE&G's gas distribution system network is composed of mains and service lines in pipe sizes ranging from 1/2" to 42" in diameter and composed of plastic, steel, and cast iron materials. PSE&G receives odorized gas from city-gate stations, where gas volumes are measured and the pressure is reduced to the distribution levels. PSE&G operates an integrated gas distribution network comprised of four pressure levels: Utilization Pressure (UP, approximately 0.25 psig[35]) and four Elevated Pressures levels (EP, 15 psig, 60 psig, 120 psig, and above 120 psig, respectively). The total miles for each of the distribution systems and construction materials are summarized in Table 2 below.

Table 2 Inventory of PSE&G Distribution Mains by Operating Pressure (Expressed in Miles)

DISTRIBUTION MAINS (1)					
		ELEVATED PRESSURE (EP)			
MILES	UTILIZATION PRESSURE (UP)	15 PSIG	60 PSIG	120 PSIG	OVER 120 PSIG
Cast Iron	3,294	438	57		
Steel	494	1,683	3,532	128	12
Plastic	543	2,482	5,191	2	
Other	1	4	3		
Total	4,332	4,606	8,783	130	12
(1) Miles at the end of 2016					

PSE&G'S CONTRACTED FIRM DELIVERED GAS CAPACITY

Physically, PSE&G's gas system is connected to and supplied by five interstate pipeline systems: Texas Eastern Transmission (Texas Eastern), Algonquin Gas Transmission (Algonquin)[36], Transcontinental Gas Pipeline (Transco), Tennessee Gas Pipeline (Tennessee), and Columbia Gas Transmission (Columbia). In addition to the LNG and LPG peak shaving plants owned and operated by PSE&G, additional LNG peak shaving capacity is contracted through Transco.

[35] Pounds per square inch gauge (PSIG).
[36] Texas Eastern and Algonquin are both owned and operated by Enbridge, Inc.

Based on the design day[37] requirement to serve its firm gas customers, PSE&G has contracted for approximately 2,525 MDth per day[38] of firm transportation and storage capacities on the interstate gas pipeline system for the 2016-2017 winter period. In addition, PSE&G owns and operates peaking capacities of approximately 265 MDth per day, consisting of 67 MDth per day of LNG and 197 MDth per day of LPG. The contracted firm transportation, storage, and peaking capacities ensure PSE&G's continued ability to provide reliable services to its firm customers.

PSE&G delivers an annual average of approximately 450 Bcf of natural gas to its customers. A tabular summary of the percentage of gas volumes supplied through each of the interstate pipelines and peaking facilities is provided in Table 3.

Table 3 PSE&G Contracted Firm Delivered Gas Capacity (inclusive of Third Party Supply) by Interstate Pipelines and Peaking Facilities

INTERSTATE PIPELINES AND PEAKING FACILITIES	PERCENT OF GAS SUPPLY
Enbridge (Texas Eastern and Algonquin gas transmission systems)	32
Transco – Leidy*	17
Transco – Gulf *	28
Tennessee	5
Columbia Gas	1
Peaking supplies – LNG and LPG	17

*The Transco pipeline system is treated as two separate delivery systems due to the separate geography of the Leidy and Gulf Systems. The Transco-Leidy system is sourced from the Pennsylvania area and the Transco-Gulf system is sourced from the Gulf of Mexico area. They deliver gas into the PSE&G system at different locations.

THE INTERSTATE PIPELINE SYSTEMS SERVING NEW JERSEY

The five interstate pipeline systems serving PSE&G and other gas distribution utilities in New Jersey represent major components of the United States natural gas delivery infrastructure. The Tennessee, Texas Eastern and Transco pipeline systems bring gas supplies to the Northeast, including New Jersey, from Texas, Louisiana, and the Gulf of Mexico. The Tennessee pipeline system, unlike the Transco and Texas Eastern systems, extends its service northward as far as New Hampshire and is a major transporter of natural gas to Connecticut, Massachusetts, and Rhode Island.

The Tennessee pipeline system is also a source of supply for the regional Algonquin pipeline system which is the principal interstate pipeline serving the Boston, Massachusetts area. The Texas Eastern

[37] A design day for a gas distribution utility is a 24 hour period of the greatest theoretical gas demand, used as the basis for designing purchase contracts, production facilities, and delivery system capacity.
[38] This amount excludes approximately 318 MDth per day of anticipated peak day third party deliveries of gas which is used to supply PSE&G's end-use transportation service customers, and includes approximately 275 MDth per day of LNG peaking capacity contracted through Transco.

pipeline system is the primary source of supply for the Algonquin pipeline system, delivering approximately 65 percent of Algonquin's requirements at interconnections in New Jersey. The Algonquin pipeline system (1,100 miles in length) has the capability to move 1.5 Bcf of gas per day of its 3.3 Bcf per day system capacity from New Jersey into the New York metropolitan area. The Transco pipeline system consists of approximately 10,200 miles of transmission lines, extending from South Texas to New York City, is a major supplier to the northeastern and southeastern states. It has a design capability to move approximately 14 Bcf of gas per day.

The largest interstate natural gas pipeline system operating in the region is Columbia. The Columbia system consists of approximately 11,300 miles of transmission lines and delivers an average of approximately 3.0 Bcf of gas per day. This pipeline system has an extensive network of natural gas pipelines that provide service in the region to the States of Maryland, New Jersey, New York, Pennsylvania, Virginia, and West Virginia, but also extends into Ohio in the Midwest and Kentucky and North Carolina in the Southeast Region. Columbia receives Gulf of Mexico natural gas at the Kentucky border from its major trunk line transporter, Columbia Gulf, but it also transports Appalachian (regional) production as well.

To illustrate the geographic extent of these interstate pipeline systems, Figure 5 presents a simplified map of the Texas Eastern interstate pipeline system.

Figure 5 **Simplified Map of the Texas Eastern Interstate Pipeline System**

The interstate pipelines serving PSE&G enter into New Jersey at multiple points and connect to PSE&G's gas distribution system at various city gate locations throughout PSE&G's service territory. The Texas Eastern pipeline system has 9,096 miles of pipeline and connects Texas and the Gulf

Coast with high demand markets in the northeastern U. S. Texas Eastern can transport 11.7 Bcf per day and has available approximately 74 Bcf of gas storage. Texas Eastern also connects to the Algonquin pipeline system in New Jersey. Figure 6 presents a map of the five interstate pipeline systems supplying PSE&G (as well as the other gas distribution utilities located in New Jersey).

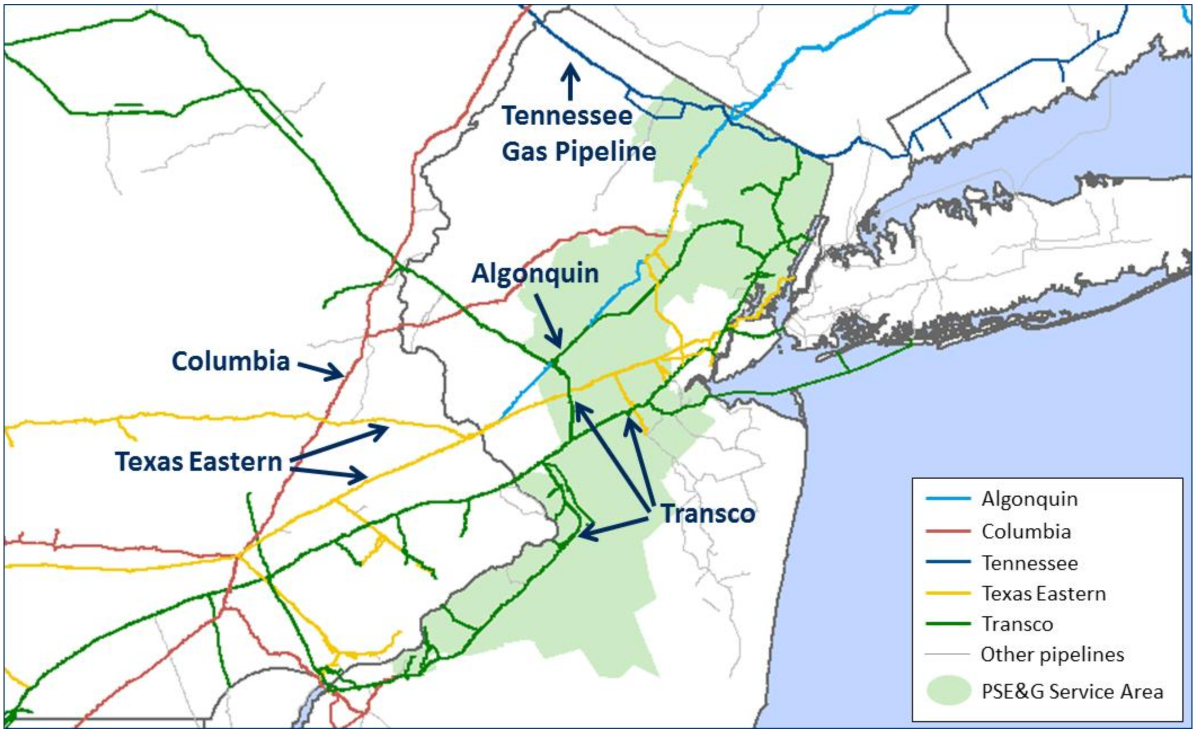


Figure 6 Map of the Five Interstate Pipeline Systems Serving PSE&G

(Source: Velocity Suite, ABB Enterprise Software)

Texas Eastern has multiple interconnection points with PSE&G through the center portion of its service territory as is shown in Attachment 1, Schedule WEM-ESII-4 accompanying Wade Miller's Direct Testimony in PSE&G's ES II Program filing.

PSE&G'S OBLIGATION TO SERVE, GOALS AND OBJECTIVES

PSE&G has an obligation as a utility to provide "safe, adequate, and proper" service pursuant to N.J.S.A. 48:2-23 and the BPU rule at 14:3-3.1N.J.A.C. 14:3-3.1. Black & Veatch understands PSE&G is of the view that BAU meets the safe, adequate, and proper standard. PSE&G's proposed proactive investments identified in the ES II Gas Program will address risks and concerns addressed herein, address the investment objectives identified in the IIP rule, and are important for PSE&G to continue to provide the high quality of service that it is historically known to provide.

As part of PSE&G's objective to continue to provide quality service, it has the ongoing business objective of making certain its natural gas system is resilient, reliable, and sufficiently reinforced to provide uninterrupted gas service to its firm customers during all types of extreme weather and disruptions in an efficient, economic, and safe manner despite the aging of its system. To meet the forgoing objectives, PSE&G proposed the M&R Upgrade Subprogram in the ES II Gas Program to meet the challenges of aging plant and weather.

In conjunction with its evaluation of these objectives, PSE&G has identified a particular aspect of resiliency that it believes warrants further attention as a fundamental part of the ES II Gas Program – specifically gas pipeline supply resiliency. For a gas distribution utility such as PSE&G, this gas system characteristic is directly related to the ability of its gas pipeline suppliers to provide firm gas deliverability to the gas utility's city-gate locations up to the maximum contracted levels to satisfy the gas demand requirements of its firm customers. The gas outage events experienced on interstate pipeline systems identified earlier underscore the need for a gas distribution utility to be mindful of its gas supply deliverability risks and the need for potential mitigation strategies to enhance supply resiliency. To meet the objective of supply resiliency, PSE&G has proposed its Curtailment Resiliency Subprogram.

PSE&G'S CURRENT OPERATIONAL NEEDS

With its operational goals and objectives as context, PSE&G concluded that it was necessary and appropriate to reevaluate its gas system resiliency. Of particular concern was the Delmont, Pennsylvania outage incident on the Texas Eastern system described above. This outage had a direct impact on PSE&G's natural gas operations. As part of its reevaluation, PSE&G conducted a vulnerability analysis to address the potential for gas supply curtailments with its interstate pipeline suppliers. This analysis examined the utilization of each interstate pipeline serving PSE&G to determine if it would be able to continue to supply gas to all of its firm customers depending upon gas demands and the extent and duration of the interstate pipeline curtailment.

For each of its five interstate pipeline suppliers, PSE&G simulated the operation of its gas distribution system to minimize the supply requirements from each pipeline system, one at a time, while maintaining the system operation in accordance with PSE&G's minimum gas pressure requirements. The resulting system gas volume requirements were totaled and compared to the maximum available contract volumes, including gas supplies from third parties. This analysis was conducted for conditions simulating average daily temperatures of 30° F, 20° F, 10° F, and 5° F. If the gas supplies required to provide service to PSE&G's firm customers from an individual pipeline system could not be completely replaced, then the resulting volume of gas utilized was considered PSE&G's limit of gas pipeline supply resiliency.

As would be expected for a gas distribution utility such as PSE&G, the analysis showed that PSE&G is more vulnerable to interstate gas pipeline curtailments at times of higher customer gas usage, namely during the gas industry's winter heating season – the 151 days during the months of November through March. The temperatures used by PSE&G in this analysis regularly occur in its service territory during that colder seasonal period. [39]

Table 4 presents the estimated level of firm customers who would lose gas service if a 100 percent curtailment lasting one day occurred on one of PSE&G's interstate pipeline suppliers during the 2016-2017 winter season. In interpreting Table 4, it should be noted that PSE&G has full resiliency against a gas outage event on the Columbia pipeline system because the gas volume delivered into PSE&G's gas system is a small amount compared to its total gas deliveries and the parts of PSE&G's service territory served by Columbia gas supplies can be adequately supported by PSE&G's other pipeline suppliers. In contrast, PSE&G's other interstate pipeline suppliers cannot adequately

[39] This analysis and its results represents step 1 of a two-step analytical process. PSE&G conducted its *Gas Supply Curtailment Vulnerability* analysis, as described in this section, and as summarized in Table 4. Step 2 consisted of PSE&G performing a specific and more detailed assessment of the gas outage scenario on the Enbridge interstate pipeline system. Black & Veatch then used the results of step 2 in its benefit evaluation analysis.

support a gas outage event on the Tennessee pipeline system because this pipeline system supplies gas to serve customers in the northern portion of PSE&G's service territory which is relatively isolated, making access to PSE&G's other interstate pipeline suppliers infeasible.

While Table 4 presents the estimated number of customer outages in the event the various interstate pipeline systems become unavailable, it also demonstrates the relative and high degree of curtailment resiliency that exists today in PSE&G's gas distribution system. In fact, under BAU conditions, Table 4 demonstrates that the configuration of PSE&G's existing gas distribution system and its current pipeline capacity levels can largely withstand significant gas outage events on any of its interstate pipeline suppliers. However, if the nature of the gas outage event creates a level of gas curtailments that exceeds PSE&G's resiliency threshold, as portrayed in Table 4, firm customers would be at risk of losing gas service at a time of greatest need and would be unable to meet critical gas requirements such as space heating. From that point forward, there would be additional days without gas service for those customers that were curtailed by PSE&G as it works to restore gas service to each individual premise; this is a very time-consuming and expensive process, as will be explained in greater detail later in this report.

Table 4 PSE&G's Gas Supply Curtailment Vulnerability[40]

	POTENTIAL NUMBER OF FIRM CUSTOMERS WITHOUT GAS SERVICE[41]				ESTIMATED NUMBER OF FIRM CUSTOMERS NORMALLY SERVED[42]
	AVERAGE DAILY TEMPERATURE				
Interstate Pipeline System with Gas Outage	**5° F**	**10° F**	**20° F**	**30° F**	
Enbridge (Texas Eastern and Algonquin)	407,000	292,000	197,000	129,000	809,000
Transco Leidy	332,000	215,000	0	0	569,000
Transco Gulf	94,000	0	0	0	364,000
Tennessee	50,000	49,000	43,000	37,000	139,000
Columbia	0	0	0	0	0
Total					**1,881,000**

[40] PSE&G's gas supply curtailment vulnerability analysis was premised upon a single day gas outage and an individual assessment of customer gas curtailments on each interstate pipeline system with all other pipeline suppliers continuing to provide the contacted level of gas deliverability required by PSE&G.
[41] All interruptible customers are 100% curtailed during the gas outage event. No additional load curtailment -- as prescribed in PSE&G's Gas Emergency Procedures and NJAC Title 14, Chapter 29 -- was considered for this assessment.
[42] The customer values shown are approximate since there is a degree of fungibility in serving customers between the Texas Eastern, Transco and Tennessee pipeline systems, so the amounts shown represent only one possible combination.

Most importantly, once customers have lost gas service, they will not be restored until the gas outage event and gas curtailments from the affected interstate pipeline supplier have ended, or at least improved, either by some level of supply restoration or a lowering of gas demands due to moderating temperatures.[43]

PSE&G has an ongoing obligation to provide safe and adequate gas service to its firm service customers. The projects PSE&G has included in its proposed ES II Gas Program support these obligations. These projects are described below.

Curtailment Resiliency Subprogram

This subprogram consists of five proposed distribution facility projects that are designed to provide PSE&G with additional gas system resiliency by moving gas supplies across its service territory between areas served by its different interstate pipeline systems. An additional LNG facility is designed to inject additional gas into PSE&G's gas system during a time of curtailment. These six projects are designed to continue serving firm gas customers to the extent possible for those areas of the service territory that could be most affected by a gas outage event. As presented in the direct testimony of Wade E. Miller, the six projects are as follows:

1. **Project 1: Central - South Plainfield:** PSE&G proposes to modify the Central (Edison) M&R station to add a 600 psi alternate supply line to PSE&G's Woodbridge-Central transmission system and a new 120 psi distribution system. Under this proposal, this new 24" 120 psi system would extend 5.4 miles from Central M&R station towards the South Plainfield M&R station. A new 120psi/60psi regulator station would be installed in the vicinity of Stelton Road and New Brunswick Avenue in South Plainfield. This project would provide the ability to move Transco gas from the Central M&R station into an area supplied by Texas Eastern from the South Plainfield M&R station. Additionally, through the connection to PSE&G's Woodbridge-Central transmission system, the project enables the movement of Transco gas into another area supplied by Texas Eastern at PSE&G's Sayreville regulating station.

2. **Project 2: Hamilton - West Windsor**: PSE&G proposes to extend its existing 150 psi distribution line 11.5 miles from Hamilton Township to West Windsor Township. The project would consist of 1.5 miles of 24" diameter pipe and 10 miles of 20" diameter pipe. Two new 150psi/60psi regulator stations would be installed off this new 150 psi system in the vicinity of White Horse Avenue & Kuser Road, Hamilton Township, and US Route 1 & Alexander Road, West Windsor Township. This project would provide the ability to move Transco gas from the Hamilton M&R station into an area supplied by Texas Eastern from the Hillsborough M&R station and from the Jamesburg M&R station.

3. **Project 3: Mahwah-Paramus-Wanaque**: PSE&G proposes to modify the Mahwah M&R station and Wanaque M&R station. PSE&G also proposes to add a new joint 120 psi system that will tie-in to the existing 120 psi system out of the Paramus M&R station to create one interconnected 120 psi system between the Mahwah, Paramus, and Wanaque M&R stations. In order to accomplish this, PSE&G would need to construct large diameter 120 psi distribution main across its northern territory to connect the stations. In addition, PSE&G

[43] The gas utility would have to feel confident that the rising temperatures will hold to safely engage in the restoration work. If temperatures drop, demand would increase, and there would be additional gas outages.

proposes extending the existing Hanover Roseland 120 psi system. The following would be included under this project :

- 11.1 miles of 24" main would be installed from Mahwah M&R station to PSE&G's existing Glen Rock 120psi/15psi regulator stations off the existing Paramus 120 psi line. Three new regulator stations would also be installed off this new 120 psi line. Two would feed into PSE&G's Northern 60 psi system in the vicinity of Hillside Avenue and Forest Road in Allendale, and North Central Avenue and Swan Street in Ramsey. The third new regulator station would feed into PSE&G's Northern 15 psi system in the vicinity of Goffle Road and Goffle Hill Road in Hawthorne.
- 10.2 miles of 24" main would be installed from Wanaque M&R station to the Glen Rock psi/psi regulator stations off the existing Paramus 120 psi line. One new 120 psi/60 psi regulator station would be installed in the vicinity of Willard Street and Ringwood Avenue in Pompton Lakes.
- 4.1 miles of 24" main would be installed from Wanaque M&R station going west towards Kinnelon. A new 120psi/60psi regulator station would be installed in the vicinity of Keil Ave & Route 23, Kinnelon. The main would then be reduced in size to 12" steel and continue 7.2 miles towards PSE&G's West Milford system. A new 120psi/60psi regulator station will be installed in the vicinity of La Rue Road & Union Valley Road, West Milford.
- 4.5 miles of 12" main would be installed from Wanaque M&R station towards Ringwood M&R. A new 120psi/60psi regulator station would be installed in the vicinity of Greenwood Lake Turnpike. & Skyline Lake Drive., Ringwood.
- 0.7 Miles of 24" main would be installed from Paramus M&R station going north from the station. A new 120psi/15psi regulator station would be installed in the vicinity of Spring Valley Road. & Forest Avenue., Paramus.
- In addition, PSE&G would extend its existing Hanover-Roseland 120psi system by installing 5.1 miles of 20" main north towards Little Falls. A new 120psi/15psi regulator station would be installed in the vicinity of Furler Street & Union Boulevard, Totowa.

This project would provide the ability to move Transco gas from the Paramus M&R station page and/or Texas Eastern gas from the Wanaque M&R station into an area supplied by Tennessee from the West Milford M&R station, Ringwood M&R station and the Mahwah M&R station. This project would also provide the ability to move Transco gas from the Paramus M&R station and the Roseland M&R station and/or Tennessee gas from the Mahwah M&R station into an area supplied by Texas Eastern from the Wanaque M&R station. Finally, this project would provide the ability to move Texas Eastern gas from the Wanaque M&R station and/or Tennessee gas from the Mahwah M&R station into an area supplied by Transco from the Paramus M&R station and will mitigate a supply curtailment on any of these pipeline systems.

4. **Project 4: Sayreville - Jamesburg**: PSE&G would modify the Sayreville M&R station and add a new 20" 120 psi system that would extend 10.3 miles between the Sayreville M&R station and the Jamesburg M&R station. In addition, a new 120psi/60psi regulator station would be installed in the vicinity of Ridge Road and Cranbury South River Road in South Brunswick Township. This project would provide the ability to move Transco gas from the

Sayreville M&R station into an area normally supplied by Texas Eastern from the Jamesburg M&R station.

5. **Project 5: Bernards-Gillette-Parsippany-Chatham-Bridgewater**: The Bernards, Gillette, Parsippany, Chatham and Bridgewater M&R stations would be modified and new 120 psi distribution systems would be added. PSE&G would need to construct large diameter 120 psi distribution mains across its northern territory from these stations. The following would be included:

   - 7.3 miles of 12" main would be installed from Parsippany M&R station going southwest towards the Bernards/Gillette 60 psi system. One new 120psi/60psi regulator would also be installed off this new 120 psi line. It would feed into PSE&G's Bernards/Gillette 60 psi system in the vicinity of US-24 & Glen Gary Drive in Mendham Township.
   - 3.5 miles of 12" main would be installed from Chatham M&R station going west. One new 120psi/15psi regulator would also be installed off this new 120 psi line. It would feed into PSE&G's Northern 15 psi system in the vicinity of Blue Mill Road & Spring Valley Road, Chatham Township.
   - 7.2 miles of 24" main would be installed between the Bernards and Gillette M&R stations. Two new 120psi/60psi regulators would be installed near each station, feeding into the Bernards/Gillette 60 psi system. The 120psi/60psi regulators would be installed in the vicinity of US-202 and Childs Road, Bernardsville and Morristown Road & Valley Road, Long Hill Township.
   - 3.2 miles of 12" main would branch off the 24" installed between Bernards and Gillette M&R stations and proceed southwest to an additional 120psi/60psi regulator feeding into the Bernards/Gillette 60psi system. This 120psi/60psi regulator would be installed in the vicinity of Lyons Road & Church Street, Bernards Township.
   - 6.6 miles of 12" main would be installed from Bridgewater M&R stations going north. One new 120psi/60psi regulator would also be installed off this new 120 psi line. It would feed into the Bernards/Gillette 60 psi system in the vicinity of US-206 & Hills Drive, Bedminster Township.

   This project would provide the ability to move Transco gas from the Gillette M&R station, Chatham M&R station, and Bridgewater M&R station and Columbia gas from the Parsippany M&R station into an area supplied by the Algonquin Gas Transmission pipeline from the Bernards M&R station and the Morris M&R station. This project would also provide the ability to move Algonquin gas from the Bernards M&R station into an area supplied by Transco from the Gillette M&R station.

6. **PSE&G's Proposed LNG Project Under its Curtailment Resiliency Subprogram**: An LNG facility with the ability to deliver 50.0 MDth per day would be constructed at PSE&G's property in Linden, NJ or PSE&G's property in Edison, NJ. This facility can supplement 50.0 MDth per day for either Enbridge or Transco curtailment.

It is important to understand how the value of enhanced supply resiliency for PSE&G's gas distribution system is created by each of these projects during a gas outage event on one of PSE&G's interstate pipeline suppliers. To illustrate this concept, Figure 7 graphically depicts a gas outage on the Enbridge interstate pipeline system and how the various projects included in PSE&G's

Curtailment Resiliency Subprogram contribute to maximizing the number of firm customer outages avoided during the gas outage.

For example, Projects Nos. 1 through 4 enable gas volumes supplied by the Transco interstate pipeline system (the Alternative Supplier) to be moved into the areas of PSE&G's gas distribution system normally supported by the Enbridge interstate pipeline system (the Texas Eastern portion) to continue providing firm gas service to the customers in those areas. Figure 7 also shows that Project 3 can also enable gas volumes supplied by the Tennessee interstate pipeline system to be moved into one of those same areas of PSE&G's gas distribution system to minimize the number of firm customer curtailments. This dual capability with Project No. 3 highlights the increased operational flexibility this project provides to PSE&G during a gas outage event on the Enbridge interstate pipeline system which serves to enhance its overall supply resiliency.

Similarly, there is another project (Project No. 5) which can serve a similar function during an Enbridge gas outage by enabling gas supplies from the Columbia or Transco interstate pipeline system to be moved into the area of PSE&G's gas distribution system supplied by Enbridge's Algonquin interstate pipeline system.

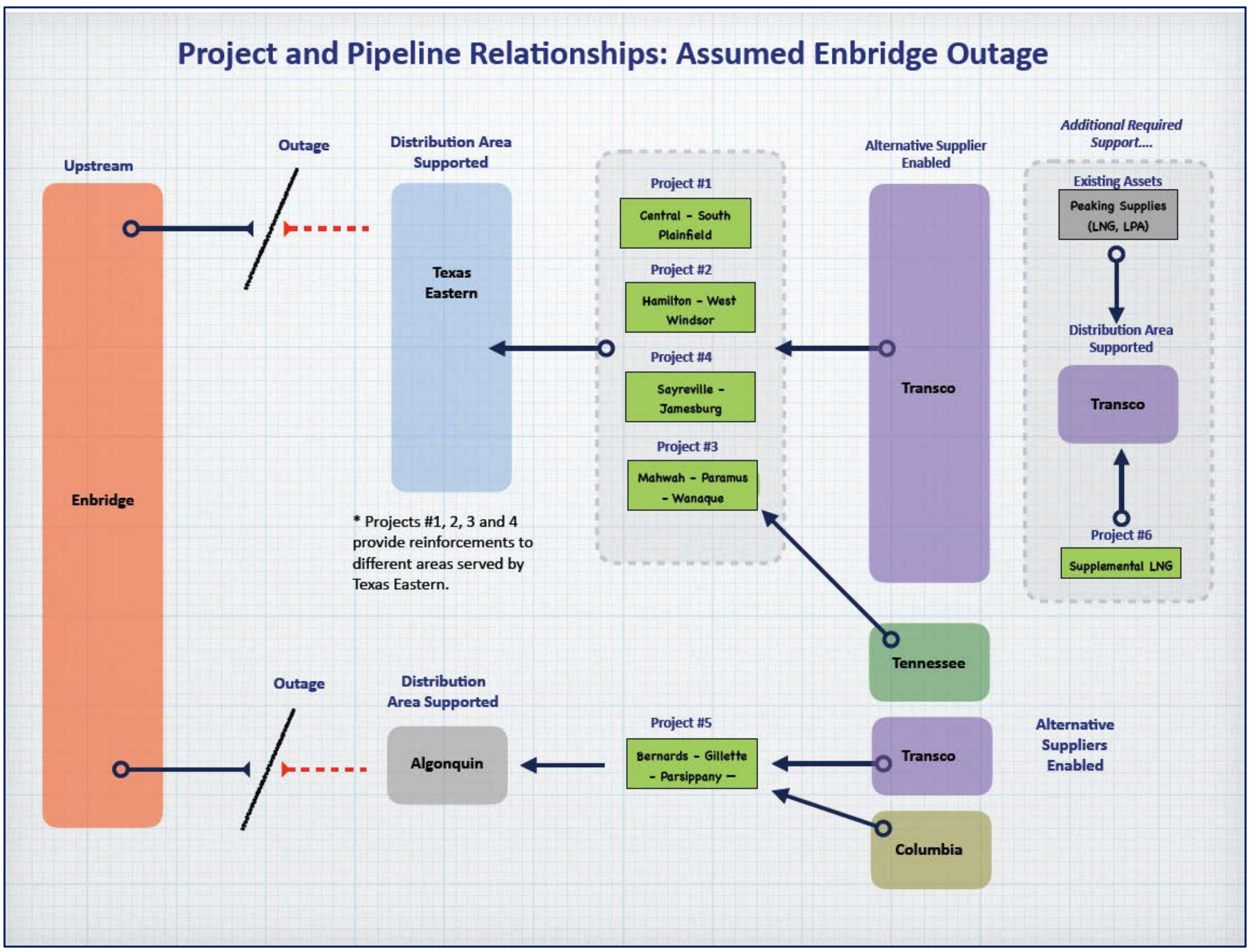


Figure 7 **Illustration of Individual Roles of Curtailment Resiliency Subprogram**

M&R Upgrade Subprogram

This subprogram consists of the rebuilding of seven M&R stations. Their designs are outdated and their equipment and structures are aging. Two of the stations are located in areas designated by FEMA as within the 100 year flood zone and, therefore, could flood under heavy rain or storm surge conditions. PSE&G's Camden, East Rutherford, Central, Paramus, Westampton, Mt. Laurel, and Hillsborough M&R Stations are included in the proposed ES II M&R Upgrade Subprogram. Station selection was based on PSE&G's use of an asset risk model, which scored and ranked the M&R stations using risk-based criteria. This approach provided an objective basis to make the selections for the ES II Gas Program.

RESILIENCY AND RELIABILITY NEEDS ADDRESSED BY OTHER GAS UTILITIES

There are a number of natural gas industry examples where other gas distribution utilities have planned, or undertaken, gas system infrastructure projects to address similar resiliency and reliability needs as those being addressed by PSE&G in its ES II Gas Program. Two are highlighted below, and additional examples from Con Edison, SDG&E, SoCalGas, National Grid, NMGC - New Mexico, Spire STL Pipeline - St. Louis, and Vermont Gas Systems) are presented in Appendix C - Resiliency and Reliability Needs Addressed by Other Gas Utilities.

New Jersey Natural Gas Company's Southern Reliability Link Pipeline Project

In early April 2015, New Jersey Natural Gas Company ("NJNG") submitted separate applications with the BPU seeking a range of approvals associated with the construction and operation of its proposed Southern Reliability Link ("SRL") Pipeline, a 30-inch natural gas transmission main capable of providing NJNG with an alternate major source of natural gas for its customers in Ocean, Burlington, and Monmouth Counties. The proposed SRL Pipeline has been designed to support the safe and reliable distribution of natural gas to NJNG's customers. NJNG's gas system will be more resilient in the face of risks, and customers will be less exposed to the consequences of those risks.[44]

The SRL Pipeline will provide a major interstate pipeline connection between NJNG's distribution system that serves customers in the above three Counties and the Transco interstate pipeline system adjacent to the New Jersey Turnpike. By reinforcing NJNG's natural gas supply with a major feed from Transco into the southern end of its system, the SRL Pipeline will lower the risk of customer interruptions, improve system resiliency, and help ensure safe, reliable natural gas service for the region. Under the route approved by the BPU, the length of the SRL Pipeline will be approximately 30 miles.

South Jersey Gas Company's Proposed Pipeline Reliability Project

South Jersey Gas Company ("SJG") has proposed construction of a new 24" natural gas high pressure transmission pipeline to provide gas transportation service to the B.L. England ("BLE") power plant to enable the conversion of the facility from a coal and oil burning electrical generation

[44] The BPU in its Decision and Order of March 18, 2016 cites NJNG's testimony: (a) "Safety and resiliency are improved through *redundancy*…. The Project would allow NJNG to minimize service disruptions associated with potential interruptions, as well as to minimize costs associated with such interruptions" (emphasis added); (b) "The company further represents that, by creating a new redundant major feed, the Project will support safe, reliable, and resilient delivery of natural gas to its customers in Ocean, Burlington and Monmouth Counties" (Page 2). Furthermore, the BPU concluded that "NJNG, through its testimony and responses to interrogatories, has shown that the potential for an upstream supply interruption or disruption to its transmission backbone system exists" (Page 39). In other words, the Board found that the risks NJNG is responding to are real and not hypothetical.

power plant to one that burns natural gas. In addition, a portion of this pipeline, through a new interconnect with the SJG gas system, will be able to provide system reliability and reinforcement enhancements for its gas customers served in the south and east portions of its service area (specifically Cape May and Atlantic Counties).

Among the benefits of this project is a second transmission line that will allow service to be provided from an alternative direction in the event of a failure, reinforcing the South Jersey Gas system and providing customers with increased reliability. Approximately 142,000 customers in Cape May and Atlantic counties are currently served with just one natural gas transmission pipeline.

Benefits of PSE&G's Curtailment Resiliency Subprogram

CONTEXT FOR THE RISK OF GAS SUPPLY CURTAILMENT

A number of major gas outage events are described earlier in this Report. Additionally, and more broadly, during 2013 the U.S. Department of Energy through its Office of Electricity Delivery and Energy Reliability, Energy Infrastructure Modeling and Analysis Division conducted an analysis to assess the adequacy of natural gas pipeline capacity in the Northeast U.S.[45] This analysis examined the adequacy of the pipeline system to meet "essential human needs"[46] based on the near-term ability of the Northeast market to withstand outages of interstate pipeline capacity for up to one month during peak winter and summer demand periods.[47] PSE&G's gas distribution service territory falls within the scope of this study.

The study concluded there are two factors that determine the severity of a gas supply disruption's effects on the ability to meet the gas demands of essential human needs: (1) the size and duration of the pipeline disruption relative to the total in-bound capacity serving the affected region; and (2) the level of essential human needs' gas demands in the region. The study approach was designed to estimate how large of a disruption to in-bound pipeline capacity each market area could withstand and still supply natural gas to essential human needs customers.

Under much colder than normal January temperatures,[48] the study found that the New Jersey region could withstand a reduction in pipeline capacity of 36 percent from a gas disruption on the interstate pipelines serving the region and still meet the gas demands of essential human needs customers. In other words, if a pipeline disruption occurred during a much colder than normal weather condition, New Jersey gas distribution utilities would have to begin curtailing their essential human needs customers if the disruption was greater than 36 percent of the total contracted pipeline capacity serving the region.

It is important to emphasize that these results are not transferrable to the cost-benefit analysis prepared for PSE&G. These results are average values for the entire state of New Jersey. Additionally, the study evaluates total contracted pipeline capacity supporting all the utilities in the state and not specific gas outages occurring on a specific interstate pipeline that impact a particular gas distribution utility. Notwithstanding this limitation, for PSE&G, this type of study underscores the importance of evaluating on a periodic basis its vulnerability to the curtailment of gas supplies from its various interstate pipeline suppliers and the need to mitigate such risks if it is determined that outages to firm gas customers could result from a gas outage event such as the ones considered in this Report. Consistent with this evaluation need, the results of the most recent gas curtailment vulnerability analysis conducted by PSE&G is presented later in this Report.

[45] *Assessment of the Adequacy of Natural Gas Pipeline Capacity in the Northeast United States*, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability Energy Infrastructure Modeling and Analysis Division (November 2013*).*

[46] Essential human needs were defined in the study by the American Gas Association ("AGA") as gas demands including space and water heating for households, hospitals, nursing homes and buildings used to enhance public safety (e.g., fire and police stations).

[47] The DOE analysis examined ten (10) separate regions in the Northeast U.S., including New Jersey as a separate region.

[48] "Much Colder than Normal" temperatures were defined as average daily temperatures colder than 90 percent of observed January temperatures over the past 85 years.

OPERATIONAL ANALYSIS OF THE GAS OUTAGE EVENT

The cost-benefit analysis is based on the detailed evaluation of an upstream outage event. Once the gas outage event commences, PSE&G will immediately experience a drop in gas delivery pressures at its city-gate locations served by the Enbridge interstate pipeline system. Then, as the gas pressures and flows continue to decline, PSE&G will be required to compensate for this loss of gas supply and pipeline deliverability by attempting to reroute its existing contracted gas supplies and/or secure replacement gas supplies on the spot market. These supplies would be transported on other gas pipeline systems serving PSE&G to maintain and maximize gas deliveries to its gas system.

The temperatures experienced at the start of the gas outage event, the gas demand requirements of its firm service customers at the time of the event, and the duration of the event will all impact when and the degree to which PSE&G will be required to eventually curtail its firm customers due to insufficient gas flows in its distribution system. Temperature conditions are a major factor in determining gas demand at the time of the outage. The gas outage analysis[49] conducted by PSE&G identified the number of firm customers that would be expected to experience a gas curtailment. Details of the specific response activities of PSE&G and the expected impacts on its system, customers, and region are discussed in later sections of this Report.

Table 5 summarizes the results of PSE&G's gas outage analysis for the gas outage scenario related to the Enbridge interstate pipeline system.

Table 5 Results of PSE&G's Gas Outage Scenario Analysis

GAS SYSTEM CONDITION	NUMBER OF FIRM CUSTOMERS			
	Residential	Commercial	Industrial	Total
Firm Customers Out - *Business as Usual (BAU)*	162,500	13,000	1,632	177,132
Firm Customers Out – *With the Inclusion of the Curtailment Resiliency Subprogram Investments*	0	0	0	0
Customer Outages Avoided – *With the Inclusion of the Curtailment Resiliency Subprogram Investments*	162,500	13,000	1,632	177,132

As Table 5 indicates, PSE&G's proposed Curtailment Resiliency Subprogram results in the avoidance of a curtailment of gas service for approximately 177,132 firm customers under the gas outage scenario.[50] Without this Subprogram, these 177,132 firm customers would experience an

[49] The gas outage analysis conducted by PSE&G utilized the Synergi Gas Model developed by DNV-GL, a proprietary computer model that simulates the operation of PSE&G's gas distribution system under various assumptions of hourly and daily gas supply inputs and gas flows, customers' gas demand requirements, and gas system configurations.

[50] All interruptible customers are 100% curtailed during the gas outage event. No additional load curtailment as prescribed in PSE&G's Gas Emergency Procedures and NJAC Title 14, Chapter 29 was considered for this assessment.

outage of at least 10 days before accounting for gas restoration activities. More specifically, the projects included in PSE&G's Curtailment Resiliency Subprogram are designed to address areas of its gas distribution system that will maximize the number of firm customer outages that could be avoided.

Table 6 summarizes how each project included in PSE&G's Curtailment Resiliency Subprogram is designed to enhance the resiliency of its gas distribution system if PSE&G experiences a major gas outage on the Enbridge, Tennessee or Transco interstate pipeline system at different average daily temperatures based on a single day gas outage event.[51]

Table 6 Enhanced Resiliency Results under PSE&G's Proposed Curtailment Resiliency Subprogram[52]

PROJECT DESIGNATION		5° F	10° F	20° F	30° F
	Curtailed Pipeline System	Estimated Number of Gas Outages Avoided by Firm Customers			
Project 1: Central - South Plainfield	Enbridge	0	0	54,000	40,000
Project 2: Hamilton - West Windsor	Enbridge	0	0	35,000	38,000
Project 3: Mahwah-Paramus-Wanaque	Enbridge	0	0	49,000	55,000
	Tennessee	50,000	49,000	43,000	37,000
Project 4: Sayreville – Jamesburg	Enbridge	0	0	32,000	0
Project 5: Bernards-Gillette-Parsippany-Chatham-Bridgewater	Enbridge	0	0	24,000	18,000
Project 6: Supplemental LNG Facility at PSE&G's Linden or Edison Property	Enbridge	35,000	38,000	9.000	0
	Transco	35,000	38,000	0	0
Total – Enbridge		**35,000**	**38,000**	**203,000**	**151,000**
Total – Tennessee		**50,000**	**49,000**	**43,000**	**37,000**
Total – Transco		**35,000**	**38,000**	**0**	**0**

[51] The Table 6 results are from PSE&G's *Gas Supply Curtailment Vulnerability* analysis, which is step 1 of the 2-step analytical process. PSE&G performed additional system modeling as part of step 2, the results of which go into the Black & Veatch benefit evaluation analysis for the specific 10-day outage scenario on the Enbridge interstate pipeline system. The step 1 analysis explains the degree of relative vulnerability of PSE&G's gas distribution system in relation to each interstate pipeline. The step 2 analysis identifies the specific outage impacts of a 10-day outage event on one interstate pipeline system specifically.

[52] The customer outage results are based on a single day gas outage event and are rounded to reflect an average therm/day usage for all classes of Firm gas customers.

In contrast to the multi-day gas outage used in the analysis to prepare Table 5, the use of a single day gas outage to prepare Table 6 helped facilitate the detailed analysis of gas outages on each of the other major interstate pipeline systems supplying PSE&G, across a range of average daily temperatures during the winter period, to demonstrate the ability of certain projects (i.e., Projects 3 and 6) to move gas in multiple directions on PSE&G's gas distribution system depending on which of its interstate pipeline suppliers experienced a gas outage.

Table 6 shows that the Curtailment Resiliency Subprogram proposed by PSE&G will provide significant and long-lasting benefits to its firm gas customers as measured by the number of customers who will avoid losing gas service during a major gas outage on the Enbridge, Tennessee or Transco interstate pipeline system.[53] It should be noted that on the extremely cold days during which Table 6 shows zero gas outages avoided, the results would likely be improved (i.e., an increase in the number of gas outages avoided by firm customers) by an appeal to the public by PSE&G and governmental officials for increased conservation of natural gas during the outage event. Such appeals in these types of circumstances are specifically addressed in BPU rules.[54] Moreover, the LNG project is a gas supply on hand that can be utilized to address curtailments that may occur on multiple pipeline systems that serve PSE&G. The LNG plant provides diversity of supply as a specific proposed solution to a variety of potential curtailments.

Finally, it is important to emphasize that the above-described gas outage analysis is based upon a single outage occurrence. In reality, it is conceivable that multiple outage events could be experienced by PSE&G over the physical lives of these long-lived resiliency-related assets. This important consideration will be discussed later in this Report related to the expected level of benefits from PSE&G's Curtailment Resiliency Subprogram.

IMPACTS TO PSE&G'S CUSTOMERS

To help put the significant benefits of avoiding a major gas outage in perspective, it is useful to review the general actions that would be taken by PSE&G during a major gas system outage.

Residential Customers

Under PSE&G's Gas Curtailment Plan, its residential customers would be the last group of customers to be curtailed during a major gas outage. Curtailment of residential (and commercial) service would occur in stages using a sectional curtailment process by rotating electric interruptions (in an attempt to further reduce gas usage) and another sectional curtailment by shutting down particular gas mains.

Commercial and Industrial (C&I) Customers

PSE&G's C&I customers would be the first customers to be curtailed at the start of a major gas outage event according to the following order of priority:

1. Curtail all C&I customers who receive interruptible service.
2. Curtail all firm C&I customers who use gas for process and/or feedstock purposes.

[53] While these results are for a specific outage event, each of the six projects that comprise the Curtailment Resiliency Subprogram support the loss of other interstate pipelines to varying degrees. Benefits are not restricted to this one outage event and the related interstate pipeline system.
[54] N.J.A.C. 14:29-2.2.

3. Suspend all firm commercial service of 50 thousand cubic feet per day (mcf/d) or more for other than heating.
4. Close all business and reduce heat to the minimum necessary to protect any buildings, or 40° F, whichever is lower.
5. Cease operation for firm industrial customers with over 50 mcf/d service.
6. Suspend all firm industrial service of 50 mcf/d or less. Firm industrial customers with service of 50 mcf/d or less shall cease operating and shall reduce heat to the minimum necessary to protect any buildings, or to 40° F, whichever is lower.
7. Cease operation for firm commercial customers with service of 50 mcf/d or less and reduce heat to the minimum necessary to protect any buildings, or to 40° F, whichever is lower.
8. Suspend all gas service to industrial customers, including natural gas necessary to protect buildings.

Essential Service Customers

As stated in PSE&G's Gas Curtailment Plan, every effort will be made to maintain service to critical customers such as hospitals and nursing homes. A listing of these customers by group and section has been compiled by PSE&G by geographic region. It may also be necessary for PSE&G to install additional line valves to further divide (or isolate) portions of its gas distribution system. PSE&G will also have to identify the locations of all critical customers in order to aid in restoring service to these customers as soon as possible. A standard turn-off process would be carried out in the area after gas has been shut off to the subsection in which each critical customer is located. When all customers have been shut off, gas would be reintroduced, and the critical customers would be turned back on.

Power Plants Located in PSE&G's Service Territory

The relationship between the natural gas sector and the power sector is of significant importance to utility planners and government officials. For purposes of the cost-benefit analysis, Black & Veatch and PSE&G discussed the impacts, if any, that the outage event would have on the electricity generating sector. Generally, there are two kinds of power plant customers: PSE&G provides gas service to small independent power producers, some of whom provide electric power (or steam or chilled water) to their own campuses and corporate sites, as well as the grid, with boilers and combustion turbines. These independent producers take delivery of natural gas on an interruptible or firm basis from PSE&G's gas distribution system while acquiring their own gas supplies and pipeline capacity from third-party suppliers. There are also large, centrally dispatched power plants located in PSE&G's service territory that take delivery of natural gas from PSE&G's gas system. These plants participate in the regional wholesale power market, which is highly interconnected. Black & Veatch notes that PSEG Power's generating facilities[55] (which comprise this latter category) would no longer receive gas service under the gas outage scenario.[56] At that

[55] PSEG Power's generating facilities located in PSE&G's service territory include the Bergen Generating Station, the Burlington Generating Station, the Essex Generating Station, the Kearny Generating Station, the Linden Generating Station, and the Sewaren Generating Station.
[56] PSEG Power's generating facilities are served from PSE&G's gas distribution system under "Rate Schedule CSG – Contract Service" and utilize an unused portion of the gas supplies and contracted interstate pipeline capacity procured and contracted for by PSEG Energy Resources & Trade (PSEG ER&T) on behalf of PSE&G.

point, these generating facilities could continue to operate by utilizing their alternate fuel capabilities.[57]

It is possible there could be impacts to either type of power generating facility under the assumed conditions of the gas outage scenario. However, PSE&G did not request Black & Veatch to analyze the potential impacts of the outage scenario on the wholesale electricity sector in New Jersey. Black & Veatch notes that the regional power sector is well diversified in both its transmission paths and generating facilities and under many conditions, could have adequate reserve margins to address any impacts that result from local power generating facilities impacted by gas delivery outages.

IMPACTS TO PSE&G'S GAS SYSTEM

PSE&G's gas outage scenario defined as part of the cost-benefit analysis, should it occur, represents a significant loss of gas service to PSE&G's customers. The outage scenario would be very expensive and inconvenient for PSE&G and its customers; it would create a wide range of direct and indirect costs described later in this Report.

Earlier the basic steps that PSE&G will take in responding to an outage are identified. But these do not communicate the level and intensity of activity involved with this response. Although PSE&G has prepared a comprehensive Gas Curtailment Plan, a major gas outage event of the magnitude envisioned under the gas outage scenario would be difficult to manage. PSE&G would be called to work through the Plan's steps in rapid succession if the conditions of PSE&G's gas system deteriorate to a critical point over a very short timeframe where, for example, the integrity of the gas system is at risk of extreme pressure collapse. If a significant drop in gas pressures occurs rapidly, there is a greater likelihood that firm gas service could be lost before adequate measures are taken under the Plan to reduce the use of natural gas by the pre-designated customer groups and geographic locations. Steps, such as calling for rolling electricity blackouts to conserve gas, might have little effect if circumstances deteriorate quickly.

Upon detection and notification of a major gas outage event, PSE&G would first reduce gas service to a minimum at its facilities. PSE&G would then make its first public appeal for conservation prior to the Governor of New Jersey declaring an Energy Emergency.[58] A second public appeal for conservation would be made after the Governor declares an Energy Emergency. If these efforts fail to reduce the use of natural gas to preserve gas service to PSE&G's higher priority firm customers, then PSE&G would be required to curtail gas service to its larger firm industrial and commercial customers according to its gas curtailment priorities. Rolling electricity blackouts might also be invoked (to shut down appliances such as central heating for brief periods). Finally, curtailment to residential and smaller commercial customers would occur through sectional curtailment of pre-designated gas mains in an attempt to maintain line pressures on other parts of the gas system so that gas service to some smaller number of residential and commercial customers could be preserved.

[57] It is possible that a generating facility could continue to use natural gas if it could acquire gas supplies and pipeline capacity from third-party suppliers delivered to a PSE&G alternate city-gate, but this is highly unlikely if a major gas outage event were to occur on PSE&G's gas system.

[58] Notice requirements are established as part of N.J.A.C. Title 14, chapter 29.

Figure 8 is a high-level graphical representation of the customer outages during the duration of the gas outage scenario specified earlier. It isolates the subset of PSE&G's customers affected by the gas outage scenario, as compared to all of PSE&G's customers.

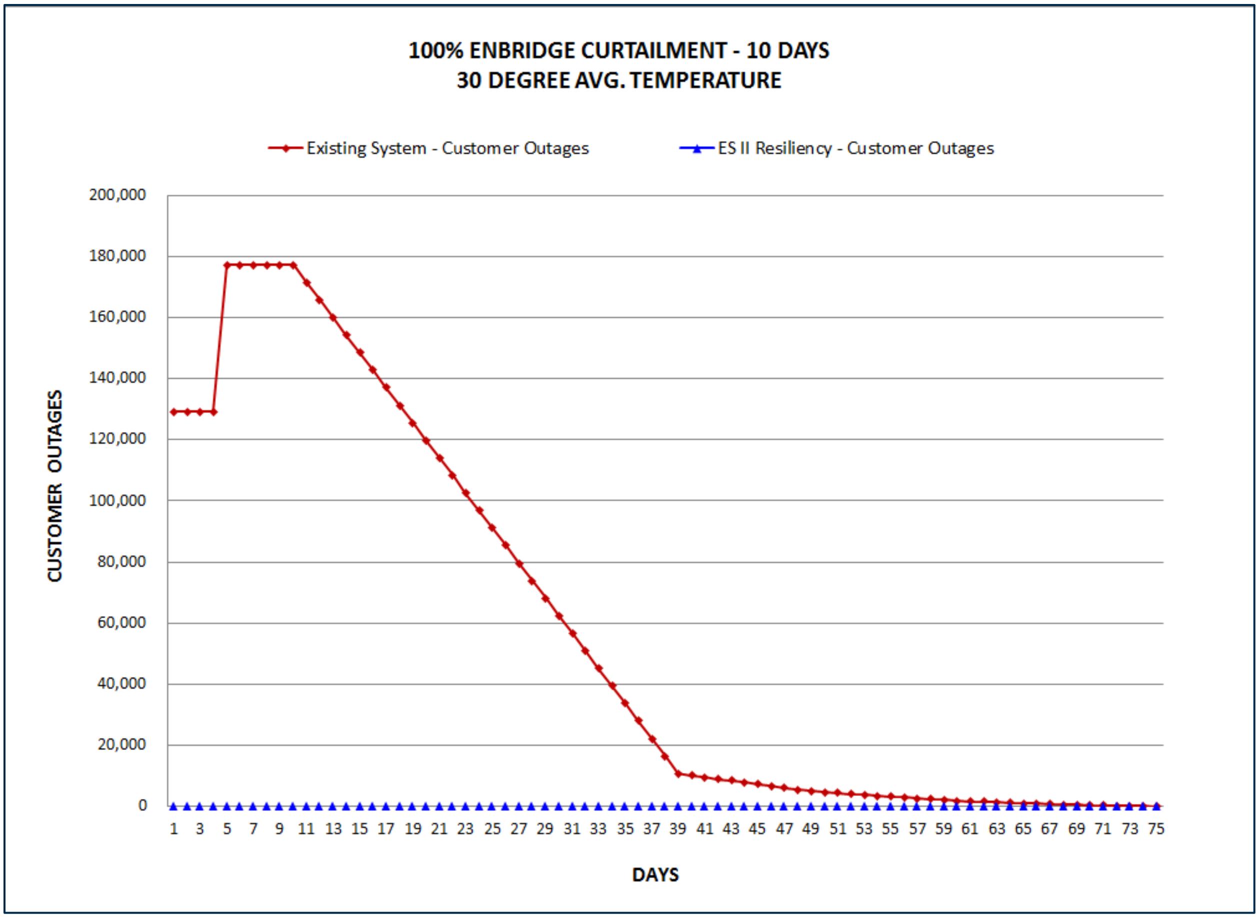


Figure 8 **Gas Outage Scenario (for impacted customers): Customer Outages by Day**

PSE&G identified and described the activities to be performed during each operational phase of a natural gas supply outage to aid in the identification of the estimated costs and duration of the outage scenario. The estimated (avoided) costs and duration of the outage scenario are applied to the cost-benefit analysis as described in this report.

PSE&G'S ACTIVITIES AND DIRECT COSTS INCURRED DUE TO AN OUTAGE EVENT

Black & Veatch chose an outage event to be reviewed in this cost benefit analysis based on an initial curtailment of the upstream pipeline system of 10 days. Once the gas distribution system is safely shut down -- and once PSE&G had confidence about when the curtailment period would end -- it would begin activities to restore the system. At that time, (Day 11) PSE&G would be able to start the process of re-pressurizing its gas distribution system and relighting its customers.

Black & Veatch worked with PSE&G to develop a detailed estimate of the steps, resources and direct company costs associated with restoring the system. (Refer to Appendix D – Gas Outage Event and Restoration Activities for details on how this information has been developed). Based on this gas outage scenario (at average daily temperatures of 30° F), it would take approximately 30 additional days for PSE&G to shut down and then substantially re-pressurize the affected sections of its gas distribution system, which means the gas outage scenario would have a *total* duration of 40 days to complete the restoration for most customers.[59]

Black & Veatch and PSE&G analyzed and estimated the directly incurred costs to safely restore its gas system. These results are presented in Table 7. The directly incurred restoration costs incurred by PSE&G are estimated at $68M for this single outage event.

Table 7 Curtailment/Gas Outage Activities and Estimated Costs[60]

PERIOD	COST	COST PER AFFECTED CUSTOMER
Gas Outage Period	$ 21,598,728	$ 121.94
Restoration Period	$ 46,003,180	$ 259.71
Total	**$ 67,601,908**	**$ 381.65**

Appendix E - Direct Costs Incurred by PSE&G during a Major Gas Outage Event, provides the assumptions and estimated operational costs during the gas outage scenario supporting the values shown in Table 7. These costs are direct company operational costs and do not include additional company costs associated with longer-term litigation and insurance claims, additional customer service support-related costs or housing and food for PSE&G employees and mutual aid workers.

The analysis includes several assumptions, which determine the overall length of time required to restore the system. The restoration period duration is estimated in detail in Appendix D – Gas Outage Event and Restoration Activities. The major assumptions affecting the duration of the outage include: (a) the size of the isolation event (miles of pipe and customers affected on the distribution system); (b) the average number of work tasks that a utility worker or a crew can perform in a 12 hour shift (productivity assumptions), including operating valves; cutting and capping mains; customer shutoffs and relights; leak surveys; and purging, clearing, and pressurizing pipelines; and (c) the availability of mutual aid crews to assist with restoration activities.[61]

Deferred Activities and Unintended Impacts

While the restoration work proceeds, there are many additional consequences of the gas outage event because the day-to-day utility work will be deferred due to the focus on safely restoring the utility's gas system. In fact, a major outage event will cause a massive diversion of company focus, effort and resources throughout the entire span of the outage event. This diversion will also cascade into the days, weeks and months after the last customer is restored because of the work

[59] Black & Veatch's specific estimate is that by Day 40 there would remain approximately 10,000 customers without gas service, and it would take another 33 days to completely restore this residual number of customers. This last 5 percent of customers represents homes and buildings where access may be difficult to gain, as customers may have left the area due to the severe outage conditions.

[60] Costs include an allowance for risk and contingency, consistent with PSE&G estimation practices.

[61] Depending on the nature of the event, mutual aid crews may not be available. In the evaluation of this outage event, this is not assumed to be a constraint.

interruption that will be created during the immediate and near-term phases of the outage. These also represent indirect costs and impacts of the outage event that could be very significant, and create further cascades of implications into utility operations.[62]

CONCEPTS UNDERLYING VALUE ARGUMENTS

The previous sections have defined the outage parameters, along with the costs the company can expect to incur in such an event. Beyond these costs, it is possible to relate the extent of this outage to customer value, for purposes of applying it to the cost-benefit analysis. The benefit of the Curtailment Resiliency Subprogram is the value that is retained because the effects of the outage event do not occur with the new infrastructure in place.

Unlike in a purely competitive market, improving the resiliency of a utility's gas delivery system is challenging since there is no market one can reference. It is difficult to observe the price consumers would be willing to pay for a greater level of resiliency from the gas utility to avoid outages because there are not easily available substitutes consumers can select on short notice. Over time they *will* adapt, but understanding how each customer values the quality of service is an important area of policy research.

Economists agree that the value customers perceive in the overall reliability of their gas service, which is enhanced through a more resilient utility gas system, is tied to the outage costs (and harm and inconveniences) they avoid, but outage costs are not always easy to identify. When power or gas is not available residential customers and businesses incur many *direct* and *indirect* impacts. A direct cost might be the additional cost to the consumer of purchasing and operating an electric space heater. An indirect cost might be the likely short-term price spike in the purchase price of the space heater (e.g., the former direct impact induces the latter impact). In a gas outage event there would be *wide ranging* impacts encompassing worker productivity, direct customer costs for extra supplies, delays to projects under construction, emergency-related costs to local governments, accidents and injuries, lower tax and fee revenues (due to a decline in economic activity) just to name a few.

Customers and businesses also face additional costs both in the short term and long term. Short-term costs are often understood as damage costs. (For example, in a gas outage, customers will have to pay more for alternative heating and temporary housing). Some customers might seek out long-term alternatives (e.g., consider moving if service remains poor). The long-term costs are often forms of adaptive behaviors to avoid the outage risk in the future (such as installing a different form of heating system). These can also be considered mitigation costs that help avoid the damage in the future.

For outages, it is also relevant to expand the impacts to beyond just observable costs. Some of the impacts of a gas outage are quantifiable in monetary terms, and hence, economic in nature; whereas other impacts reflect broad, social impacts tied to convenience, personal safety, pain and suffering, security and other less tangible, but very real, values to the customer. Outage impacts are also characterized by *externalities*, which can be either positive or negative; externalities are impacts incurred by others not party to the economic transaction. For example, an outage event may disrupt a harbor or airport and cause supply chain disruptions for manufacturers far outside the

[62] An example is that PSE&G might have to catch up on key projects to meet construction plans, and these could drive cost, quality and further schedule impacts.

immediate region. This is a form of negative "network externalities," -- it is beyond the influence of the manufacturer suffering the damage.

Some economic impacts caused by a major gas outage can be difficult to assess due to the fact that some economic activities may be deferred in time. A large-scale gas outage event, for example, could delay a utility's investments that are otherwise planned or in progress (since temporarily its priorities shift dramatically and significantly).

In the circumstance of a major utility service outage, there are many factors that influence the degree of destructiveness and harm that is caused (and the resulting cost impacts). Factors include the location of the event, its duration, the time of year, weather conditions, the extent to which other utility services are also impacted, and the types of customers affected. The resulting costs are also influenced by the effectiveness of the response of local government, emergency responders, critical care facilities, and utilities, all of whom are reacting to the emergency conditions brought on by the outage event and helping to protect public safety. Gas outage impacts are also sensitive to the nature of the businesses affected, and the degree of choice and flexibility businesses and their customers have in responding to the event.

Determining outage costs and related impacts is by no means a precise science. Care must be taken in determining a reasonable estimate of the nature and scale of activities caused by the outage, and their related costs throughout the event. In fact, one method to estimate the costs of outages is to evaluate these costs *after* the event, and to use this information as a basis for future consideration. However, such a *post hoc* approach does not remove the measurement challenges associated with the event. Additionally, outage events do not occur that frequently; they are often unique to the particular utility, and they are costly to analyze. These are some of the primary reasons why other valuation methods are pursued.

VoLL

One of the primary techniques used to estimate the value of not having power is to survey customers' willingness to absorb the direct losses imposed by outages, or, correspondingly to gauge how much customers are willing to pay to avoid them. This technique is part of a broad area of study known as Contingent Valuation, and it helps derive what is referred to as Value of Lost Load (VoLL).

It would be useful if there were price signals that provided insights about customer preferences and tradeoffs, but there is not a ready market in the short-term for alternatives to the gas service customers receive from the local gas utility. If there were, the price signals coming out of that market as people considered and purchased alternatives to achieve the desired levels of reliability could help determine how customers value changes in reliability and resiliency; this could be used as determine the right level of investment.

Economists recognize these measurement challenges (in power and other markets), and have devised survey and measurement techniques to estimate the value customers place on utility service disruptions and system integrity. This value is referred to as the VoLL. In some markets, regulators look to VoLL estimates to help determine how to inject the right amount of incentives into the market to encourage reliability and resiliency investments.[63] In other circumstances, VoLL is applied as a means to understand what costs consumers and businesses incur when facing

[63] See Estimating Value of Lost Load (VoLL), Final Report to OFGEM, prepared by London Economics, July 5, 2011.

service interruptions; therefore, it helps guide the creation of estimates about how consumers value avoiding these disruptions.

As noted earlier, the measurement techniques for VoLL fall within a broad category referred to as Contingent Valuation. Different specific techniques are often applied to residential versus C&I customer classes. For residential customers, willingness to pay (WTP) estimates (to avoid utility service outages) are estimated through survey techniques that address direct costs, inconveniences, values, substitutes, and customer choices around the services provided by the utility tied to service reliability.[64] For C&I customers, however, it is possible to evaluate WTP by analyzing firms' direct costs incurred in terms of actual lost production and output. Commercial firms have output that is put at risk when utility services are interrupted, whereas private individuals contribute to the output of firms, and suffer additional forms of damages and losses, such as inconveniences, injuries, and direct and indirect costs (both short- and long-term).

ESTIMATING THE VALUE OF LOST LOAD FOR PSE&G

Black & Veatch recommends a straightforward set of factors to determine the Value of Lost Load (VoLL) for PSE&G's selected gas outage scenario. Black & Veatch believes the factors have intuitive appeal. Because the assumptions made for the magnitude and duration of outage events are important characteristics for determining VoLL, the duration assumption for PSE&G's gas outage scenario described elsewhere in this Report is used in conjunction with VoLL factors to compute one estimate of value customers may place on avoiding such outages.

The gas outage scenario is based on an outage event duration of 10 days, with an additional 30 days needed to restore gas service to *most* customers, as described earlier. Additionally, during the restoration period, there will be a gradual increase in the number of customers restored as the utility's restoration process progresses (refer to Figure 8). To determine the equivalent loss of consumption, the restoration period is assumed to proceed in an orderly fashion whereby all customers experiencing an outage are restored at an equal rate once the gas system is able to begin re-pressurization. Taking into account all factors, on an average basis for 177,132 customers, the total outage duration is equivalent to 24.7 days.[65]

To compute the VoLL, various input assumptions are created to disaggregate the customers subject to the outage by customer segment. A residential and a C&I breakdown is used. These assumptions appear in Appendix F - VoLL Calculations for PSE&G's Curtailment Resiliency Subprogram. PSE&G estimates that there are approximately 162,500 residential customers and 14,132 firm C&I customers served within the parts of its service territory that would lose firm gas service during the gas outage event. In general terms, the VoLL estimate for PSE&G's residential customers is based on applying current tariff prices to the estimated volume of foregone gas consumption during the Curtailment Period. For PSE&G's C&I customers, the VoLL estimate is based on assumptions concerning foregone economic output during the duration of the gas outage.

[64] Survey techniques are both based on WTP and willingness to accept (WTA) approaches. The latter provides input on potential compensation schemes that might be payable to compensate customers once outages occur, whereas the former evaluates the potential value customers perceive to avoid outages.
[65] See Appendix F - VoLL Calculations for PSE&G's Curtailment Resiliency Subprogram for details on this calculation. This is the derivation of the area under the curve of Figure 8.

VoLL Estimates for PSE&G's Residential Customers

Black & Veatch offers that there are different approaches to measuring VoLL for residential customers facing costs of power interruption. Black & Veatch has noted arguments based on "contingent valuation" WTP arguments, consumer surplus-based arguments, and household income-based arguments. Black & Veatch notes that there are many variables impacting the outage scenario, such as duration, temperature, and restoration duration, all of which also impact the VoLL determination. For all of these reasons, and to provide a reasonable, yet conservative, view of VoLL, the cost-benefit analysis assumes that the customers simply value the loss of gas service at the currently effective price charged under PSE&G's residential gas tariff. The VoLL is, therefore, strictly proportionate to the foregone gas consumption during the outage period.

The assumptions and detailed calculations are presented in Appendix F - VoLL Calculations for PSE&G's Curtailment Resiliency Subprogram**.** The resulting VoLL during the outage period for PSE&G's residential customers is approximately $25M**.** On a per customer per day basis, this equates to $6.23. Black & Veatch notes that the VoLL analysis conducted for the ES I Gas Program resulted in a residential VoLL equal to $53 per day per customer, which is many times higher than this current estimate.[66] Black & Veatch's approach to computing VoLL utilizes PSE&G's current gas commodity prices, which have declined over the ensuing 4-year period since the last VoLL analysis was conducted. Higher commodity prices would thus raise this estimate of VoLL.[67]

The Black & Veatch approach makes no claim to limit prices (as part of consumer surplus-based assumptions) and other determinations of foregone gas consumption outside of assuming that in the absence of the outage event the customers would have continued to enjoy the use of the product in an uninterrupted fashion during this period. Most studies indicate, in fact, that a consumer values continued uninterrupted service at a level much higher than tariff prices for the service, recognizing as they do the significant direct and indirect costs and loss of welfare that results in a large and catastrophic event. As such, the Black & Veatch analysis approach is conservative.

VoLL Estimates for PSE&G's C&I Customers

Black & Veatch agrees that the "Value Added" concept utilized in PSE&G's ES I proceeding for evaluating the VoLL for C&I customers is a reasonable approach. This is intuitive and assumes that C&I customers will face losses due to their inability to generate economic output if they cannot conduct business during the outage. Black & Veatch also notes an adjustment that it believes is appropriate. At least one study recognizes differentials amongst customers for their sensitivity to gas use. These differences implicitly address a wide range of differences associated with these businesses and their actions and recourse in an event of an outage of their gas service. In this study, it was determined that most of the small and medium businesses either valued strongly or very strongly continued gas service, but some did not. The cost-benefit analysis relies on specific

[66] The Brattle Group. Analysis of Benefits: PSE&G's Energy Strong Program. Performed on Behalf of PSE&G. October 7, 2013. Page 33. This analysis was provided to the BPU as part of PSE&G's Energy Strong BPU petition.
[67] Black & Veatch also notes that in at least one market, compensation levels have been established to support customers in the event of a significant outage on the supply system. Compensation levels are set at approximately $42 and $70 per residential customer and small and medium commercial customer per day, respectively (based on recent exchange rate of .71 British Pounds per US Dollar, as of January 30, 2018, provided by Morningstar). See Estimating Value of Lost Load (VoLL), Final Report to OFGEM, Prepared by London Economics, July 5, 2011. Page vii explains specific compensation level recommendations. These levels compare to PSE&G's ES-I value of $53 per customer per day for VoLL, based on consumer surplus and limit price arguments.

assumptions concerning intensity of use, thus adjusting the Value Add to recognize that not all customers will be equally affected by the outage. As with residential VoLL estimates, Black & Veatch believes this is conservative and reasonable.

Using this approach as detailed in Appendix F - VoLL Calculations for PSE&G's Curtailment Resiliency Subprogram, the C&I contribution to the Gross State Product (GSP) is estimated at approximately $2,475 per day per firm C&I customer. Within the outage "footprint" there is a total of 14,632 firm C&I customers, which are assumed to produce an approximate $13B in total yearly economic output.[68] This represents around 2 percent of the state of New Jersey's total annual economic output. This figure is based on the contribution of the firm C&I customers only.

The total curtailment period duration directly impacts the total productive output of the C&I sector, and hence VoLL estimate. Due to the duration and extent of the outage event assumed for the Enbridge scenario, the total VoLL for the firm C&I customer base is estimated at $895M. This estimate takes into account the steady progress of the restoration work over the 73 calendar days. (As noted earlier, however, 95% of all customers are restored by calendar day number 40). To put this VoLL estimate into perspective, the implied loss in economic output (implied by this VoLL estimate) to the State of New Jersey under this gas outage scenario is 0.15% of the state's total annual GSP.[69]

The current VoLL estimate for the C&I customer group of $2,475 per customer per day is similar to the C&I value presented by PSE&G in its ES I Program (i.e., $1,775 per customer per day). The difference is approximately 40%. Nearly half of this difference can be explained by the underlying values for GSP. The ES I analysis assumed a GSP value of $506B for year 2012, whereas the comparative value applied in this current analysis (for 2018) is 18% higher. Another source of difference is the number of PSE&G C&I gas customers as a percentage of total New Jersey C&I gas customers. The current analysis applies a slightly higher assumption using current data.[70] Lastly, the Black & Veatch analysis is applying recent data on the percentage of firm gas customers within the PSE&G C&I customer group, which leads to a slightly higher claim on total economic output.[71]

Appendix F - VoLL Calculations for PSE&G's Curtailment Resiliency Subprogram provides details of how the current VoLL estimate for the C&I customer group was derived.

VoLL aims to evaluate customers' privately borne direct costs. There are many additional costs that are not fully accounted for within the VoLL estimate. While the VoLL value estimate seeks out individual customer preferences and tries to identify customers' WTP to secure greater energy security, it is not possible to include in the outage value estimate all direct costs, indirect costs, and externalities that result from the outage.

[68] This result is based on an straightforward apportionment of economic output to the C&I gas customers on a pro rata basis.
[69] Another point of comparison is estimates of the costs incurred by the State of New Jersey due to Hurricane Sandy. ES I indicated this storm resulted in direct costs of over $12B. The outage VoLL impacted estimated here for the C&I customers is 6% of this value.
[70] The current analysis assumes that PSE&G's C&I gas customers represent 34% of all State of New Jersey C&I gas customers, vs. the ES I analysis, which assumed 27%.
[71] The current ES II analysis assumes 79% of PSE&G gas C&I customers are firm customers. This is then used to split the economic output assumption 79%/21%, to ensure that non-firm customer gas use does not influence the VoLL result. This compares with the ES I assumption that assumed that 75% of total C&I gas customer Value Add was assignable to firm customers.

A major disruption, for example, will create public safety risks and may result in accidents and injuries. Outages place huge burdens on many types of local government services. They also delay the benefits of utility investment programs that may be delayed for an extended period of time. Outages can also depress economic output well beyond the duration of the outage itself as businesses and consumers recover from the outage. Additionally, customers may engage in long-term behaviors to mitigate future outage risks and they may also suffer long-term losses such as higher taxes and insurance premiums. These are just some examples of costs and impacts not included in the VoLL estimate. In short, VoLL is an effective tool to help address the value lost during an outage event, but does not claim to capture all potential direct and indirect impacts of the outage event over all time scales and for all market participants.[72] The next section discusses some of these impacts in more detail.

OTHER IMPORTANT BENEFITS PROVIDED BY PSE&G'S CURTAILMENT RESILIENCY SUBPROGRAM

Care is needed when agglomerating all potential avoided costs and benefits to reach a total benefit value. Notwithstanding this caution, there are additional beneficial impacts beyond the VoLL estimates that are important to consider in the full accounting of cost and benefit effects. Some of these are alluded to briefly in the previous section. Some of these benefits represent costs excluded from the VoLL consideration. Others are public or social costs. Still others represent specific externalities (e.g., costs incurred by other entities should a major outage event occur). Together with VoLL, they reinforce the tremendous scale of impacts and costs businesses and consumers will face in the event of a major outage event.

Some of the additional benefits identified below have been further estimated, and are explicitly included in the benefit-to-cost ratio shown in Figure 1. Others are noted as qualitative benefits as part of Figure 1.

- **Construction Period Impacts** -- PSE&G's proposed Curtailment Resiliency Subprogram injects $863M of investment into the local economy. This provides benefits in terms of wages, taxes and fees and helps stimulate the local economy. (Qualitative; i.e. not included in benefit-to-cost ratio in Figure 1).
- **Restoration Costs** -- By avoiding gas outages, PSE&G's direct costs of outage restoration are avoided. Under the gas outage scenario, it is estimated that PSE&G would incur $68M of costs to safely restore its gas system. (This is included in Figure 1, and within the benefit-to-cost ratio.)
- **Direct Customer Costs and Impacts (Heating, Housing, Damages)** -- Certain customers will incur direct costs due to damage to their homes caused by pipe damage and flooding. Other customers will also incur additional direct costs related to space heating, temporary housing and relocation, and other daily support costs if displaced from their homes by the gas outage event. (Included within the benefit-to-cost ratio.)
- **Lost Wages** -- Customers will experience economic costs in the form of lost wages. If these wage losses are not included in the VoLL estimate for C&I customers, this would be considered an

[72] A recent study conducted for Pacific Gas and Electric Company of a major electricity outage in downtown San Francisco found that indirect costs of the outage to businesses ranged from 50 percent to two times the size of the direct costs to business. See the Application of Pacific Gas and Electric Company for a Certificate of Public Convenience and Necessity Authorizing the Construction of Embarcadero-Potrero 230 kV Transmission Project, Application 12-12-004, Pacific Gas and Electric Company's (U 39 E) Opening Brief, p. 12.

additional benefit if the gas outage is avoided. (An estimate of some wage losses that are excluded from VoLL are included within the benefit-to-cost ratio.)[73]

- **Long Term Business Impacts** -- Local business could likely suffer beyond the duration of the immediate gas outage event. The *long-term* depressive effects on the economy are not well captured in the VoLL estimates because they are hard to gauge. If the outage event causes long-term damage to property and businesses, and results in actions such as company relocations of their activities or production capabilities, these are also reasonable costs to consider. (Qualitative).
- **Delays in Other Utility Programs** -- A significant gas outage event, together with the associated prolonged restoration period, would interrupt PSE&G's gas capital programs that are underway. This could defer and push back the effected parts of these programs for a period of time until they could be safely restarted. Any deferral has the effect of pushing back the achievement of the beneficial effects of these programs unless additional costs are incurred to accelerate the programs once the restoration is completed. (Qualitative).
- **Delays in Other Construction Programs** -- A significant gas outage event may delay many local construction activities to the extent that workers are impacted, material deliveries are delayed, and permitting and inspection work is delayed. (Qualitative).
- **Impacts to Local Government Services** -- A significant outage event would impact local government, transit, emergency responders, and critical care facilities by impairing their operations with inconveniences (such as loss of heating and appliance use), impair their ability to provide care to displaced residents (for example shelter services), drive up costs for such things as overtime expenses, and drive additional costs on vehicles and other forms of equipment. Effects could be compounded if the outage event occurs during periods of severe weather, like a snowstorm, where there would be additional service demands being placed on these entities. (Qualitative).
- **Additional Transportation Costs (Fuel, Emissions, Congestion)** -- Additional transportation costs will be incurred if residents and business have to travel further for supplies and to attend to family and business needs. (For the C&I sector some of these costs could be captured under VoLL).
- **Education and Day Care** -- Local schools and day care facilities for younger residents may have to close for the entire duration of the event. Parents will have to stay home from work, or transport children to alternative, temporary schools and facilities. The school year could be extended due to losing school days. (Qualitative).
- **Government Fees and Taxes** -- Local and county government will experience a decline in sales tax revenues and user fees in the event of a decline in overall economic activity. This will happen while costs increase. Unemployment compensation claims may also increase. (Qualitative).
- **Cascading Economic Impacts Outside Local Region** -- Impacts to local commerce will have a cascading impact on other regional and state businesses outside of the outage vicinity. These other businesses (outside of the outage area) may experience losses excluded from the direct costs (e.g., included in VoLL) incurred by the C&I customers directly impacted by the outage. These impacts can translate into lost wages for local and regional workers, amplifying effects. (Qualitative).

[73] The VoLL for C&I captures the contributions of workers to economic output. However, not all workers impacted by the outage work within the limited, specific, outage "footprint".

- **Loss of Gas Revenues** -- PSE&G would suffer other losses in many forms. It would incur additional outage-related costs not included in the restoration cost estimate (such as back office support costs), would lose gas sales revenues, and it may also have to perform emergency repair work. (Qualitative).
- **Public Safety** -- A large outage event places the public in harm's way. Accidents, illness, and injuries may occur as the outage proceeds. For example, people will be without heating and may turn to more hazardous means of space heating, resulting in fires. The elderly may be at risk if homes are not heated. (Qualitative).
- **Loss of Public Confidence** – A major outage event such as the one described could significantly impair the confidence that people place in the integrity of the region's infrastructure, altering perceptions and decisions about investment opportunities. (Qualitative).
- **Loss of General Welfare** –From an economic perspective, when residents are focused on attending to basic needs they are foregoing leisure in its many forms. This is a general loss of welfare in economic terms. (Qualitative).

Table 8 documents estimates developed to address additional areas of impact during a gas outage event. These items are identified above as included in the benefit-to-cost ratio shown in Figure 1. The estimates are scaled to represent the impacts associated with the 10-day outage scenario. Key assumptions are listed.

Table 8 Additional Benefits of PSE&G's Curtailment Resiliency Subprogram

COST ITEM	ESTIMATE	DESCRIPTION
Temporary Housing Costs and Other Incidentals	$70,490,818	Assumes costs for temporary housing as part of an extended outage event. Assuming 162,500 residential outages over 10+40 day outage (which equals approximately 25 day equivalents, or 4M customer-outage days). 7% of customers not dependent on natural gas heating. 10% of residual seeks alternative housing. Cost estimate assumes extended stay arrangements at a daily cost consistent with IRS guidelines for per diems in high cost areas. * 162,500 x 93% x 10% x 4M customer outage days * Per Diem per IRS guidelines = $191 / day.[74]
Additional Electricity Costs for Space Heating Needs	$23,210,226	Assumes 162,500 customers, 93% who are dependent on natural gas for space heating needs. $120 equipment costs per customers for two space heaters, for 50% of customers. Other assumptions: 1,500W avg load, 16 hours per day, 15 cents / kWh.
Lost Wages and Productivity for Hourly	$20,000,000	Wage earners loss of productivity throughout outage period. Based on assumptions for hourly wage earners losing 10% of

[74] IRS Publication n-17-54. Available at: https://www.irs.gov/pub/irs-drop/n-17-54.pdf. Section 4. Rate for Incidental Expense Only Deduction. Page 2.

COST ITEM	ESTIMATE	DESCRIPTION
Workers		productivity for one month period. Assumes 25% of workers are employed within the outage area and 75% work outside the area.
Total	**$113,701,044**	

Black & Veatch acknowledges that the monetary estimates of these impacts are illustrative as some assumptions are speculative. For example, there is no research we are aware of to indicate how many electric space heaters might be purchased by customers facing an extended outage during 30 degree temperatures, or how many will seek temporary housing. (Certainly many customers would find this to be a financial burden). However, while illustrative in nature, Black & Veatch also believes it is irrefutable that 435,500 customers facing a loss of gas services for an extended, multi-week period will make specific accommodations to secure their personal needs, which in turn will drive these types of costs.[75]

APPLICATION OF PSE&G'S PROJECT EVALUATION METHOD TO ITS CURTAILMENT RESILIENCY SUBPROGRAM

In conjunction with the evaluation and selection of its ES II Gas Program projects, PSE&G determined the relative importance and risk mitigating capabilities of each project included in its Curtailment Resiliency Subprogram. The method used by PSE&G was based on each project's total project resiliency potential over the winter heating season. This was determined for each potential project by the number of firm customer outages avoided at representative daily temperatures and the average number of expected occurrences per winter of those daily temperatures. This process resulted in a measure for each project of the total equivalent customer outage days avoided.

Using its recent weather experience, and for purposes of developing the analysis that goes into the cost-benefit estimates, PSE&G determined that during a winter season (defined as the 151 days between November 1 and March 31), it experienced the temperature occurrences per winter shown in Table 9.

PSE&G evaluated the relative resiliency potential for each project by measuring the daily gas volumes that could continue to be served by the additional facilities included in the project under a gas outage event[76] and applied that amount to use per customer values to derive the number of customer outages avoided at each of the above-listed temperatures. The total equivalent customer days was then derived by multiplying the number of customer outages by the number of temperature occurrences per winter. The resulting values are presented by project in Table 9.

The results presented in Table 10 provide a relative ranking of each project's ability to mitigate the loss of firm gas service to customers under a variety of gas outage conditions across a range of temperature conditions. Taking into account these considerations and the geographic areas that the different pipeline systems serve, Black & Veatch understands that PSE&G has developed the

[75] Additionally, the conservative approach used for the residential VoLL estimate excludes many additional direct costs.
[76] PSE&G uses the Synergi Gas Model to estimate the condition of its system under various scenarios.

resiliency solutions proposed under its Curtailment Resiliency Subprogram to maximize the number of customer outages that could be avoided from these additional gas system investments.

Table 9 PSE&G's Winter Season Temperature Occurrences

AVERAGE DAILY TEMPERATURE	NUMBER OF OCCURRENCES PER 151 DAY HEATING SEASON[77]
5° F	Less than 1*
10° F	3
20° F	13
30° F	32

PSE&G's most recent weather study indicates that it experiences a 5 degree day only once every 10 years.

Table 10 PSE&G's Prioritization of Curtailment Resiliency Subprogram Distribution Projects[78]

PROJECT NUMBER	PROJECT DESIGNATION	ESTIMATED PROJECT COST ($ MILLION) [79]	CUMULATIVE WINTER CUSTOMER OUTAGE DAYS AVOIDED	COST PER CUSTOMER OUTAGE DAYS AVOIDED
1	Central - South Plainfield	$61.7	2,002,000	$30.80
2	Hamilton-West Windsor	$81.9	1,690,000	$48.50
3	Mahwah-Paramus-Wanaque-Roseland	$271.0	4,383,000	$61.80
4	Sayreville-Jamesburg	$59.7	416,000	$143.50
5	Bernards-Gillette-Parsippany-Chatham-Bridgewater	$230.0	897,000	$256.40

[77] All values are from actual PSE&G experience except for the 5 degree F condition, which has not been experienced in recent past.
[78] The results shown in Table 10 are part of the PSE&G vulnerability analysis. As explained earlier, the cost-benefit analysis uses the information from the step 2 of the analysis process, which is the specific evaluation of the 10 day Enbridge outage scenario. The results reflect the cost-effectiveness of the projects; the avoided customer outage days for each project are based on all possible outage conditions.
[79] Based on PSE&G's cost estimates, as presented in the Direct Testimony of Wade M. Miller, PSE&G Director of Gas Transmission and Distribution Engineering.

Table 10 provides a measure of cost-effectiveness of the distribution projects in terms of their cost per customer outage days avoided.

OVERALL RESULTS OF PSE&G'S CURTAILMENT RESILIENCY SUBPROGRAM COST-BENEFIT ANALYSIS

Black & Veatch has analyzed the impacts and results of a specific gas outage event on the interstate pipeline system supplying PSE&G in order to demonstrate the costs, benefits and resulting value of the ES II Curtailment Resiliency Subprogram. This outage represents a 40+ day curtailment of gas supply during the winter months[80] impacting approximately 435,500 New Jersey residents. Should this event occur, it should be viewed as a major, if not catastrophic event impacting upwards of half a million people, in this case during colder weather conditions.

The following considerations have gone into creating the cost-benefit analysis, and rendering a result, including:

- PSE&G's customers will experience both direct and indirect costs and other impacts during, and as a consequence of, the gas outage event. These impacts are directly proportional to the number of gas customers impacted, the length of time they are without gas service, and the temperature conditions throughout the outage event.
- The cost-benefit analysis is based on creating a set of reasonable assumptions about the outage event.
- The gas outage scenario that has been analyzed includes assumptions for: the particular interstate pipeline experiencing the outage, the outage duration, temperature conditions during the outage, the capacity of and operational decisions about utilization of PSE&G's peak shaving resources, the availability of substitute firm gas supplies, and labor resources and task sequences needed to restore PSE&G's gas distribution system once the outage event has ended.
- A temperature condition of 30^0F is assumed for the gas outage scenario. This assumption reflects temperatures historically experienced in PSE&G's service territory over a reasonable number of days throughout the year and demonstrates the mitigation value of the ES II Gas Program investments.
- Key inputs for the outage scenario come from PSE&G's detailed gas system modeling of the outage scenario, which yields the extent of the outage, the pipeline assumption, and the volume of foregone gas consumption on a daily basis.
- Black & Veatch believes the 10-day outage event duration is reasonable, in light of recent events, for use within its cost-benefit analysis. There are examples of gas outage events lasting much longer, and several having shorter durations. Based in part on this initial condition and on an analysis of the required restoration activities by PSE&G, it would take an additional 30 calendar days to restore gas service to around 95 percent of all customers, and another 43 days to restore gas service to all customers.

[80] "40+ day" is used here because the restoration work is substantially complete – to 95% -- by Day 40, but additional time is required to restore all customers, due to customer contact and scheduling challenges.

- The cost-benefit analysis has evaluated a reasonable range of direct, indirect and other impacts that are driven by the gas outage, and these have been included in the resulting benefit-to-cost ratio for the outage event.
- Measures of VoLL are applied to value the impact of the outage. VoLL is proportional to the number of customers experiencing an outage, and the outage duration, amongst other variables. VoLL represents a value of direct costs borne by customers due to the outage.
- A single point estimate is computed for the cost-benefit analysis result. This is expressed in terms of total benefits (stated in nominal dollars) compared to total investment costs. These are depicted in Figure 9, along with the resulting benefit-to-cost ratio of 1.3. These values include estimates for VoLL and several other directly incurred customer and system costs.
- Figure 9 depicts additional costs and other impacts that have not been monetized, but represent additional, qualitative impacts of the gas outage scenario.
- Black & Veatch believes this single point estimate provides meaningful result and input to decision makers, and demonstrates the value of avoiding this low probability, but high consequence event in ways not possible under expected value techniques.

Figure 9 summarizes these results. The ES II Gas Program investment costs, together with the avoided costs (benefits) represent the avoidance of a single outage event (per the defined outage scenario). Multiple outage assumptions over the life of the assets would increase the benefit values, and improves the benefit-to-cost ratio.

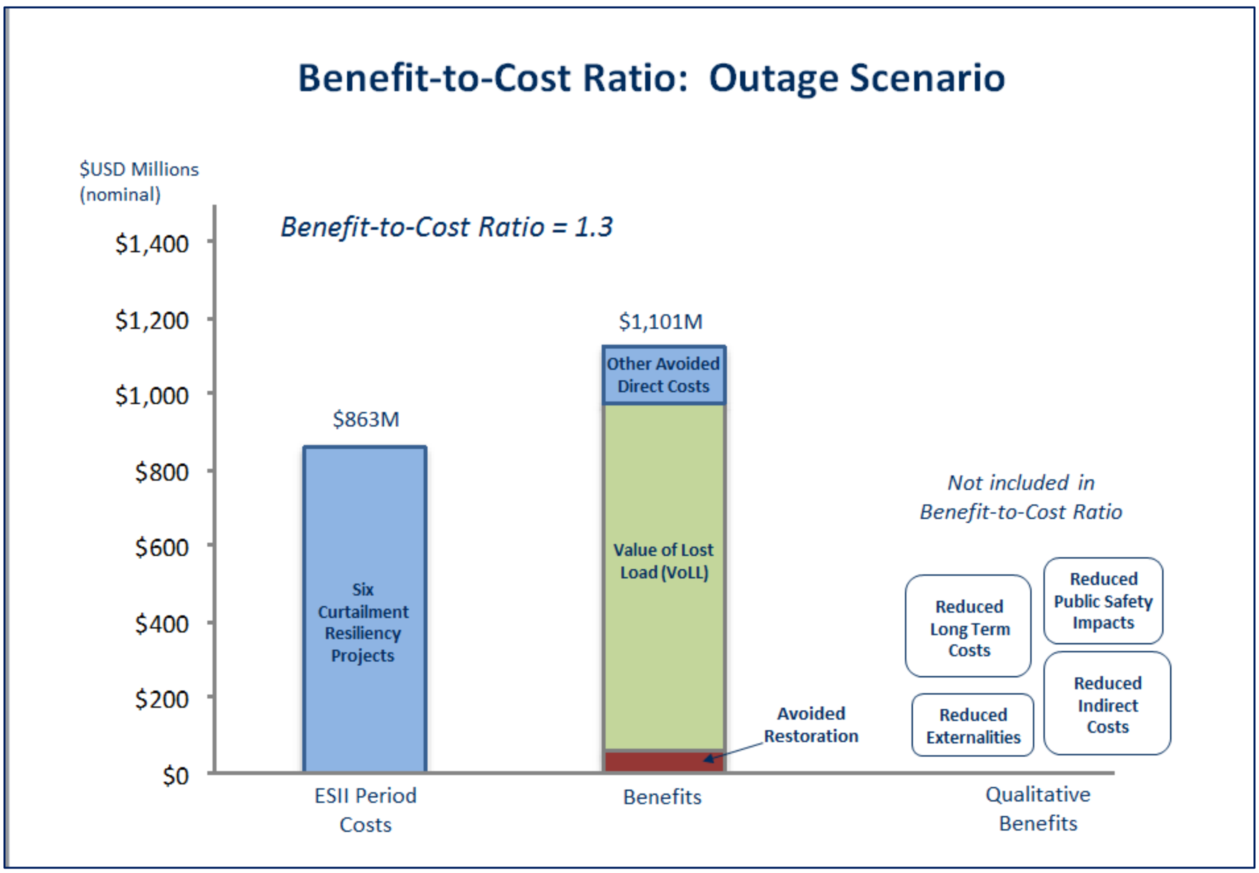


Figure 9 **Benefit-to-Cost Ratio for the Curtailment Resiliency Subprogram**

As shown in Figure 9, the resulting benefit-to-cost ratio is 1.3. The benefit-to-cost ratio is based on today's nominal dollars (2018). No effort is made to estimate a time value that speculates on when the outage event occurs. As enumerated in detail earlier, there are qualitative benefits that are represented in Figure 9, but are not included in the benefit-to-cost ratio. These increase the value of the cost-benefit result qualitatively. For purposes of this cost benefit analysis, formally estimating these impacts are beyond the study scope.

Since costs are, in fact, spread out over many decades through the normal rates process, -- and the benefits are avoided in full for any single outage avoided – the simple benefit-to-cost ratio helps frame the insurance aspect of the yearly cost burden to customers. Customers, in effect, are asked to invest yearly (through the rates process) in a fraction of the ES II Gas Program costs to avoid on a continuous basis -- and over many decades -- the enormous costs, inconvenience and harm that would result should an outage occur. Stated differently, the ES II Gas Program investments will remain in service for many decades, and provide a *continuous* mitigation benefit to this kind of outage risk. The results in Figure 9 only reveal the value of avoiding *one* outage event. Over many decades there could be more than one event that the ES II Curtailment Resiliency Subprogram investments mitigate.

Sensitivity Analyses

As a general matter, the strength of a single point estimate for the cost-benefit analysis result – and for purposes of demonstrating the value of the ES II Curtailment Resiliency Subprogram, – is the level of detail, thoroughness and rigor that can be applied to it. At the same time, it does not reveal directional changes in the results as key input variables are adjusted. This section discusses several key variables and how altering them will impact total value.

There are dozens of variables that go into creating the cost-benefit analysis result. The principal assumptions include:

- The specific pipeline that experiences the outage influences the extent of the outage and the outage locations. It influences the nature of the work to secure and shut down the system, and the resources needed to restore it. It also influences the relative contribution of the six Curtailment Resiliency projects to mitigating the outage conditions.
- Temperature conditions influence the way the system performs, and the amount of natural gas people and business require. It influences the degree of support that is possible from the peak shave resources. It also influences conditions in the wider gas supply market, and can influence firm gas supply conditions.
- Throughout the outage, PSE&G will face operating decisions about how to use its peak shaving facilities. These decisions depend on many factors, including how much it knows about the outage conditions during the early part of the outage and its understanding of how long the outage will last. These facilities – including the proposed new LNG facility as part of the ES II Curtailment Resiliency Subprogram – have unique contributions over the duration of the outage event to mitigating the extent of the outage.
- The duration of the outage event itself on the upstream pipeline system influences the degree of harm created to both businesses and people. It dictates the limits to how much additional gas supply support can be provided by alternative suppliers across various laterals within the gas distribution system.

- The duration of the restoration activities determines how long customers are without the benefit of natural gas, and this in part depends on the ability of PSE&G to mobilize its work force, and the availability of mutual aid resources.
- Firm gas supplies also play a major role. The outage scenario assumes that firm gas supplies are available. It is possible that they would not be available, depending on the nature of the outage and its persistence.
- These factors are also compounding. The longer the total event, the greater the size of the event, the lower the temperatures, the greater chance of compounding and cascading impacts. These are largely unaccounted for in the cost-benefit analysis in any specific and formal way. (A January 7, 2018 water pipe break at a JFK airport terminal demonstrates an example of an indirect and compounding impact, one that affected thousands of people and hundreds of airplane flights).

The resulting value that is driven by the choices of these variables is not a simple linear function. Influences can stop and change direction. For example, as the outage grows as temperatures drop, a limiting factor of the benefit value of the Subprogram is the availability of firm gas supply. More infrastructure will not provide further benefit once this limit is reached. Or, as the outage duration grows there is only so much support that the peak shave facilities can provide (given their capacity and location), and therefore customers will experience an outage at some point regardless of the ES II infrastructure.

Due to these considerations, an over-arching value perspective should be considered, namely the relationship of the mitigation benefits to time. Hazards increase and multiply as temperatures drop. Providing support to the system -- and avoiding outages for as long as possible – has value in absolute terms because it represents option value: time permits other choices to be considered and decisions to be carried out that result in people being protected from harm. Secondly, for each individual customer who avoids an outage condition for the marginal day, value results in absolute terms.

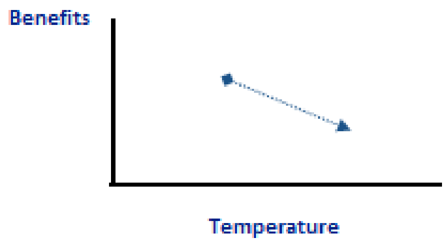
The main variables described here intertwine in complex ways. Figure 10 depicts the directional changes to benefits (VoLL and other savings), based on directional changes of these variables.

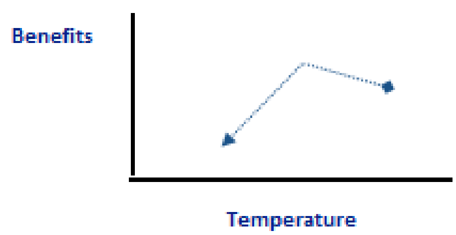
Sensitivity Analyses

Estimating impacts across all variables is analytically rigorous process. The following statements describe directional impacts related to benefit value of ES II Curtailment Resiliency investments.

- Temperature
- Gas Outage Duration
- Supplemental LPA and LNG Resource Dispatch and Capacity
- Pipeline (Alternative to Base Case, which is Enbridge)
- Restoration Period Resource Assumptions
- Current Capacity Limits on Other Pipelines

Role of Temperature



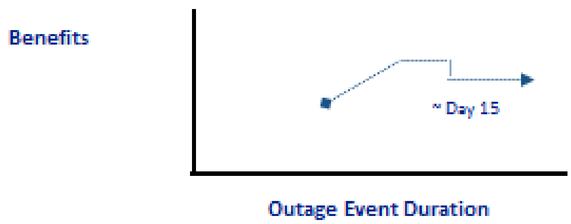


- As temperatures increase, gas demand falls off, and outage extent pressure lessens
- With fewer customer outages, the mitigation value of the ESII Curtailment investments decline

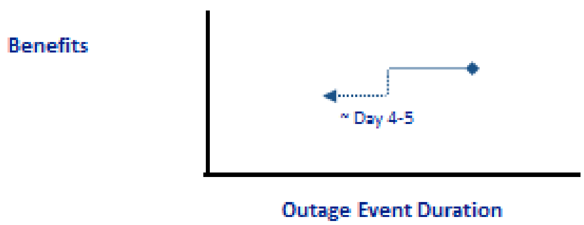
- As temperatures decrease, gas demand increases, and outage extent grows.
- Hazards grow as conditions become more severe with temperature declines.
- However, firm gas capacity is limited, and at some point in cycle can not support system.
- ESII Value increases to a point, and then ceases to grow, once system in outage area collapses.

Sensitivity Analyses

Role of Outage Duration



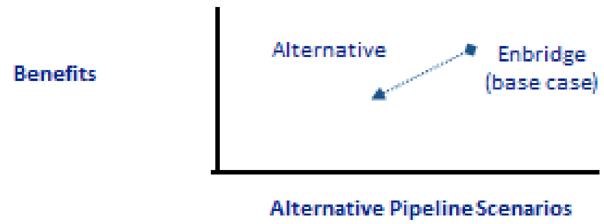
- As the outage duration grows, ESII Program value grows, *all else being equal.*
- ESII Program value increases to a point, and then ceases to grow (reaches a limit), once peak shave resources are depleted, and system in outage area collapses. (around Day 16)
- There is a slight reduction in value after Day 15 due to restoration costs being incurred regardless.



- As the outage duration declines (less than 10 days), ESII Program value holds steady, *all else being equal.*
- PSE&G must securely shut down the system *regardless*, and this may take up to 10 days *regardless*.
- Restoration work can not start until system is secure.
- However, outage extent does fall off around Day 4 (129,000, vs. 177,132)

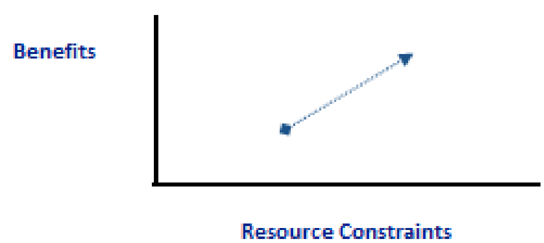
Sensitivity Analyses

Role of Alternative Pipeline Assumption



- Outages on other pipelines have reduced outage mitigation effects, all else being equal.

Role of Resource Constraints



- The greater the resource constraints related to the restoration work (labor, efficiencies, productivity, access to equipment etc.), the more value ESII Program delivers, all else being equal.
- Reducing the time it takes to restore the system reduces the duration of any customer outage.
- Conversely, the longer it takes, the more mitigation value there is to ESII.

Figure 10 Sensitivity Analyses Based on Principal Variables

Benefits of PSE&G's M&R Station Upgrade Subprogram

BACKGROUND

As part of the ES I Program, PSE&G funded $50M to storm harden six of its M&R stations that were prone to flooding hazards. This hardening was completed on the following stations:

- Crown Central M&R Station and LPG Storage in Linden
- Piles Creek M&R Station in Linden
- Newark Airport M&R Station in Newark
- West End M&R Station in Jersey City
- Harrison M&R Stations (2) in Harrison
- Harrison LPG peak shaving plant in Harrison
- Burlington LNG Plant station (auxiliary generator only).

Whereas in the ES-I Program PSE&G's focus was to raise and protect these stations from flood hazards, PSE&G's focus within the ES II Gas Program is to fully upgrade several stations. By bringing stations into conformance with current, modern design practices and building codes, PSE&G will reduce the risk stations pose to the gas distribution system due to their growing obsolescence.

Black & Veatch has evaluated this Subprogram's costs and benefits, which are presented in this section.

STATION SELECTION PROCESS AND RESULTS

PSE&G has identified seven M&R stations for inclusion in its ES II Gas Program based on the use of its Asset Management Risk model. This model prioritizes stations using a risk matrix. The two main components of the matrix are measurements of the consequence of failure and likelihood of failure of M&R station assets.[81]

Consequence of failure is comprised of the following factors: safety impact, customer impact, asset reliability impact, and environmental impact. Each factor has specific criteria to calculate station consequence of failure, with examples such as stations located in proximity to populated areas, replacement part availability, and redundancy. Likelihood of failure is based upon equipment age, structural integrity, and station design. Equipment age and maintenance practices are used to plot assets along industry depreciation curves in order to calculate the likelihood of failure. The stations are organized in the risk matrix based upon their calculated consequence and likelihood of failure.

The seven M&R stations prioritized for inclusion in PSE&G's M&R Upgrade Subprogram through use of the Risk model are as follows:[82]

- **Camden -** The proposed new station would be constructed adjacent to the existing station where buildings and critical components would be at an elevation a minimum of one foot above the

[81] The product of the Consequence of Failure and the Likelihood of Failure is a common measure of risk.
[82] The stations are described here in the order of their replacement priority. The stations are presented identically in the direct testimony of Wade E. Miller.

FEMA 100 year flood elevation. New underground piping rated for the full pipeline company maximum allowable operating pressure (MAOP) would be installed, eliminating the need for high pressure relief valves. Series regulators with a working regulator and a monitor regulator for overpressure protection would be the new standard design. Downstream distribution system relief valves would also be installed as a third line of overpressure protection. Major equipment that is not near end of life condition and operationally can be relocated would be relocated to the appropriate elevation at the new station location.

- **East Rutherford** – The proposed new station would be constructed adjacent to the existing station where buildings and critical components would be at an elevation a minimum of one foot above the FEMA 100 year flood elevation. New underground piping rated for the full pipeline company MAOP would be installed, eliminating the need for high pressure relief valves. Series regulators with a working regulator and a monitor regulator for overpressure protection would be the new standard design. Downstream distribution system relief valves would also be installed as a third line of overpressure protection. Major equipment that is not near end of life condition and operationally can be relocated would be relocated to the appropriate elevation at the new station location.
- **Central** – The existing stations would be consolidated into a new building. New underground piping rated for the full pipeline company MAOP would be installed, eliminating the need for high pressure relief valves. Series regulators with a working regulator and a monitor regulator for overpressure protection would be the new standard design. Downstream distribution system relief valves would also be installed as a third line of overpressure protection. Major equipment that is not near end of life condition and operationally can be relocated would be relocated to the new station location.
- **Paramus** – New piping rated for the full pipeline company MAOP would be installed, eliminating the need for high pressure relief valves. Series regulators with a working regulator and a monitor regulator for overpressure protection would be the new standard design. Downstream distribution system relief valves would also be installed as a third line of overpressure protection. Major equipment that is not near end of life condition and operationally can remain in service would not be replaced.
- **Westampton** – New piping rated for the full pipeline company MAOP would be installed, eliminating the need for high pressure relief valves. Series regulators with a working regulator and a monitor regulator for overpressure protection would be the new standard design. Downstream distribution system relief valves would also be installed as a third line of overpressure protection. Major equipment that is not near end of life condition and operationally can remain in service would not be replaced.
- **Mount Laurel** – New piping rated for the full pipeline company MAOP would be installed, eliminating the need for high pressure relief valves. Series regulators with a working regulator and a monitor regulator for overpressure protection would be the new standard design. Downstream distribution system relief valves would also be installed as a third line of overpressure protection. Major equipment that is not near end of life condition and operationally can remain in service would not be replaced.
- **Hillsborough** – New piping rated for the full pipeline company MAOP would be installed, eliminating the need for high pressure relief valves. Series regulators with a working regulator and a monitor regulator for overpressure protection would be the new standard design. Downstream distribution system relief valves would also be installed as a third line of

overpressure protection. Major equipment that is not near end of life condition and operationally can remain in service would not be replaced.

SINGLE HAZARD EVENT

To put the nature of the risks for the M&R stations into context, there are few hazard events outside of a flood that would "knock out" the stations in a single event, based on what PSE&G has observed in running its fleet of M&R stations over many decades. There are also few individual plant components that pose a high risk of taking the entire station off line should it fail. Rather, it is the growing trend of obsolescence, the increased costs associated with addressing corrective maintenance, the opportunity costs associate with increasing maintenance activities (diverting resources away from other plant needs), and the growing risk posed by these stations (as quantified in the risk model) that justify their replacement.[83]

SAFETY AND COMPLIANCE CONSIDERATIONS

There are many safety and building standard conformance opportunities that are identified for the new M&R stations. These opportunities represent important qualitative benefits for the M&R Subprogram cost-benefit analysis, and they reinforce the conclusions of the Risk model evaluation. In comparison to new M&R station designs, the existing seven M&R stations identified for replacement as part of the ES II Gas Program rely on many mechanically and electrically outdated components and systems, even though the stations have historically provided reliable service.

- The replacement M&R Stations will be designed and built to the latest version of the Department of Transportation Pipeline and Hazardous Material Safety Administration (PHMSA) Pipeline Safety Regulations Part 192 and to the American Society of Mechanical Engineers (ASME) B31.8 Gas Code.
- The replacement M&R buildings will be built according to current local building codes addressing fire, safety, and other design features.
- The replacement M&R stations will include improved: an improved overpressure protection design, modern noise abatement design features, modern design for gear values (improving ease of operation); improved cathodic protection for all underground piping; improved atmospheric corrosion protection on all aboveground piping using most current coating technology;
- Use of improved, modern materials and construction techniques; use of modern inspection techniques during all phases of construction;
- Improved recording keeping systems and documentation on equipment;
- Pressure testing of all newly installed piping and equipment (upon commissioning);
- New stations improve security by having the regulation equipment housed in a secure building.

[83] Notwithstanding these observations, there are hazards that could take stations off-line, and these outages would impact customers directly. Under some set of assumptions related to temperature, the availability of supplies from PSE&G's LNG and LPG plants, and other operating conditions, there could be a large number of customer outages if a M&R station experienced a station-level failure. For purposes of the cost-benefit analysis, however, Black & Veatch recommended to PSE&G that this risk is sufficiently low to not form the basis of cost-benefit estimation. Rather the cost-benefit analysis for the M&R stations is based on increasing corrective maintenance costs, avoided BAU investment costs, a wide range of strong qualitative benefits tied to modern design opportunities, and risk reduction benefits as identified through the risk modeling analysis.

Rebuilding the stations will also provide visible evidence within the community of PSE&G's ES II Gas Program and its commitment to improve the gas distribution system.

Some of these items are described in further detail below.

DAY-TO-DAY OPERATIONS AND MAINTENANCE RESPONSIBILITIES

Day-to-day operations will improve -- and the overall burden of maintenance work will decline – with upgraded stations that meet today's level of design practices. As an indication of growing and uncertain corrective maintenance challenges, PSE&G reports that its O&M costs for the seven M&R stations have increased 49 percent between 2012 and 2016, rising from $149,226 to $222,152 annually.

As equipment and piping continue to age, it is not unreasonable to assume that maintenance costs may climb further. A pattern of increased O&M costs is common with aging systems and infrastructure, and would not be unexpected or unusual. In fact, at some point, it becomes impossible to repair equipment due to the inability to obtain parts needed to make repairs (or alternatively it becomes impractical, costly and inefficient to have parts specially made to complete repairs

The following are some examples of how station designs meeting current standards improve day-to-day operations:

- New stations components, equipment, and piping will be laid out in a manner that allows for easy operational access and maintenance, thus improving the overall ease of operation and the safety of station operations.
- A new station will achieve lower levels of noise emissions, benefiting both public and PSE&G workers.
- New piping and equipment improves operations and makes maintenance easier, faster, and generally safer to conduct.
- New stations may result in reduced greenhouse gas emissions due to the removal of high pressure relief valves and installation of worker/monitor regulators.
- The new stations will reduce building insurance costs as hazards are reduced.

FLOOD HAZARDS

Two of the stations—Camden and East Rutherford—are located in places that have been identified within a 100-year flood zone in accordance with FEMA standards. Consequently, to address the flood hazard, these stations need to be raised to the higher of 1 foot above the FEMA flood elevation level or 1 foot above the highest observed flood level. Additionally, the stations require design and construction in accordance with the New Jersey Department of Environmental Protection (NJDEP) flood hazard rules.

While it is not certain that a storm surge or other flooding event would knock out the stations, this could occur. Furthermore, should this occur, it is not certain that PSE&G could avoid customer outages. Much depends on operating conditions at the time of such an event, and whether the company can operate its system in a way to replace gas deliveries impaired by the outage from other facilities. It is reasonable for PSE&G to replace these two stations to avoid this outage risk.

Not addressing the flood risks run directly counter to PSE&G's imperatives to operate and maintain M&R stations to reliably meet its customers gas service requirements in a manner: (a) that is safe for workers, customers, and the general public at all times; (b) that maximizes the long-term value of the company assets through excellence in operational and periodic maintenance practices; and (c) that minimizes the long-term life cycle costs of the assets, as part of deploying effective asset management strategies.

AVOIDED COSTS OF M&R STATION REPLACEMENTS

PSE&G has indicated to Black & Veatch that it is confident it must replace at least three of these stations over the next 15-20 years given the risks these stations pose to the continued reliable and safe operation to the system. The three stations PSE&G expects to replace as part of base capital spending are (in order of priority): Camden, East Rutherford, and Central. In fact, one station – Camden – requires replacement in the next several years. For cost-benefit analysis purposes, these future investment costs are part of the BAU scenario, and should be compared to the ES II Gas Program costs. Accordingly, the cost-benefit analysis recognizes a value of $35M as a benefit, which is the present value of the avoided investment at a later date for these three stations.[84]

M&R STATION BENEFITS

Appendix G - Benefits of PSE&G's M&R Upgrade Subprogram summarizes the benefits of replacing the seven M&R stations, where a dot indicates that the benefit will be achieved for that station. Additional benefit detail is provided in the descriptions within this section.

- **PHMSA Pipeline Code -** The new station design will bring the M&R stations up to the current Department of Transportation PHMSA Part 192 Pipeline Safety Regulations code and to the ASME B31.8 Gas Code.
- **Replace Technically Outdated Equipment –**Equipment will be replaced with state-of-the-art equipment, vastly improving spare part availability. Not only will parts be available but they can be shipped in a timely and predictable manner.
- **New Buildings -** The new buildings that house the regulator stations will be built to the current local building codes. This will result in increased noise abatement to the surrounding areas. The building will be a pre-fabricated and properly sized for the regulator station equipment. Additionally, new buildings are typically designed with modern security features, reducing risks related to vandalism and sabotage.
- **M&R Site Layout -** The new station piping and equipment will be laid out in a manner that allows personnel easy access for operations and maintenance activities, improving the safety and quality of these activities.
- **PSE&G's New Station Design –** The M&R stations will be built to PSE&G's current station design requirements and standards. This has many important benefits including incorporating multiple regulator runs verses a single regulator run. This provides a redundant regulator run in case one regulator run becomes nonoperational.

[84] Black & Veatch assumes that Camden is replaced in Year 3, the East Rutherford station is replaced in Year 10, and the Central station in Year 16. These assumptions are used to derive the present value, using a discount factor of 6.9 percent. Investment costs are assumed to escalate at 2.1% per year, and this influences the values that are subject to discounting.

- **Overpressure Protection -** The new underground piping from the gas supplier to the inlet of the regulator station will be rated for the transmission company's full maximum operating pressure. This eliminates the need for large capacity relief valves. PSE&G is replacing the method of using relief valves that vent gas to the atmosphere upon an overpressure event; instead it is applying more modern and environmental friendly worker and monitor regulators, which is consistent with PHMSA Part 192.197overpressure protection standards.
- **Noise Reduction -** As the population has grown around the M&R stations, noise abatement has become an operational issue in relation to PSE&G's vigilance to maintain good community relations. The new regulators will assist in noise abatement for stations adjacent to public areas. The removal of the high-pressure relief valve and replacement with a monitor regulator as part of the station upgrades will additionally reduce noise levels. The new stations will also include noise attenuation features incorporated into its design.
- **Relief Valves -** As an additional level of safety to the public, PSE&G will install downstream relief valves as a third line of overpressure protection in the unlikely event that the worker and monitor regulators fail simultaneously.
- **Valves -** New gear-operating ball valves will be installed that will be easier to operate and maintain as compared to the existing plug style valves that were commonly installed.
- **Cathodically Protected Piping -** All underground piping will be coated and cathodically protected with the most current pipeline coating system and protection systems. This helps prevent corrosion and maintain the integrity of the pipeline for many years.
- **Material Selection, Inspection and Construction Techniques -** Over the past decades pipeline materials, construction, and inspection techniques have improved, providing a superior product compared to just 40 years ago. The new M&R stations will benefit from these improvements.
- **Atmospheric Corrosion -** All new equipment and piping will be coated and/or painted with the most current coating technology to help prevent atmospheric corrosion.
- **Operating Pressure -** All proposed piping, fittings, and equipment will be designed and rated to safely operate up to the maximum allowable operating pressure of the system.
- **Documentation -** All new piping and equipment will have the proper written documentation to verify the integrity of the pipeline and equipment and to ensure that it is capable of operating at the pressures and conditions at the M&R stations.
- **Pressure Testing -** All new piping will be hydrostatic tested to PHMSA codes, ensuring that all piping, fittings, etc., are designed and constructed to handle the elevated pipeline pressures prior to regulation.
- **Public Perception –** New, well-constructed M&R stations enhance PSE&G's public presence, communicating to its customers that it is a modern, well-operated utility.

By rebuilding these aging M&R stations these benefits will be secured. The inverse is also true. Deferring the rebuilding of these stations means these benefits are not achieved. Additionally, the operational and maintenance risks associated with their continued operation grow.

RESULTS OF M&R UPGRADE SUBPROGRAM COST-BENEFIT ANALYSIS

As documented in the above sections, the cost-benefit analysis for the M&R stations is based on improved safety performance, increasing corrective maintenance costs, avoided BAU investment costs, a wide range of strong qualitative benefits tied to modern design opportunities, and risk reduction benefits as identified within the risk modeling analysis. Figure 11 summarizes these results.

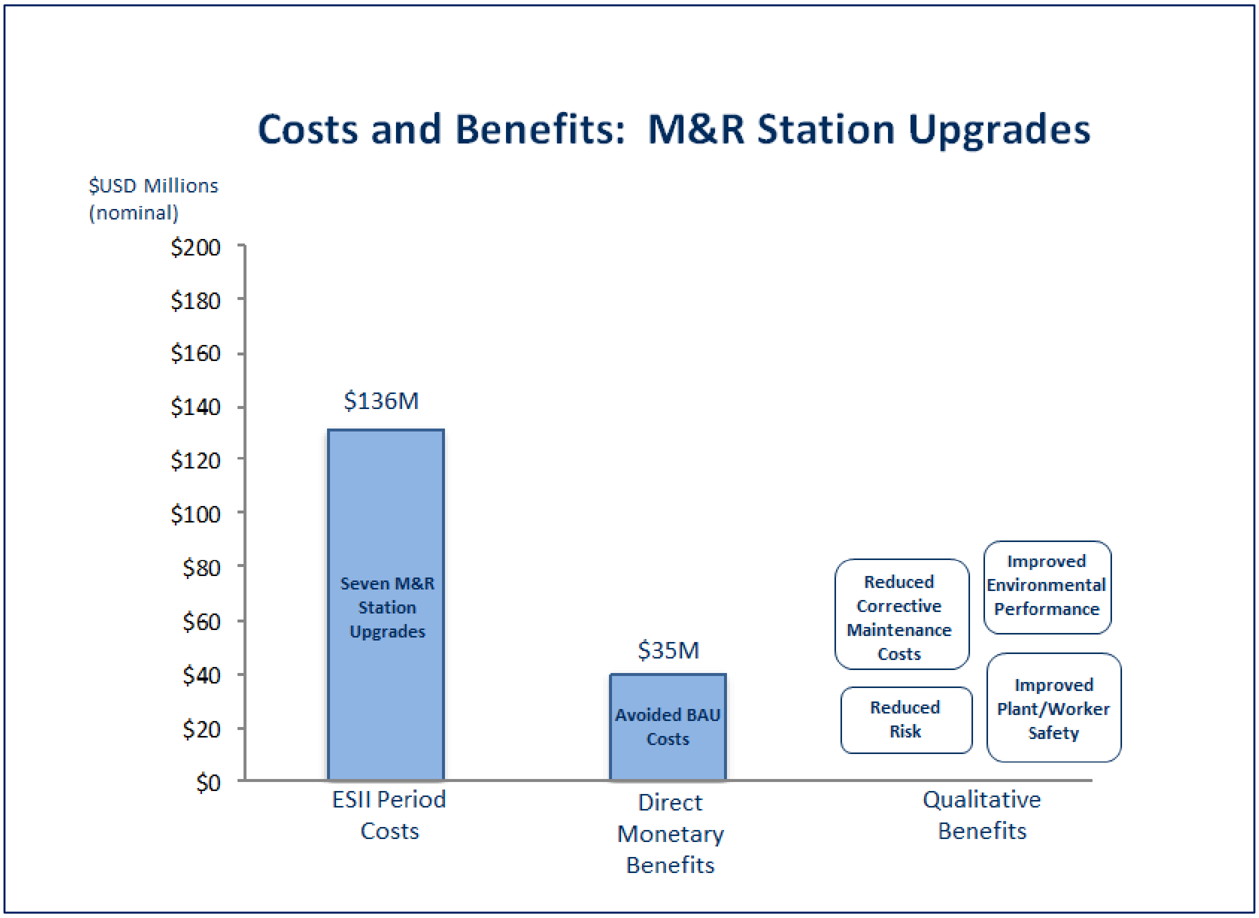


Figure 11 Costs and Benefits for the M&R Station Upgrade Subprogram

As revealed in Figure 11, the narrow monetary benefit-to-cost ratio is less than 1. However, this monetary result excludes consideration of the substantial qualitative benefits, which are enumerated in this section, and which are illustrated in Figure 11 to the right.

RISK MANAGEMENT CONSIDERATONS FOR PSE&G'S M&R STATIONS

In the case of the risks faced by PSE&G in relation to the continued operation of these seven M&R stations, PSE&G considered three risk management options:

1. Run the M&R Stations to failure (Run to Failure).
2. Delay the M&R project(s) and instead choose to closely monitor the increasing level of risks and O&M activities and expenses.
3. Rebuild and/or relocate the M&R stations.

The Run to Failure option exposes PSE&G customers to the risk that the M&R station may experience an outage due to the failure of individual components, the lack of availability of replacement parts, and/or the degradation of the physical structure to a point where operations are unsafe. Due to the customer's reliance on having natural gas available 100 percent of the time and the need to protect public and worker safety, PSE&G concluded this option was not viable.

Another choice of action is to delay the improvements and closely monitor the performance and safety of the M&R station. This too was deemed by PSE&G as not viable. Two of the seven M&R stations are in the 100 year FEMA flood zones, and all the stations are becoming increasingly obsolete and in need of rebuilding or replacement. PSE&G does not observe anything that will reverse these trends and it expects them to continue and potentially accelerate. Thus, the risk of not replacing the M&R stations will only increase the risk levels over time.

The focus on these seven M&R stations in PSE&G's M&R Upgrade Subprogram is part of PSE&G's day-to-day efforts to manage and keep in good operating condition a total of 58 M&R stations. Maintenance costs are increasing at many of these stations. The replacement of these seven stations as part of PSE&G's M&R Upgrade Subprogram supports PSE&G's efforts to safely and cost-effectively manage *all* of its M&R stations, not just those that are part of the ES II Gas Program scope. By addressing seven as part of the ES II Gas Program now, PSE&G will be in a stronger position to sustain the remaining stations.

SUMMARY FOR THE M&R STATION UPGRADE SUBPROGRAM

The cost-benefit analysis for the M&R stations is based on increasing corrective maintenance costs, avoided BAU investment costs, a wide range of strong qualitative benefits tied to modern design opportunities, and risk reduction benefits as identified through the risk modeling analysis. Many of the design features improve safety and improve overall environmental performance. While the formal monetary benefit-to-cost ratio is less than 1, this quantitative result does not reflect or include the tremendous value of many qualitative benefits described above.

Conclusions

The cost-benefit analysis developed by Black & Veatch for the PSE&G ES II Gas Program identifies many quantified and monetary as well as qualitative benefits of the two Subprograms that form the Program. In Black & Veatch's opinion, the form, structure and merits of the benefits provide a meaningful and important input to demonstrate the value and importance of PSE&G's gas system resiliency efforts. The benefits identified are reasonable, tangible, and – given the long service lives of the ES II Gas Program infrastructure – long lasting.

The purpose of PSE&G's proposed **Curtailment Resiliency Subprogram** is to support continued service to firm gas customers, to the maximum extent feasible, if a major gas outage on one of the interstate pipeline systems supplying PSE&G was to occur upstream of its various city gate delivery points. The purpose of PSE&G's proposed **M&R Upgrade Subprogram** is to modernize designs and reduce the likelihood and consequence of equipment failure and avoid future reliability, operational, and/or safety concerns.

Black & Veatch reached the following conclusions based on its benefit assessment of PSE&G's ES II Gas Program:

- The ES II Gas Program's resiliency-focused investments go beyond minimum legal service requirements, and help demonstrate PSE&G's commitment to achieving a high level of system and service reliability. The ES II Gas Program's core design criteria – to design and promote investments that enhance PSE&G's gas supply resiliency, and the modernizing and hardening of its gas distribution system facilities – are sound in relation to the vulnerabilities PSE&G perceives and under which it currently operates.
- Both of PSE&G's proposed ES II Gas Subprograms have substantial benefits related to gas supply resiliency, operational flexibility, safety, and security. These drive a range of qualitative and quantitative (monetized) benefit outcomes. The monetary benefit outcomes have been described and captured as part of a specific outage scenario and reveal the value that accrues to PSE&G and its customers from mitigating the significant consequences to gas distribution system customers of this event on the interstate gas pipeline system.
- While Black & Veatch has not speculated on the nature of the risk to the upstream pipeline system (there are many), it has offered guidance that an outage event can be reasonably described as lasting ten days (followed by a lengthy restoration period). The avoidance of this outage leads to over $1.1B of associated benefits alone. This reflects the VoLL associated with the scale and duration of this outage, and many direct costs that would be incurred by the utility and other market participants. This result does not include many other direct and indirect avoided costs or numerous qualitative benefits, such as the impacts to many public services, safety-related impacts, and the impacts to local schools. It also does not include long-term impacts to hard-to-value considerations such as loss of business confidence. These items that are not measured improve the value of the Program since it mitigates these various forms of losses.
- There is substantial value created by the rebuilding of the seven proposed M&R stations on similar grounds. While Black & Veatch has not attempted to describe a catastrophic outage event, there are growing and long terms risks to the general condition of these facilities, and their outdated conditions. Some are very old. They do not conform to modern building standards, and represent growing hazards. Two of the seven are also located in FEMA designated areas for flood hazards.

- Replacing some of these stations in the foreseeable future is not a question of if, but when, as they grow increasingly obsolete. In fact, PSE&G expects to replace three of the Stations during the next several years, given their advanced age and condition. Advancing this replacement as part of ES II is aligned to the purposes of the IIP rule, which aims to advance needed investment so as to avoid larger and costly problems in the future. Accordingly, for the M&R station upgrades, the cost-benefit analysis identifies and describes a benefit-to-cost ratio of 0.3, reflecting the limited quantifiable and monetary benefits associated with avoiding future base capital spending.
- Combining the results of both Subprograms yields a benefit-to-cost ratio of 1.1, as summarized in Figure 12.

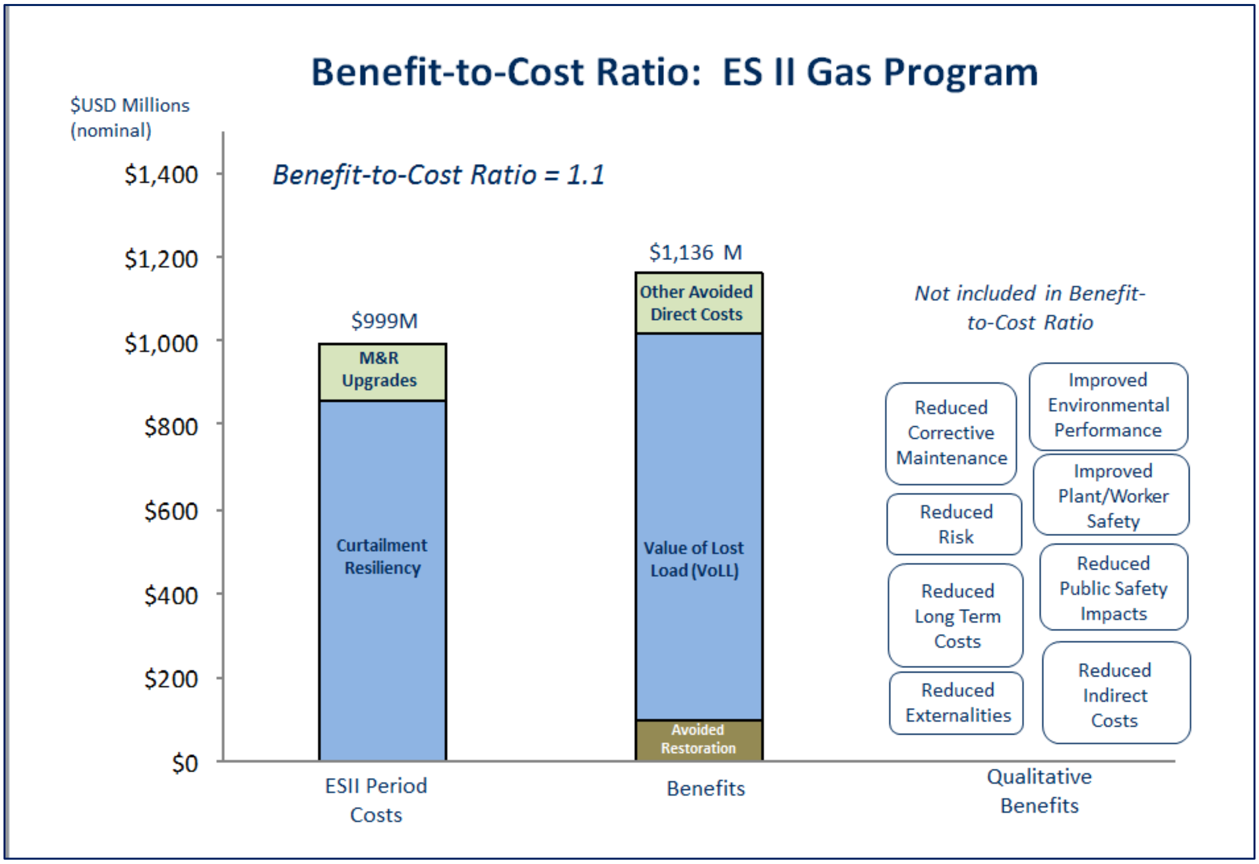


Figure 12 Benefit-to-Cost Ratio for the ES II Gas Program

- There is value created through these subprogram investments akin to an insurance policy, and this value is independent of any specific risk event having to occur that causes an outage. Such certain forecast knowledge will never exist. Rather, the construction and operation of the proposed infrastructure reduces overall system risk on a continuous basis, 24 hours a day, 365 days a year, and over many decades of planned service life. This "always on" risk reduction benefit is a reasonable way to interpret the cost-benefit analysis results. Nothing, for example, limits risks growing, and actual outage events from re-occurring, thereby increasing the benefit estimates. Moreover, since the customers are funding these investments through the rates process they will be exposed to a fraction of the ES II Gas Program cost each year while receiving the full value of the risk reduction benefits on a continuous basis. This "always on" aspect of these investments in providing risk reduction benefits is not reflected in the benefit-to-cost ratio.

- Understanding in precise and formal ways the value of impacts and associated avoided costs, -- and the loss of value from the impacts of resiliency-scale outage events, -- is recognized as a challenge within the electric and gas utility community. What is not controversial is the fact that a major outage impacts the system – and PSE&G's valued customers -- significantly, and leads to significant directly incurred and indirect costs. What is not known is the full extent of these impacts.

Appendix A - Detailed Characteristics of PSE&G's ES II Gas Subprograms

PROJECT NUMBER	PROJECT NAME	DESCRIPTION	SUPPLY	PIPELINE CHARACTERISTICS DIAMETER (INCHES)	LENGTH (MILES)	PRESSURE (PSIG)	NEW REGULATOR STATION(S) (PSIG)	COST
1	Central M&R - South Plainfield	Install 5.4 miles of 24 inch 120 psig pipeline from the Central M&R station towards South Plainfield M&R station	Project provides the ability to move Transco gas into an area currently supplied by TETCO	24	5.4	120	1	$61.70
2	Hamilton M&R- West Windsor	Install 1.5 miles of 24 inch and 10 miles of 20 inch 150 psig pipeline	Project provides the ability to move Transco gas into an area supplied by TETCO and support a supply curtailment on the Enbridge system.	24	1.5	150	2	$81.90
				20	10			
3	Mahwah- Paramus-Wanaque-Roseland							
	A	Install 11.1 miles of 24 Inch pipeline from Mahwah M&R to PSEG Glen Rock Regulator Station	Project interconnects Tennessee, out of Mahwah, Transco, out of Paramus, TETCO, out of Wanaque, and Transco, out of Roseland and will support a supply curtailment on any of these pipeline systems.	24	11.1	120	3	$271.0
	B	Installed 10.2 miles of 24 inch from Wanaque M&R to Glen Rock Regulator Station		24	10.2	120	1	
	C	Install 4.1 miles of 24 inch pipeline from Wanaque towards Kinnelon. Pipeline reduces to 12 inch and continues toward West Milford		24	4.1	120	2	
				12	7.2			
	D	Install 4.5 miles of 12 inch pipeline from Wanaque M&R towards Ringwood M&R		12	4.5	120	1	
	E	Install 0.7 miles of 24 inch pipeline from Paramus M&R going north		24	0.7	120	1	
	F	Extend the Hanover- Roseland pipeline by installing 5.1 miles of 20 inch pipeline north towards Little Falls		20	5.1	120	1	
4	Sayreville M&R - Jamesburg	Sayreville M&R will be modified to add a new 120 psi system. Install 10.3 miles of 20 inch pipeline from Sayreville M&R to Jamesburg M&R	Project provides the ability to move Transco gas into an area supplied by TETCO and support a supply curtailment on the Enbridge system	20	10.3	120	1	$59.70

PROJECT NUMBER	PROJECT NAME	DESCRIPTION	SUPPLY	PIPELINE CHARACTERISTICS			NEW REGULATOR STATION(S) (PSIG)	COST
				DIAMETER (INCHES)	LENGTH (MILES)	PRESSURE (PSIG)		
5	Bernards-Gillette-Parsippany-Chatham-Bridgewater	Install 7. 3 miles of 12 inch pipeline from Parsippany N&R to the Bernards/Gillette System	Project will interconnect Transco, out of Gillette, Chatham and Bridgewater and Enbridge, out of Bernards and Columbia, out of Parsippany and will support a supply curtailment on the Enbridge system	12	7.3	120	1	$230.00
		Install 3.5 miles of 12 inch main would be installed from Chatham M&R going west		12	3.5	120	1	
		Install 7.2 miles of 24 inch main wbetween Bernards and Gillette M&R to connect the 2 stations.		24	7.2	120	2	
		Install 3.2 miles of 12 inch main branching off the 24 inch installed between Bernards and Gillette M&R and proceed southwest to an additional psi/psi regulator feeding into the Bernards / Gillette 60psi system.		12	3.2	120	1	
		Install 6.6 miles of 12 inch main from Bridgewater M&R going north		12	6.6	120	1	
6	Supplemental LNG at Linden or Edison	Supplemental LNG facility adjacent to PSE&G facilities	Provides 50MDTH of supply					$158.90
7	Meter & Regulation Stations Upgrades							
	A	Camden	Upgrade outdated stations to current design standards including the elimination of upstream RVs, installation of 2nd regulator run with monitor regulators. Other equipment such as scrubbers, heaters, etc. will be individually evaluated for replacement.					$18.2
	B	East Rutherford						$18.9
	C	Central						$23.3
	D	Paramus						$23.3
	E	Westampton						$15.0
	F	Mt. Laurel						$20.6
	G	Hillsborough						$16.8
TOTAL					97.9		19	$999.2

Appendix B - Examples of Major Natural Gas Outage Events

- On October 11, 2017, Texas Eastern Transmission ("TETCO"), which is owned and operated by Enbridge, Inc., declared a force majeure on an unplanned gas outage that occurred at its Berne Compressor Station in Eastern Ohio. As a result, the pipeline notified shippers that gas nominations scheduled through this compressor station on its 30-inch line were being reduced to zero on October 12th (from about 1.6-2.3 Bcf per day). The pipeline returned to service on October 15th.
- On October 1, 2017, a 30-inch gas pipeline of Southern California Gas Company ("SoCalGas") exploded in Newberry Springs, California, and a second line was also damaged. The shutdown of the two pipelines meant that SoCalGas lost the ability to ship about 0.8 Bcf per day into the region. The severely damaged pipeline will remain shut down until the cause of the failure is known. The other pipeline that was damaged could be repaired by the end of December. While the impacted pipelines typically have gas flows of 0.3 to 0.5 Bcf of gas per day, and no gas customers have been curtailed to date, officials are concerned that there will be an increased risk of gas service interruptions later this winter.[85]
- TETCO also experienced a force majeure event on April 29, 2016, due to an unplanned outage downstream of its Delmont Compressor Station in Delmont, Pennsylvania. As a result, TETCO notified shippers that nominations scheduled through the Delmont Compressor Station on the Penn Jersey Line were being reduced to 0 Dekatherms per day ("Dth/d") in accordance with the curtailment procedures in Section 4.2 of TETCO's FERC Gas Tariff. The initial supply reduction was 75% for a period of approximately two weeks, at which time the curtailment was reduced to approximately 58% for a period of weeks. The curtailment was steadily reduced and ended as TETCO replaced the damaged segment and verified the integrity of the adjacent pipelines. Overall, there was some level of curtailment on the TETCO system for a total of six (6) months. Fortunately, this unplanned outage did not occur during the winter heating season but, it bears repeating: gas supply disruptions are not theoretical events. From discussions with PSE&G staff, Black & Veatch understands that if the curtailment on TETCO had occurred on a design day with an average daily temperature of 5^0F, it is possible that PSE&G may have had to curtail firm gas service to as many as 259,000 customers.
- On January 25, 2014, a pipeline break and subsequent fire occurred on a TransCanada PipeLines ("TCPL") mainline pipeline near the community of Otterburne, Manitoba, Canada (about 30 miles south of Winnipeg). As a result, approximately 4,000 gas customers of Manitoba Hydro lost gas service. Hundreds of employees and contractors across Canada worked around the clock to get specialized equipment to the site to begin repairs and support the response to get heat back on and provide assistance to those affected by the outage. Gas service was restored to all Manitoba Hydro customers within a 6-day period after the incident occurred. In addition, gas shortages occurred in the U.S., with Xcel Energy that provides gas service to over 100,000 customers in

[85] The U.S. Energy Information Agency's (EIA) Dashboard dated January 19, 2018 reports: "Natural gas pipeline outages on the Southern California Gas Company (SoCalGas) system continue to affect how SoCalGas imports natural gas into Southern California along key corridors. On January 17, 2018, new unplanned remediation work on a major pipeline reduced capacity by 270 million cubic feet per day (MMcf/d) through a key corridor on the SoCalGas distribution system. At the end of December 2017, SoCalGas completed repairs and maintenance on its natural gas pipeline network, providing more redundancy, increasing capacity by 740 MMcf/d, and helping SoCalGas manage its winter-peaking needs.
See: https://www.eia.gov/special/disruptions/socal/winter/#commentary

North Dakota, Wisconsin, and Minnesota, requesting that its customers reduce their natural gas usage until such time that the disruption ended.

- In May of 2010, a delivery station served by Florida Gas Transmission ("FGT") that delivers natural gas to TECO Peoples Gas' Jupiter and North Palm Beach County areas experienced a loss in pressure that impacted TECO Peoples Gas' ability to serve approximately 10,500 gas customers. Peoples Gas personnel from its other service areas across Florida were mobilized to assist with isolating the main distribution lines, the first stage of the restoration process. Initially, the exact restoration time was determined, but the utility indicated that it expected to be several days and could extend beyond that with critical facilities such as hospitals, nursing homes, schools and emergency response receiving first priority. It was six days before 100% of the utility's customers who experienced the gas outage had their gas service fully restored.

Appendix C - Resiliency and Reliability Needs Addressed by Other Gas Utilities

Con Edison's Commitment to and Participation in Spectra Energy's NJ-NY Expansion Project

On December 20, 2010, TETCO and Algonquin Gas Transmission, LLC ("Algonquin") filed with the FERC an application requesting authorization for their proposed New Jersey-New York Expansion Project ("NJ-NY Project") to provide up to 800,000 Dth/d of firm transportation service into the Borough of Manhattan, New York. The parties who signed up for pipeline capacity from this expansion, including Con Edison, claimed that the project was needed to eliminate existing operational constraints, mitigate the risk of severe disruption to Con Edison's gas system, provide new and existing gas consumers (e.g., utilities and electric generators) with greater sources of gas supplies, meet escalating residential and commercial demands for energy, and improve regional air quality.

Con Edison specifically stated that the proposed project would improve its ability to satisfy the operational and load demands of its end-users in Manhattan. At the time of Spectra's application, a single interstate pipeline, Transco, delivered gas to Con Edison in Manhattan. Con Edison stated that interconnecting a second interstate pipeline would enhance the flexibility, reliability, and security of its gas supply.[86] Moreover, in a letter submitted to the FERC in the referenced certificate proceeding, Con Edison's Chairman, President Chief Executive Officer stated that, "Spectra's new pipeline interconnection in Manhattan is designed to enhance the reliability of New York City's natural gas system, which is currently served by a limited number of interstate pipeline connections. A new interconnection such as Spectra's New Jersey-New York Expansion Project will mitigate the risk of a severe disruption that could result from the loss of an existing Manhattan gate station during both peak and non-peak periods of natural gas demand in New York City."[87]

Con Edison specifically contracted for an additional 170,000 Dth/d of interstate pipeline capacity from TETCO to a new point of delivery on the Con Edison System in lower Manhattan that was put in-service on November 1, 2013. This new capacity enhances reliability by adding a new delivery point to the Con Edison system and enhances supply diversity by opening access to multiple sources of supply. It also benefits customers by increasing the amount of pipeline capacity and delivered services to the area.

To accommodate the above-described gas supply-related project, Con Edison completed its Lower Manhattan Interconnection Project, which was a project that linked Con Edison's gas transmission system to TETCO's new delivery point on the lower west side of Manhattan. This interconnection, which was done as part of the larger NJ-NY Project, required the installation of approximately 1,500 feet of 30" diameter steel piping, over-pressure protection equipment, and a remotely operated valve. The project was completed in 2013 at a total cost of approximately $11M.

Planned Pipeline Safety and Reliability Gas Pipeline Project in California

San Diego Gas & Electric Company ("SDG&E") and Southern California Gas Company ("SoCalGas") recently filed for a Certificate of Public Convenience and Necessity ("CPCN") with the California Public Utilities Commission ("CPUC")[88] for its proposed pipeline safety and reliability project. The

[86] Order Issuing Certificates and Approving Abandonment, FERC Docket No. CP11-56, issued May 21, 2012, pages 9-10.
[87] Letter to FERC Chairman Jon Wellinghof from Kevin Burke, dated May 14, 2011.
[88] CPUC Docket No. Application 15-09-013 filed on September 30, 2015.

proposed project is needed to meet three fundamental objectives: (1) implementing pipeline safety requirements for one of its existing lines and modernizing the system with state-of-the-art materials; (2) improving system reliability and resiliency[89] by minimizing dependence on a single pipeline; and (3) enhancing operational flexibility to manage stress conditions by increasing system capacity.

With regard to their reliability and resiliency needs, SDG&E and SoCalGas plan to simultaneously improve the reliability and resiliency of their combined gas system by replacing their Line 1600[90] with a 36-inch-diameter gas transmission pipeline so that core and noncore customers will continue to receive gas service in San Diego in the event of a planned or unplanned service reduction or outage of the existing 30-inch-diameter Line 3010 or the Moreno Compressor Station. San Diego County is essentially completely reliant on the compressor station in the City of Moreno Valley and Line 3010, which together provide approximately 90 percent of SDG&E's capacity. SDG&E and SoCalGas indicated they were not aware of any other major metropolitan area that was so dependent on a single pipeline. A system outage on Line 3010 or the Moreno Compressor Station would constrain available capacity in San Diego, which may lead to gas curtailments. This would be alleviated with the new 36-inch-diameter line providing resiliency for both Line 3010 and the Moreno Compressor Station.

As prudent system operators, SDG&E and SoCalGas stated that they design, construct, maintain, and inspect facilities to minimize and/or prevent both planned and unplanned reductions in service or outages. Construction of temporary bypass piping or work on pipelines operating at a reduced pressure is routinely done to keep the pipelines in service and to minimize impacts to customers. However, pipelines can and do experience both planned and unplanned reductions in service levels and outages. Their gas system could suffer an unplanned reduction in service or outage in response to many threats, including excavation damage; corrosion; compressor station-related equipment failure; automatic valve malfunction; weather; and other physical/operational, technical/cyber, natural, and man-made events.

Interruption of natural gas service may have significant consequences, including the unplanned loss of electric service to customers; negative impact on business operations; interruption of service for cooking, heating, and hot water; and inability to fuel private and public transportation that is reliant on natural gas.

San Diego essentially is reliant on the compressor station in the City of Moreno Valley and Line 3010, which together provide approximately 90 percent of SDG&E's capacity. A complete outage of Line 3010 would result in a loss of gas service to SDG&E's core and noncore customers. A partial outage due to a loss of compression or pressure reduction on the pipeline is very likely to impact noncore customers and may affect core customers, depending on its scope, location, and duration. From an electric reliability perspective, a single point failure on the gas system could place firm electric load at risk due to electric generation curtailments. The new 36-inch-diameter pipeline

[89] SDG&E and SoCalGas defined "resiliency" as the ability to prepare for and adapt to changing conditions, and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents. SDG&E and SoCalGas use the terms "resiliency" and "redundancy" interchangeably throughout their application because a redundant transmission pipeline enables a gas system to be resilient.
[90] Line 1600 is an existing, approximately 50-mile natural gas transmission line constructed in 1949 that has not been pressure tested in accordance with modern day practices and recently-adopted regulations. In Decision 14-06-007, the CPUC adopted a Pipeline Safety Enhancement Plan prepared by SDG&E and SoCalGas which called for pressure testing or replacing the transmission function of Line 1600.

provides redundancy for both compression and pipeline service interruptions and addresses the single point of failure scenario.

Responses to Superstorm Sandy by the Gas Distribution Utilities Serving New York City

In the wake of Superstorm Sandy, gas service was lost to approximately 80,000 National Grid and approximately 4,000 Consolidated Edison customers. As the Storm intensified, Con Edison and National Grid needed to take immediate action, resulting in the shutdown of sections of their respective distribution systems. In some parts of the low-pressure distribution system, the pressure of floodwaters quickly exceeded the pressure inside the gas mains, resulting in water intrusion through cracks, holes and other weak points. Meanwhile, in the high-pressure distribution system, floodwaters entered some customer service lines. The net effect of the preemptive actions and the inundation damage was loss of gas service in a number of city neighborhoods, including Coney Island, Howard Beach, the Rockaways, Edgewater Park, Locust Point, City Island, and portions of the East Village and South Street Seaport. Additionally, some of Con Edison's gas control and monitoring equipment stopped functioning, due to the loss of power and telecommunications services.

As Sandy's floodwaters receded, restoration primarily depended on the removal of water from distribution mains, equipment and pipe inspections, and the re-lighting of customers' appliances. Though this work began almost immediately, damage to some system components was extensive. For example, in the weeks following the storm, National Grid had to replace 13 miles of gas mains serving Breezy Point (which had also been damaged by fire) and New Dorp (in Staten Island).

Coming out of this situation, there were two important operational initiatives that were identified to address the reliability issues related to the two gas distribution utilities serving New York City.[91]

1. *Work with pipeline operators to expand and diversify natural gas supply* - the natural gas connections to New York City generally have sufficient capacity to provide the city's customers with gas, but on days when demand is high, all five city-gate connections are needed to prevent forced shutdowns. The City will continue to support ongoing projects by gas pipeline operators to install additional city-gate capacity linking New York City to new natural gas pipelines.

2. *Work with utilities and regulators to strengthen the in-city gas transmission and distribution system* - even when adequately supplied from the outside, New York's natural gas system has limited capacity to move gas within the city. If one city-gate were to shut down on a high demand day, the New York Facilities may be unable to supply the area that the city-gate serves from elsewhere, which could cause significant outages. The City, working through its Office of Long-Term Planning and Sustainability ("OLTPS"), will collaborate with pipeline companies, Con Edison, and National Grid to assess this risk and develop plans to strengthen the in-city transmission system.

Responses of Gas Distribution Utilities to a Severe Weather Event in the Southwest U.S.

As a result of the major gas outages and curtailments that occurred during the Southwest U.S. severe weather event of February 1-5, 2011, various "peak day supply project" plans were prepared by the gas distribution utilities serving New Mexico, Texas, and Arizona. Natural gas customers experienced extensive curtailments of service during the event. These curtailments were longer in

[91] City of New York, A Stronger More Resilient New York, dated June 11, 2013.

duration than the electric outages that occurred in the region because relighting customers' equipment had to be accomplished manually at each customer's location. Gas distribution utilities interrupted gas service to more than 50,000 customers in New Mexico, Arizona and Texas. New Mexico was the hardest hit with outages of over 30,000 customers in widespread areas across the state. New Mexico provides a representative example of how each of these states responded to this serious event.

The extreme cold weather during the week of January 30 through February 5, and its effect on electric utility service, pipeline operations, and gas production resulted in a significant disruption to the supply of natural gas to New Mexico Gas Company ("NMGC"). At the same time, the weather resulted in a significant increase in demand by NMGC's customers. This combination led to decreased operating pressures on NMGC's system, resulting in the declaration of a system emergency, first on the south segment in the Alamogordo, Tularosa and La Luz areas and in the Silver City area, and then the declaration of a system emergency on the north segment in the Bernalillo and Placitas area, and for the communities serviced by the Taos Mainline including Taos, Espanola, Questa, Red River and surrounding communities and Pueblos. The result was the curtailment of over 28,000 of NMGC's customers on February 3.

The shut-off of individual gas meters, which is the first stage of restoring service, began shortly after NMGC cut off service on the morning of February 3. In some areas, NMGC personnel began shutting off meters within minutes of the curtailment. As restoration efforts got underway, the company sought additional help through its mutual assistance agreements with the American Gas Association and the Southern Gas Association, whereby member gas utilities agree to help each other in emergency situations. That morning, NMGC asked other member gas utilities by email and by conference call to send personnel to help them restore service in the affected areas. Out-of-state gas utilities responded by sending qualified service personnel, who began to arrive the following day. NMGC also sought help from other New Mexico gas utilities, and hired local contractors and plumbers to help restore service. Police, fire department, and National Guard personnel all eventually played roles in the effort to restore service. Relighting continued through the weekend and into the following week, with a workforce of more than 700 persons participating. Service was restored to some areas as early as February 5, but the statewide relighting effort was not substantially completed until the following week, on February 10.

On February 15, 2011, the New Mexico Public Regulation Commission (the "Commission") issued an Order commencing an investigation[92] into: (1) the causes for the curtailments; (2) whether the curtailments could have reasonably been avoided or mitigated; (3) how New Mexico Gas Company (NMGC) identified which customers should be curtailed and whether those decisions complied with NMGC's tariff on file with the Commission; (4) what steps can and should be taken to avoid similar curtailments from recurring in the future; (5) whether procedures used to recommence service to NMGC's customers were adequate or could be improved for the future; and (6) whether Public Service Company of New Mexico ("PNM"), El Paso Electric Company ("EPE") and Southwest Public Service Company ("SPS") curtailed or interrupted delivery of power to NMGC or interstate natural gas pipelines supplying gas to NMGC during the week of February 1, 2011, and if so, the dates and time(s) of the day such curtailments or interruptions occurred, the estimated amount of power (in kWh) that was curtailed or interrupted during each such time(s), and whether any and all of those curtailments or interruptions caused or contributed to NMGC's gas utility service curtailments.

[92] New Mexico Public Regulation Commission, In the Matter of an Investigation into New Mexico Gas Company's Curtailments of Gas Deliveries to New Mexico Consumers and Electric Utilities, Case No. 11-00039-UT (Final Order issued on December 13, 2012).

During the proceeding, NMGC presented a preliminary evaluation of six potential options to increase peak day system gas supply to NMGC's service territory: (1) developing underground storage facilities in New Mexico; (2) constructing an interstate pipeline to a new gas supply basin; (3) construction of a peak-shaving liquefied natural gas facility; (4) compressed natural gas storage; (5) propane-air enrichment plants; and (6) the acquisition and drilling of producing wells with processing facilities.93 NMGC considered a wide range of gas pipeline and operational options that would minimize the impact of future weather events by enhancing the reliability and resiliency of its gas supply sources and gas transmission system. These options included:

- *Potential Raton Basin Pipeline* - NMGC evaluated options for a new pipeline from the Raton Basin in Colorado to NMGC's Taos Mainline. The new pipeline would tie directly into the NMGC gas transmission system thereby providing additional supply. Additionally, this project would provide 50 MMcfd supply to the NMGC gas system from a new supply basin not connected to the existing interstate pipelines. Because of the variations in routes and capacity, the estimated cost of the project would range between $180M and $300M. The timeframe for this project is approximately three to four years for permitting, rights of way and construction.
- *Potential Looping of the Rio Puerco Pipeline* - This proposal loops NMGC's existing 16-inch Rio Puerco pipeline from the Redonda Compressor Station to the Santa Fe Junction. The proposed route follows an existing NMGC pipeline corridor across the Pueblo of Laguna, terminating at the West Mesa takeoff just north of 1-40. This new line would tie into NMGC's 24-inch diameter pipeline that was completed in 2003 and would provide additional supply capacity of approximately 200 MMcfd onto the NMGC Rio Puerco pipeline. The project is estimated to cost $41.2M and would require approximately three years of lead time for permitting and construction.
- *Potential Pipeline from Ojito to a NMGC Pipeline with Compression* - The proposed line would run approximately 29 miles along State Highway 537 from NMGC's Williams Ojito Compressor Station to the interconnect with its 12-inch Transmission Mainline near US Highway 550. The pipeline would continue another 23 miles, to interconnect with the 18-inch and 20-inch Albuquerque Transmission Mainlines in the northeast corner of McKinley County, approximately 6 miles southeast of NMGC's Star Lake Compressor Station for a total of 52 miles of new pipeline. In addition, a 5,500 high pressure (HP) compressor station near the intersection of Highway 537 and 550 would need to be constructed. The estimated cost of the pipeline, compression and metering is $115M with a three-year lead time required for permitting and construction. The assumption is made that sufficient incremental firm supply is secured to satisfy peak day needs. This project would provide an additional supply capacity of 100 MMcfd into the Albuquerque Mainlines within the San Juan Basin.
- *Potential Pipeline from Ojito to Taos Mainline at Hernandez* - This project would require construction of approximately 102 miles of 10-inch diameter pipeline south and east from the Williams Ojito Compressor Station to the 8-inch Taos Mainline near Hernandez, New Mexico. The selected route would generally follow State Highway 96 through the communities of Gallina and Coyote, New Mexico. This project is presently estimated to cost approximately $191M and would also require approximately three years of lead time for permitting and construction.
- *Potential East Mountain Pipeline* - This proposed project consists of approximately 96 miles of 24-inch diameter pipeline from a new interconnect with the interstate pipelines in Torrance County, New Mexico. The route would follow existing road corridors and interconnect with the NMGC

[93] NMPRC Case No. 11-00039-UT, Exhibit NMGC KO-5.

system just south of Santa Fe. This project is estimated to cost $100M and would require approximately two years of lead time for permitting, right-of-way and construction. This project would provide additional supply capacity of approximately 300 MMcfd directly to Santa Fe and the pipelines feeding the northern communities.

- On April 18, 2016, the New Mexico Gas Company Inc. filed an application for approval of a revised proposal to address situations like the February 2011 interruption, which appears to be pending.[94]

Planned Gas Pipeline Project in the St. Louis Area to Address Reliability and Supply Security

On January 26, 2017, Spire STL Pipeline LLC filed an Application for a Certificate of Public Convenience and Necessity with the Federal Energy Regulatory Commission ("FERC") to construct approximately 59 miles of greenfield 24-inch-diameter pipeline facilities (the "24-inch pipeline") originating at an interconnection with the Rockies Express Pipeline LLC ("REX") and connecting with an existing natural gas pipeline facility in St. Louis County, Missouri that is currently owned and operated by Laclede Gas Company (a gas utility subsidiary of Spire Inc.).[95]

The Project is a new interstate pipeline designed to provide incremental firm pipeline capacity and access to competitively-priced and productive supply basins to serve homes and businesses in the St. Louis metropolitan area and surrounding counties in eastern Missouri. The Project will enhance reliability and supply security; reduce reliance upon older natural gas pipelines; reduce reliance upon mature natural gas basins (which are connected to the older pipelines), which are subject to increased competition for their supplies and price risk; and eliminate reliance on propane peak-shaving infrastructure. Laclede Gas will contract for approximately 87% of the new pipeline's total capacity. Finally, the Project is also designed to provide a transportation path into the St. Louis market area that avoids an area of known seismic activity, and in so doing, provides an additional measure of supply security to the region.

Other Natural Gas Infrastructure Projects Seeking to Address System Reliability Concerns

In general, a gas distribution utility makes reliability improvements to its gas system when it seeks to improve system reliability in distribution areas that may be experiencing low pressure issues, where it may have experienced considerable growth, or where there are risks to outages due to upstream supply considerations (as in the case of PSE&G).

Many gas distribution systems have one main pipeline supply source into an area, and so they face a reliability risk should there be an emergency outage within that single delivery path. To alleviate the constraint and reduce the reliability risk, the gas distribution utility would provide an additional delivery path into these systems by looping existing pipelines or extending facilities from higher pressure pipelines.

[94] The April 2016 NMGC petition is available at: *164.64.85.108/infodocs/2016/4/PRS20221362DOC.PDF*. A full update on this revised proposal is beyond the scope of this study.
[95] Black & Veatch is aware of the completion of the federal Environmental Assessment (EA) prepared by the U.S. Army Corp of Engineers and the Illinois Department of Agriculture for the Federal Energy Regulatory Commission (FERC). This is part of FERC Docket CP17-4-00-000 and 001. The notice of availability is dated September 29, 2017. See: *https://www.ferc.gov/industries/gas/enviro/eis/2017/CP17-40-EA/notice.pdf*. The comment period for the EA closed on October 30, 2017. Black & Veatch is not aware of additional FERC actions beyond this stage in the certification process.

The Looping Project undertaken by Vermont Gas Systems, Inc. ("VGS") is a multi-phase, multi-year process that began in 1995 to reinforce or "loop" VGS' transmission-pressure pipeline network in order to provide necessary capacity to enhance reliability and serve its growing customer base. Phases I through VI of the Looping Project have involved 16-inch diameter pipe constructed and tested for a maximum allowable operating pressure of 1,440 psig, along with whatever interconnection facilities were required in each phase.

For most of its gas transmission system, VGS currently operates a single-line transmission system.[96] If there was serious damage on this section of the transmission line, it would affect the ability to serve the customers downstream of the damage. Adding a second line to loop the transmission system provides VGS with the opportunity to bypass the damaged pipeline and repair it without curtailing service to customers. Also the Project will provide additional line pack in the event of a temporary disruption of supply upstream of the VGS border station with which to serve its customers. The design and engineering criteria utilized by VGS with this Project will ensure that the existing system stability and reliability are not adversely affected by the Project.

Another example of this type of operational solution is a recent pipeline project that was considered by Peoples Natural Gas Company, LLC to improve the reliability of an area in Butler County, Pennsylvania (North of Pittsburgh). There is an area of the gas utility's service territory that has several thousand residential customers and numerous commercial customers relying on a single feed pipeline with limited capacity. The gas utility's System Reliability Improvement Project was to install a second, high pressure supply feed into that area allowing for better service reliability by providing an additional supply feed as well as a backup feed of supply in case the existing feed were to fail in the winter.

[96] VGS receives all of its gas supplies from a location north of the Burlington area at the U.S./Canadian border through the inter-provincial gas transmission facilities of Trans Canada PipeLines Limited.

Appendix D – Gas Outage Event and Restoration Activities

Black and Veatch reviewed PSE&G's key policies in order to clarify the critical tasks that PSE&G must accomplish during a major outage event. These policies include:

- **Curtailment for Natural Gas Load** policy which details the Gas Curtailment Plan, from public appeal for conservation of gas resources to curtailment of residential and commercial services.
- **Customer Restoration** policy which provides guidelines on how PSE&G will restore various types of public gas outages from a partial (loss of gas pressure and supply for a brief period of time) to a complete outage (zero pressure in the affected distribution system).
- **Gas Restoration Contingency Manual,** which covers:
  - Delivery Emergency Response Center (DERC) Command Center
  - Field Command Points
  - Designated Responsibilities
  - Field Coordination
  - Damage Assessment
  - Materials Assessment
  - Gas Restoration Safety Procedure
  - Restoration Tracking Forms
  - Mutual Aid Responsibilities
  - Logistics
  - Normal workload during restoration

Using as inputs the findings of the ***high-consequence, low-probability*** gas outage scenario described in this report, Black & Veatch, with input from PSE&G, identified a sequence of events based on a Enbridge supply disruption, from hour 0. Of the 177,132 meters within the outage area, 92 percent are residential (162,500). This translates into a loss of gas service to approximately 435,500 residents.[97] As is shown in Figure 13, these residents would be without natural gas anywhere from 4 days to 73 days (with the majority of the customers being restored within 40 calendar days.)

[97] This is based on applying a factor of 2.68 for each household, as determined by the 2010 U.S. Census for the State of New Jersey. U.S. Census. Housing Characteristics: 2010. 2010 Census Briefs. Report c2010br-14. Table 4, page 10. Available at: https://www.census.gov/2010census/data/2010-census-briefs.php

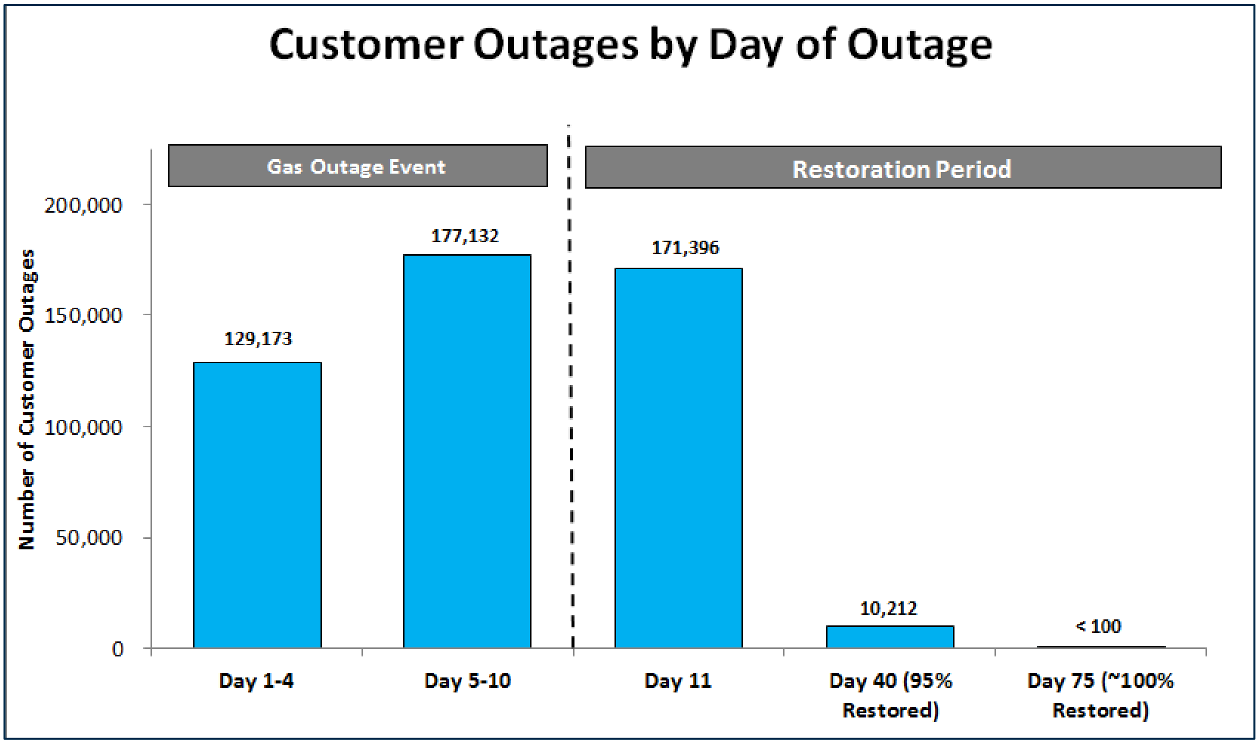


Figure 13 Customer Outages by Day of Outage[98]

It is useful to note the following relationships when reviewing the outage steps and stages:

- **177,132 Customers** - The outage analysis is based on the number of meter customers.
- **123,000 Services** - There are fewer services than customers or meters, as several customers can be supplied off of one distribution service line. Certain activities described below are related to services, not meters or customers.
- **435,500 Residents** - Black & Veatch estimates (using Census information) that there are these numbers of total residents associated with the 162,500 residential customers.

Outage Activities

Black and Veatch obtained information to determine the duration of the restoration period, identify the critical tasks involved during the gas outage event and restoration period, and estimate the number of qualified personnel required to safely and efficiently carry out the customer notice, system protection and system restoration activities. These activities include the mobilization of the needed work force to safely perform the shutdown of the affected distribution system areas; the turn-off of gas to each individual service and safe and efficient restoration of gas service to all affected customers in a timely manner. A list of high level activities is shown below:

[98] 30 days of restoration covers the substantial completion of re-light activities. 75 days is an estimate of the time to complete nearly all restoration activities.

Day 1 Activities

- **Loss of Enbridge Supply** - PSE&G receives word from Enbridge or notices a major drop in pressure from the supplier. This is unplanned, and could occur at any time of day or day of week.
- **Communication**- PSE&G notifies its emergency response chain of command.
- **Peaking Plants** - PSE&G commences the start up all gas peaking plants.
- **Curtailment/Interruptions** - PSE&G starts the customer curtailment process.
- **Public Appeal** - PSE&G commences public appeal.
- **Delivery Emergency Response Center (DERC) Command Center** - PSE&G opens and staffs its DERC.
- **M&R Stations -** PSE&G sends crews to operate valves at M&R stations affected by the loss of supply. An M&R station typically represents the demarcation point of facility ownership between the natural gas supplier and PSE&G (10 M&R stations in the outage footprint area).
- **Rolling Blackouts** - PSE&G starts rolling electric blackouts, pursuant to its emergency response procedures.[99]
- **Hydraulic Models** - Based on information available PSE&G analysts develop a hydraulic model to determine the potential impact of the outage on affected customers.
- **Critical Valves** - PSE&G sends field personnel to shutoff critical valves in order to isolate areas (129 valves to be closed).

Day 2-10 (9 days) Activities

For context, it is useful to point out that during the early part of the outage PSE&G may not have good information about the scope and scale of the outage, and cannot easily predict when gas supplies will be restored. It is likely that for several days PSE&G will not have good information on when to expect a restoration of gas supplies. Additionally, it is important to recognize that facing this uncertainty PSE&G would proceed to shut down the affected areas of the distribution system as quickly as safely and reasonably possible. PSE&G would want to be in a strong position to re-light the system as soon as the gas outage event ends.

- **Critical Valves** - PSE&G crews continue to shut off valves to isolate areas.
- **Contractors** - PSE&G contacts qualified contractors for assistance in excavation for isolation activities.
- **Cuts and Caps** - PSE&G sends field crews to cut and cap mains that do not have accessible valves (56 locations).
- **High Pressure Regulators Stations** - PSE&G closes valves to high pressure regulator stations supplying isolated areas (6 HP regulator stations).
- **Utilization Pressure Regulator Stations** - PSE&G closes valves to utilization pressure regulators supplying isolated areas (26 UP regulator stations).

[99] Because many gas loads are driven by electric pumps and fans (such as home furnaces), the rolling electricity blackouts curtail gas loads during the duration of the blackouts.

- **Staging Areas** - Based on the areas isolated, PSE&G sets up command centers and staging areas.
- **Service Shut-offs** - PSE&G commences shut of services (123,100 services).
- **Drips** - PSE&G checks drips for water intrusion (150 drips).
- **Verification** - PSE&G verifies that all services have been shut-off prior to starting the restoration phase.

Day 10 Activities

For context, the outage scenario assumes that the gas outage period ends at the end of Day 10. As noted above, PSE&G may not have a good estimate of this milestone during the preceding 10 days.

- **Restoration of Enbridge Supply** - Supplier reintroduces gas back into the pipeline and gas is available at PSE&G's M&R stations.

Day 11 - 40 (30 days) Activities

- **M&R Stations** - PSE&G opens valves at M&R stations and repacks PSE&G's main trunk lines (larger diameter and higher pressure pipelines). (10 M&R stations)
- **Critical Valves** - PSE&G starts the process of opening critical valves to repack pipelines serving isolated areas that were curtailed (129 valves to be opened).
- **High Pressure Regulator Stations** - PSE&G opens valves to high pressure regulator stations supplying isolated areas (6 HP regulator stations).
- **Utilization Pressure Regulator Stations -** PSE&G opens valves to utilization pressure regulators supplying isolated areas (26 UP regulator stations).
- **Contractors** - PSE&G contacts qualified contractors for assistance in excavation for stop offs, purging, and clearing activities.
- **Stop offs on Low Pressure System** - In order to introduce gas safely and in a systematic manner PSE&G installs stop-offs at key locations on utilization pressure systems (1,056 locations).
- **Purge or Clear Pipelines** - Before re-introducing gas into the distribution system all pipelines and services must be purged or cleared of air prior to re-introducing natural gas into any pipeline or service (832 purges and 1,768 clears).
- **Customer (Meter) Service Restoration** - Once pipelines to an isolated area have been purged or cleared of air and natural gas has been safely re-introduced back into the system the customer meters re-light process can begin. By day 40 approximately 95% of the customers should be restored. (177,132 customer meters)
- **Drips** - PSE&G checks drips for water intrusion (150 drips).

Day 41- 73 (33 days) Activities

- **Continued Customer Restorations** - PSE&G will continue to contact and restore the remaining 5 percent of customers who may not have been available during the initial 30-day restoration activity.
- **Post Emergency Procedures** - Following the restoration activity, PSE&G will conduct a post emergency assessment to determine:

- What parts of the outage restoration went as planned?
- What parts of the restoration plan did not go as planned?
- What were some of the restoration activities that should have been done but were not?
- What were some of the restoration activities that were done but should not have been done?
- PSE&G will review the critical valve locations, cut and cap locations and sectioning of isolated areas for improved isolation methods and locations of key valves.

Outage Personnel

Based on a 10 day gas outage event of approximately 123,100 services the estimated number of personnel required by PSE&G to shut these services off is developed below. For purposes of these estimates, PSE&G has assumed that it would proceed with the shut off activities at an extremely aggressive pace, working seven days per week and 12-14 hours shifts. It would need to call in extensive support from its workers in other parts of its service territory.

Additionally, PSE&G would not have immediate knowledge of the duration of the gas outage event, and the fact that outages would grow from an initial 129,173 customers to 177,132 customers by Day 5 (generating an additional 31,400 services that will require shut off). This observation is noted in the augmentation of the field crew counts on Day 4 of the outage, as explained below.

Gas Outage Event Duration (10) days

- **Service Personnel (shut-offs)**- 318 crews - increases to 493 crews on day four when peaking supplies are exhausted and an additional 31,400 services are lost.
- **M&R Station Personnel** - Five M&R crews and based on performing ten M&R shut-offs in one day.
- **Critical Valve Personnel**- Twenty seven valve crews to shut off 129 critical valves in 2 days.
- **Regulator Station Personnel** - Three regulator crews to shut off valves at thirty two regulator stations in one day.
- **Cut & Cap Distribution Personnel** - Seven crews to cut & cap 56 mains locations in two days.
- **Contractors Crews for Cut & Cap Excavations** - Six contractor excavation crews for the cut & cap excavations in two days.
- **Contractor Crews for Services Excavations** - Sixty contractor crews to perform 2,400 service line excavations for shut-offs in eight days.
- **Supervision** - Maximum of eighty supervisors based on one to ten (1-10) span of control.

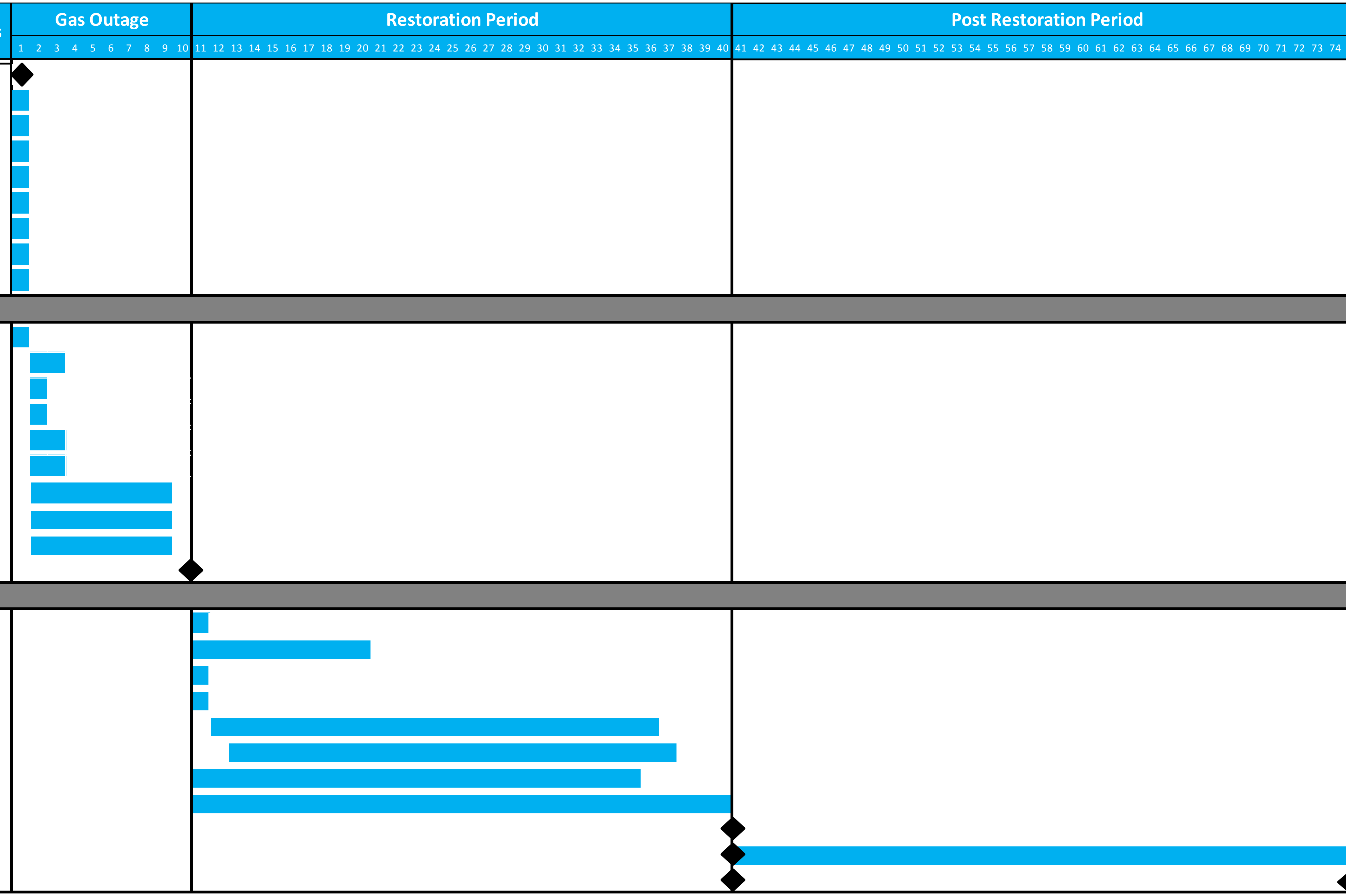
PSE&G Restoration Duration

- **Service Personnel (restoration)** - 233 service crews to restore service to 177,132 meters.
- **M&R Station Personnel** - Five M&R crews based on performing ten M&R turn-ons in one day.

- **Critical Valve Personnel**- Five valve crews to open 129 critical valves in 10 days. Crews will work in systematic method working within the restoration plan as pipelines and services are purged and cleared.
- **Regulator Station Personnel** - Three regulator crews to open valves in 32 regulator stations in one day.
- **Purge and Clear Pipelines** - 29 crews to purge and clear 2,600 mains locations in 25 days.
- **Contractors Crews for Purge and Clear Excavations** - 27 contractor excavation crews for the purge and clear activities.
- **Contractors Crews for Stop Off Excavations** - Nine contractor excavation crews for the excavations for the stop offs on UP main (1,056).
- **Supervision** - Maximum of 54 field supervisors based on one to ten (1-10) span of control.

Figure 14 illustrates the gas outage and restoration activities described above.

PSEG Activity	No.	Days
Supplier Disruption Event Starts		
Internal Communication		1
Start Peaking Plants		1
Call for Interruptions		1
Start Rolling Blackouts		1
Perform Hydraulic Model		1
Commence Public Appeal		1
Open DERC		1
Commence Logistic Response		1
Gas Outage Duration Activities		
M&R Station Shut-offs	10	1
Critical Valves Closure	129	2
HP Regulator Stations Closure	6	1
UP Regulator Stations Closure	26	1
Cut & Cap Activities	56	2
Excavation (Cut & Cap)	56	2
PSEG shutoffs (UP Services)	2,400	8
Excavation (UP Services)	2,400	8
Service Shut-offs	123,100	8
Supplier Disruption Event Ends		
Gas Restoration Activities		
M&R Station Open	10	1
Critical Valves Open	129	10
HP Regulator Stations Open	6	1
UP Regulator Stations Open	26	1
Purge & Clear Pipelines	2,600	25
Stop Offs on UP systems	1,056	25
Excavation (Purge/Clear/Stop Offs)	4,488	25
Service Restoration	168,000	30
Restore to 95% of Customers		
Service Restoration (last 5%)	9,132	33
Restoration to 100% of Customers		



Legend:
- ◆ Milestones
- Activities

Figure 14 **Gas Outage and Restoration Duration Gantt Chart**

Appendix E - Direct Costs Incurred by PSE&G during a Major Gas Outage Event

	Number	Units	Productivity per Crew	People per Crew	Hours	Cost per Person	Total Cost
Gas Outage Activities							
Critical M&R/Regulator Station/Valve Operations							
M&R Stations - Close	10	Ea	5 hr / ea	2	100	$ 196	$ 19,600
HP Regulator Stations- Close	6	Ea	1 hr / ea	2	12	$ 196	$ 2,352
UP Regulator Stations- Close	26	Ea	1 hr / ea	1	26	$ 196	$ 5,096
Critical Valve Operation	129	Ea	5 hr / ea	2	1,290	$ 196	$ 252,840
Cut & Caps to Isolate Mains	56	Ea	4 ea / day	3	504	$ 196	$ 98,784
Contractor Excavation	56	Ea	per excavation			$ 1,500	$ 84,000
Check drips	150	Ea	2 hr / ea	3	900	$ 196	$ 176,400
Customer Work							
Customer Shutoffs	123,100	Ea	36 ea / day	1	41,033	$ 196	$ 8,042,533
Excavation (Shutoffs)	2,400	Ea	6 ea / day	3	14,400	$ 196	$ 2,822,400
Contractor Excavation	2,400	Ea	per excavation			$ 1,500	$ 3,600,000
Materials							
Materials							$ 1,510,401
Total Gas Out Cost							**$ 16,614,406**

	Number	Units	Productivity per Crew	People per Crew	Hours	Cost per Person	Total Cost
Restoration Activities							
Critical M&R/Regulator Station/Valve Operations							
M&R Stations - Open	10	Ea	2 hr / ea	2	40	$ 196	$ 7,840
HP Regulator Stations - Open	6	Ea	1 hr / ea	2	12	$ 196	$ 2,352
UP Regulator Stations - Open	26	Ea	1 hr / ea	1	26	$ 196	$ 5,096
Critical Valve Operation	129	Ea	3 hr / ea	2	774	$ 196	$ 151,704
Re-Introduce Gas Into System							
Purge Pipelines	832	Ea	3 ea / day	3	9,984	$ 196	$ 1,956,864
Purging Contractor Excavation	1,664	Ea	per excavation				$ 2,496,000
Clear Pipeline	1,768	Ea	4 ea / day	3	15,912	$ 196	$ 3,118,752
Clearing Contractor Excavation	1,768	Ea	per excavation				$ 2,652,000
Stop Offs on UP systems	1,056	Ea	5 ea / day	3	12,672	$ 196	$ 2,483,712
Contractor Excavation	1,056	Ea	per excavation			$ 1,500	$ 1,584,000
Check Drips	300	Ea	2 hr / ea	3	1,800	$ 196	$ 352,800
Customer Relights							
Relight Customers	177,132	Ea	24 ea / day	1	88,566	$ 196	$ 17,358,936
Materials							
Materials							$ 3,217,006
Total Restoration Costs							**$ 35,387,062**
Summary							
Total Gas Out + Restore Costs							$ 52,001,467
Risk & Contingency	AACE Cost Classification Class 4 Estimate						$ 15,600,440
Grand Total							$ 67,601,908
Total Cost per Affected Customer							**$ 381.65**

Appendix F - VoLL Calculations for PSE&G's Curtailment Resiliency Subprogram

VoLL Estimate - Gas

Input Value =	
Derived Value =	
Input from other Analysis Effort =	
Key Result =	

Input Assumptions

Gas Outage Scenario Duration (in Days) - Upstream Curtailment + Restoration		
Upstream Outage Event Duration	10	Days (per Outage Scenario)
End of Curtailment Recovery Period (95% level)	40	Days (bookend; based on "gas relight" scenario)
Total Restoration Period (to 95%)	30	
Equivalent Total Outage Days (Upstream Curtailment + Restoration)	24.7	Black & Veatch Analysis Result: Per Outage Restoration Duration Evaluation
Daily Gas Consumption Curtailed During Gas Outage Scenario		
Residential Customers	111,600	Dth/d - Per PSE&G Analysis
Commercial Customers	14,700	Dth/d - Per PSE&G Analysis
Industrial Customers	36,800	Dth/d - Per PSE&G Analysis
Number of Customers Curtailed During Gas Outage Scenario		
Residential	162,500	Customers - Per PSE&G Analysis
Commercial	13,000	Customers - Per PSE&G Analysis
Industrial	1,632	Customers - Per PSE&G Analysis
Total	177,132	Customers - Per PSE&G Analysis
Residential	91.7%	
Commercial	7.3%	
Industrial	0.9%	
Total	100.0%	
Current Average Retail Rate - Residential (Base + BGSS Charge)	$9.077	per Dth - PSE&G Data

Residential Segment VoLL (Applying Current Gas Tariff)

Daily Gas Consumption Curtailed During Outage	111,600	Dth/d (Referenced from Above)
Total Gas Consumption Curtailed During Outage	2,755,980	Dth
Retail Price of Natural Gas (Dth)	$9.077	Per Dth (Referenced from Above)
Value of Foregone Use (Based on Full Tariff Price)	**$25,016,034**	
Daily Value per Customer	$6.23	

C&I Customer Segment: Value Added Method (based on GSP estimates)

GSP - Entire State Output for 2017 (per BEA)	$585,726,000,000	Per BEA **
Rate of Change (per BEA) 2016-2017	2.2%	U.S. Bureau of Economic Analysis
GSP - Estimated Total State Output -- 2018	$598,388,970,902	Per Year
GSP allocated to PSE&G (Based on the Number of PSE&G's Firm C&I Gas Customers)		
Total Number of C&I Electric Customers in New Jersey	526,508	EIA (US DOE) Form 861 (2016). Assumes each C&I gas customer also requires electric service
Total Number of C&I Gas Customers Served by PSE&G	181,000	PSE&G Data (12 months Ended November 2016)
PSE&G portion of Value Add, based on Percentage	34.4%	
2018 Total PSE&G C&I Gas Customer Value Add	$205,710,841,494	Per Year
Percent of Firm C&I Gas Customers Served by PSE&G	79.5%	Source: PSE&G Annual Gas Consumption Data (Twelve Months Ended November 2016)
2018 PSE&G Firm C&I Gas Customer Value Add For Entire Service Territory	$163,540,118,988	Per Year
Percent of PSE&G's Firm C&I Gas Customers Curtailed During the Gas Outage	8.1%	
2018 PSE&G Firm C&I Gas Customer Value Add For Customers Curtailed	$13,220,547,077	Per Year
GSP Daily Rate for Firm C&I Gas Customers Curtailed	$36,220,677	Per Day
GSP Daily Rate Per Firm C&I Gas Customer (GSP/Day/Customer) For Customers Curtailed	$2,475	Per Day Per Customer *(Compare with Brattle, Page 33, Table II-3: $2,351 Unadjusted, $1,775 Adjusted)*
Accumulated GSP for Firm C&I Gas Customers Over Duration of Gas Outage	**$894,475,600**	
Value Added Impact, per Outage Scenario, as % GSP	0.15%	*This is impact of gas outage as a percent of total economic output of New Jersey*
Value Added Impact, per Outage Scenario, as % GSP (of PSEG territory)	0.43%	*This is impact of gas outage as a percent of total economic output within the PSE&G service territory*

Summary

C&I VoLL (*Based on the Value of Direct Business Impacts from Gas Outage*)	**$894,475,600**
Residential VoLL (*Based on the Current Retail Price of Natural Gas*)	**$25,016,034**
Total	**$919,491,634**

*** https://www.bea.gov/iTable/iTable.cfm?reqid=70&step=1&isuri=1&acrdn=1#reqid=70&step=10&isuri=1&7003=200&7035=-1&7004=naics&7005=-1&7006=34000&7036=-1&7001=5200&7002=5&7090=70&7007=2017&7093=levels*

Appendix G - Benefits of PSE&G's M&R Upgrade Subprogram

Station Name	Attributes			Benefits of Replacement & Upgrade						
	New Station	Proposed Construction Adjacent to Existing Station	Consolidate Existing stations into New Building	Relieve flooding Issue (Raise Building above 100 Year FEMA Elevation)	Replacement of Obsolete Equipment - Hard to Repair - Hard to Find Suitable Replacement Parts	Reduces Methane Release Points	Remove Upstream Relief Valve - New Piping Rated at MAOP of Pipeline Company	New Design - with Series Regulators with a Working Regulator and Monitor Regulator for Overpressure Protection	Downstream Relief Valve Installed- Protects Downstream Piping	Improved Site Remediation Opporunties
Camden	●	●		●	●	●	●	●	●	●
East Rutherford	●	●		●	●	●	●	●	●	
Central			●		●	●	●	●	●	
Paramus	●				●	●	●	●	●	
Westampton	●	●	●		●	●	●	●	●	
Mount Laurel	●	●	●		●	●	●	●	●	
Hillsborough	●	●	●		●	●	●	●	●	

NOTICE TO PUBLIC SERVICE ELECTRIC AND GAS COMPANY GAS CUSTOMERS

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of The Second Energy Strong Program (Energy Strong II)

Notice of Filing and Notice of Public Hearings

BPU Docket No.: XXXXXXXXXX

TAKE NOTICE that, on June 8, 2018 Public Service Electric and Gas Company (Public Service, PSE&G, the Company) filed a Petition and supporting documentation with the New Jersey Board of Public Utilities (Board, BPU). The Company is seeking Board approval to implement and administer an extension to PSE&G's Energy Strong Program (ES II or the Program) and to approve an associated cost recovery mechanism.

PSE&G seeks Board approval to invest up to $1.503 billion in ES II Electric Program Investments across its service territory. Over the Program's duration, PSE&G plans to upgrade 31 substations, upgrade circuits to protect them from storms, modernize the distribution system with communications and controlled mechanisms and invest in contingency reconfiguration strategies to harden its electric system. In addition, PSE&G seeks Board approval to invest up to $999.2 million, $ 910.9 million of which will be ES II Gas Program Investments. Over the Program's duration, PSE&G plans to complete projects that will improve the resiliency of its gas distribution system to potential interstate gas pipeline curtailments and modernization and storm harden Metering and Regulation stations across its gas service territories.

In conjunction with the implementation of the Program, PSE&G will seek Board approval to recover in base rates the revenue increases associated with the capital investment costs of ES II. While the Company is not seeking an increase at this time, PSE&G is seeking authority to recover a return on and return of its investments through semi-annual adjustments to its base rates beginning on March 1, 2021 for electric and September 1, 2022 for gas. The Company estimates that the rate change for electric rates effective March 1, 2021 would increase rates by approximately $20.1 million and the rate change for gas rates effective September 1, 2022 would increase rates by approximately $17.2 million. These rate changes are only estimates at this time and are subject to change.

For illustrative purposes, the March 1, 2021 and September 1, 2022 estimated base rates including New Jersey Sales and Use Tax (SUT) for residential Rate Schedules RS and RSG, respectively, are shown in Table #1. Tables #2 & #3 provides customers with the approximate effect of the proposed change in base rates relating to the Program, if approved by the Board, effective March 1, 2021 for electric and September 1, 2022 for gas. The annual percentage increase applicable to specific customers will vary according to the applicable rate schedule and the level of the customer's usage.

Under the Company's proposal, a residential electric customer using 750 kilowatt-hours per month during the summer months and 7,200 kilowatt-hours on an annual basis would see an initial increase in the annual bill from $1,215.76 to $1,220.96, or $5.20 or approximately 0.43%. The approximate effect of the proposed electric base rate change on typical gas residential monthly bills, if approved by the Board, is illustrated in Table #4.

Under the Company's proposal, a residential gas heating customer using 100 therms per month during the winter months and 610 therms on an annual basis would see an initial increase in the annual bill from $558.56 to $564.42, or $5.86 or approximately 1.05%. Also, a typical residential gas heating customer using 165 therms per month during the winter months and 1,010 therms on an annual basis would see an initial increase in the annual bill from $879.16 to $888.68, or $9.52 or approximately 1.08%. The approximate effect of the proposed gas base rate change on typical gas residential monthly bills, if approved by the Board, is illustrated in Table # 5.

Based upon current projections and assuming full implementation of the complete Program as proposed, the anticipated incremental annual bill impact for the typical residential electric customer using 7,200 kilowatt-hours annually would be: $5.20 or approximately 0.43% effective 3/1/2021; $5.20 or approximately 0.43% effective 9/1/2021; $4.72 or approximately 0.39% effective 3/1/2022; $12.64 or approximately 1.04% effective 9/1/2022; $12.96 or approximately 1.07% effective 9/1/2023; $7.24 or approximately 0.60% effective 3/1/2024; $0.56 or approximately 0.05% effective 9/1/2024.

Based upon current projections and assuming full implementation of the complete Program as proposed, the anticipated incremental annual bill impact for the typical residential gas heating customer using 1,010 therms annually would be: $9.52 or approximately 1.08% effective 9/1/2022; $7.34 or approximately 0.83% effective 9/1/2023; $42.94 or approximately 4.88% effective 9/1/2024.

Tables #6, #7, #8, & #9 provide customers with the estimated incremental and cumulative rate impacts of the Program to typical and class average customers for Residential, Commercial, and Industrial classes, respectively. The annual percentage increase applicable to specific customers will vary according to the applicable rate schedule and the level of the customer's usage. It is anticipated that the Company will make semi-annual filings each year of the Program to request the Board's approval to implement that Program Year's revenue requests. The Board's decisions may increase or decrease the percentages shown.

Any rate adjustments with resulting changes in bill impacts found by the Board to be just and reasonable as a result of the Company's filing may be modified and/or allocated by the Board in accordance with the provisions of N.J.S.A 48:2-21 and for other good and legally sufficient reasons to any class or classes of customers of the Company. Therefore, the described charges may increase or decrease based upon the Board's decision.

Copies of the Company's filing are available for review by the public at the Company's Customer Service Centers, online at the PSEG website at http://www.pseg.com/pseandgfilings and at the Board of Public Utilities at 44 South Clinton Avenue, Seventh Floor, Trenton, New Jersey 08625-0350.

The following dates, times and locations for public hearings have been scheduled on the Company's filing so that members of the public may present their views. Information provided at the public hearings will become part of the record of this case and will be considered by the Board in making its decision.

Date 1, 2018	Date 2, 2018	Date 3, 2018
Time 1	Time 2	Time 3
Location 1	Location 2	Location 3
Location 1 Overflow	Location 2 Overflow	Location 3 Overflow
Room 1	Room 2	Room 3
Room 1 Overflow	Room 2 Overflow	Room 3 Overflow
Address 1	Address 2	Address 3
City 1, New Jersey Zip 1	City 2, New Jersey Zip 2	City 3, New Jersey Zip 3

In order to encourage full participation in this opportunity for public comment, please submit any requests for needed accommodations, such as interpreters, listening devices or mobility assistance, no less than 48 hours prior to the above hearings to the Board's Secretary at the following address.

Customers may also file written comments with the Secretary of the Board of Public Utilities at 44 South Clinton Avenue, Third Floor, Suite 314, P.O. Box 350, Trenton, New Jersey 08625-0350 ATTN: Secretary Aida Camacho-Welch, whether or not they attend the public hearings. To review PSE&G's rate filing, visit http://www.pseg.com/pseandgfilings.

Table # 1
BASE RATES
For Residential RS and RSG Customers
Rates if Effective March 1, 2021 for Electric and September 1, 2022 for Gas

Rate Schedule			Base Rates	
			Charges in Effect June 1, 2018 Including SUT	Estimated Charges Including SUT
Electric				
RS				
	Service Charge	per month	$2.42	$2.42
	Distribution 0-600, June-September	$/kWh	0.037079	0.038815
	Distribution 0-600, October-May	$/kWh	0.035553	0.035553
	Distribution over 600, June-September	$/kWh	0.041153	0.042889
	Distribution over 600, October-May	$/kWh	0.035553	0.035553
Gas				
RSG	Service Charge	per month	$5.82	$5.82
	Distribution Charge	$/Therm	0.320241	0.329774
	Off-Peak Use	$/Therm	0.160120	0.164887
	Basic Gas Supply Service-RSG (BGSS-RSG)	$/Therm	0.368938	0.368844

Table #2
Proposed Percentage Change in Revenue
By Customer Class for Electric Service
For Rates if Effective March 1, 2021

Electric		
	Rate Class	Percent Change
Residential	RS	0.43%
Residential Heating	RHS	0.42
Residential Load Management	RLM	0.35
Water Heating	WH	0.78
Water Heating Storage	WHS	0.13
Building Heating	HS	0.53
General Lighting & Power	GLP	0.39
Large Power & Lighting- Sec.	LPL-S	0.28
Large Power & Lighting- Pri.	LPL-P	0.21
High Tension-Subtr.	HTS-S	0.13
High Tension-HV	HTS-HV	0.12
Body Politic Lighting	BPL	1.38
Body Politic Lighting-POF	BPL-POF	0.51
Private Street & Area Lighting	PSAL	1.36
Overall		0.36

The percent increases noted above are based upon June 1, 2018 Delivery Rates, the applicable Basic Generation Service (BGS) charges, and assumes that customers receive commodity service from Public Service Electric and Gas Company.

Table # 3
Proposed Percentage Change in Revenue
by Customer Class for Gas Service
For Rates if Effective September 1, 2022

	Rate Class	Percent Change
Residential Service	RSG	1.07%
General Service	GSG	0.81
Large Volume Service	LVG	0.57
Street Lighting Service	SLG	1.32
Firm Transportation Gas Service	TSG-F	0.50
Non-Firm Transportation Gas Service	TSG-NF	0.26
Cogeneration Interruptible Service	CIG	0.33
Overall		0.85

The percent increases noted above are based upon June 1, 2018 Delivery Rates, the applicable Basic Gas Supply Service (BGSS) charges, and assumes that customers receive commodity service from Public Service Electric and Gas Company.

Table #4
Residential Electric Service for Rates if Effective March 1, 2021

If Your Annual kWh Use Is:	And Your Monthly Summer kWh Use Is:	Then Your Present Monthly Summer Bill (1) Would Be:	And Your Proposed Monthly Summer Bill (2) Would Be:	Your Monthly Summer Bill Increase Would Be:	And Your Monthly Summer Percent Increase Would Be:
1,920	200	$35.33	$35.67	$0.34	0.96%
4,320	450	76.47	77.25	0.78	1.02
7,200	750	127.90	129.20	1.30	1.02
7,800	803	137.35	138.75	1.40	1.02
13,160	1,360	236.69	239.05	2.36	1.00

(1) Based upon Delivery Rates and Basic Generation Service Residential Small Commercial Pricing (BGS-RSCP) charges in effect June 1, 2018 and assumes that the customer receives BGS-RSCP service from Public Service Electric and Gas Company.

(2) Same as (1) except includes the proposed change for the Energy Strong II Program.

Table # 5
Residential Gas Service for Rates if Effective September 1, 2022

If Your Annual Therm Use Is:	And Your Monthly Winter Therm Use Is:	Then Your Present Monthly Winter Bill (1) Would Be:	And Your Proposed Monthly Winter Bill (2) Would Be:	Your Monthly Winter Bill Change Would Be:	And Your Monthly Percent Change Would Be:
180	25	$26.06	$26.29	$0.23	0.88%
360	50	46.30	46.77	0.47	1.02
610	100	88.48	89.43	0.95	1.07
1,010	165	142.23	143.79	1.56	1.10
1,224	200	171.18	173.06	1.88	1.10
1,836	300	253.84	256.67	2.83	1.11

(1) Based upon Delivery Rates and Basic Gas Supply Service (BGSS-RSG) charges in effect June 1, 2018 and assumes that the customer receives commodity service from Public Service.

(2) Same as (1) except includes change for the Energy Strong II Program..

Table # 6
Residential Electric Service
Projected Incremental Percent Change
From Annual Bills Effective June 1, 2018

Rate Class	Forecasted % Increase 3/1/2021	Forecasted % Increase 9/1/2021	Forecasted % Increase 3/1/2022	Forecasted % Increase 9/1/2022	Forecasted % Increase 9/1/2023	Forecasted % Increase 3/1/2024	Forecasted % Increase 9/1/2024
RS	0.43%	0.43%	0.39%	1.04%	1.07%	0.60%	0.05%
RHS	0.41%	0.40%	0.37%	0.99%	1.02%	0.57%	0.04%
RLM	0.33%	0.33%	0.30%	0.80%	0.83%	0.46%	0.03%
GLP	0.38%	0.39%	0.35%	0.94%	0.96%	0.54%	0.04%
LPL-S	0.28%	0.28%	0.26%	0.69%	0.70%	0.39%	0.03%
LPL-P	0.21%	0.21%	0.19%	0.50%	0.51%	0.29%	0.02%
HTS-S	0.13%	0.13%	0.12%	0.32%	0.33%	0.18%	0.01%

The percent increases noted above are based upon Delivery Rates in effect June 1, 2018 and the applicable Basic Generation Service (BGS) charges and assuming customers receive commodity service from Public Service Electric and Gas Company. It is anticipated that the Company will make semi-annual filings each year of the Program to request the Board's approval to implement that Program Year's revenue requests. The Board's decisions may increase or decrease the percentages shown above.

Table # 7
Electric Service
Projected Cumulative Percent Change
From Annual Bills Effective June 1, 2018

Rate Class	Forecasted Cumulative % Increase 3/1/2021	Forecasted Cumulative % Increase 9/1/2022	Forecasted Cumulative % Increase 3/1/2022	Forecasted Cumulative % Increase 9/1/2022	Forecasted Cumulative % Increase 9/1/2023	Forecasted Cumulative % Increase 3/1/2024	Forecasted Cumulative % Increase 9/1/2024
RS	0.43%	0.86%	1.24%	2.28%	3.35%	3.94%	3.99%
RHS	0.41%	0.81%	1.18%	2.18%	3.20%	3.77%	3.81%
RLM	0.33%	0.66%	0.97%	1.77%	2.60%	3.06%	3.09%
GLP	0.38%	0.77%	1.12%	2.06%	3.02%	3.55%	3.59%
LPL-S	0.28%	0.57%	0.82%	1.51%	2.22%	2.61%	2.64%
LPL-P	0.21%	0.41%	0.60%	1.10%	1.61%	1.90%	1.92%
HTS-S	0.13%	0.26%	0.38%	0.71%	1.03%	1.22%	1.23%

The percent increases noted above are based upon Delivery Rates in effect June 1, 2018 and the applicable Basic Generation Service (BGS) charges and assuming customers receive commodity service from Public Service Electric and Gas Company. It is anticipated that the Company will make semi-annual filings each year of the Program to request the Board's approval to implement that Program Year's revenue requests. The Board's decisions may increase or decrease the percentages shown above. The cumulative totals in Table #7 may not agree to Table #6 due to rounding.

Table # 8
Gas Service
Projected Incremental Percent Change
From Annual Bills Effective June 1, 2018

Rate Class	Forecasted % Increase 9/1/2022	Forecasted % Increase 9/1/2023	Forecasted % Increase 9/1/2024
RSG	1.08%	0.83%	4.88%
GSG	0.79%	0.61%	3.61%
LVG	0.56%	0.45%	2.58%
TSG-F	0.48%	0.36%	2.18%
TSG-NF	0.31%	0.24%	1.40%
CIG	0.34%	0.26%	1.54%

The percent increases noted above are based upon Delivery Rates in effect June 1, 2018 and the applicable Basic Gas Supply Service (BGSS) charges and assuming customers receive commodity service from Public Service Electric and Gas Company. It is anticipated that the Company will make up to semi-annual filings each year of the Program to request the Board's approval to implement that Program Year's revenue requests. The Board's decisions may increase or decrease the percentages shown above.

Table # 9
Residential Gas Service
Projected Cumulative Percent Change
From Annual Bills Effective June 1, 2018

Rate Class	Forecasted % Increase 9/1/2022	Forecasted % Increase 9/1/2023	Forecasted % Increase 9/1/2024
RSG	1.08%	1.92%	6.80%
GSG	0.79%	1.40%	5.01%
LVG	0.56%	1.01%	3.59%
TSG-F	0.48%	0.84%	3.02%
TSG-NF	0.31%	0.55%	1.95%
CIG	0.34%	0.60%	2.14%

The percent increases noted above are based upon Delivery Rates in effect June 1, 2018 and the applicable Basic Gas Supply Service (BGSS) charges and assuming customers receive commodity service from Public Service Electric and Gas Company. It is anticipated that the Company will make up to semi-annual filings each year of the Program to request the Board's approval to implement that Program Year's revenue requests. The Board's decisions may increase or decrease the percentages shown above. The cumulative totals in Table #9 may not agree to Table #8 due to rounding.

Matthew M. Weissman, Esq.
General Regulatory Counsel - Rates

PUBLIC SERVICE ELECTRIC AND GAS COMPANY