RECEIVED 2018 JUN 29 4:04 PM

pepco
An Exelon Company

Dennis P. Jamouneau
Assistant General Counsel

EP9628
701 Ninth Street NW
Washington, DC 20068-0001

Office 202.872.3034
Fax 202.331.6767
pepco.com
djamouneau@pepcoholdings.com

June 29, 2018

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street N.W., Suite 800
Washington, DC 20005

Re: Formal Case No. 1119

Dear Ms. Westbrook-Sedgwick:

As directed by the District of Columbia Public Service Commission in Order No. 18148, Pepco Holdings LLC (PHI) submits its 2017 Across the Fence Report. Paragraph 108 of Order No. 18148 provides as follows:

> Exelon and PHI shall file annual across-the-fence reports comparing the performance and status of the utilities within the Exelon family. The reports shall address substantive areas as directed by the Commission and may include subject areas such as reliability, customer service, safety, rate and regulatory matters, interconnections, energy-efficiency and demand-response programs, and deployment of new technologies, including smart meters and smart grid, automated technologies, microgrids and utility-of-the future initiatives. The annual reports shall only be filed under separate cover in the event that the across-the-fence comparison is not duplicative of analysis provided in a separate report required by the Commission.

Please feel free to contact me if you have any questions regarding this matter.

Sincerely,

Dennis P. Jamouneau

Enclosure:

cc: All Parties of Record

Pepco Holdings
An Exelon Company

Exelon Utilities

Annual Across the Fence Report

(For Year 2017)

Submitted to the Public Service Commission of the District of Columbia
by Pepco Holdings on behalf of Potomac Electric Power Company
In Accordance with Formal Case No. 1119
Attachment B, Paragraph No. 108 of Order No. 18148.

June 29, 2018

Table of Contents

Section 1: Introduction 1
Section 2: Reliability 3
2.1 SAIFI 3
2.2 SAIDI 4
2.3 CAIDI 4
Section 3: Customer Service 5
3.1 Abandon Rate 5
3.2 Service Level 5
3.3 Calls Per Customer 6
3.4 Busy Out Rate 6
3.5 Response Time Agreement Rate 6
Section 4: Safety 7
4.1 OSHA Recordable Injury Rate 7
4.2 Vehicle Accidents 8
2017 Operational Performance Summary 9
Section 5: Rate & Regulatory Matters 10
5.1 Distribution Rate Cases 10
5.2 Adjustment and Alternative Ratemaking Mechanisms 12
5.3 Rate Design 16
Section 6: Interconnections 23
6.1 Interconnection Applications 23
6.2 Active Systems Connected 24
Section 7: Energy-Efficiency and Demand Response 25
7.1 Energy Savings (in MWH) from Energy Efficiency Programs 25
7.2 Total Resource Cost Test for Energy Efficiency 26
7.3 Total MW Available from Demand Response 27
Section 8: Deployment of New Technologies 28
8.1 Smart Meters 28
8.2 Automated Technologies 31
8.3 Microgrids 34
8.4 Electric Vehicles 37
8.5 Energy Storage 39
Section 9: Conclusion 42

Section 1: Introduction

As directed by the District of Columbia Public Service Commission (Commission) in Order No. 18148, Pepco Holdings LLC (PHI) submits its 2017 Across the Fence Report. Paragraph 108 of Order No. 18148 provides as follows:

> *Exelon and PHI shall file annual across-the-fence reports comparing the performance and status of the utilities within the Exelon family. The reports shall address substantive areas as directed by the Commission and may include subject areas such as reliability, customer service, safety, rate and regulatory matters, interconnections, energy-efficiency and demand-response programs, and deployment of new technologies, including smart meters and smart grid, automated technologies, microgrids and utility-of-the future initiatives. The annual reports shall only be filed under separate cover in the event that the across-the-fence comparison is not duplicative of analysis provided in a separate report required by the Commission. As part of a Commission proceeding or work group, BGE, Delmarva, and Pepco may offer consensus comments or program recommendations if appropriate; however, the Commission reserves the right to require each company to file separate reports and present separately before the Commission.*

The Exelon Corporation (Exelon) family of utilities (Exelon Utilities) includes:

- PHI, which is comprised of three utilities operating in the mid-Atlantic Region:
  - Potomac Electric Power Company (Pepco) operating in the District of Columbia (DC) and Montgomery and Prince George's Counties in Maryland (MD);
  - Delmarva Power & Light Company (Delmarva Power) operating in Delaware (DE) and eastern Maryland; and
  - Atlantic City Electric Company (ACE) operating in southern New Jersey (NJ).
- Baltimore Gas and Electric Company (BGE) operating in central Maryland;
- PECO Energy Company (PECO) operating in southeastern Pennsylvania (PA); and
- Commonwealth Edison Company (ComEd) operating in northern Illinois (IL).

This Across the Fence Report contains 2017 year-end performance information on each of the PHI utilities in addition to the legacy Exelon Utilities, BGE, PECO and ComEd. Additional 2018 updates may be included in certain sections for informational purposes. For those utilities, operating in multiple territories, information is presented for each jurisdiction where available. The performance information covers various aspects of the utility business including reliability, customer service, safety, rate and regulatory matters, interconnections, energy-efficiency and demand response, and the deployment of new technologies. In an effort to continuously improve, Exelon's utilities ensure that they compare themselves to their peers to evaluate their performance. Peer comparison allows for the utilities to analyze, assess, identify and adopt best practices to continuously drive performance improvements.

The legacy Exelon Utilities, BGE, PECO and ComEd, have experienced significant operational performance improvements since Exelon's 2012 merger with BGE. Those years were marked with continuous collaboration, learning, and sharing of best practices amongst all three utilities. During the second year in the Exelon family, PHI experienced notable operations improvements, including continued progress in reliability, customer service and safety.

Section 2: Reliability

The following reliability performance data compares each utility's System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI) at year-end 2017. Each utility's reliability performance is affected by regional variables including geography, weather patterns, infrastructure and density. The performance indices provided show performance using the IEEE 2.5 Beta Method. The intent of the 2.5 Beta Method is to separate major events days (MEDs)[1], as defined by IEEE Standard 1366, from the calculation of reliability statistics for SAIFI, SAIDI, or CAIDI. This approach allows major events to be studied separately from daily operations and better identify trends in daily operations that may be hidden by the large statistical effect of major events. In addition, the indices provided also show All-In performance, which includes MEDs.

2.1 SAIFI

SAIFI is defined as the interruption frequency the average customer experiences, excluding interruptions lasting 5 minutes or less in duration and planned interruptions. The table below shows the All-In SAIFI IEEE and SAIFI IEEE 2.5 Beta Method.

Table 2.1
2017 SAIFI - All-In SAIFI IEEE and IEEE 2.5 Beta Method[2]

SAIFI	Pepco - DC	Pepco - MD	Delmarva Power – MD	Delmarva Power – DE	ACE	BGE	PECO	ComEd
All-In SAIFI IEEE	0.55	0.74	1.34	1.01	1.09	0.73	0.80	0.72
SAIFI – IEEE 2.5 Beta	0.55	0.74	1.13	0.82	0.87	0.63	0.72	0.56
Major Event Days	0	0	3	3	3	4	3	10

[1] MED is any day where the SAIDI, which is the product of SAIFI and CAIDI, is greater than a threshold value. The threshold value is computed with 5 years of historic SAIDI per day using 2.5 standard deviation (beta) above the mean (alpha).

[2] There was a total of three Major Event Days in Delmarva Power – MD and Delmarva Power – DE.

2.2 SAIDI

SAIDI is defined as the interruption duration the average customer experiences, excluding interruptions lasting 5 minutes or less in duration and planned interruptions. The table below shows the All-In SAIDI IEEE and SAIDI IEEE 2.5 Beta Method.

Table 2.2
2017 SAIDI - All-In SAIDI IEEE and IEEE 2.5 Beta Method[3]

SAIDI	Pepco – DC	Pepco - MD	Delmarva Power - MD	Delmarva Power – DE	ACE	BGE	PECO	ComEd
All-In SAIDI IEEE	58	64	195	179	117	74	82	85
SAIDI – IEEE 2.5 Beta	58	64	91	79	66	52	66	45
Major Event Days	0	0	3	3	3	4	3	10

2.3 CAIDI

CAIDI is defined as the average number of minutes required to restore service when a customer experiences an interruption, excluding interruptions lasting 5 minutes or less in duration and planned interruptions. The table below shows the All-In CAIDI IEEE and CAIDI IEEE 2.5 Beta Method.

Table 2.3
2017 CAIDI - All-In CAIDI IEEE and IEEE 2.5 Beta Method[4]

CAIDI	Pepco – DC	Pepco - MD	Delmarva Power – MD	Delmarva Power – DE	ACE	BGE	PECO	ComEd
All-In CAIDI IEEE	104	86	145	177	107	101	102	118
CAIDI – IEEE 2.5 Beta	104	86	81	97	76	82	91	81
Major Event Days	0	0	3	3	3	4	3	10

[3] There was a total of three Major Event Days in Delmarva Power – MD and Delmarva Power – DE.
[4] There was a total of three Major Event Days in Delmarva Power – MD and Delmarva Power – DE.

Section 3: Customer Service

A core function of Customer Care at Exelon Utilities is to maximize the resolution of customer questions and concerns on first contact. This function provides valuable and efficient service to customers with a focus on meeting and exceeding customers' expectations. The following customer service performance data compares each utility's Abandon Rate, Service Level, Calls Per Customer, Busy Out Rate, and Response Time Agreement Rate at year-end 2017.

3.1 Abandon Rate

The Abandon Rate is calculated as the actual number of calls abandoned while waiting in queue to be answered by a Customer Service Representative (CSR) divided by the total number of calls offered (including vendors). A call is considered offered as soon as it enters the Interactive Voice Response (IVR) platform. Calls transferred between CSRs and between centers are only counted once (at the first CSR) in these calculations.

Table 3.1
2017 Abandon Rate

Pepco –DC	Pepco –MD	Delmarva Power	ACE	BGE	PECO	ComEd
0.68%	0.73%	0.20%	0.27%	1.00%	1.15%	0.80%

3.2 Service Level

The Service Level rate presented below is the count of calls answered within 30 seconds, divided by the total number of calls offered. A call is considered offered as soon as it enters the IVR platform, includes all handling methods (IVR and CSR) and excludes transfers.

Table 3.2
2017 Service Level

Pepco –DC	Pepco –MD	Delmarva Power	ACE	BGE	PECO	ComEd
91.7%	93.2%	94.9%	92.2%	89.6%	90.2%	93.7%

3.3 Calls Per Customer

The Calls Per Customer rate presented in the following table is the total calls handled (includes CSR, IVR and outsourced) divided by the total customers. Calls transferred between CSRs/centers are excluded.

Table 3.3
2017 Calls Per Customer

Pepco –DC	Pepco –MD	Delmarva Power	ACE	BGE	PECO	ComEd
3.40	3.89	3.67	3.31	2.65	2.47	2.70

3.4 Busy Out Rate

The Busy Out Rate presented in the following table is the number of customer calls that received a busy signal divided by the total number of calls offered. Calls transferred between CSRs and between centers will only be counted once (at the first CSR) in these calculations.

Table 3.4
2017 Busy Out Rate

Pepco	Delmarva Power	ACE	BGE	PECO	ComEd
0.0000	0.0000	0.0000	0.0001	0.0001	0.0001

3.5 Response Time Agreement Rate

The Response Time Agreement rate represents the percentage of call center offline and relevant backoffice work that is completed within its individual response time agreement (service level agreement) as it relates to the total offline work completed for a given time period.

Table 3.5
2017 Response Time Agreement Rate

Pepco	Delmarva Power	ACE	BGE	PECO	ComEd
90.88%	97.19%	97.68%	92.20%	93.60%	95.30%

Section 4: Safety

The Exelon Utilities strive to operate all aspects of their businesses in a manner that protects the safety and health of its employees, contractors, customers and the general public. Exelon fosters a safety culture in which everyone believes and demonstrates that accidents, injuries and occupational illnesses are preventable and all employees understand their responsibility for maintaining a safe and healthful workplace. Further, each employee recognizes and accepts his or her right and obligation to question, stop and correct any unsafe conditions or behaviors. The Exelon Utilities work together to identify and implement best safety practices.

4.1 OSHA Recordable Injury Rate

Occupational Safety and Health Administration (OSHA) recordable injuries include every occupational death, every non-fatal occupational illness or injury which involves one or more of the following: loss of consciousness, restriction of work or motion, transfer to another job, or medical treatment (not first-aid). The following table represents each utility's OSHA recordable rate.

Table 4.1a
2017 OSHA Recordable Rate

Pepco	Delmarva Power	ACE	BGE	PECO	ComEd
1.51	0.79	0.99	1.21	0.81	0.86

The OSHA DART (Days Away, Restricted or Transferred) rate includes every non-fatal occupational illness or injury which involves days away from work, restriction of work and/or transfer to another job. The following table represents each utility's OSHA DART rate as 200,000 labor hours divided by the number of exposure hours.

Table 4.1b
2017 OSHA DART Rate

Pepco	Delmarva Power	ACE	BGE	PECO	ComEd
1.10	0.49	0.57	1.15	0.42	0.49

4.2 Vehicle Accidents

A Motor Vehicle Accident (MVA) is an event in which the first harmful event involves a motor vehicle in motion coming in contact with another motor vehicle, other property, person(s) or animal(s). The MVA Frequency Rate is calculated as the number of MVAs that occur for every million miles driven.

Table 4.2a
2017 MVA Frequency Rate

Pepco	Delmarva Power	ACE	BGE	PECO	ComEd
14.89	5.05	3.11	8.12	10.61	6.36

A Responsible Vehicle Accident (RVA), a subset of MVA, is a motor vehicle accident in which an employee failed to do everything that reasonably could have been done to avoid the collision. The RVA Frequency Rate presented in the following table is calculated as the number of RVAs that occur for every million miles driven.

Table 4.2b
2017 RVA Frequency Rate

Pepco	Delmarva Power	ACE	BGE	PECO	ComEd
3.68	2.20	1.24	2.21	2.74	1.91

2017 Operational Performance Summary

A summary of the year-end 2017 operational performance for the Exelon Utilities discussed in Sections 1 through 4 of this report is presented below:

2017 Exelon Utilities Operations Performance

Category	Metric	Pepco DC	Pepco MD	DPL DE	DPL MD	ACE	BGE	PECO	ComEd
Reliability	All-In SAIFI - IEEE	0.55	0.74	1.01	1.34	1.09	0.73	0.80	0.72
	SAIFI - IEEE 2.5 Beta	0.55	0.74	0.82	1.13	0.87	0.63	0.72	0.56
	All-In SAIDI - IEEE	58	64	179	195	117	74	82	85
	SAIDI - IEEE 2.5 Beta	58	64	79	91	66	52	66	45
	All-In CAIDI - IEEE	104	86	177	145	107	101	102	118
	CAIDI - IEEE 2.5 Beta	104	86	97	81	76	82	91	81
Customer Service	Abandon Rate	0.68%	0.73%	0.20%		0.27%	1.00%	1.15%	0.80%
	Service Level	91.7%	93.2%	94.9%		92.2%	89.6%	90.2%	93.7%
	Calls Per Customer	3.40	3.89	3.67		3.31	2.65	2.47	2.70
	Busy Out Rate	0.0000		0.0000		0.0000	0.0001	0.0001	0.0001
	Response Time Agreement Rate	90.88%		97.19%		97.68%	92.20%	93.60%	95.30%
Safety	OSHA Recordable Rate	1.51%		0.79%		0.99%	1.21%	0.81%	0.86%
	OSHA DART Rate	1.10		0.49		0.57	1.15	0.42	0.49
	Motor Vehicle Accident Freq. Rate	14.89		5.05		3.11	8.12	10.61	6.36
	Responsible Vehicle Accident Freq. Rate	3.68		2.20		1.24	2.21	2.74	1.91

Section 5: Rate & Regulatory Matters

5.1 Distribution Rate Cases

The Exelon Utilities file rate cases with their regulatory commissions seeking changes to rates and other terms of their electric transmission, distribution and gas distribution (if applicable) service to recover their costs and earn a fair return on their investments. The outcomes of these regulatory proceedings impact the utilities' current and future results of operations, cash flows and financial position. The following tables provide a comparison of the jurisdictional requirements for rate cases in the operating areas of the Exelon Utilities (Table 5.1a) as well as the distribution rate case activity for the Exelon Utilities as of year-end 2017 (Table 5.1b).

Table 5.1a
Comparison of requirements for rate cases by Exelon Utility (as of 2017)

Rate Cases	District of Columbia	Maryland	Delaware	New Jersey	Pennsylvania	Illinois
Partially Forecasted Test Year	Yes	Yes	Yes	Yes	Fully Projected Future Test Year	Yes[5]
Required to Update Test Year Data to Actual	No[6]	Yes	No	Yes	No	Yes
Timing for Rate Implementation	No statute; target to complete cases within 9-12 mos. of filing	Statute - 7 mos.; rates automatically go into effect subject to refund, unless company agrees to extension	Statute - 7 mos.; company files request to implement rates, subject to refund	Combination of statute and regulation - 9 mos.; company files request to implement rates, subject to refund[7]	Statute – 9 mos. to complete cases	Statute – January 1 of the year following the filing
Time Restrictions on Initiating Subsequent Rate Filings	No	No	No	No	No, not unless agreed upon	Yes – Annually as part of a formula rates mechanism
Staff Party to Case	No	Yes	Yes	Yes	Yes	Yes

[5] When forecasting for the test year, ComEd's formula rates mechanism uses the prior year's financials as a proxy for the O&M forecasts. For capital costs, plant projected to be in service in the forecast year is included, along with the related accumulated depreciation, depreciation expense and deferred taxes associated to the projected plant.
[6] The DC PSC allows rates to be developed using a partially forecasted test period. The Company is required to update test period to actual within 180 days of completion of rate proceeding.
[7] The regulatory deadline for New Jersey Board of Public Utilities decisions in rate cases has not been strictly followed; fully litigated cases can take 12 months or more for decision. A recently promulgated regulation provides a process for a utility to implement rates subject to refund 9 months after filing of a base rate case.

Table 5.1b
Exelon Utilities 2017 Distribution Rate Case Summary[8]

ACE Electric Final Order	
Authorized Revenue Requirement Increase	$43.0M
Authorized ROE	9.60%
Common Equity Ratio	50.47%
Order Received	9/22/17
Pepco MD Final Order	
Authorized Revenue Requirement Increase	$(15.0)M
Authorized ROE	9.50%
Common Equity Ratio	50.44%
Order Received	5/31/18
ComEd Final Order	
Authorized Revenue Requirement Increase	$95.6M
Authorized ROE	8.34%[11]
Common Equity Ratio	45.89%
Order Received	12/6/17
Delmarva DE Gas Filing	
Requested Revenue Requirement Increase	$3.9M
Requested ROE	10.10%
Requested Common Equity Ratio	50.52%
Order Expected	Q4 18

Delmarva MD Final Order	
Authorized Revenue Requirement Increase	$13.4M
Authorized ROE	9.50%[9]
Common Equity Ratio	N/A[10]
Order Received	2/9/18
Pepco DC Filing	
Requested Revenue Requirement Increase	$(24.1)M
Requested ROE	9.525%
Requested Common Equity Ratio	50.44%
Order Expected	7/1/18
Delmarva DE Electric Filing	
Requested Revenue Requirement Increase	$12.6M
Requested ROE	10.10%
Requested Common Equity Ratio	50.52%
Order Expected	Q3 18

Additional Distribution Rate Case Details

The links provided below for each of the Exelon Utilities are to their respective Public Service Commission websites, detailing the latest filed distribution rate cases in each jurisdiction.

Pepco DC
Formal Case No. 1150 / 1151
https://edocket.dcpsc.org/public/search/casenumber/fc1150

[8] PECO and BGE did not have distribution rate cases filed or completed in 2017.
[9] Settlement states cost of equity solely for purposes of calculating AFUDC and regulatory asset carrying costs shall be 9.50%.
[10] The Common Equity Ratio is not explicitly stated in the Commission approved black box settlement.
[11] ComEd's Authorized ROE is determined by a formula rates mechanism.

Pepco MD
Case No. 9472
http://www.psc.state.md.us/search-results/?keyword=9472&search=all&search=case&x.x=28&x.y=19

Delmarva Power DE - Electric
Docket No. 17-0977
https://delafile.delaware.gov/AdvancedSearch/AdvancedSearchDocket.aspx

Delmarva Power DE – Gas
Docket No. 17-0978
https://delafile.delaware.gov/AdvancedSearch/AdvancedSearchDocket.aspx

Delmarva Power MD
Case No. 9445
http://www.psc.state.md.us/search-results/?keyword=9455&search=all&search=case&x.x=26&x.y=13

Atlantic City Electric
BPU Docket No. ER17030308:
http://www.nj.gov/rpa/case/electric/casematter_atlantic_city_electric.html

ComEd
Docket No. 17-0196
https://www.icc.illinois.gov/docket/files.aspx?no=17-0196&docId=259505

5.2 Adjustment and Alternative Ratemaking Mechanisms

Adjustment and alternative ratemaking mechanisms allow utilities to reduce financial risk and mitigate regulatory lag. These regulatory constructs include formula-based rate plans, such as ComEd's formula distribution rates, which provide comprehensive adjustment mechanisms that automatically adjust rates in the event that the earned return is above or below an authorized range. The presence of these tools varies throughout the utility industry and is largely dependent on the territory in which a utility operates since approval must be granted by the jurisdictional governing body. The following table presents the adjustment mechanisms and alternative ratemaking mechanisms for a number of comparable electric utilities and for the Exelon utilities that have been authorized through rate cases and other regulatory proceedings.

Table 5.2

Adjustment Clauses and Alternative Ratemaking Allowed for Exelon Utilities and Other Electric Utilities

			Adjustment Clauses (as of May 2018)						
Company	Parent	State	Fuel/ Purchased Power	Decoupling (F/P) [1]	New Capital Investment [2]	Energy Efficiency [3]	Renewables & RPS [4]	Environmental [5]	Other [6]
Ameren Illinois Company	AEE	Illinois	✓		✓	✓	✓	✓	✓
Union Electric Company	AEE	Missouri	✓	P		✓		✓	✓
Southwestern Electric Power Company	AEP	Arkansas	✓	P	✓	✓		✓	✓
Indiana Michigan Power Company	AEP	Indiana	✓	P	✓	✓	✓	✓	✓
Kentucky Power Company	AEP	Kentucky	✓	P	✓	✓		✓	✓
Southwestern Electric Power Company	AEP	Louisiana	✓	P	✓	✓		✓	✓
Indiana Michigan Power Company	AEP	Michigan	✓	P		✓	✓	✓	✓
Ohio Power Company	AEP	Ohio	✓	F	✓	✓	✓		✓
Public Service Company of Oklahoma	AEP	Oklahoma	✓	P	✓	✓		✓	✓
Kingsport Power Company	AEP	Tennessee	✓						✓
AEP Texas Central Company	AEP	Texas	NA		✓	✓		✓	✓
AEP Texas North Company	AEP	Texas	NA		✓	✓			✓
Southwestern Electric Power Company	AEP	Texas	✓		✓	✓	✓		✓
Appalachian Power Company	AEP	Virginia	✓		✓	✓	✓	✓	✓
Appalachian Power / Wheeling Power	AEP	West Virginia	✓		✓	✓			✓
ALLETE (Minnesota Power)	ALE	Minnesota	✓			✓	✓	✓	✓
Superior Water, Light and Power Company	ALE	Wisconsin	✓						
Black Hills Colorado Electric Utility Company, LP	BKH	Colorado	✓		✓	✓	✓		✓
Black Hills Power, Inc.	BKH	South Dakota	✓	P	✓	✓		✓	✓
Black Hills Power, Inc.	BKH	Wyoming	✓						
Cheyenne Light, Fuel and Power Company	BKH	Wyoming	✓	P		✓			✓
Consumers Energy Company	CMS	Michigan	✓			✓	✓		✓
CenterPoint Energy Houston Electric	CNP	Texas	NA		✓	✓		✓	✓
Virginia Electric and Power Company	D	North Carolina	✓			✓	✓	✓	
Virginia Electric and Power Company	D	Virginia	✓		✓	✓	✓		✓
DTE Electric Company	DTE	Michigan	✓			✓	✓	✓	✓
Duke Energy Florida	DUK	Florida	✓			✓		✓	✓
Duke Energy Indiana	DUK	Indiana	✓	P	✓	✓	✓	✓	✓
Duke Energy Kentucky	DUK	Kentucky	✓	P		✓			✓
Duke Energy Carolinas	DUK	North Carolina	✓	P		✓	✓	✓	✓
Duke Energy Progress	DUK	North Carolina	✓		✓	✓	✓		
Duke Energy Ohio	DUK	Ohio	✓	P	✓	✓	✓		✓
Duke Energy Carolinas	DUK	South Carolina	✓	P		✓	✓	✓	✓
Duke Energy Progress	DUK	South Carolina	✓			✓	✓	✓	✓
Rockland Electric Company	ED	New Jersey	✓			✓	✓		✓
Consolidated Edison Company of New York, Inc.	ED	New York	✓	F	✓	✓	✓	✓	✓
Orange and Rockland Utilities, Inc.	ED	New York	✓	F	✓	✓	✓		✓
El Paso Electric Company	EE	New Mexico	✓			✓			✓
El Paso Electric Company	EE	Texas	✓			✓			✓
Connecticut Lt. & Pwr.	ES	Connecticut	✓	F		✓		✓	✓
NSTAR Electric	ES	Massachusetts	✓	F	✓	✓	✓		✓
Western Mass. Electric	ES	Massachusetts	✓	F	✓	✓	✓		✓
Public Service Company of New Hampshire	ES	New Hampshire	✓			✓			✓
Hawaii Electric Light Company, Inc.	HE	Hawaii	✓	F	✓	✓	✓		✓
Hawaiian Electric Company, Inc.	HE	Hawaii	✓	F	✓	✓	✓		✓
Maui Electric Company	HE	Hawaii	✓	F	✓	✓	✓		✓
Idaho Power Co.	IDA	Idaho	✓	F		✓			✓
Idaho Power Co.	IDA	Oregon	✓			✓	✓	✓	✓
Interstate Power and Light Company	LNT	Iowa	✓			✓	✓	✓	✓
Wisconsin Power and Light Company	LNT	Wisconsin	✓						
NorthWestern Energy	NWE	Montana	✓			✓			✓
NorthWestern Energy	NWE	South Dakota	✓			✓		✓	✓
Oklahoma Gas and Electric Company	OGE	Arkansas	✓	P	✓	✓		✓	✓
Oklahoma Gas and Electric Company	OGE	Oklahoma	✓	P		✓			✓
Otter Tail Power Company	OTTR	Minnesota	✓		✓	✓	✓	✓	✓
Otter Tail Power Company	OTTR	North Dakota	✓		✓		✓	✓	✓
Otter Tail Power Company	OTTR	South Dakota	✓		✓	✓		✓	✓
Public Service Company of New Mexico	PNM	New Mexico	✓			✓	✓		✓
Texas-New Mexico Power Company	PNM	Texas	NA		✓	✓			✓
Arizona Public Service Company	PNW	Arizona	✓	P		✓	✓	✓	✓
Portland General Electric Company	POR	Oregon	✓	P		✓	✓	✓	✓
Alabama Power Company	SO	Alabama	✓		✓			✓	✓
Gulf Power Company	SO	Florida	✓			✓		✓	✓
Georgia Power Company	SO	Georgia	✓		✓	✓		✓	✓
Mississippi Power Company	SO	Mississippi	✓	P		✓	✓	✓	✓
Wisconsin Electric Power	WEC	Michigan	✓			✓	✓		✓
Wisconsin Electric Power	WEC	Wisconsin	✓						
Wisconsin Public Service Company	WEC	Wisconsin	✓						
Public Service Company of Colorado	XEL	Colorado	✓	P	✓	✓	✓	✓	✓
Northern States Power Company - WI	XEL	Michigan	✓			✓			
Northern States Power Company - MN	XEL	Minnesota	✓	F	✓	✓	✓	✓	✓
Southwestern Public Service Company	XEL	New Mexico	✓			✓	✓		✓
Northern States Power Company - MN	XEL	North Dakota	✓		✓		✓		✓
Northern States Power Company - MN	XEL	South Dakota	✓	P	✓	✓		✓	✓
Southwestern Public Service Company	XEL	Texas	✓		✓	✓			✓
Northern States Power Company - WI	XEL	Wisconsin	✓						
Potomac Electric Power Company	EXC	Maryland	✓	F		✓		✓	✓
Potomac Electric Power Company	EXC	District of Columbia	✓	F			✓		✓
Delmarva Power & Light	EXC	Maryland	✓	F		✓		✓	✓
Delmarva Power & Light	EXC	Delaware	✓				✓		✓
Atlantic City Electric	EXC	New Jersey	✓		✓	✓	✓	✓	✓
Baltimore Gas & Electric	EXC	Maryland	✓	F	✓	✓	✓		✓
PECO Energy	EXC	Pennsylvania	✓		✓	✓		✓	✓
Commonwealth Edison	EXC	Illinois	✓	F		✓	✓	✓	

Table 5.2 (continued)
Adjustment Clauses and Alternative Ratemaking Allowed for Exelon Utilities and Other Electric Utilities

			Alternative Regulation / Incentive Plans						
			Future Test Year Allowed in Jurisdiction [7]	Formula-Based Rates	Price Freeze/ Cap	Earnings Sharing	Formula-Based ROE	Service Quality/ Performance	Merger Savings
Ameren Illinois Company	AEE	Illinois		✓		✓	✓	✓	
Union Electric Company	AEE	Missouri	K						
Southwestern Electric Power Company	AEP	Arkansas	✓						
Indiana Michigan Power Company	AEP	Indiana	✓						
Kentucky Power Company	AEP	Kentucky	✓						
Southwestern Electric Power Company	AEP	Louisiana	K	✓	✓	✓			
Indiana Michigan Power Company	AEP	Michigan	✓						
Ohio Power Company	AEP	Ohio			✓	✓			
Public Service Company of Oklahoma	AEP	Oklahoma	K						
Kingsport Power Company	AEP	Tennessee	✓						
AEP Texas Central Company	AEP	Texas	K						
AEP Texas North Company	AEP	Texas	K						
Southwestern Electric Power Company	AEP	Texas	K						
Appalachian Power Company	AEP	Virginia	K			✓	✓	✓	
Appalachian Power / Wheeling Power	AEP	West Virginia	K						
ALLETE (Minnesota Power)	ALE	Minnesota	✓						
Superior Water, Light and Power Company	ALE	Wisconsin	✓						
Black Hills Colorado Electric Utility Company, LP	BKH	Colorado	✓						
Black Hills Power, Inc.	BKH	South Dakota	K						
Black Hills Power, Inc.	BKH	Wyoming	✓						
Cheyenne Light, Fuel and Power Company	BKH	Wyoming	✓						
Consumers Energy Company	CMS	Michigan	✓						
CenterPoint Energy Houston Electric	CNP	Texas	K						
Virginia Electric and Power Company	D	North Carolina	K						
Virginia Electric and Power Company	D	Virginia	K		✓	✓	✓	✓	
DTE Electric Company	DTE	Michigan	✓						
Duke Energy Florida	DUK	Florida	✓						
Duke Energy Indiana	DUK	Indiana	✓		✓				
Duke Energy Kentucky	DUK	Kentucky	✓						
Duke Energy Carolinas	DUK	North Carolina	K		✓				
Duke Energy Progress	DUK	North Carolina	K						
Duke Energy Ohio	DUK	Ohio				✓			
Duke Energy Carolinas	DUK	South Carolina			✓				
Duke Energy Progress	DUK	South Carolina							
Rockland Electric Company	ED	New Jersey	K						
Consolidated Edison Company of New York, Inc.	ED	New York	✓			✓			
Orange and Rockland Utilities, Inc.	ED	New York	✓		✓	✓			
El Paso Electric Company	EE	New Mexico	✓						
El Paso Electric Company	EE	Texas	K	✓					
Connecticut Lt. & Pwr.	ES	Connecticut	K						
NSTAR Electric	ES	Massachusetts	K		✓			✓	
Western Mass. Electric	ES	Massachusetts	K		✓			✓	
Public Service Company of New Hampshire	ES	New Hampshire	K		✓	✓			
Hawaii Electric Light Company, Inc.	HE	Hawaii	✓		✓	✓			
Hawaiian Electric Company, Inc.	HE	Hawaii	✓			✓			
Maui Electric Company	HE	Hawaii	✓			✓			
Idaho Power Co.	IDA	Idaho	✓			✓			
Idaho Power Co.	IDA	Oregon	✓						
Interstate Power and Light Company	LNT	Iowa	K		✓				
Wisconsin Power and Light Company	LNT	Wisconsin	✓		✓	✓			
NorthWestern Energy	NWE	Montana	K						
NorthWestern Energy	NWE	South Dakota	K						
Oklahoma Gas and Electric Company	OGE	Arkansas	✓						
Oklahoma Gas and Electric Company	OGE	Oklahoma	K						
Otter Tail Power Company	OTTR	Minnesota	✓						
Otter Tail Power Company	OTTR	North Dakota	✓						
Otter Tail Power Company	OTTR	South Dakota	K						
Public Service Company of New Mexico	PNM	New Mexico	✓						
Texas-New Mexico Power Company	PNM	Texas	K						
Arizona Public Service Company	PNW	Arizona	K		✓				
Portland General Electric Company	POR	Oregon	✓						
Alabama Power Company	SO	Alabama	K	✓					
Gulf Power Company	SO	Florida	✓						
Georgia Power Company	SO	Georgia	✓		✓	✓			
Mississippi Power Company	SO	Mississippi	✓	✓			✓	✓	
Wisconsin Electric Power	WEC	Michigan	✓						
Wisconsin Electric Power	WEC	Wisconsin	✓		✓				
Wisconsin Public Service Company	WEC	Wisconsin	✓						
Public Service Company of Colorado	XEL	Colorado	✓		✓	✓			
Northern States Power Company - WI	XEL	Michigan	✓						
Northern States Power Company - MN	XEL	Minnesota	✓						
Southwestern Public Service Company	XEL	New Mexico	✓		✓				
Northern States Power Company - MN	XEL	North Dakota	✓						
Northern States Power Company - MN	XEL	South Dakota	K		✓				
Southwestern Public Service Company	XEL	Texas	K		✓				
Northern States Power Company - WI	XEL	Wisconsin	✓						
Potomac Electric Power Company	EXC	Maryland	K						
Potomac Electric Power Company	EXC	District of Columbia	K						
Delmarva Power & Light	EXC	Maryland	K						
Delmarva Power & Light	EXC	Delaware	K						
Atlantic City Electric	EXC	New Jersey	K						
Baltimore Gas & Electric	EXC	Maryland	K						
PECO Energy	EXC	Pennsylvania	✓						
Commonwealth Edison	EXC	Illinois	✓	✓		✓	✓	✓	

Table 5.2 (continued)
Adjustment Clauses and Alternative Ratemaking Allowed for Exelon Utilities and Other Electric Utilities

Notes:	
	A mechanism may cover one or more cost categories; therefore, designations may not indicate separate mechanisms for each category. Texas T&D utilities do not have retail obligation, thus do not need a purchased power clause.
	[1] Full or partial decoupling (such as Straight-Fixed Variable rate design, weather normalization clauses, and recovery of lost revenues as a result of Energy Efficiency programs).
	[2] Includes recovery of costs related to targeted new generation projects, infrastructure replacement, system integrity/hardening, Smart Grid, AMI metering, and other capital expenditures.
	[3] Utility-sponsored conservation, energy efficiency, load control, or other demand side management programs.
	[4] Recovers costs associated with renewable energy projects, Distributed Energy Resources, REC purchases, net metering, RPS expense, and renewable PPAs.
	[5] EPA upgrade costs, emissions control & allowance purchase costs, nuclear/coal plant decommissioning, and other costs to comply with state and federal environmental mandates.
	[6] Pension expenses, bad debt costs, storm costs, vegetation management, RTO/Transmission Expense, capacity costs, transmission costs, government & franchise fees and taxes, economic development, and low income programs.
	[7] Source: Regulatory Resarch Associates Commission Profiles. Jurisdictions where future test years are allowed or historically granted to utilities in the jurisdiciton. K = Historical test year with known and measurable changes included.
	Sources: *Alternative Regulation/Incentive Plans: A State-by-State Overview*, November 19, 2013; Regulatory Research Associates, *Adjustment Clauses: A State-by-State Overview, September 12, 2017;* Regulatory Research Associates *Commission Profile*; SEC Form 10-Ks; Company Tariffs.

5.3 Rate Design

The following tables summarize the state regulatory commission-approved rate designs employed by the Exelon Utilities for distribution base rates as of December 31, 2017.

Table 5.3a
Pepco DC Approved Rate Design

	Customer Charge	Meter Charge	Bundled Service Only (Supply and Delivery)	Distribution		Transmission[12]		Supply Service Available[13]	
				Cents/ kWh	$/KW	Cents/ kWh	$/KW	Fixed	Hourly[14]
Residential	Y	N	N	Y	N	Y	N	Y	N
Small C&I <1MW[11]	Y	N	N	Y	Y	Y	N	Y	Y
Large C&I > 1MW	Y	N	N	Y	Y	Y	Y	Y	Y
Lighting	Y	N	N	N	N	N	N	Y	Y
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 5.3b
Pepco MD Approved Rate Design

	Customer Charge	Meter Charge	Bundled Service Only (Supply and Delivery)	Distribution		Transmission[15]		Supply Service Available[16]	
				Cents/ kWh	$/KW	Cents/ kWh	$/KW	Fixed	Hourly[17]
Residential	Y	N	N	Y	N	Y	N	Y	N
Small C&I <1MW[14]	Y	N	N	Y	Y	Y	Y	Y	N
Large C&I > 1MW	Y	N	N	Y	Y	Y	Y	N	Y
Lighting	Y	N	N	N	N	N	N	Y	N
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

[12] If a customer takes supply service from a third party supplier (TPS), transmission services are provided by the TPS.
[13] Hourly supply customers incur a fixed per kW charge for capacity and an hourly energy charge.
[14] Commercial customers returning to Pepco from TPS may select SOS or hourly service.
[15] If a customer takes supply service from a TPS, transmission services are provided by the TPS.
[16] Hourly supply customers incur a fixed per kW charge for capacity and an hourly energy charge.
[17] Large C&I secondary customers with a PLC greater than or equal to 600 kW must take either TPS supply or hourly supply.

Table 5.3c
Delmarva Power MD Approved Rate Design

	Customer Charge	Meter Charge	Bundled Service Only (Supply and Delivery)	Distribution		Transmission[18]		Supply Service Available[15]	
				Cents/ kWh	$/KW	Cents/ kWh	$/KW	Fixed	Hourly[19]
Residential	Y	N	N	Y	N	Y	N	Y	N
Small C&I <1MW	Y	N	N	N	Y	Y	Y	Y	N
Large C&I > 1MW[20]	Y	N	N	N	Y	N	Y	Y	Y
Lighting	Y	N	N	Y	N	N	N	Y	N
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 5.3d
Delmarva Power DE Approved Rate Design

	Customer Charge	Meter Charge	Bundled Service Only (Supply and Delivery)	Distribution		Transmission[21]		Supply Service Available[18]	
				Cents/ kWh	$/KW	Cents/ kWh	$/KW	Fixed	Hourly[22]
Residential	Y	N	N	Y	N	N	Y	Y	N
Small C&I <1MW[23]	Y	N	N	Y	Y	N	Y	Y	Y
Large C&I > 1MW[24]	Y	N	N	N	Y	N	Y	Y	Y
Lighting	Y	N	N	Y	N	N	N	Y	N
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

[18] If a customer takes supply service from a TPS, transmission services are provided by the TPS.
[19] Hourly supply customers incur a fixed per kW charge for capacity
[20] Large C&I secondary customers over 1,000 kW PLC may choose fixed supply service from Delmarva Power. Those served under primary or transmission level voltage must take either TPS supply or hourly supply.
[21] If a customer takes supply service from a TPS, transmission services are provided by the TPS.
[22] Hourly supply customers incur a fixed per kW charge for capacity
[23] Small C&I (SGS-ND) is only remaining C&I service classification with a cents/kWh distribution rate.
[24] Large C&I secondary customers over 1,000 kW PLC may choose fixed supply service from Delmarva Power. Those served under primary or transmission level voltage must take either TPS supply or hourly supply.

Table 5.3e
Delmarva Power Gas Approved Rate Design

				Distribution			Utility Default[26] Supply Service Available
	Customer Charge	Information Fee[25]	Bundled Service Only (Supply and Delivery)	Single Rate$/MCF	2 Step Rates $/MCF	Demand[27] $/MCF of MDQ	Varies by Month $/MCF
Residential	Y	N	N	Y	N	N	Y
Small C&I - Non-Interruptible (<20,000 ccf and MDQ , 5,000 ccf monthly)[28]	Y	N	N	Y	N	N	Y
Medium C&I Non-Interruptible(>2,000 MCS and MDQ <500 MCF monthly)	Y	N	N	Y	N	Y	Y
Large C&I - Non-Interruptible (MDQ >500 MCF monthly)	Y	N	N	N	N	Y	Y
Small & Large C&I – Interruptible	Y	N	N	Y	N	Y	N
Lighting	Y	N	N	N	N	N	Y

[25] Large C&I customers who are with an alternative supplier and interruptible customers are charged an information fee.
[26] Lighting Customers are on a flat monthly per light rate.
[27] The Customer's Billing Demand is the Maximum Daily Quantity (MDQ) or the greatest amount of gas delivered to the Customer during any day (10:00 a.m. to 10:00 a.m.). MDQ is measured to the nearest whole MCF.

Table 5.3f
ACE Approved Rate Design

	Customer Charge	Meter Charge	Bundled Service Only (Supply and Delivery)	Distribution		Transmission[29]		Supply Service Available[22]	
				Cents/ kWh	$/KW	Cents/ kWh	$/KW	Fixed	Hourly
Residential	Y	N	N	Y	N	Y	N	Y	Y
Small C&I <1MW	Y	N	N	Y	Y	N	Y	Y	N
Large C&I > 1MW	Y	N	N	N	Y	N	Y	Y	N
Lighting	Y	N	N	Y	N	N	N	Y	N
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 5.3g
BGE – Electric Approved Rate Design

	Customer Charge	Meter Charge	Bundled Service Only (Supply and Delivery)	Distribution		Transmission[30]		Utility Default[31] Supply Service Available	
				Cents/ kWh	Demand $/kW	Cents/ kWh	Demand $/kW	Fixed Cents/kWh	Hourly Cents/kWh
Residential	Y	N	N	Y	N	Y	N	Y	N
Small C&I <60kW	Y	N	N	Y	N	Y	N	Y	N
Large C&I >60kW[32]	Y	N	N	Y	Y	N	Y	Y	Y
Lighting[33]	Y	N	N	Y	N	N	N	Y	N
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

[29] If a customer takes supply service from a TPS, transmission services are provided by the TPS.
[30] If a customer takes supply service from a TPS, transmission services are provided by the TPS.
[31] Utility Default Supply Service price includes electric supply and transmission service, with the exception of Lighting customers which are not charged for transmission. Large C&I Utility Default Supply Service customers also incur a fixed per kW charge for transmission.
[32] Customers above 600kW take default supply service and have hourly rates.
[33] BGE leases lighting equipment to its Street Lighting customers upon request, as well as to all of its Private Area Lighting customers.

Table 5.3h
BGE – Gas Approved Rate Design

	Customer Charge	Information Fee[34]	Bundled Service Only (Supply and Delivery)	Distribution			Utility Default[35] Supply Service Available
				Single Rate$/therm	2 Step Rates[36] $/therm	Demand[37] $/therm	Varies by Month $/therm
Residential	Y	N	N	Y	N	N	Y
Small C&I - Non-Interruptible (<120,000 therms annually)[38]	Y	N	N	N	Y	N	Y
Large C&I - Non-Interruptible (>120,000 therms annually)	Y	Y	N	N	Y	N	Y
Small & Large C&I – Interruptible	Y	Y	N	Y	N	Y	N
Lighting[39]	Y	N	N	Y	N	N	Y

[34] Only large C&I customers who are with an alternative supplier and Interruptible service customers are charged an information fee.
[35] Lighting Customers must take default supply service from BGE. All Interruptible service customers must choose an alternative retail gas supplier (ARGS).
[36] Customer's first 10,000 therms per month are priced at a "1st step" fixed rate, and remaining therms are priced at a "2nd step" lower fixed rate.
[37] The Customer's Billing Demand is the maximum winter day measured demand during the latest 12 month period, adjusted to the nearest whole Dth.
[38] If a C&I customer is with an alternative supplier and consumes between 90,000 - 120,000 therms annually, they may elect to have a large C&I AMR meter and become a Daily-Metered Customer (i.e., Large C&I per table above).
[39] The gas lighting rate schedule is closed to new customers.

Table 5.3i
PECO – Electric Approved Rate Design

	Customer Charge	Meter Charge	Bundled Service Only (Supply and Delivery)	Distribution		Transmission[40]		Supply Service Available[31]	
				Cents/ kWh	$/KW	Cents/ kWh	$/KW	Fixed	Hourly[41]
Residential	Y	N	N	Y	N	Y	N	Y	N
Small C&I	Y	N	N	N	Y	N	Y	Y/N	Y/N
Large C&I	Y	N	N	N	Y	N	Y	N	Y
Lighting	Y[42]	N	N	Y	N	Y	N	Y	N
Railroad	Y	N	N	N	Y	N	Y	N	Y

Table 5.3j
PECO – Gas Approved Rate Design

	Customer Charge	Meter Charge	Bundled Service Only (Supply and Delivery)	Distribution	Transmission	Supply Service Available[43]
				$/Ccf	$/Ccf	$/Ccf
Residential	Y	N	N	Y	N	Y
Small C&I	Y	N	N	Y	N	Y
Large C&I	Y	N	N	Y	N	Y
Transportation	Y	N	N	Y	N	Y

[40] If a customer takes supply service from an Electric Generation Supplier (EGS), both generation and transmission services are provided by the EGSs.
[41] For SCI customer up to 100 KW, a fixed rate is applied. For SCI customer greater than 100KW, hourly energy price and capacity price are applied.
[42] Lighting Customer Charge includes location charge.
[43] If a customer takes supply service from a Natural Gas Supplier (NGS) under the Low Volume Transportation program (Gas Choice) or High Volume Transportation program, Supply Service is provided by the NGSs.

Table 5.3k
ComEd Approved Rate Design

	Customer Charge	Meter Charge	Bundled Service Only (Supply and Delivery)	Distribution		Transmission[44]		Supply Service Available[35]	
				Cents/ kWh	$/KW	Cents/ kWh	$/KW	Fixed	Hourly[45]
Residential	Y	Y	N	Y	N	Y	N	Y	Y
Small C&I <1MW[46]	Y	Y	N	N	Y	Y	N	N	Y
Large C&I > 1MW	Y	Y	N	N	Y	Y	N	N	Y
Lighting	Y	Y	N	N	Y	Y	N	Y	Y
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

[44] If a customer takes supply service from an ARES, transmission services are provided by the ARESs.
[45] Hourly supply customers incur a fixed per kW charge for capacity
[46] Small C&I customers under 100 kW may choose fixed supply service from ComEd. Those above 100 KW must take either ARES supply or hourly supply.

Section 6: Interconnections

The Exelon Utilities are committed to providing transparent, efficient, and clear processes for review and approval of interconnection to the utilities' distribution systems of proposed renewable-energy projects and other distributed energy resources (DERs). As interconnection applications continue to accelerate in both volume and total capacity (MW) across the country, there is an increasing need to streamline the interconnection application review process to minimize delays, decrease operating issues, and improve the overall customer interconnection experience. The review process also ensures safe and reliable operation of the distribution system and that no customers are detrimentally impacted by the introduction of DERs operating in parallel with the distribution system. The Exelon Utilities work together to identify and implement best practices in both the DER application review processes as well as effectively integrating DERs to the electric distribution systems.

6.1 Interconnection Applications

The following tables present the number of interconnection applications received and approved by the Exelon Utilities by year-end 2017.

Table 6.1a
Number of Applications Received in 2017

Pepco - DC	Pepco - MD	Delmarva Power - MD	Delmarva Power - DE	ACE	BGE	PECO	ComEd
1,082	5,692	1,561	1,236	11,250	6,978	2,875	656

Table 6.1b
Number of Applications Approved in 2017

Pepco - DC	Pepco - MD	Delmarva Power - MD	Delmarva Power - DE	ACE	BGE	PECO	ComEd
825	5,082	1,266	991	8,817	6,978	2,368	445

6.2 Active Systems Connected

Table 6.2a presents the number of DERs connected to each of the Exelon Utilities in 2017, by number of systems and MW. Table 6.2b presents the total number of active systems interconnected to each of the Exelon Utilities as of December 31, 2017.

Table 6.2a
Number of Active Systems and Megawatts (MW) Connected in 2017

	Pepco -DC	Pepco -MD	Delmarva Power - MD	Delmarva Power - DE	ACE	BGE	PECO	ComEd
Number of New Systems Connected in 2017	714	4,705	1,008	950	6,732	5,830	2,368	412
MW from New Systems Connected in 2017	13.0	43.3	11.4	12.3	62.9	194.1	18.8	21.3

Table 6.2b
Total Number of Active Systems and MW Connected as of December 31, 2017

	Pepco -DC	Pepco - MD	Delmarva Power - MD	Delmarva Power – DE	ACE	BGE	PECO	ComEd
Total Connected Systems as of December 31, 2017	3,790	16,973	3,377	4,902	24,617	27,148	8,281	1,007
Total MW from New Connected Systems as of December 31, 2017	40.9	162.67	66.1	53.8	312.1	395.4	143.8	101.8

Section 7: Energy-Efficiency and Demand Response[47]

Demand Response (DR) programs are operated by PJM and/or utility companies to elicit energy savings to reduce demand during an emergency and provide customers with opportunities to save money by curtailing usage. Energy efficiency (EE) programs available to customers are designed to lower overall energy consumption and reduce peak demand. Some of these programs are administered by utility companies, typically pursuant to state utility commission-approved plans, while other programs are administered by external agencies. The various DR and EE programs administered by the Exelon Utilities vary depending on jurisdiction and infrastructure capabilities. Dynamic Pricing programs available in many of the Exelon Utilities jurisdictions provide residential customers the ability to receive a bill credit for reducing use during critical peak hours as called by the utility.

7.1 Energy Savings (in MWH) from Energy Efficiency Programs

Table 7.1

Energy Savings (MWH)	Pepco -DC[48]	Pepco - MD[49]	Delmarva Power - MD[50]	Delmarva Power - DE[51]	ACE[52]	BGE[53]	PECO	ComEd[54]
Residential Customers	N/A	156,610	33,393	N/A	2,555	323,656	242,632	1,456,435
Non-Residential Customers	N/A	83,041	47,071	N/A	N/A	194,986	121,254	1,409,138

[47] Energy and demand savings are reported at gross wholesale.
[48] Pepco DC currently does not offer any EE programs.
[49] The residential energy savings includes “traditional” EE rebate programs (106,421), Behavioral Program: OPOWER (49,463) and Low Income which is administered by the State (726). Not included are impacts from CVR (80,396) and Transformers (1,160).
[50] The residential energy savings includes “traditional” EE rebate programs (21,046), Behavioral Program: OPOWER (11,438) and Low Income which is administered by the State (909). Not included are impacts from CVR (12,057) and Transformers (764).
[51] Delmarva Power DE currently does not offer any EE programs.
[52] The residential energy savings include one residential program (451) and Behavioral Program (2,104). ACE does not offer any non-residential programs.
[53] The residential energy savings includes “traditional” EE rebate programs (175,865 MWH), Smart Energy Manager (BGE’s Behavioral Program: OPOWER) – 145,243 MWH and Low Income which is administered by the State – 2,548 MWH. Not included are impacts from CVR (137,879), Streetlights (5,256) and Transformers (1,953).
[54] The above are PY8 incremental MWh savings at the meter. Savings include Energy Efficiency Portfolio Standard (EEPS) and Illinois Power Agency (IPA) programs which include several third-party implemented programs. Savings exclude public sector and low-income programs that are administered by the Illinois Department of Commerce and Economic Opportunity (DCEO). Final PY8 evaluation reports are available at http://www.ilsag.info/comed_eval_reports.html.

7.2 Total Resource Cost Test for Energy Efficiency

The Total Resource Cost (TRC) test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. The test is applicable to EE as well as DR programs. However, the costs in this test are only the EE program costs paid by both the utility and the participants. The benefits calculated in the TRC are the avoided supply costs and the reduction in transmission, distribution, and generation for the periods of time the energy savings are in place for EE or for when there is a load reduction for DR. The specific benefits and costs included in the TRC test will vary by state requirement as will the methodologies to calculate the included benefits and costs. The annual reporting timeframe also varies depending on the jurisdiction.

The TRC test is being presented as a ratio that represents

Benefit Cost Ratio = $(\text{NPV} \sum \text{benefits}_{\$}) \div (\text{NPV} \sum \text{costs}_{\$})$

A TRC ratio ≥ 1 is cost effective meaning the total benefits exceed or are equal to the total cost of the program and indicates that the total cost of energy in the utility service territory will be lower over the life of the benefits produced by the program.

Table 7.2
Annual TRC Ratios for the Exelon Utilities as Reported in 2017[55]

Cost Savings	Pepco - DC	Pepco – MD	Delmarva Power – MD	Delmarva Power - DE	ACE	BGE	PECO	ComEd[56]
Residential Customers	N/A	1.7	1.2	N/A	N/A	1.9	1.6	5.2
Non-Residential Customers	N/A	1.7	1.4	N/A	N/A	2.8	1.9	2.5

[55] The reporting period for Pepco MD, Delmarva Power MD and BGE are the 12 months ended December 31, 2016.
The reporting period for PECO is the 12 months ended May 31, 2017.
The reporting period for ComEd is the 12 months ended May 31, 2017.
Pepco DC and Delmarva Power DE do not offer EE programs; therefore, a TRC has not been calculated.
A TRC calculation has not been performed on the programs (Comfort Partners and Behavioral Programs) offered in ACE and ACE does not offer any non-residential EE programs.

[56] The PY6 total portfolio TRC was 1.97, which includes portfolio costs and benefits not directly assigned to residential or business programs. ComEd's next goals docket (for PY7-9) will not commence until after the conclusion of the current plan cycle, and TRC results for those years will not be available until that time. These values do not include certain gas-only benefits and costs for programs jointly run by ComEd and the northern Illinois gas utilities. Illinois' statutory definition does not currently define a discount rate, so ComEd uses its weighted average cost of capital. Illinois' definition also allows inclusion of natural gas impacts and other quantifiable societal benefits; ComEd has not included market price suppression as a benefit. It also requires ComEd to include a reasonable estimate of the financial costs associated with regulation of greenhouse gas emissions in its TRC benefits. Effective June 1, 2017, P.A. 99-0906 changed the TRC definition to require the use of a societal discount rate, and modestly expand the universe of non-electric benefits while explicitly excluding market price suppression as a benefit.

For additional information on results for all Maryland electric distribution company utility programs including Pepco MD, Delmarva Power MD, and BGE http://webapp.psc.state.md.us/newIntranet/Maillog/submit_new.cfm?MaillogPath=217474&DirPath=C:\Casenum\Admin%20Filings\200000-249999\217474&maillognum=217474

For additional information on results for PECO's programs, please refer to PECO's Act 29 Report (http://www.puc.state.pa.us/filing_resources/issues_laws_regulations/act_129_information/electric_distribution_company_act_129_reporting_requirements.aspx)

For additional information on results for ComEd's programs, please refer to the Illinois Energy Efficiency Stakeholder Advisory Group Evaluation Reports (http://www.ilsag.info/evaluation-documents.html)

7.3 Total MW Available from Demand Response

Demand Response (DR) programs are dispatched on an as needed basis where customers reduce their electricity usage during certain periods to proactively manage the peak demand in the utility zone. A common DR program in the Exelon Utilities is a Direct Load Control (DLC) program where a customer's air conditioning system is either cycled or shut down at certain times to manage the utility's peak load. Table 7.3 presents the total MW of DLC participation in each of the Exelon Utilities.

Table 7.3

Total MW	Pepco -DC[57]	Pepco - MD[58]	Delmarva Power - MD[59]	Delmarva Power - DE[60]	ACE[61]	BGE[62]	PECO	ComEd[63]
Residential Customers	19.5	334.1	62.0	144.2	54.2	687.0	25.0	120.0
Non-Residential Customers	N/A	10.7	5.3	N/A	N/A	N/A	N/A	915.4

[57] Pepco DC includes DLC (19.50 MW).
[58] Pepco MD includes DLC (199.60 MW) and Dynamic Pricing (134.50 MW).
[59] Delmarva Power MD includes DLC (31.50 MW) and Dynamic Pricing (30.51 MW).
[60] Delmarva Power DE includes DLC (47.70 MW) and Dynamic Pricing (96.50 MW).
[61] ACE includes DLC (54.20 MW) and Dynamic Pricing (0 MW).
[62] BGE includes DLC (357 MW) and Peak Time Rebates (330 MW).
[63] Residential programs include AC Cycling, Peak Time Savings, and Hourly Pricing. The Voluntary Load Reduction (VLR) program is the only non-residential program. Net at the meter MW are provided and a line loss factor of 9.1% is assumed.

Section 8: Deployment of New Technologies

The Exelon Utilities continue to move forward on deployment of new technologies such as Smart Meters (also known as automated metering infrastructure or AMI), Distribution Automation, Microgrids, Electric Vehicles and Energy Storage. Investment in these new technologies represents Exelon's commitments to finding new methods to provide customers with more reliable service through improved outage restoration and to preserving the environment.

Each of the Exelon Utilities' jurisdictional regulatory environment influences many aspects of new technology deployment such as AMI, microgrids and electric vehicles. This can lead to differences in operation, ownership and cost recovery. However, the Exelon Utilities believe innovation is best achieved through a collaborative process of sharing information, ideas and best practices between all of the utilities. This process also ensures the utilities' policies align where possible.

The Exelon Utilities are active participants in ongoing grid modernization proceedings before their state regulatory commissions, including "Modernizing the Energy Delivery System for Increased Sustainability" (MEDSIS) in the District of Columbia, "Transforming Maryland's Electric Grid" (PC44) in Maryland and "NextGrid" in Illinois.

8.1 Smart Meters

The following table presents the number and percentage of customers with electric Smart Meters installed across the Exelon Utilities' territories as of December 31, 2017.

Table 8.1
Electric Smart Meters Deployed in Exelon Utilities through 2017

	Pepco DC	Pepco MD	Delmarva MD	Delmarva DE	ACE[64]	BGE	PECO	ComEd
Number of Smart Meters Deployed to Customers as of December 2017	306,206	579,227	213,654	325,552	N/A	1,262,505	1,720,000	3,858,100
Percentage of Customers with Smart Meters	98.74%	99.36%	99.40%	99.93%	N/A	95.20%	100%	91.73%

PHI: PHI (Pepco and Delmarva Power only) has over 1.4 million AMI Electric Meters installed and activated for over the air meter reading, remote provisioning and interval data provided to customer via My Account.

[64] AMI has not been approved in ACE.

Some of the highlights of AMI include:

Remote Meter reading, Remote Provisioning, Remote Meter program configuration, Remote Storm Support, Peak Energy Savings programs, My Account, OMS Integration, Advanced Data Analytics Use Cases, and Revenue Protection.

- Remote Meter Reading – Meter Reading rate has improved and AMI has moved PHI in the direction of moving within the first quartile
- Remote Provisioning – T/on and T/off can be done over the air therefore saving a truck roll as well as responding faster to customer requests
- Remote Meter Program configuration – Remote configuration of meters to change a meter to net energy metering, faster response to customers that participate in net energy metering, no truck roll or physical exchange required, saves thousands of truck rolls per year
- Remote Storm Support – Remote pinging the meters associated with a single no light order to confirm the status of the meter, this activity saves non-value-added truck rolls during storms
- Enable Peak Energy Savings program – Peak Energy Credit – held several events in the last several years
- Interval Data available to customers on My Account – this provides customers with details around their usage patterns to help them make decisions on conservation
- OMS Integration – PHI’s AMI system is fully integrated into their OMS system. OMS receives outage events and restore events from AMI meters. This integration has vastly improved outage modeling, outage response times, and estimated restoration times
- Advanced Data Analytics – PHI Meter Engineering has developed several unique algorithms to identify theft, equipment damage, hazardous conditions, meter failures, and power quality issues. These analytics have resulted in recovered revenue, lessened workloads, and more efficient work practices
- Revenue Protection/Revenue Investigation support – Interval data patterns and meter events can help identify the date tamper started to hold customers accountable

.

BGE: BGE has over 1.2 million AMI Electric Meters installed and activated for over the air meter reading, remote provisioning and interval data provided to customer via BGE.com.

Some of the highlights of the BGE AMI include:

Remote Meter reading, Remote Provisioning, Remote Meter Program Configuration, Smart Energy Rewards programs, Customer Interval Data, OMS Integration, Storm Support, Advanced Data Analytics Use Cases, and Revenue Protection.

- Remote Meter Reading – BGE has a meter read rate that is first quartile and has an active program to maintain that performance

- Remote Provisioning – T/on and T/off can be done over the air therefore saving a truck roll as well as responding faster to customer requests
- Remote Meter Program configuration – Remote configuration of Meters to change a meter to net energy metering, faster response to customers that participate in net energy metering, no truck roll or physical exchange required, saves thousands of truck rolls per year
- Enable Smart Energy Rewards program –Successfully held several Energy Savings Day events in the last several years
- Interval Data available to customers on BGE.com – this provides customers with details around their usage patterns to help them make decisions on conservation
- OMS Integration – BGE's AMI system is fully integrated into their OMS system. OMS receives outage events and restore events from AMI meters. This integration has improved outage modeling, detection of nested events, outage response times, and tracking restoration times. The system provides the field force and back office with situational awareness of real time outage conditions, which has improved field force productivity
- Storm Support – Pinging selected meters in order to confirm the status of the meter saves non-value-added truck rolls during storms
- Advanced Data Analytics – BGE has developed several algorithms to identify theft, equipment damage, hazardous conditions, meter failures, meter tampering, and voltage issues. These analytics have resulted in lessened workloads and more efficient work practices
- Revenue Protection/Revenue Investigation support – Interval data patterns and meter events can help identify the date tamper started to hold customers accountable
- CVR support – BGE has used AMI voltage data to improve the performance of the BGE CVR system via identification and mitigation of low voltage areas on feeders

PECO: PECO is using its automated AMI disconnect capability to automatically shutoff and turnoff customers without having to dispatch a field technician.

PECO has developed an outage visualization system called AMOS that leverages its AMI meter system. Users of the outage management system can open an outage event, click on an icon, and visually see which meters are on and which are off. This is a state of the art system that provides the field force and back office with visualization of real time outage conditions. This system has significantly improved outage response time and improved field force productivity.

ComEd: As of the end of 2017, over 3.85 million smart meters have been deployed, representing over 91% of the meters in ComEd's service territory. The year 2017 was another safe and productive year for the AMI Program that included the expansion of deployment to new areas across the service territory and the enhancement and optimization of field and back office tools and technologies to drive greater customer engagement and benefit realization. Throughout 2017 ComEd installed over 789K meters in a safe and quality fashion across an expanded territory that included city, suburban, and rural geographies.

As the program nears completion, AMI has solidified itself as a value-adding technology platform for ComEd's operations and customers. It has enabled the delivery of enhanced communication and operating capabilities, innovative customer programs, and an enhanced energy marketplace that benefit customers across the service territory, all while streamlining internal operations.

The AMI Program provides economic benefits to the Illinois economy in several ways. A diverse range of jobs have been created and maintained in the field and back office, including positions for meter and network device installers, Cross Dock personnel, electricians, supervisors, project managers, IT analysts, engineers, and customer service professionals. The program also provides ComEd employees with skills, training, and technology knowledge and understanding that will benefit them in their ongoing professional development. Additionally, a supporting ecosystem of service professionals and materials manufacturers have experienced growth and development from their ongoing partnership with ComEd during the AMI Program.

The Program continues to drive the realization of benefits to ComEd and customers and enabling broad customer adoption of AMI-enabled programs such as Peak Time Savings which had over 230,000 participants enrolled for the 2017 summer season. There are also improvements in the areas of reliability, outage management, field and back office operations, customer programs and the overall customer experience – all enabled by the AMI technologies.

8.2 Automated Technologies

Distribution Automation (DA) improves system reliability through the deployment of technology. These projects involve installing advanced control systems across the distribution system in order to automatically identify and isolate faults in real time and restore service to customers in the unaffected parts of the system.

PHI: The purpose of PHI's DA initiative is to improve the reliability of the distribution system. Automated Sectionalizing and Restoration (ASR) technology is the main DA tool and is part of its overall smart grid strategy. PHI has been very successful implementing ASR on its overhead system and is now piloting the technology on underground radial feeders.

Through the deployment of DA and the activation of ASR schemes, PHI is improving infrastructure reliability, enhancing customer experience, and providing enhanced interaction levels with the grid. In late 2009, PHI was awarded a DOE Smart Grids Investments Grant to match its smart grid spending. PHI's DA approach involves installing advanced control systems, ultimately across the distribution system, to automatically identify and isolate faults in real time and promptly restore service to customers in the unaffected parts of the system. The goal of this DA strategy is to deploy technology that will enhance reliability by improving speed of isolation of trouble spots on the system, in coordination with automated restoration capability. PHI's DA efforts include the following three elements:

- Fault identification and isolation: DA can isolate critical pieces of the infrastructure to minimize customer impact in a fault area and/or allow for quicker restoration;
- Service restoration: DA can significantly reduce the duration of outages experienced by customers through automated isolation of faulted areas and restoration of customers unaffected by the fault; and
- System/Data management: DA can provide accurate and real-time information regarding the overall integrity of the distribution system, which allows for targeted deployment of corrective maintenance and upgrade measures for critical assets.

DA devices such as reclosers and auto-switches are equipped with intelligent controllers which are integrated into the energy management system (EMS) via a comprehensive telecommunications network, provide PHI the ability to monitor system status on a near real-time basis. For instance, when an ASR scheme operates through the control of reclosers and switches, the system operator can see which devices opened and closed, and can send crews to a more specific location. In addition, the operator is able to operate the devices remotely and return the system to normal once the trouble areas are fixed.

DA/ASR is first deployed in areas that can most benefit from the technology. For instance, feeders that experience multiple lockouts (large feeder main outages) per year are the best candidates for automation on a priority basis. Along with intelligent devices and a comprehensive telecommunications network, ASR must have feeders with an adequate number of feeder ties that have adequate reserve capacity to accept a transfer of customers during times of emergencies.

In 2017, PHI installed over 780 new reclosers, integrated over 300 existing reclosers into SCADA, and deployed ASR on 45 distribution feeders. The following table shows the number of devices included in ASR schemes across PHI's service territory as of December 31, 2017:

Table 8.2
ASR Schemes across PHI, 2017

PHI Utilities	Pepco DC	Pepco MD	Delmarva Power MD	Delmarva Power DE	ACE
Number of ASR Devices	87	373	252	150	334

PHI is also deploying network remote monitoring system (RMS) on the network transformers across Pepco underground network system and distribution VAR dispatch (DVD) project deploying two-way communications to the distribution capacitor banks cross PHI.

BGE: BGE started the deployment of the Itron wireless mesh communication network in 2017, and plans to complete the deployment in 2021. Upon completion, a majority of BGE's 3,200 Distribution Automation devices and 4,900 distribution line capacitors will be transferred to the Itron network. To date, approximately 200 distribution line capacitors have been moved to the new network. Distribution Automation devices are planned to begin transferring to the new network by the end of 2018. In addition, BGE is investigating the opportunities to connect other devices, including new emerging monitoring and control devices, to the Itron network. This includes remote reporting faulted circuit indicators and metering sensors

BGE has installed just under 3,200 automatic sectionalizing devices, mostly electronically controlled reclosers, on its distribution system in order to improve reliability. Automatic sectionalizing devices are programmed to automatically isolate faults and utilize tie circuits to minimize outage disruptions to customers. These devices are remotely monitored and can be controlled remotely by distribution system operators.

BGE utilizes automatic reclosing circuit breaker schemes on its distribution circuits to restore power after intermittent faults.

PECO: PECO has deployed a Sensus communication network for both AMI Metering and DA devices. PECO is considered fully deployed on its Sensus FlexNet AMI platform, and continues to work with less than 30 residential customers who initially refused to accept AMI meters. There are less than 1,100 C&I meters that are being transitioned from the MV-90 platform to the Sensus AMI system to achieve efficiency and functional improvements. These accounts already meet AMI functional requirements and have been categorized accordingly.

PECO has transferred over 630 distribution reclosers from phone pair communication to the Sensus communication network (as of 12/31/2017). PECO is working to move remaining and new reclosers to the Sensus network. PECO has also successfully connected capacitor banks, faulted circuit indicators, pole sensors, unit substation monitoring, and automated switches to its Sensus network. PECO is currently working to connect these devices and other new emerging monitoring and control devices to its Sensus network.

PECO has deployed numerous current and voltage sensing distribution recloses on its system to improve reliability. Recloser schemes are designed to isolate faults and utilize tie circuit reclosers to minimize outage disruptions to customers. These devices are remotely monitored and can be controlled remotely by distribution system operators.

PECO utilizes automated distribution capacitor banks that automatically respond to voltage or VAR conditions.

PECO utilizes automatic reclosing circuit breaker schemes on its distribution circuits to restore power after intermittent faults.

PECO has deployed smart substation technologies that enhance its ability to monitor and proactively respond to incipient equipment failures that could result in widespread outages. Technologies deployed include; thermography, dissolved gas analysis (DGA) monitoring, temperature monitoring, and enhanced PT and CT equipment.

PECO completed lab testing of residential smart inverters for their ability to perform grid-interactive functions, such as volt-var control and power factor management. When programmed for grid-interactive functions, smart inverters offer an additional, low-cost method to increase hosting capacity for solar PV on customer circuits. The outcome of this testing has informed PECO engineers on performance of these functions and on considerations for programming these devices in the field. PECO is currently conducting a follow-up pilot with two residential customers' smart inverter systems to test the effectiveness of the devices for voltage management.

ComEd: ComEd's DA technology uses "sectionalizing" and reclosing devices and remote communications to detect issues on the distribution system and automatically re-route power, accordingly, to minimize the number of customers impacted.

ComEd DA technologies include:

- Field reclosing and sectionalizing devices with distributed intelligence to detect and isolate faults at various segments of the distribution system with limited dependency on centralized communication and control;
- A radio system to facilitate peer to peer logic coordination as well as remotely transmit and relay control functions and indicate the status of various system parameters to the DMS;
- The computer systems that control, operate, monitor and store the data for the DA system.
- Intelligent line sensors integrated into the mesh radio network to bring additional intelligence back to the DMS for enhanced operational awareness

ComEd's DA installation program includes 5,960 DA devices from 2001 to 1st quarter of 2018 and the replacement of the older 900 megahertz (MHZ) radio with a new higher security communication system that meets newly-established government regulations. In addition, the 1,204 older 34kV field devices have been upgraded to the newer Intelliteam (IT-2) control hardware to allow for better flexibility with fault isolation and operation. ComEd currently has plans to continue the DA deployment through 2023 to install an additional 4,600 devices.

8.3 Microgrids

For purposes of this report, the Exelon Utilities define microgrid as a collection of interconnected loads, generation assets and advanced control equipment, installed across a defined geographic area that is capable of balancing and operating independently from or in parallel with the utility's macrogrid.

PHI:
Maryland - In 2015, PHI designed and installed a small microgrid demonstration system which consists of 10KW of solar combined with a 40KWh lithium ion battery. Located at Pepco's WaterShed Center for Sustainability in Rockville, the facility hosts visits and tours to educate the public and key stakeholders on the elements and benefits of microgrids.

Pepco also committed, as a result of the Exelon/PHI merger to develop a proposal to construct two microgrids in Montgomery and Prince George's Counties. Pepco filed its proposal on September 23, 2017 with a supplemental filing on February 15, 2018. These projects are planned to be public purpose microgrids in the 6MW to 8MW range. Identified participants include county government facilities, grocery stores, gas stations, pharmacies and medical facilities. The microgrids will incorporate a diverse generation mix including natural gas, solar PV and battery storage. A legislative-style hearing was held on the proposal on April 24, 2018 and the Company is currently awaiting a decision from the PSC. If approved, construction of the microgrids must be completed within five years.

In the Delmarva region, the Company applied for, and received, a $250,000 grant from Maryland Energy Administration for installing batteries to support Chesapeake College's critical loads during emergency scenarios and support the electrical grid. The microgrid's 1 MW, 750kWh (3/4 hr) battery was installed in the second quarter of 2017. The battery may participate in the PJM Ancillary services market and can be called on to support the grid. The microgrid's controller is currently under development.

Delaware - In the Settlement Agreement approved in Delmarva's 2017 Gas Rate Case proceeding, it was agreed that the Settling Parties would define the scope of a microgrid report to be filed with the Commission. With input from Commission Staff and the DPA, Delmarva filed its scoping document on February 7, 2018 under Docket No. 16-0650. The scoping document included discussions not limited to microgrid guiding principles, ownership structures, operations, generation, cost recovery, roles and responsibilities and selection/screening criteria. By November 7, 2018, Delmarva will file with the Commission a more detailed microgrid report for purposes of evaluating one or more locations for a potential microgrid project including specifics pertaining to customer response and benefits of a potential microgrid project as well as the costs and the cost recovery for the project(s).

New Jersey - The New Jersey Board of Public Utilities (the Board or BPU) issued an order in June 2016 establishing a budget for a microgrid feasibility study and other issues related to the state's clean energy programs. In November 2016, the Board accepted a Board Staff ("Staff") Report that provided a survey of the current number or microgrids in the state and identified issues that must be confronted to advance further microgrid development. The Board directed Staff to begin a stakeholder process for public comment to determine how to best deploy distributed energy resources and microgrids in New Jersey. This stakeholder process was also to consider funding feasibility studies for interested microgrid developments. At the January 2017 Board meeting, the Commissioners unanimously voted to open a 60-day application window for the "Town Center Distributed Energy Resources Microgrid Feasibility Study Incentive Program" and invited qualified state or local government entities to apply for incentives of up to $200,000 to cover the expense of a feasibility study. In June 2017, the BPU approved a budget to fund applications from 13 entities for approximately $2 million total. ACE will work with each of the three entities in its service territory (Galloway Township, Atlantic City, and the Cape May County Municipal Utilities Authority) on its feasibility studies.

BGE: BGE filed a proposal with the Maryland PSC for Public Purpose Microgrids in December 2015 (ML#180913). The proposal was modeled on prior work in the State and the Microgrids for Grid Resiliency Task Force. In July 2016, the PSC denied BGE's request without prejudice (MD PSC Case No. 9416). BGE has not filed a new proposal for microgrids.

PECO: PECO has testified in the Pennsylvania House of Representatives in support of House Bill 1412 which would authorize the PUC to consider pilot microgrid and energy storage projects for a five-year period and require a subsequent PUC rulemaking to determine whether utility-owned microgrids and energy storage projects are in the public interest and appropriate regulatory structures to govern their future development.

PECO is currently developing a microgrid for its Berwyn facilities to enhance the reliability and resiliency of critical operations. There will be no external customer involvement. The microgrid, titled the "Berwyn Smart Energy Campus," is also intended to provide an internal testbed and learning opportunities for grid modernization and smart energy technologies. The microgrid is sized to meet a peak campus load of 750 kW and will have a diverse mix of distributed energy resources. Additionally, PECO is also working with Argonne National Lab and the Electric Power Research Institute to establish remote monitoring and control between the microgrid and PECO's Distribution Management System as an innovative research and demonstration project toward better management of distributed energy resources, co-funded by the Department of Energy with a $1.1 million grant. The microgrid is planned to be operational by the end of 2019.

ComEd: ComEd's microgrid efforts significantly advanced in 2017. This effort was supported by two grants from the Department of Energy, including to develop a microgrid master controller (MMC) which can operate a microgrid cluster, and to install solar PV and energy storage within a microgrid. ComEd also filed a request to the ICC to install a 7 MW microgrid in the Bronzeville neighborhood of Chicago. This project would be the first utility-operated microgrid cluster.

In addition to this, ComEd continued to make significant process in completing the responsibilities towards the afore-referenced grants. ComEd expects to complete the requirements for the MMC grant by the Q3 of 2018, and will be prepared to collect data for the grant associated with the installation of solar PV and storage once the first phase of the microgrid is complete at the end of 2018.

ComEd has supported IIT on the implementation of a building level nanogrid that serves the Sports Center at IIT campus. The DC/AC nanogrid allows direct current (DC) loads to be fed directly from rooftop solar energy units into DC applications. This process reduces solar energy losses via direct AC/DC conversion and direct use of DC solar power.

8.4 Electric Vehicles

Electric vehicles (EVs) have experienced rapid growth throughout the U.S. with over 390,000 units sold in the last four years. Growth in EVs is largely driven by state incentive programs as well as consumer preferences, and has the potential to significantly shift the dynamics on the electric grid in both positive and negative ways. Utilities must manage EV opportunities such as demand response and treatment of grid assets with the potential for EVs creating reliability challenges for the distribution system.

PHI: PHI currently has 10 Chevy Volt PHEVs, 2 Kia Soul BEVs and 8 plug-in trucks (Pepco – 3, Delmarva Power – 4, and ACE – 1) in its fleet. PHI has 23 Electric Vehicle charging stations, including two District of Columbia Fast Charging Stations (Pepco – 18, DPL – 3 and ACE – 2).

District of Columbia – In April 2017, Pepco submitted a proposal to the District of Columbia PSC to promote the integration of electrical vehicles. However, Pepco is in the process of updating the proposal to include more technologies and infrastructure options for urban residents. This includes voluntary offerings including special time of use and wholehouse rates for customers with an electric vehicle as well as a discounted installation of a smart level 2 charging station. Smart charging stations are also being proposed for workplace, multi-dwelling-unit dwellings, community public spaces. Direct-current fast chargers will also be strategically placed throughout the District as public access charging stations for customers and visitors In addition, Pepco is proposing a strong education and outreach campaign to explain the benefits of EV and cost savings as well as technology demonstrations and innovation fund offerings to develop projects to serve the underserved / low income areas, allow for competitive proposals to win funding for projects, and to pilot new technologies that save energy such as frequency response and integration of storage.

Maryland - In 2015, Pepco completed a successful Demand Response Pilot for Electric Vehicle Charging with Maryland Residential Customers in which 166 customers participated and demonstrated the benefits of off-peak charging. PHI continues to look for opportunities to further support transportation electrification and is an active member of the Maryland PSC PC44 EV working group in which a joint utility proposal was submitted to the PSC in early 2018 for a robust program offering around electric vehicle incentives and infrastructure. The program offerings include special time of use and wholehouse rates for customers with an electric vehicle as well as a discounted installation of a smart level 2 charging station. Smart charging stations are also being proposed for workplace, multi-dwelling-unit dwellings, community public spaces. Direct-current fast chargers will also be strategically placed throughout the area as public access charging stations for customers and visitors. In addition, technology demonstrations and innovation fund offerings were included in the proposal in order to develop projects in underserved / low income areas, allow for competitive proposals to win funding for projects, and to pilot new technologies to save energy such as frequency response and integration of storage. A robust education and outreach campaign is also expected to communicate the benefits of electric vehicles.

PHI is also a member of the Maryland Electric Vehicle Infrastructure Council (EVIC), a Council formed by legislation in 2011 to overcome barriers to EV adoption in the state.

New Jersey – In February 2018, ACE submitted a proposal to the BPU to help seed the market. The voluntary program offerings will include special time of use and wholehouse rates for customers with an electric vehicle, as well as a discounted installation of a smart level 2 charging station. Smart charging stations are also being proposed for workplace, multi-dwelling-unit dwellings, and community public spaces. Direct-current fast chargers will also be strategically placed throughout the area as public access charging stations for customers and visitors. In addition, ACE is proposing an extensive education and outreach campaign to explain the benefits of EV and cost savings as well as technology demonstrations coupling storage and public charging as possible options.

Delaware - In 2017, Delmarva Power submitted to the Delaware Public Service Commission a robust program offering around electric vehicle incentives and infrastructure to help seed the market. The voluntary program offerings include special time of use and wholehouse rates for customers with an electric vehicle as well as a discounted installation of a smart level 2 charging station. Smart charging stations are also being proposed for multi-dwelling-units, and community public spaces. Direct-current fast chargers will also be strategically placed throughout the area as public access charging stations for customers and visitors. In addition, funding for electric buses was included. A robust education and outreach campaign is also expected to communicate the benefits of electric vehicles.

BGE: BGE has several electric vehicles in its fleet, including 2 Volts, 2 Bolts and several Prius vehicles that have been converted from simple hybrid to plug-in hybrid vehicles and several electric utility vehicles (GEMS). BGE currently has four Level 2 charging stations available for employee charging at 3 company locations, including one in the G&E HQ garage. Work is underway for additional sites to be added in 2018 at these and other company locations, for a total of around 25 chargers. BGE has a voluntary whole house rate specific for customers with EV's.

BGE participates in the Maryland PSC PC44 Electric Vehicles working group in which a joint utility proposal was submitted to the PSC in early 2018 with EV infrastructure advancement proposals. BGE is also a member of the EVIC.

PECO: PECO has installed electric vehicle charging infrastructure to support workplace charging in 39 parking spaces for employees at 7 PECO worksites. PECO fleet has added plug-in electric vehicles to its operational fleet including 22 plug-in hybrid bucket trucks a heavy duty aerial truck and a splicer truck. PECO owns and operates two Chevy Volts. Additional employee charging infrastructure is planned for the future.

PECO has offered customers who register their EVs with the utility a $50 incentive and is analyzing charging patterns to better understand anticipated future system impacts. To date, over 1,300 customers have taken advantage of the rebate.

PECO supports HB 1446 which would set a state transportation electrification goal, require utilities serving major metropolitan areas to sponsor independent third-party infrastructure need assessments and authorize utilities to file infrastructure investment plans with the PUC to support infrastructure developments. This process would be updated every four years.

ComEd: ComEd has installed 105 charging stations, single and dual port, in more than 20 locations. This results in 167 ports available for different purposes (ComEd employee EV, ComEd fleet and public purpose).

ComEd has introduced Electric Vehicles to its fleet, having more than 200 conventional hybrid vehicles and75 plug-in hybrid vehicles including cars, pickups, vans and trucks. Acquisition of additional EV to include in the light and heavy duty fleet is planned for the next 4 years.

8.5 Energy Storage

The price of energy storage technologies has been dropping rapidly, and the Exelon Utilities expect increased use of energy storage by customers, other parties and by the utilities. Energy storage systems can be installed in a variety of configurations, each of which will have different impacts and implications for the distribution grid. Various technical and regulatory issues will need to be addressed to assure safe and reliable integration of energy storage systems into the distribution grid in an efficient manner so as to not inhibit growth in energy storage development.

PHI: PHI is actively seeking opportunities to site and implement Energy Storage where it makes sense to mitigate a power quality issue or defer the need for capacity. PHI is working to integrate battery storage within its existing distribution planning process as battery storage, like other new and emerging technologies, has the potential to improve performance through improved system reliability, mitigating the effects of high penetration DER and alternatives to capital expansion.

Maryland - PHI utilities in Maryland are participating in the PC44 storage working group which is considering issues relating to energy storage deployment in Maryland. In addition, Pepco currently has proposals pending before the Maryland Public Service Commission for storage sited with two microgrids. PHI utilities in Maryland have also proposed storage sited with electric vehicle DC fast charging stations as part of the PC44 EV working group filings.

As previously mentioned, Delmarva Power is currently assisting with the deployment of a 1MW Battery Storage solution located a Chesapeake College. In working with the college as well as the battery storage and solar energy vendors, the combination of solar and the battery can also be used to create a small campus microgrid solution for resiliency purposes.

New Jersey – Following passage of the Renewable Energy legislation in 2018, ACE will be working to advance provisions of the act that require the Board to conduct and complete an energy storage analysis by May 2019. Once the report is complete, the Board will initiate a proceeding to establish a process and mechanism for achieving the goal of 600 MW of energy storage by 2021 and 2,000 MW of energy storage by 2030.

BGE: BGE, in conjunction with other Exelon Utilities, is actively participating in PC44 and considering a number of issues relating to energy storage deployment in Maryland. It is anticipated that a Workgroup report could be filed in 2018. BGE has evaluated a number of possible applications for battery storage on the distribution system, particularly in lieu of other, more typical, investments to address system needs. BGE has updated its distribution investment review process to include consideration of battery storage alternatives.

BGE has developed the engineering and planning to deploy a 5 MW/20 MWh battery storage solution at BGE's Coldspring substation. This project will reduce the peak load on the Coldspring substation, allowing the deferral of the construction of a major new distribution substation. The first phase of the project consisting of the installation of a 1 MW/1 MWh battery storage system was completed in Q2 2018. In addition to peak shaving, BGE is studying how to use the battery storage system to control substation bus voltage.

PECO: PECO is pursuing many different battery applications.

PECO is currently piloting and evaluating the use of lithium ion and aqueous hybrid batteries for non-NERC SCADA substation applications, particularly for protection and control systems. Also, PECO is working with Exelon IT to pilot the use of lithium-ion batteries for fiber optic SONET communications at ten substation locations. Based on the success of the pilot, the remaining 80+ substations will also have their OC-48 Valve Regulated Lead Acid (VRLA) batteries replaced with two C&D lithium-ion modules.

As part of PECO's Berwyn Smart Energy Campus, a microgrid under development for PECO's own critical facilities, two lithium-ion battery energy storage systems will be incorporated into the microgrid. There will be one 1 MW / 500 kWh system interconnected at primary voltage, and one 250 kW / 500 kWh system interconnected at secondary voltage to simulate a behind-the-meter customer installation. PECO intends for the two systems to support the following use cases: microgrid islanding, microgrid black-start, renewables firming, energy arbitrage, load shifting, and peak shaving. A campus microgrid controller will autonomously manage the two battery systems. PECO is targeting the end of 2019 for full operation of the microgrid.

PECO has sponsored a lithium-ion battery system for a commercial building microgrid system that is under development by Penn State University as a demonstration and research project at The Navy Yard in Philadelphia, PA. The system will utilize a building microgrid controller to optimize and manage several distributed energy resources within the building microgrid. It is currently expected that this system will be fully operational and use case testing will begin by the end of 2019.

PECO has testified in the Pennsylvania House of Representatives in support of House Bill 1412 which would authorize the PUC to consider pilot microgrid and energy storage projects for a five-year period and require a subsequent PUC rulemaking to determine whether utility-owned microgrids and energy storage projects are in the public interest and appropriate regulatory structures to govern their future development.

ComEd: ComEd has developed a ten-year roadmap for application of battery energy storage in ComEd's system based on detailed Benefit Cost Analysis (BCA) for specific distribution applications such as Capacity deferral, Integration of Distributed Generation, Reliability and Resiliency. The objective is to assess the total beneficial amount of energy storage for a multi-year deployment by extrapolating the results to the whole system.

As part of ComEd's grant from the DOE to develop and test the Sustainable and Holistic Integration of Energy Storage and Solar PV (SHINES), it continued to prepare for a demonstration project within a Bronzeville Community Microgrid. ComEd will install at least 0.75 MW of Solar PV and 0.5 MW of energy storage within the footprint of a microgrid. The SHINES technology looks to address availability and variability issues inherent in the solar photovoltaic (PV) technology by utilizing smart inverters for solar PV/battery storage and working synergistically with other components within a microgrid community.

ComEd purchased a Community Energy Storage (CES) device for a pilot to address reliability issues for Customers Experiencing Multiple Interruptions (CEMI). The small-scale energy storage unit operates on the low voltage side of the utility transformer, serving approximately 3 customers during an outage.

Section 9: Conclusion

PHI will continue to file the Across the Fence Report comparing the Exelon Utilities' performances in a variety of categories and through different metrics. PHI's performance and innovation in many areas have reflected improvements as it continues to align with established Exelon policies and procedures, and shares practices with other utilities in the Exelon group. In an effort to provide enhanced safe and reliable service, PHI has continued to invest in replacing and upgrading aging equipment as well as the installation of new technology. In PHI's second year post-merger, each company is providing faster and better service than ever before which included delivering record reliability statistics in 2017. The Companies' focus on grid modernization and improved service supports Exelon's vision of providing best in-class performance for our customers and communities.

CERTIFICATE OF SERVICE

I hereby certify that a copy of Pepco Holdings LLC (PHI) 2017 Across the Fence Report was served this June 29, 2018 on all parties in Formal Case No. 1119 by electronic mail.

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street N.W. Suite 800
Washington, DC 20005
bwestbrook@psc.dc.gov

Sandra Mattavous-Frye, Esq.
People's Counsel
Office of the People's Counsel
1133 15th Street, NW, Suite 500
Washington, DC 20005
smfrye@opc-dc.gov

Christopher Lipscombe, Esq.
Public Service Commission of DC
1325 G Street NW - Suite 800
Washington, DC 20005
clipscombe@psc.dc.gov

Frann G. Francis, Esq
Nicola Y. Whiteman, Esq.
Apartment and Office Building Association of Metropolitan Washington
1025 Connecticut Avenue NW, Suite 1005
Washington, DC 20036
ffrancis@aoba-metro.org
nwhiteman@aoba-metro.org

Bruce R. Oliver
Revilo Hill Associates, Inc.
7103 Laketree Drive
Fairfax Station, Virginia, 22039
revilohill@verizon.net

Laurence Daniels
Arick R. Sears
Travis Smith
Barbara Burton
Nicole Sitataman
Dwayne Houston
Office of the People's Counsel
1133 15th Street, NW, Suite 500
Washington, DC 20005
ldaniels@opc-dc.gov
asears@opc-dc.gov
tsmith@opc-dc.gov
bburton@opc-dc.gov
nsitaraman@opc-dc.gov
dhouston@opc-dc.gov

Brian Caldwell
Office of the Attorney General
441 4th Street, N.W. Suite 1130 N
Washington, D.C. 20001
Brian.caldwell@dc.gov

Nancy White
Michael Engelman
Counsel
Squire Patton Boggs
2550 M Street, N.W.
Washington, D.C.
Nancy.white@squirepb.com
Michael.engelman@squirepb.com

David J. Arkush
DC Sun and Public Citizen
901 Fifteenth Street, N.W.
Washington, DC 20005
darkush@citizen.org

Olivia Wein
NCLC
1001 Connecticut Avenue Suite 510
Washington, DC 20036
owein@nclc.org

James K. McGee, Esq.
Law Offices of Alexander & Cleaver, P.A.
on behalf of the Washington, D.C. Chapter of the Sierra Club and the Grid 2.0 Working Group
11414 Livingston Road
Fort Washington, MD 20744
jmcgee@alexander-cleaver.com

Telemac N. Chryssikos
Washington Gas Energy Services
101 Consitution Avenue NW Suite 319
Washington, DC 20080
TelemacChryssikos@washgas.com

Carolyn Elefant
2200 Pennsylvania Avenue Fourth Floor
Washington, D.C. 20037
Carolyn@carolynelefant.com

Abraham Silverman
NRG Energy, Inc.
211 Carnegie Center Drive
Princeton, NJ 08540
Abraham.silverman@nrgenergy.com

Dennis Goins
Potomac Management Group on behalf of the United States
General Services Administration
P.O. Box 30225
Alexandria, VA 22310
dgoinspmg@verizon.net

Jeffrey W. Mayes
Monitoring Analytics, LLC on behalf of Independent Market
Monitor for PJM
2621 Van Buren Avenue Suite 160
Eagleville, PA 19403
Jeffrey.mayes@monitoringanalytics.com

Brian R. Greene
GreeneHurlocker, PLC on behalf of Maryland DC Virginia
Solar Energy Industries Association
1807 Libbie Avenue Suite 102
Richmond, VA 23226
bgreene@greenehurlocker.com

Randy E. Hayman, Esq.
DC Water and Sewer Authority
5000 Overlook Avenue SW
Washington, DC 20032
Randy.hayman@dcwater.com

Randall L. Speck
Kaye Scholer LLP on behalf of DC Solar United Neighborhoods
901 Fifteenth Street NW
Washington, DC 20005
Randall.speck@kayscholer.com

John Chelen
DC Public Power
1701 K Street NW - Suite 650
Washington, DC 20006
jchelen@dcpublicpower.org

Larry Martin
GRID2.0 Working Group
4525 Blagden Ave. NW
Washington, DC 20011
lmartindc@gmail.com

Charles Rories
GRID 2.0 Working Group
6309 Rockwell Road
Burke, VA 22015

Charles Harak
Attorney on behalf of NCLC/NHT/NHT-Enterprise
7 Winthrop Square
Boston, MA 02110
charak@nclc.org

John Tobey
US General Services Administration
1800 F Street, NW
2nd Floor
Washington, DC 20405

Richard M. Lorenzo
Loeb & Loeb LLP
345 Park Avenue
New York, NY 10154
rlorenzo@loeb.com

Dennis P. Jamouneau