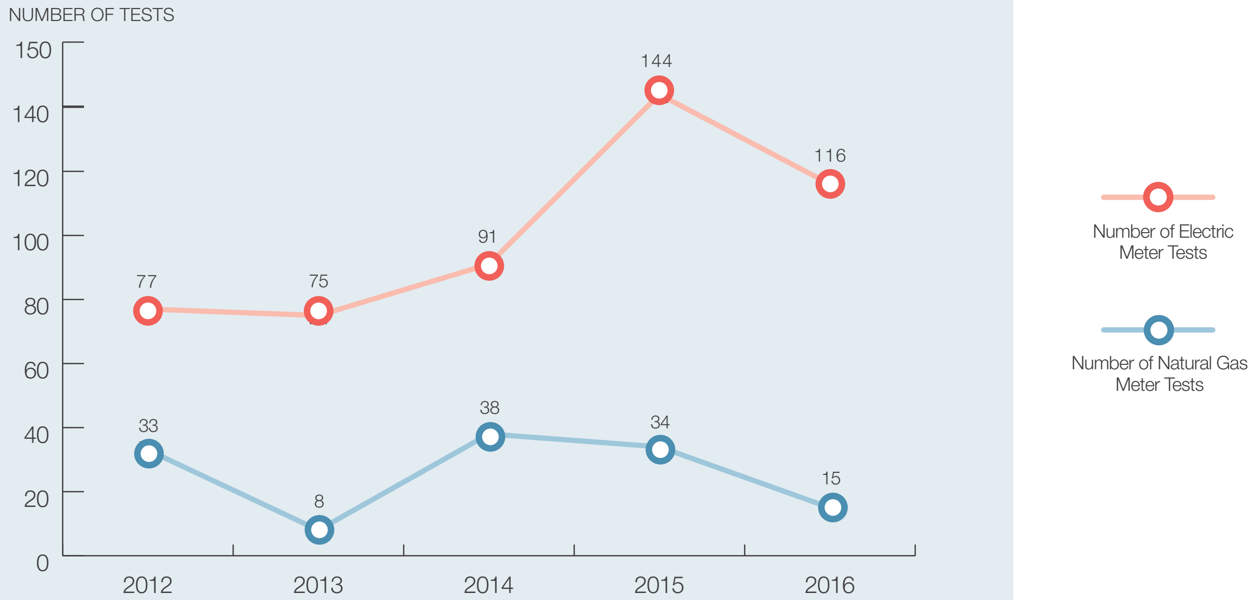
45. NUMBER OF ELECTRIC AND NATURAL GAS METER TESTS WITNESSED IN CY 2012–CY 2016

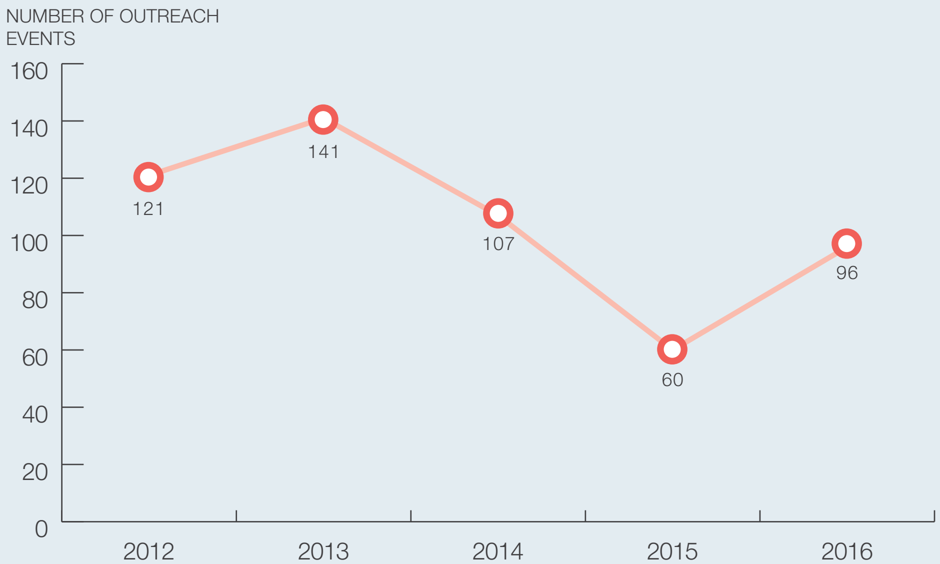


Meter tests are witnessed by the Commission pursuant to a request by a consumer.

There were 15 natural gas meter tests in CY 2016 and 116 electric meter tests.

Source: DCPSC of the District of Columbia

46. NUMBER OF OUTREACH ACTIVITIES (EXCLUDING METER TESTS) IN CY 2012–CY 2016



In 2016, the Commission returned to more historic levels of outreach activities under the direction of the Consumer Education and Outreach Specialist, who continued strategic partnerships with other District agencies, Advisory Neighborhood Commissions (ANCs), community groups and civic organizations. Though the aggregate number of outreaches increased from the previous calendar year, the Commission continued its focus on consumer engagement and the quality of consumer contacts, rather than quantity.

Source: DCPSC of the District of Columbia

KEY OUTCOMES

47. DIVERSE SUPPLIERS AND CERTIFIED BUSINESS ENTERPRISES ("CBE") CY 2013–CY 2016 PERFORMANCE

SYSTEM-WIDE DIVERSE SUPPLIERS COMPARED TO TOTAL CBE SYSTEM PROCUREMENT

Utility	2013	2014	2015	2016
	Diverse Supplier Percentage of Total System Spend	Diverse Supplier Percentage of Total System Spend	Diverse Supplier Percentage of Total System Spend	Diverse Supplier Percentage of Total System Spend
Pepco	13.29%	13.24%	13.30%	16.70%
WGL	20.28%	22.86%	26.60%	29.10%
Verizon	12.63%	44.13%	39.00%	48.20%

D.C.-BASED CERTIFIED BUSINESS ENTERPRISES (CBE) COMPARED TO TOTAL SYSTEM PROCUREMENT

Utility	2013	2014	2015	2016
	CBE Percentage of Total System Spend	CBE Percentage of Total System Spend	CBE Percentage of Total System Spend	CBE Percentage of Total System Spend
Pepco	3.14%	5.51%	7.10%	7.20%
WGL	5.79%	7.48%	8.30%	7.70%
Verizon	14.08%	18.52%	17.70%	18.40%

D.C.-BASED CERTIFIED BUSINESS ENTERPRISES (CBE) COMPARED TO D.C. PROCUREMENT

Utility	2013	2014	2015	2016
	CBE Percentage of Total D.C. Procurement Spend	CBE Percentage of Total D.C. Procurement Spend	CBE Percentage of Total D.C. Procurement Spend	CBE Percentage of Total D.C. Procurement Spend
Pepco	50.9%	96.7%	97.20%	61.40%
WGL	38.86%	50.57%	57.10%	53.40%
Verizon	N/A	N/A	N/A	N/A

In 2015, Pepco, WGL and Verizon filed their Supplier Diversity Annual Reports in accordance with the February 12, 2012 Memoranda of Understanding (MOU) between the companies and the DCPSC regarding contracting with diverse suppliers and Certified Business Enterprises (CBEs). A diverse supplier is a minority business enterprise, a women business enterprise, a service disabled veteran business enterprise or a non-profit. CBEs are defined as businesses certified by the D.C. Department of Small and Local Business Development.

Pepco and WGL reported higher percentages of Supplier Diversity and CBE participation in 2015 compared to 2014.

Verizon does not file D.C.-specific procurement dollars spent. Therefore, the CBE percentage cannot be calculated.

Source: 2016, 2015, 2014, 2013 Supplier Diversity Reports from Pepco, WGL and Verizon

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(202) 626-5100
www.dcpsc.org

Betty Ann Kane
Chairman

May 1, 2017

VIA HAND DELIVERY

Nyasha Smith
Secretary to the Council
Council of the District of Columbia
1350 Pennsylvania Avenue, NW
Washington, D.C. 20004

Re: Report on the Renewable Energy Portfolio Standard for Compliance Year 2016

Dear Ms. Smith:

Attached is the Public Service Commission of the District of Columbia's ("Commission") Report on the Renewable Energy Portfolio Standard, which is filed in accordance with § 34-1439 of the District of Columbia Official Code. Specifically, this section requires the Commission to file a report with the Council on or before May 1st of every year on the status of implementation of the Renewable Energy Portfolio Standard Act, including: the availability of tier one renewable resources; certification of the number of credits generated by the utilities meeting the requirements of § 34-1432; and any other such information as the Council shall consider necessary.

Thank you. If you have any questions, please do not hesitate to contact me.

Sincerely,

Betty Ann Kane

Betty Ann Kane

Attachment

cc: The Honorable Willie Phillips, Commissioner, Public Service Commission
The Honorable Richard Beverly, Commissioner, Public Service Commission

Public Service Commission

of the

District of Columbia

Report on the Renewable Energy Portfolio Standard for Compliance Year 2016

May 1, 2017

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EXECUTIVE SUMMARY

The *Renewable Energy Portfolio Standard Act* ("REPS Act") requires the Public Service Commission of the District of Columbia ("Commission") to annually report to the Council of the District of Columbia on the status of implementation of the Renewable Portfolio Standards ("RPS"), including the number of renewable generators approved by the Commission and eligible to participate in the District's RPS program; the availability of renewable resources; and the certification of the number of credits generated by the utilities meeting the requirements of D.C. Official Code § 34-1432, which outlines the minimum percentages to be derived from certain renewable resources—and any other such information as the Council shall consider necessary. This annual report fulfills the reporting requirement outlined in the REPS Act for the most recent compliance year of 2016.

Pursuant to the Commission's RPS rules, 35 active electricity suppliers and Pepco—the default electricity supplier—with retail electricity sales in the District submitted compliance reports due by April 1, 2017 reporting on their RPS compliance in 2016.[1] These reports show that electricity suppliers generally met the RPS requirements through purchasing renewable energy credits ("RECs") and making compliance payments. Thirteen electricity suppliers submitted a compliance payment representing in most cases a portion of their compliance obligation. The compliance fees are deposited into the Renewable Energy Development Fund which is administered by the District's Department of Energy and Environment ("DOEE"). The total amount of compliance payments for 2016 was $15,230,000, compared to $19,910,000 in fees generated in 2015. The decrease in the compliance fees, compared to 2015, generally reflects the increase in use of solar RECs to meet the RPS requirements. Suppliers retired 38,167 solar RECs in 2015, but the amount increased by roughly 63 percent in 2016, with 62,173 solar RECs retired.

Although the reported retail sales did not increase significantly—up about 0.6 percent, from 11.214 million megawatt-hours ("MWH") in 2015 to 11.286 million MWH in 2016—the available capacity from solar energy systems certified for the District's RPS program is still well below the required capacity, resulting in a shortage of qualifying solar RECS. This shortage of solar capacity will only increase as the solar requirement continues to rise over time. In addition, the shortage of solar capacity has also contributed to high solar REC prices in the District of Columbia, currently trading around $470 per REC and by far the highest among the Mid-Atlantic states.

As of April 7, 2017, there are 5,342 renewable generators approved by the Commission and eligible to participate in the District's RPS program. Of the facilities approved, 5,294 (99.1 percent) use Tier I resources (including biomass, methane from landfill gas, solar, and wind) and 48 (0.9 percent) use Tier II resources (i.e., biomass and hydroelectric). Since these renewable generators may be certified in other states that have a RPS requirement as well, the renewable energy credits associated with the generating capacity are not necessarily fully available to meet the District's RPS.

---

1 Pepco submits a compliance report on behalf of the Standard Offer Service ("SOS") program, in its capacity as SOS Administrator.

There are currently 5,164 solar energy systems (including both solar photovoltaic and solar thermal) eligible to meet the District's solar RPS requirement, of which 2,879 are located within the District. The 2,879 District RPS-eligible solar energy systems are located in all 8 wards in the following numbers: Ward 1 - 322; Ward 2 - 131; Ward 3 – 400; Ward 4 – 463; Ward 5 – 406, Ward 6 – 471; Ward 7 – 440; and Ward 8 – 246.[2] Outside of the District, there are six states with more than 100 RPS-eligible solar energy systems including Pennsylvania (928), Virginia (493), Maryland (237), North Carolina (156), Delaware (150), and Ohio (132). These six (6) states account for roughly 92 percent of the non-DC solar energy systems approved for the District's RPS program. There are also RPS-eligible solar energy systems in eight additional states.

As a result of the adoption of the *Distributed Generation Amendment Act of 2011* ("DGAA"),[3] which required all solar photovoltaic and solar thermal facilities certified by the Commission after January 31, 2011 to be located in the District or on a distribution feeder serving the District, the District had seen a significant decrease in the number of solar generator applications—on a calendar year basis—for the RPS program. In particular, the number of applications, primarily solar, increased from 461 in 2009 to 2,034 in 2010, before falling to 1,846 in 2011, and 257 in 2012. However, since 2013, the declining trend has been reversed. The RPS applications increased to 391 in 2013, 473 in 2014, 717 in 2015, and 818 in 2016. This reversal in applications reflects the growth of solar resources in the District and may be attributed to a number of factors, which could include the increase in use of leasing programs which eliminate or reduce the upfront costs for homeowners and businesses, the continued high solar REC prices in the District, and expenditures by the District's Sustainable Energy Utility and the District Department of Energy and Environment. As of April 7, 2017, the Commission has received 174 applications in 2017.

The total reported capacity associated with the approved 5,164 solar energy systems as of April 7, 2017 is about 54.7 megawatts ("MW"). About 33.8 MW of this capacity is located in the District. The current certified solar capacity is up from 19.2 MW of solar capacity as of April 19, 2016. Currently, the capacity indicated in the District now exceeds the out-of-state solar capacity (about 20.9 MW[4]) that was grandfathered into the RPS program by roughly 62 percent. However, the retirement of out-of-state solar RECs for the 2016 compliance year is nearly the same as the retirement of District solar RECs.[5]

---

2 See Attachment 3.

3 D.C. Act 19-126 (August 1, 2011). The permanent version of this legislation, the Distributed Generation Amendment Act of 2011, became law on October 20, 2011. *See* D.C. Law 19-0036.

4 This includes solar energy systems, in a small portion of Maryland, which are in a location served by feeders serving the District of Columbia

5 A REC represents one megawatt-hour of electricity generation, attributable to a particular renewable energy source.

While the amount of DC-based capacity is still increasing, it is still well below the solar capacity that is necessary to meet the solar RPS requirement of the DGAA. That need is an estimated 70.0 MW for 2016 to meet the required 0.825 percent of all District of Columbia retail electricity sales and 83.2 MW in 2017 to meet the required 0.980 percent of all District of Columbia retail electricity sales. The enactment of the *Renewable Portfolio Standard Expansion Amendment Act of 2016* enables 15 MW solar energy systems in the District or in a location served by a distribution feeder serving the District, and no cap on the size of solar installations owned by District agencies, to be eligible for certification. This has the potential to accelerate the number of DC-based solar RECs that may be available to suppliers for compliance purposes in the upcoming years. However, compliance costs will most likely continue to rise over time to the extent that the solar energy requirements outstrip the availability of systems certified to meet the requirement.

The Commission tracks the number of renewable energy credits submitted for compliance. A breakdown of the number of RECs for 2016, submitted by fuel type, is provided in the table below:

Renewable Energy Credits Submitted for 2016 Compliance

	No. of RECs	Share of Tier
Tier I Resource		
Black Liquor	183,749	13.6%
Methane from Landfill Gas	189,345	14.0%
Wind	451,607	33.5%
Wood Waste	414,275	30.7%
Non-Solar Tier I (out-of-state solar)	47,400	3.5%
Solar Carve-Out	62,173	4.6%
Total Tier I and Solar Carve-Out	1,348,549	100.0%
Tier II Resource		
Hydroelectric	205,670	92.0%
Black Liquor	4,867	2.2%
Wood Waste	12,935	5.8%
Municipal Solid Waste	-	0.0%
Total Tier II	223,472	100.0%
Total Tier I, Solar Carve-Out, and Tier II	1,572,021	

In 2016, suppliers provided the REC prices for all of their resources. In general, non-solar REC prices have been relatively stable in recent years, despite the rise in RPS requirements. However, solar REC prices for the District have trended upward since 2011 as the impact of the DGAA has made the District's solar REC prices the highest in the region. Suppliers spent $31.93 million on the acquisition of RECs, driven largely by the cost of solar RECs. Taken together, the estimated total cost of compliance—including the cost of RECs and compliance fees—amounted to $47.16 million for the 2016 RPS compliance, up from $38.54 million for the 2015 RPS compliance.

The Commission addressed various changes to the RPS Rules included in the *Renewable Portfolio Standard Expansion Amendment Act of 2016* (D.C. Law 21-154, effective October 8, 2016) in Order No. 18749 (released April 13, 2017). The rules will become effective upon publication of the NOFR in the *D.C. Register*. In addition, the Commission is addressing changes to its interconnection rules in a Notice of Proposed Rulemaking ("NOPR") published on February 17, 2017 in the *D.C. Register*, as the RPS Expansion Amendment Act of 2016 increased the capacity of solar facilities qualified for SRECs in the District from 5 MW to 15 MW.

Finally, pursuant to the requirements of the RPS Expansion Amendment Act of 2016, the Commission submitted its report to the D.C. Council in fulfillment of Section 2b of the Act (D.C. Code § 34-1432(f)) which provides that:

> No later than March 1, 2017, the Commission shall provide a report to the Council that includes:
>
> (1) An estimate of the amount of solar energy generated annually by solar energy systems in the District that could qualify to be used to meet the annual solar energy requirement, but for which renewable energy credits cannot be purchased by electricity suppliers to meet the solar energy requirement; and
> (2) A recommendation for how the Commission could adjust the annual solar requirement to account for the amount of solar generation identified in paragraph (1) of this subsection.

The Commission made use of its database of certified renewable facilities and Pepco's database of facilities that have been approved for interconnection with the distribution system. By comparing the solar photovoltaic ("PV") systems that have been interconnected to Pepco's distribution system with the solar PV application that have been submitted to the Commission for certification and approved for the District's RPS program, any difference in capacity can be identified. In addition, the Commission considered information obtained from the Renewable Electric Plan Information System ("REPIS") database developed by the National Renewable Energy Laboratory ("NREL"). Based on this available information, the report indicated that an estimated 5,046 MWH (or 5,046 solar RECs) would not be available to suppliers to meet the District's solar energy RPS requirement at this time. Accounting for these unavailable solar RECs would lower the 2016 RPS requirement, for example, from 0.825% to 0.779% (an adjustment of 0.046%).

I. Introduction and Background

The Council of the District of Columbia ("Council") enacted the *Renewable Energy Portfolio Standard Act* ("REPS Act") on January 19, 2005 and established a renewable energy portfolio standard ("RPS"), through which a minimum percentage of District electric providers' supply must be derived from renewable energy resources beginning January 1, 2007. The RPS minimum requirements, among other things, were amended by the *Clean and Affordable Energy Act of 2008* ("CAEA").[6] Further changes to the RPS program occurred on August 1, 2011, when the *Distributed Generation Emergency Amendment Act of 2011* ("DGAA") became law.[7] Additional amendments to the RPS program became effective on April 30, 2015, as a result of the *Renewable Energy Portfolio Standard Amendment Act of 2014* ("RPS Amendment Act of 2014"), and October 8, 2016, as a result of the *Renewable Portfolio Standard Expansion Amendment Act of 2016* ("RPS Expansion Amendment Act of 2016).

Renewable energy resources are divided into two categories, Tier I and Tier II, with Tier I resources including solar energy, wind, biomass, methane, geothermal, ocean, and fuel cells, and Tier II resources including hydroelectric power other than pumped storage generation and waste-to-energy.[8] Although minimum percentage requirements are specified for Tier I and Tier II resources, Tier I resources can be used to comply with the Tier II standard. In addition, a minimum requirement is carved out specifically for solar energy. The REPS Act allows an electricity supplier to begin receiving and accumulating renewable energy credits as of January 1, 2006.

The REPS Act required that the Public Service Commission of the District of Columbia ("Commission") adopt regulations, or orders, governing the application and transfer of renewable energy credits and implementation of the REPS Act. The RPS rules became effective upon the publication of the Notice of Final Rulemaking in the *D.C. Register* on January 18, 2008. The Commission's Rules can be found in Chapter 29 of 15 DCMR. As part of its RPS rules, the Commission established a process for certifying eligible generators. The certification process includes a streamlined application that the Commission developed. Renewable generators do not need to submit as much documentation for the streamlined application and the Commission is required to take action in a shorter period of time.

On October 22, 2008, the permanent version of the CAEA became law. The law, among other things, amended the REPS Act and changed the definition of solar energy to

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6 D.C. Official Code § 34-1432(c) (2012 Supp.).

7 D.C. Act 19-126 (August 1, 2011). The permanent version of this legislation, the Distributed Generation Amendment Act of 2011, became law on October 20, 2011. *See* D.C. Law 19-0036. Since emergency and permanent versions of the legislation are identical, both are referred to as the DGAA.

8 As of January 1, 2013, the incineration of solid waste is no longer eligible to generate renewable energy credits for the District's RPS program. In addition, the RPS Amendment Act of 2014 resulted in the transfer of certain biomass resources to Tier II.

provide eligibility for solar thermal applications that do not generate electricity, raised the RPS requirements to 20 percent by 2020, and increased certain alternative compliance fees.

The DGAA disallowed most new solar energy systems located outside of the District from being certified by the Commission for the RPS program, after January 31, 2011—although solar energy systems located outside of the District that were certified prior to February 1, 2011 were "grandfathered" and remain eligible under the RPS program. In addition, among other things, the legislation increased the solar RPS requirement from 2011 through 2023 (up to 2.5 percent by 2023 as opposed to 0.4 percent by 2020), disallowed the certification of solar energy systems larger than 5 megawatts ("MW") in capacity, amended the solar compliance fees for 2011 through 2023, and changed the eligibility requirements for solar thermal systems.

Pursuant to the DGAA, in Order No. 16528 (September 9, 2011), the Commission denied all applications of solar energy facilities seeking certification as eligible District of Columbia renewable energy standards generating facilities, which were not located within the District, nor in locations served by a distribution feeder serving the District, and pending before the Commission on August 1, 2011. Moreover, in Order No. 16529 (September 9, 2011), the Commission decertified 1,426 solar energy facilities not located within the District, or in locations served by a distribution feeder serving the District, and certified by the Commission between February 1, 2011, and the effective date of the Act, August 1, 2011, as well as any solar facilities with a capacity larger than 5 MW, regardless of the date certified.

As a result of the RPS Amendment Act of 2014, the eligibility of "qualifying biomass" resources was changed. The legislation requires that, to qualify as a Tier I resource, a generation unit using biomass must achieve a total system efficiency of at least sixty-five (65) percent on an annual basis, demonstrate that it achieved a total system efficiency of at least 65 percent on an annual basis through actual operational data after one year, and demonstrate that it started commercial operation after January 1, 2007 and refrain from using black liquor. Under this law, those biomass generation units that cannot achieve a total system efficiency of at least 65 percent, or that started commercial operations on or before December 31, 2006, or that use black liquor, can no longer qualify as Tier I resources. Rather, they now qualify as Tier II resources. Finally, any extension or renewal of energy supply contracts executed on or after August 1, 2011 shall be subject to the higher solar energy requirement.

Subsequently, the RPS Expansion Amendment Act of 2016 raised the RPS requirement to 50.0 percent from Tier I resources by 2032, with not less than 5.0 percent from solar energy. In addition, among other things, the 2016 Act amended the solar compliance fee and kept it at 50 cents per kilowatt-hour ("kWh") shortfall through 2023, before decreasing to 5 cents per kWh by 2033. Previously, the solar compliance fee was set to begin decreasing in 2017.[9]

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[9] Under the DGAA, the solar energy compliance payment was set to decrease from 50 cents per kWh in 2016 to 35 cents in 2017; then 30 cents in 2018; then 20 cents in 2019 through 2020; then 15 cents in 2021 through 2022; until reaching 5 cents in 2023 and thereafter.

In calendar year 2016 there were 35 electricity suppliers plus the default Standard Offer Service ("SOS") Provider who reported electricity sales to retail customers in the District. Pursuant to the Commission's RPS rules, each of these active suppliers submitted the required compliance report that was due by the then applicable deadline of April 1, 2017. These reports show that electricity suppliers and Pepco, the SOS administrator, generally met the RPS requirements through purchasing renewable energy credits ("RECs") and making compliance payments. Thirteen suppliers submitted a compliance payment in addition to acquiring RECs.[10] Based on the available information, the total amount of money generated from compliance payments in 2016 was $15,230,000—compared to $19,910,000 in 2015. The decrease in the amount of 2016 compliance fees reflects the greater use of solar RECs to meet the RPS compliance obligation. In 2016, electricity suppliers retired 62,173 solar RECs, about 63 percent more than the 38,167 solar RECs retired in 2015.

In Section II, we provide a summary of the steps that the Commission has taken to implement the RPS in the District. Section III reviews the RPS compliance reports submitted for the 2016 compliance year. In Section IV, we present some information on the current availability of renewable resources. Finally, Section V summarizes other ongoing actions to implement the RPS in the District and next steps. In addition, we include Attachment 1, which provides a national perspective on what other states are doing with respect to the implementation of their renewable portfolio standards.[11] Attachment 2 contains a list of selected orders that the Commission has issued to implement the RPS. Lastly, Attachment 3 includes a map of the certified solar energy systems in the District of Columbia.[12]

II. Summary of the Implementation of the Renewable Energy Portfolio Standard

This section provides a brief description of the history of actions that the Commission has undertaken to implement the RPS.[13] In order to establish a record and to begin implementation of the REPS Act, the Commission issued Order No. 13566 on April 29, 2005, inviting interested parties to submit their views on twelve (12) RPS-related issues. The twelve issues addressed:

- the process and timeline that the Commission should adopt to implement the Act;
- the procedure to apply for, verify, and transfer renewable energy credits;

---

10 The compliance fee payments are deposited into the Renewable Energy Development Fund administered by the District's Department of Energy and Environment ("DOEE").

11 States such as Connecticut, Hawaii, Michigan, Nevada, North Carolina, Ohio, and Pennsylvania include energy efficiency in their RPS.

12 The map was produced by Commission staff using the data maintained for the RPS generator certification.

13 Attachment 2 of this Report contains a list of selected Commission Orders and Notices addressing the implementation of the RPS program.

- the type(s) of renewable energy projects that are feasible within the District;
- the process for certifying the eligibility of generating facilities;
- the standards that should apply to customer generators;
- the information that should be submitted in an electricity supplier's annual compliance report;
- the appropriate procedures for cost recovery by Pepco;
- the standards that the Commission should employ for determining whether the compliance costs claimed by Pepco were prudently incurred;
- the verification of an electricity supplier's compliance with the RPS;
- the imposition of an administrative fee;
- the data and confidentiality concerns of stakeholders; and
- the states that qualify as being within or adjacent to the PJM Interconnection Region.

In Order No. 13766, released on September 23, 2005, the Commission addressed the various issues based on the record developed in response to Order No. 13566. Among other things, the Commission directed interested parties to form a RPS Working Group to examine in more detail certain issues related to the implementation of the REPS Act, and to propose a timeline and recommendations for a two-phased approach to resolving those issues.[14] The Commission also indicated that the PJM Environmental Information Services ("PJM-EIS") Generation Attribute Tracking System ("GATS") would be used in the implementation of the Act. In addition, the Commission indicated its intent to establish regulations to govern the application and transfer of RECs, on an interim basis, prior to January 1, 2006.

RPS Rules

Based on input from the RPS Working Group, the Commission established interim RPS rules in Order No. 13840 (December 28, 2005). These rules were subsequently amended in Order No. 13899 (March 27, 2006) and Order No. 14225 (March 2, 2007). The Commission eventually established a formal rulemaking process and on November 2, 2007, a Notice of Proposed Rulemaking ("NOPR") appeared in the *D.C. Register* requesting comments on revised RPS rules that were based, in part, on the interim RPS rules. After receiving and reviewing comments on the NOPR, the Commission issued Order No. 14697 (January 10, 2008) and adopted Chapter 29 of Title 15 District of Columbia Municipal Regulations ("Final Rules"). The Final Rules became effective upon the publication of the Notice of Final Rulemaking ("NOFR") in the *D.C. Register* on January 18, 2008.

The rules establish definitions for various terms consistent with the REPS Act, compliance requirements for electricity suppliers, certification of renewable generators, policies regarding the creation and tracking of RECs, and directives concerning the recovery of fees and costs.

[14] In Attachment A of Order No. 13766, the RPS Working Group was asked to address 23 issues.

Compliance Requirements for Electricity Suppliers

The RPS rules include compliance requirements for electricity suppliers beginning in 2007. Under the current requirements, suppliers are to file annual reports that include the following components: (1) the quantity of annual District retail electricity sales; (2) a calculation of the annual quantity of required Tier I, Tier II, and Solar Energy Credits; (3) the quantity of Tier I, Tier II, and Solar Energy Credits purchased and evidence of those purchases; (4) the quantity of Tier I, Tier II, and Solar Energy Credits transferred to the electricity supplier by a Renewable On-Site Generator; (5) a calculation of any compliance fees owed by the energy supplier; (6) certification of the accuracy and veracity of the report; (7) all documentation supporting the data in the annual compliance report; (8) a list of all RECS used to comply with the RPS; (9) a summary report of RECs retired during the reporting period; and (10) the total price paid for Tier I, Tier II, and Solar Energy Credits. Suppliers that purchase RECs solely via bundled products are exempt from including the total price paid for Tier I, Tier II, and Solar Energy Credits in their annual compliance report. The Commission allows the information in item (10) to be filed confidentially. An electricity supplier that fails to meet its RPS requirements must submit an annual Compliance Fee to the District of Columbia Renewable Energy Development Fund administered by the District Department of the Environment's Energy Office ("DDOE") by April 1 of the calendar year following the year of compliance.

To facilitate the compliance reporting, the Commission issued Order No. 14782 on April 10, 2008 and adopted a 2007 Compliance Report form for the District's RPS Program, along with the associated filing instructions. This material was made available on the Commission's website. Electricity suppliers used the form to submit the 2007 compliance reports due May 1, 2008. A revised compliance reporting form was included in a January 2, 2009 NOPR, to reflect changes mandated by the CAEA. The revised compliance reporting form was adopted in Order No. 15233 (April 7, 2009) and became effective upon publication of the NOFR in the *D.C. Register* on April 10, 2009. The compliance reporting form was revised again in order to address the DGAA legislation, with a NOPR appearing in the *D.C. Register* on January 13, 2012. The revised compliance reporting form was adopted in Order No. 16738 (March 15, 2012) and became effective upon publication of the NOFR in the *D.C. Register* on March 23, 2012.

Certification of Renewable Generators

The RPS rules outline the process for certifying renewable generating facilities within a certain period of time. Renewable generators, including behind-the-meter ("BTM") generators, must be certified as a qualified Tier I (including solar energy systems) or Tier II resource through the completion of an application form approved by the Commission.[15] In situations where the applicant has obtained certification as a renewable energy resource by

[15] A behind-the-meter generator is defined as a renewable on-site generator that is located behind a retail customer meter such that no utility-owned transmission or distribution facilities are used to deliver the energy from the generating unit to the on-site generator's load.

another PJM state where the Commission determines certification to be comparable to the RPS requirements in the District, the applicant may submit a "streamlined" application that requires less documentation to be filed. The Commission assigns a unique certification number to each eligible renewable generator that is approved. Renewable generators may be decertified by the Commission if they are determined to no longer be an eligible renewable resource due to a material change in the nature of the resource, or fraud. Before being decertified, a renewable generator will be given thirty (30) days' written notice and an opportunity to show cause why it should not be decertified.

In Order No. 14809, issued May 12, 2008, the Commission directed the Renewable Energy Portfolio Standard Working Group ("Working Group") to submit an update for the Tier I and Tier II eligibility matrices, in order to comply with the RPS rules. The matrices allow an applicant that has already been certified by another PJM state to use the streamlined process for certification, provided that the Commission determines that the certification by the other PJM state is comparable to the RPS requirements in the District. The RPS Working Group responded on October 31, 2008 that no update was required. Subsequently, the Commission issued Order No. 15192 on February 18, 2009, directing the RPS Working Group to again comply with the rules and submit an update for the Tier I and Tier II eligibility matrices within 60 days of the date of the Order. The Commission noted in that Order that since 2007, four (4) additional states that are part of the PJM Interconnection region—Illinois, Michigan, North Carolina, and Ohio—have adopted renewable energy portfolio standards and/or begun certifying renewable energy generators. In Order No. 15707 (February 25, 2010), the Commission granted the Potomac Electric Power Company ("Pepco"), filing on behalf of the RPS Working Group, a Motion for Enlargement of Time to file the annual update of the eligibility matrices by March 1, 2010. Subsequently, in Order No. 17062 (February 1, 2013), the Commission adopted the 2011 filing of the Renewable Energy Portfolio Standard Working Group's proposed Tier I and Tier II Eligibility Matrices with certain modifications.[16] On January 13, 2014, in Order No. 17349, the Commission adopted the RPS Working Group's proposed Tier I and Tier II Eligibility Matrices submitted for 2013. On January 30, 2014, the RPS Working Group's filing indicated that there were no modifications needed to the eligibility matrices presented in the 2013 Working Group report. Thus, no Commission action was necessary as the Working Group's 2013 eligibility matrices were adopted in Order No. 17349. Subsequently, on January 29, 2015, the RPS Working Group filed its 2015 Update to the Renewable Generator Eligibility Matrix and determined that the information submitted in the 2014 Report remains unchanged, so no Commission action was necessary.[17]

On October 3, 2008, the Commission published a NOPR in the *D.C. Register* that contained revisions to the RPS rules that would, among other things, allow an applicant

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16 The RPS Working Group did not file a report in 2012. On January 30, 2013, the RPS Working Group submitted a request for an extension of time to file its annual report for 2013. The RPS Working Group filed its 2013 report on February 28, 2013.

17 The RPS Working Group filed its report for 2016 on January 28, 2016 and the 2017 report on January 30, 2017.

seeking to certify a renewable generator for the District's RPS program to provide a self-certified Affidavit of Environmental Compliance. This Affidavit helps provide documentation that the renewable generating facility complies with all applicable state and federal environmental requirements. On January 2, 2009, the Commission issued an amended NOPR that superseded the October 3 NOPR. OPC filed comments on February 11, 2009. Subsequently, in Order No. 15233 (April 7, 2009), the Commission adopted the amendments to Chapter 29. The amendments to the RPS rules became effective upon publication of a NOFR in the *D.C. Register* on April 10, 2009. Subsequently, at the discretion of the Commission, a NOFR appeared in the *D.C. Register* on January 16, 2015 to remove the application requirement for an Affidavit of Environmental Compliance from solar energy systems that exceed 10 kW.

Creation and Tracking of Renewable Energy Credits ("RECs")

The RPS rules specify that RECs shall be created and tracked through PJM-EIS's Generation Attribute Tracking System ("GATS") beginning January 1, 2006. Through the GATS process, PJM-EIS collects generation data from facilities certified for RPS programs in various states. Upon issuance of a District-specific RPS certification number, a facility may open a GATS account for use with the District's RPS program. Facilities often are eligible for participation in several state RPS programs and, thus, will be certified with multiple states and receive multiple state certification numbers. GATS creates RECs at the end of each month. One REC represents one megawatt-hour of electricity from a renewable resource. The number of RECs created reflects the amount of electricity generation associated with renewable resources. Each REC tracked has a unique serial number that aids in ensuring against the double counting of RECs and helps distinguish between RECs that are created by a certain facility and by fuel type, in a given month.

According to the RPS rules, RECs are valid for a three-year period from the date of generation beginning January 1, 2006. A REC shall be retired after it is used to comply with any state's RPS requirement. The accumulation of retroactive RECs created before January 1, 2006 is not allowed. In Order No. 13804, the Commission noted that the intent of the REPS Act is to encourage the production and siting of renewable resources prospectively, so as to reduce the need for the use of retroactive RECs.

With respect to behind the meter ("BTM") generators, the RPS rules require an authorized representative of the renewable on-site generator to file a BTM generator report with the Commission. RECs created by BTM generators must be recorded in GATS at least once each calendar year, in order to be eligible for compliance. The BTM generator report contains, at a minimum, the following information: (a) a certification that the RECs attributable to the on-site generation have not expired, been retired, been transferred, or been redeemed; and (b) a report or statement indicating the quantity of electricity generated as determined by an engineering estimate (if appropriate) or revenue-quality meter.

To ensure that all BTM generators were in compliance with the Commission's rules, Order No. 14798 (issued April 29, 2008) directed BTM generators certified for the District's RPS program to submit a BTM generation report by May 20, 2008. In addition, as part of the approval of 20 solar generators in Order No. 15185 (issued February 9, 2009), the Commission initially required that these generators provide BTM generation reports consistent with the RPS rules. However, upon learning that PJM-EIS makes available BTM generation information through its website, the Commission subsequently removed the reporting requirement for BTM generators when the RPS rules were amended by the NOFR that went into effect on March 23, 2012.

Recovery of Fees and Costs

The RPS rules state that the local electric distribution company may recover prudently incurred RPS compliance costs, including REC purchases and any compliance fees, through a non-bypassable surcharge on customers' bills pursuant to Commission rule 2904 and D.C. Code § 34-1435 (2014 Supp.) Pepco, as the Standard Offer Service ("SOS") Administrator, has never sought to recover RPS compliance costs for SOS through a non-bypassable surcharge on customers' bills. Instead, winning SOS suppliers bid a full requirements product that includes all costs (including RPS costs) – other than transmission and distribution costs which are tariffed costs.

Like SOS suppliers, competitive electricity suppliers simply provide generation rather than breaking out the cost of generation into line items such as RPS compliance costs. RPS compliance costs are generally imbedded in the cost of generation charged by competitive electricity suppliers. Consistent with Commission Rule 2904 and D.C. Code § 34-1435, competitive electricity providers can also seek to recover prudently incurred compliance fees through a Commission-approved non-bypassable surcharge on customers' bills. To date, no electricity supplier has ever sought or received the Commission's approval to recover the cost of compliance fees.

Clean and Affordable Energy Act of 2008

On October 22, 2008, the permanent version of the CAEA became law. This legislation amended the REPS Act and the amendments are discussed briefly below. The Commission addressed these amendments, as appropriate, in a NOPR issued on April 3, 2009. After reviewing the comments to the NOPR, the Commission adopted the NOFR in Order No. 15561 (September 28, 2009). The amendments to the RPS rules became effective upon publication of the NOFR in the *D.C. Register* on October 2, 2009.

Solar Energy Definition

The RPS Rules originally defined "solar energy" to mean "radiant energy, direct, diffuse, or reflected, received from the sun at wavelengths suitable for conversion into thermal, chemical, or electrical energy". The CAEA changed the definition of "solar energy" to add the new language in bold:

> "...radiant energy, direct, diffuse, or reflected, received from the sun at wavelengths suitable for conversion into thermal, chemical, or electrical energy, **that is collected, generated, or stored for use at a later time.**"

Solar System Ratings

The CAEA allowed the certification of solar thermal energy systems as follows:

"For nonresidential solar heating, cooling, or process heat property systems producing or displacing greater than 10,000 kilowatt hours per year, the solar systems shall be rated and certified by the SRCC [Solar Rating and Certification Corporation] and the energy output shall be determined by an onsite energy meter that meets performance standards established by OIML [International Organization of Legal Metrology]."

"For nonresidential solar heating, cooling, or process heat property systems producing or displacing 10,000 or less than 10,000 kilowatt hours per year, the solar systems shall be rated and certified by the SRCC and the energy output shall be determined by the SRCC OG-300 annual system performance rating protocol applicable to the property, by the SRCC OG-100 solar collector rating protocol, or by an onsite energy meter that meets performance standards established by OIML;" and

"For residential solar thermal systems, the system shall be certified by the SRCC and the energy output shall be determined by the SRCC OG-300 annual rating protocol or by an onsite energy meter that meets performance standards established by OIML."

RPS Requirements

The CAEA amended the requirements for the RPS. In particular, beginning in 2011, the RPS requirements increased. By 2020, the CAEA requires that 20 percent of electricity supplied comes from Tier I renewable resources only and not less than 0.4 percent comes from solar energy. Previously, the RPS requirement called for 8.5 percent of electricity supplied coming from Tier I resources only by 2020 and 0.329 percent from solar energy.[18]

Solar Requirement

The CAEA required that:

"...an electricity supplier shall meet the solar requirement by obtaining the equivalent amount of renewable energy credits from solar energy systems interconnected to the distribution grid serving the District of Columbia. Only after an electricity supplier exhausts all opportunity to meet this requirement that the solar energy systems be connected to the grid within the District of Columbia, can that supplier obtain renewable energy credits from jurisdictions outside the District of Columbia."

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[18] Previously, the RPS stated that in 2022 and later, the RPS requirement would be 11 percent from Tier I resources, 0 percent from Tier II resources, and not less than 0.386 percent from solar energy. The CAEA did not explicitly state that the RPS obligation is to continue after 2020.

Compliance Fees

The CAEA increased the compliance fees for Tier I and solar energy requirements. In particular, the Tier I fee is raised from 2.5 cents per kilowatt-hour to 5 cents per kilowatt-hour of shortfall. For solar energy resources, the compliance fee is raised from 30 cents to 50 cents in 2009 until 2018 for each kilowatt-hour of shortfall.[19]

Distributed Generation Amendment Act of 2011

On October 20, 2011, the permanent version of the DGAA became law. The legislation amended Sections 34-1431-1439 of the Renewable Energy Portfolio Standard.[20] These amendments to the statute are discussed briefly below. The Commission addressed these statutory revisions, as appropriate, in a NOPR amending the RPS rules issued on January 13, 2012. No comments were received on the NOPR and the Commission adopted the proposed amendments to the RPS rules in Order No. 16738 (March 15, 2012). The amendments to the RPS rules became effective upon publication of a NOFR in the *D.C. Register* on March 23, 2012.

Solar Thermal Systems

The DGAA amended the requirements for eligible solar thermal energy systems to remove the requirement that all such systems have a certification from the Solar Rating and Certification Corporation ("SRCC"). The new language is as follows:

> "For nonresidential solar heating, cooling, or process heat property systems producing or displacing greater than 10,000 kilowatt hours per year, the solar collectors used shall be SRCC OG-100 certified and the energy output shall be determined by an onsite energy meter that meets performance standards established by OIML."

> "For nonresidential solar heating, cooling, or process heat property systems producing or displacing 10,000 or less than 10,000 kilowatt hours per year, the solar collectors used shall be SRCC OG-100 certified and the energy output shall be determined by the SRCC OG-300 annual system performance rating protocol or the solar collectors used shall be SRCC OG-100 certified and the energy output shall be determined by an onsite energy meter that meets performance standards established by OIML."

> "For residential solar thermal systems, the systems shall be SRCC OG-300 system certified and the energy output shall be determined by the SRCC OG-300 annual rating protocol or the solar collectors used shall be SRCC OG-100 certified and the

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19 In the January 2, 2009 NOPR, the solar energy compliance fee was indicated to be $300 for the 2008 compliance year.

20 D.C. Official Code §§ 34-1431 - 1439 (2010 Repl. & 2012 Supp.).

energy output shall be determined by an onsite energy meter that meets performance standards established by OIML."

These changes also made it easier for large nonresidential solar thermal systems to participate in the RPS program as these larger systems are able to meet the requirements for the certification of solar collectors under SRCC OG-100, but not the system certification under SRCC OG-300.

RPS Solar Requirements

The DGAA amended the requirements for the RPS. In particular, beginning in 2011, the RPS solar requirements increase through 2023. By 2023, the DGAA requires 2.5 percent from solar energy resources. Previously, the RPS requirement called for 0.4 percent from solar energy resources by 2020.[21] In addition, the DGAA legislation restricted the location of eligible solar energy resources:

"...an electricity supplier shall meet the solar requirement by obtaining the equivalent amount of renewable energy credits from solar energy systems no larger than 5 MW [megawatts] in capacity located within the District or in locations served by a distribution feeder serving the District."

Moreover, the DGAA included a "grandfathering" provision that exempted electricity supply contracts, signed prior to the effective date of the legislation, from the increased solar RPS requirements.

Generation Certification

The DGAA also amended the requirements for certification:

"After January 31, 2011, the Commission shall not certify any tier one renewable source solar energy system larger than 5 MW in capacity or any tier one renewable source solar energy system not located within the District or in locations served by a distribution feeder serving the District."

"Any tier one renewable source solar energy system larger than 5 MW in capacity shall be decertified by the Commission. Any tier one renewable source solar energy system not located within the District or in locations served by a distribution feeder serving the District, first certified by the Commission between February 1, 2011, and the applicability date of the Distributed Generation Amendment Act of 2011, passed

21 The DGAA also clarifies that the RPS obligation is to continue after 2023.

on 2nd reading on July 12, 2011 (Enrolled version of Bill 19-10), shall be decertified by the Commission."[22]

Compliance Fees

The DGAA altered the compliance fees for solar energy. In particular, for each kilowatt-hour ("kWh") of shortfall from required solar energy sources, the compliance payment is 50 cents in 2011 through 2016; 35 cents in 2017; 30 cents in 2018; 20 cents in 2019 through 2020; 15 cents in 2021 through 2022; and 5 cents in 2023 and thereafter.

Renewable Energy Portfolio Standard Amendment Act of 2014

On April 30, 2015, the RPS Amendment Act of 2014 became effective. The legislation primarily affected the eligibility of qualifying biomass resources. The amendments to the statute are discussed briefly below. The Commission addressed these statutory revisions, as appropriate, in an amendment to the RPS rules that became effective upon publication of a NOFR in the *D.C. Register* on April 1, 2016.

RPS Compliance Requirements

Under the DGAA, energy supply contracts entered into prior to August 1, 2011, shall not be subject to the increased solar energy requirement as required by law. However, as a result of the RPS Amendment Act, any extension or renewal of such contracts, executed on or after August 1, 2011, shall be subject to the higher solar energy requirement as required by law. This affects the ability of electricity suppliers to take advantage of the grandfather provision that was included in the DGAA.

Generator Certification and Eligibility

The RPS Amendment Act, in part, requires qualifying biomass facilities to meet a certain efficiency standard in order to be eligible as a Tier I resource. Thus, the Commission now requires every facility using qualifying biomass to generate electricity and certified as a qualifying resource by the Commission to submit annually by June 1, starting in 2016, information demonstrating each facility's total system efficiency for the current calendar year.

Definitions and Applicability

The relevant changes (in bold) to the definitions and applicability of the RPS statutes as implemented in the RPS rules are indicated below:

Black liquor - **the spent cooking liquor from the Kraft process of paper making.**

22 As a result of the DGAA, in Order No. 16529, issued on September 9, 2011, the Commission decertified 1,426 solar energy facilities. Thus, for the 2011 compliance year and beyond, any RECs submitted from decertified solar energy facilities will not be accepted.

Fuel input - **the higher heating value of the input fuel type, measured in BTU/LB, based on the standardized heating type of fuel type, multiplied by the annual fuel used in as delivered tons, multiplied by 2000.**

Qualifying biomass - a solid, non-hazardous, cellulosic waste material that is segregated from other waste materials, and is derived from any of the following forest-related resources, with the exception of old growth timber, **construction and demolition-derived wood and whole trees that are not part of a closed-loop biomass system, cleared solely for the purpose of energy production**, unsegregated solid waste, or post-consumer wastepaper

Construction and demolition-derived wood and whole trees that are not part of a closed-loop biomass system, cleared solely for the purpose of energy production, shall be considered qualifying biomass, if a) this material was used to generate RECs and those RECs are retired for compliance purposes with respect to electricity consumed by SOS customers on or before May 31, 2015; or b) this material was used by a facility certified before April 30, 2015, the effective date of the Renewable Energy Portfolio Standard Amendment Act of 2014, to generate RECs, which were purchased by an electricity supplier pursuant to a contract executed before April 30, 2015, and those RECs are retired for compliance purposes with respect to electricity consumed by non-SOS customers on or before December 31, 2017.

In all other instances, the construction and demolition-derived wood and whole trees that are not part of a closed-loop biomass system, cleared solely for the purpose of energy production, shall not be considered qualifying biomass, as of April 30, 2015.

Tier one renewable source -- one (1) or more of the following types of energy sources:

(c) **Qualifying biomass used at a generation unit that achieves a total system efficiency of at least sixty-five percent (65%) on an annual basis, can demonstrate that it achieved a total system efficiency of at least 65% on an annual basis through actual operational data after one year, and that started commercial operation after January 1, 2007;**

The qualifications to qualifying biomass in subsection (c) shall not apply to RECs retired for compliance purposes with respect to electricity consumed by SOS customers on or before May 31, 2015; or with respect to electricity consumed by non-SOS customers on or before December 31, 2017, provided that these RECs were produced by a facility certified as a Tier I energy source before April 30, 2015 and were purchased by an electricity supplier pursuant to a contract executed before April 30, 2015. In all other instances, subsection (c) shall apply as of April 30, 2015.

Tier two renewable source -- one (1) or more of the following types of energy sources:

(c) Qualifying biomass used at a generation unit that started commercial operation on or before December 31, 2006; or achieves a total system efficiency of less than 65%; or uses black liquor.

Subsection (c) shall not apply to RECs retired for compliance purposes with respect to electricity consumed by SOS customers on or before May 31, 2015; or with respect to electricity consumed by non-SOS customers on or before December 31, 2017, provided that these RECs were produced by a facility certified as a Tier I energy source before April 30, 2015 and were purchased by an electricity supplier pursuant to a contract executed before April 30, 2015. In all other instances, subsection (c) shall apply as of April 30, 2015.

<u>Total system efficiency</u> - the sum of the net useful thermal energy output measured in BTUs divided by the total fuel input.

<u>Useful thermal energy output</u> - energy in the form of direct heat, steam, hot water, or other thermal form that is used in production and beneficial measures for heating, cooling, humidity control, process use, or other valid thermal end use energy requirements and for which fuel or electricity would otherwise be consumed. Useful thermal energy output does not include thermal energy used for the purpose of drying or refining biomass fuel.

<u>Renewable Portfolio Standard Expansion Amendment Act of 2016</u>

The RPS Expansion Amendment Act of 2016 became effective on October 8, 2016. The legislation, among other things, increased and extended the RPS requirement to 50.0 percent by 2032—with the solar energy requirement rising to 5.0 percent by 2032. The amendments to the statute are discussed briefly below. The Commission addressed these statutory revisions, as appropriate, in Order No. 18749 (issued April 13, 2017) and the amendment to the RPS rules will become effective upon publication of a NOFR in the *D.C. Register*.

RPS Requirements

The RPS Expansion Amendment Act of 2016 amended the RPS and raised the requirement from 2024 through 2032. By 2023, 20.0 percent of the electricity supplied must be associated with Tier I renewable resources only and not less than 2.5 percent comes from solar energy. As a result of the 2016 Act, the RPS requirement continues to rise from 2024 till it reaches 50.0 percent by 2032, with 5.0 percent from solar energy.

Under the DGAA, and as part of meeting the solar requirement, a supplier was obligated to obtain SRECs from solar energy system no larger than 5 MW in capacity located within the District or in locations served by a distribution feeder serving the District. However, SRECs from solar energy systems larger than 5 MW in capacity located on property owned by the District, or by an agency or independent authority of the District, may be used to meet the solar requirement as well. The RPS Expansion Amendment Act of 2016 increased the 5 MW amount referenced earlier to 15 MW.

Compliance Fees

The RPS Expansion Amendment Act of 2016 altered the compliance fees for solar energy. Under the DGAA, the solar energy compliance payment was set to decrease from 50 cents per kWh in 2016 to 35 cents in 2017; then 30 cents in 2018; then 20 cents in 2019 through 2020; then 15 cents in 2021 through 2022; until reaching 5 cents in 2023 and thereafter. As a result of extending the RPS requirement to 2032 and increasing the solar energy requirement to 5.0 percent by 2032, the solar energy compliance payment is now set at 50 cents from 2016 through 2023; 40 cents from 2024 through 2028; 30 cents from 2029 through 2032; and 5 cents in 2033 and thereafter.

Definitions and Applicability

The Act also added "raw or treated waste water used as a heat source or sink for a heating or cooling system" to the definition of a Tier I renewable resource.

III. RPS Compliance Reports for 2016

Pursuant to the Commission's RPS rules, active electricity suppliers and the default supplier with retail sales in 2016 are required to submit a compliance report by April 1, 2017 for that calendar year:[23] A total of thirty-six (36) suppliers, including Agera Energy; Ambit Energy; AEP Energy; Champion Energy Services; Calpine Energy Solutions; CleanChoice Energy; Clearview Energy; Consolidated Edison Solutions; Constellation NewEnergy; Constellation Energy Services; Devonshire Energy; DC Gas and Electric; Direct Energy Business; Direct Energy Business Marketing; Direct Energy Services; Eligo Energy; Energy.me; ENGIE Resources; Horizon Power and Light; IDT Energy; Liberty Power; Major Energy Electric Services; MidAmerican Energy; NextEra Energy Services; Potomac Electric Power Company ("Pepco"); Public Power; Reliant Energy Northeast; Renaissance Power and Gas; Source Power and Gas; Starion Energy; Stream Energy; Talen Energy Marketing; UGI Energy Services; Viridian Energy; WGL Energy Services; and XOOM Energy.[24] Suppliers met the RPS requirements through acquiring RECs or making a compliance payment.

[23] Since April 1 fell on a Saturday, the reports were due Monday, April 3, 2017.

[24] As the provider of Standard Offer Service, Pepco compiles a report based on the compliance of its wholesale electricity suppliers.

Renewable Energy Credits ("RECs") and Compliance Payments

All of the electricity suppliers did not have to pay a compliance fee in order to meet the Tier I or Tier II requirements in 2016.[25] In general, in order to meet the solar requirement, the statute provides that RECs must be generated by solar energy facilities that are located within the District of Columbia or in locations served by a distribution feeder serving the District. However, solar energy systems that were certified by the Commission prior to February 1, 2011, may also be used to meet the solar requirement. These latter solar energy systems are referred to as "grandfathered" facilities.

The compliance payments have increased substantially in recent years. Based on the available information, the total amount of money raised from compliance payments was $15,230,000 in 2016, down from the $19,910,000 in 2015.[26] The decrease in the compliance fees, compared to 2015, generally reflects the increase in use of solar RECs to meet the RPS requirements.[27] Electricity suppliers retired 38,167 solar RECs in 2015, but the amount increased by roughly 63 percent in 2016, with 62,173 solar RECs retired.[28] The total compliance payments submitted in various reporting years are provided in the table below:[29]

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25 For 2016, the Tier I requirement was 11.5 percent, the Tier II requirement was 2.0 percent, and the solar requirement was 0.825 percent. For 2017, the Tier I requirement rises to 13.5 percent, the Tier II requirement declines to 1.5 percent, and the solar requirement increases to 0.980 percent.

26 The compliance payments are sent directly to DOEE and the funds are deposited into the Renewable Energy Development Fund.

27 While the solar carve out percentage requirement increases over time, the price of the Alternative Compliance Payment ("ACP") for the solar requirement—currently $500 per solar REC shortfall—will not decline till after 2023. In 2024 through 2028 the ACP is set at $400 per solar REC shortfall and in 2029 through 2032 the ACP will drop to $300 per solar REC shortfall. After 2032 the ACP will go to $50 per solar REC shortfall. Since the price of the ACP acts as a cap on the solar REC price, the revenue stream from this source will decrease over time.

28 The solar requirement increased from 0.700 percent in 2015 to 0.825 percent in 2016. Reported retail electricity sales in the District only increased by 0.64 percent from 2015—up to nearly 11.3 million megawatt-hours in 2016.

29 In 2007 and 2008, the compliance payments generally resulted from electricity suppliers paying the solar compliance fee to meet the solar requirement. In 2009, the increase in the compliance payment from the previous year was due, in part, to the increase in the solar compliance fee from $300 to $500 per REC—as a result of the CAEA. In 2010, as a result of the substantial increase in approved solar energy systems, electricity suppliers were generally able to acquire a substantial number of solar RECs instead of paying the compliance fee. In 2011, the jump in the compliance payment was due to one electricity supplier failing to obtain solar RECs and, thus, having to pay the compliance fee. This particular supplier accounted for the majority of the compliance fees—$225,500 out of a total of $229,500. In 2012, suppliers were largely able to meet the RPS through REC purchases and were subject to only $4,900 in compliance fees.

Compliance Payments

	Total
2007	$199,490
2008	$399,320
2009	$429,320
2010	$55,850
2011	$229,500
2012	$4,900
2013	$699,140
2014	$6,308,710
2015	$19,910,000
2016	$15,230,000

Some suppliers used Tier I RECs to meet their Tier II requirement based on § 34-1433(a)(2) of the D.C. Official Code, which indicates that energy from a Tier I resource may be applied to the percentage RPS requirements for either Tier I or Tier II renewable sources.[30] Wind resources accounted for the largest share—nearly 34 percent—of Tier I and solar RECs retired for compliance purposes. The next highest share of Tier I and solar RECs was attributed to wood waste resources—about 31 percent.[31] Methane from landfill gas and black liquor each accounted for roughly 14 percent of the Tier I and solar RECs. In addition, as a result of the *Fiscal Year 2015 Budget Support Act of 2014*, solar facilities located in PJM or in a state adjoining PJM may be certified by the Commission and their RECS may be used by electricity suppliers to meet the Tier I renewable resource requirement that falls outside of the DC-based solar requirement. The non-solar Tier I resources accounted for about 4 percent of the Tier I resources. Solar energy resources able to meet the solar carve-out amounted to nearly 5 percent of Tier I and solar RECs. Tier II RECs were from hydroelectric facilities, black liquor, and wood waste facilities, as municipal solid waste ("MSW") is no longer eligible for compliance purposes.[32] A breakdown of the number of RECs submitted in 2016 by fuel type is provided in the table below:

30 In particular, only four (4) of the suppliers used Tier I RECs to meet the Tier II requirement, with two (2) out of the 4 suppliers using only Tier I RECs.

31 The RPS Amendment Act of 2014 changed the definition of qualifying biomass that resulted in moving black liquor and wood waste to Tier II. However, the legislation grandfathered RECs purchased by an electricity supplier pursuant to a contract executed prior to April 30, 2015, the effective date of the Act.

32 Order No. 17350 (issued January 13, 2014) decertified the two municipal solid waste facilities previously approved for the RPS and noted that the MSW RECs from these facilities were no longer eligible for RPS compliance purposes in 2013 and going forward.

Renewable Energy Credits Submitted for 2016 Compliance

	No. of RECs	Share of Tier
Tier I Resource		
Black Liquor	183,749	13.6%
Methane from Landfill Gas	189,345	14.0%
Wind	451,607	33.5%
Wood Waste	414,275	30.7%
Non-Solar Tier I (out-of-state solar)	47,400	3.5%
Solar Carve-Out	62,173	4.6%
Total Tier I and Solar Carve-Out	1,348,549	100.0%
Tier II Resource		
Hydroelectric	205,670	92.0%
Black Liquor	4,867	2.2%
Wood Waste	12,935	5.8%
Municipal Solid Waste	-	0.0%
Total Tier II	223,472	100.0%
Total Tier I, Solar Carve-Out, and Tier II	1,572,021	

Suppliers submitted RECs generated from 2013 through 2016. About 1.4 percent of the RECs used for compliance were generated in 2013, while roughly 31.0 percent of the RECs were generated in 2014, with 28.6 percent generated in 2015, and nearly 39.0 percent generated in 2016. Section 2903.2 of the RPS Rules indicates that RECs shall be valid for a three-year period from the date of generation, beginning January 1, 2006, except where precluded by statute.

In 2016, electricity suppliers provided the REC prices for all of their resources. The range and weighted average of the reported REC prices for 2008 through 2016, by fuel type, is provided in the table below:[33]

Average Price of Reported Compliance RECs

	2008	2009	2010	2011	2012	2013	2014	2015	2016
Tier I Resource									
Black Liquor	$0.64	$1.30	$0.90	$1.94	$2.74	$2.78	$1.81	$1.20	$1.09
Methane from Landfill Gas	$0.84	$0.82	$1.51	$1.42	$2.22	$2.51	$2.46	$2.84	$2.44
Wind	$1.24	$0.47	NA	$2.67	$2.37	$2.38	$2.55	$2.15	$1.87
Wood Waste	$0.74	$0.60	$0.67	$1.58	$2.77	$2.40	$2.07	$1.62	$1.26
Non-solar Tier I (out-of-state solar)	NA	NA	NA	NA	NA	NA	NA	$1.00	$2.18
Solar Carve-Out	NA	$425.90	$351.80	$300.16	$327.59	$364.75	$416.50	$435.12	$477.18
Tier II Resource									
Hydroelectric	$0.55	$0.59	$0.41	$0.50	$0.60	$1.12	$1.13	$0.52	$0.49
Black Liquor	NA	NA	NA	NA	NA	NA	NA	NA	$2.20
Wood Waste	NA	NA	NA	NA	NA	NA	NA	NA	$1.75
Municipal Solid Waste	$0.71	$0.66	$0.78	$0.43	$0.60	NA	NA	NA	NA

33 A REC represents one megawatt-hour of electricity attributable to a particular renewable resource. Prior to 2014, not all of the electricity suppliers fully reported their REC prices. Recent solar REC ("SREC") prices from the Flett Exchange are trading around $470 per REC.

As seen in the above table, non-solar REC prices have been relatively stable in recent years, despite the rise in RPS requirements over time. However, solar REC prices for the District have trended upward since 2011 as the impact of the DGAA has made the District's solar REC prices the highest in the region.

Taken together, the estimated total cost of compliance—including the cost of RECs and compliance fees—amounted to $47.2 million for the 2016 RPS compliance, up from $38.5 million for the 2015 RPS compliance. The increase in the solar RPS requirement over time will continue to place upward pressure on the cost of compliance.

IV. The Availability of Renewable Resources

This section discusses the availability of Tier I renewable sources, as required in the REPS Act. The issue of available resources is affected by geographic restrictions in the RPS. The REPS Act indicated that a:

> "Renewable energy credit" or "credit" means a credit representing one megawatt-hour of electricity consumed within the PJM Interconnection Region that is derived from a Tier I renewable source or a Tier II renewable source that is located:
>
> 1. In the PJM Interconnection region or in a state that is adjacent to the PJM Interconnection Region; or
> 2. Outside the area described in subparagraph (1) of this paragraph but in a control area that is adjacent to the PJM Interconnection region, if the electricity is delivered into the PJM Interconnection Region.

The REPS Act did not provide a definition for adjacent states or an adjacent control area. In its third report in 2005, the RPS Working Group was not able to reach a consensus on the definition of "adjacent" states and, thus, presented two different interpretations. Ultimately, the Commission adopted the broader definition of "adjacent" and determined that states "adjacent" to the PJM Interconnection Region should help lessen the cost that ratepayers will have to pay for the renewable portion of their fuel mix.[34] In particular, the following states are currently deemed adjacent to PJM: Alabama, Arkansas, Georgia, Iowa, Mississippi, Missouri, New York, South Carolina, and Wisconsin. Thus, from the outset, the District's RPS program allowed a relatively broad geographic participation.

Subsequently, the *Fiscal Year 2011 Budget Support Act of 2010* amended the definition of a REC to read as follows:

[34] The RPS rules indicate that states within the PJM Interconnection Region are currently defined to include: Delaware, the District of Columbia, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

"Renewable energy credit" or "REC" means a credit representing one megawatt-hour of energy produced by a tier one or tier two renewable source located within the PJM Interconnection region or within a state that is adjacent to the PJM Interconnection region.[35]

The change in the definition of a REC actually made it easier for the Commission to approve renewable energy systems located in states adjacent to the PJM Interconnection Region. That is, the previous definition's reference to "electricity consumed within the PJM Interconnection Region" suggested that at least the potential to deliver electricity was required in order for a renewable energy system to be approved for the District's RPS program. As a result, prior to the change in the REC definition, the Commission denied several applications from solar generator systems located in New York. In its decisions, the Commission generally indicated that the applicant did not provide sufficient information to demonstrate or document the amount of energy that can be delivered into the PJM Interconnection Region for consumption.[36] However, the new definition refers only to where the energy is produced, not consumed. As a result of the revised statutory REC definition, the Commission began approving solar generator applications from states such as New York and Wisconsin in 2010; however, with the passage of the DGAA, out-of-state solar energy systems are now generally not eligible to be certified by the Commission for generation of SRECs for compliance with the solar portion of the RPS. However, pursuant to the clarification language included by the Council in the *Fiscal Year 2015 Budget Support Act of 2014*, out-of-state solar facilities may be certified for use in complying with the non-solar portion of the Tier I RPS requirement.

The table below provides a measure of some of the renewable resources available in the PJM region for 2016. The following information provides a perspective on the renewable resources in the PJM region associated with the generation of electricity. Based on the table below, the overall renewable resources in the PJM Interconnection Region represents less than five percent of the available fuels. Wind power accounts for the largest share among renewable resources, about two percent. Among other renewable sources, hydroelectric power represents the second largest resource—around one percent—followed by municipal solid waste—less than one percent. Methane gas, biomass-related fuels, and solar photovoltaics are approximately 0.3, 0.2, and 0.1 percent, respectively.[37]

35 D.C. Official Code § 34-1431 (10) (2012 Supp.).

36 See Order No. 15699 (February 23, 2010), Order No. 15775 (April 20, 2010), and Order No. 15812 (May 18, 2010).

37 Coal mine methane gas is not generally eligible under most RPS policies.

PJM System Fuel Mix
2016

Fuel	Share
Coal	34.26%
Nuclear	34.70%
Natural Gas	26.34%
Oil	0.20%
Hydroelectric	1.04%
Other Renewable	3.42%
Captured Methane Gas (Landfill or Coal Mine)	0.32%
Geothermal	0.00%
Solar PV	0.13%
Municipal Solid Waste	0.52%
Wind	2.23%
Wood, other biomass	0.23%
Total Renewable Resources	4.46%
Total	100.00%

Source: PJM-EIS GATS

Through the Reliable Energy Trust Fund, DOEE previously administered the Renewable Energy Demonstration Project ("REDP"), approved by the Commission in Order No. 12778 (July 9, 2003). The objective of the REDP was to increase the awareness and use of renewable energy grid-connected technologies by District ratepayers. Through the REDP, DOEE awarded grants to help finance renewable energy projects in the District. The CAEA replaced the REDP with the Renewable Energy Incentive Program ("REIP").

As of April 7, 2017, there are 5,342 renewable generators eligible for the District's RPS program. Of these facilities, 5,294 (roughly 99 percent) use Tier I resources (including biomass, methane from landfill gas or waste water treatment, solar, and wind) and 48 (roughly one percent) use Tier II resources (including hydroelectric and biomass).[38] Since these renewable generators may be certified in other states that have a RPS as well, the RECs associated with the generating capacity are not necessarily fully available to meet the District's RPS requirement. The table below provides a breakdown of the renewable generators by fuel type and location:[39]

[38] Nearly all—except one facility in Alabama—of the qualifying biomass resources are now Tier II resources.

[39] The Commission has approved DC Water's 10 MW generating facility for the RPS program. This facility uses methane from wastewater treatment.

Number of Renewable Generators Certified for the District's RPS Program by Fuel Type and Location
(as of April 7, 2017)

	Biomass	Hydroelectric	Methane from landfill or waste water treatment	Solar PV	Solar PV (NSTI)	Solar Thermal	Wind	Total
District of Columbia			1	2,769		110		2,880
Alabama	2							2
Delaware			2	149		1		152
Georgia	3				1			4
Iowa					1		2	3
Illinois		2	22	7			14	45
Indiana			15	42			10	67
Kentucky	2		6	55	1	1		65
Maryland	1	2		227	2	10		242
Michigan	1		3	6				10
Missouri			1		6		5	12
North Carolina		4	1	78		78		161
New Jersey				8				8
New York		1		28		1		30
Ohio	2	1	2	128	1	4	3	141
Pennsylvania		4	8	912		16	6	946
Tennessee	1							1
Virginia	6	9	13	373		120		521
Wisconsin	1	1		11				13
West Virginia		6		24		6	3	39
Total	19	30	74	4,817	12	347	43	5,342

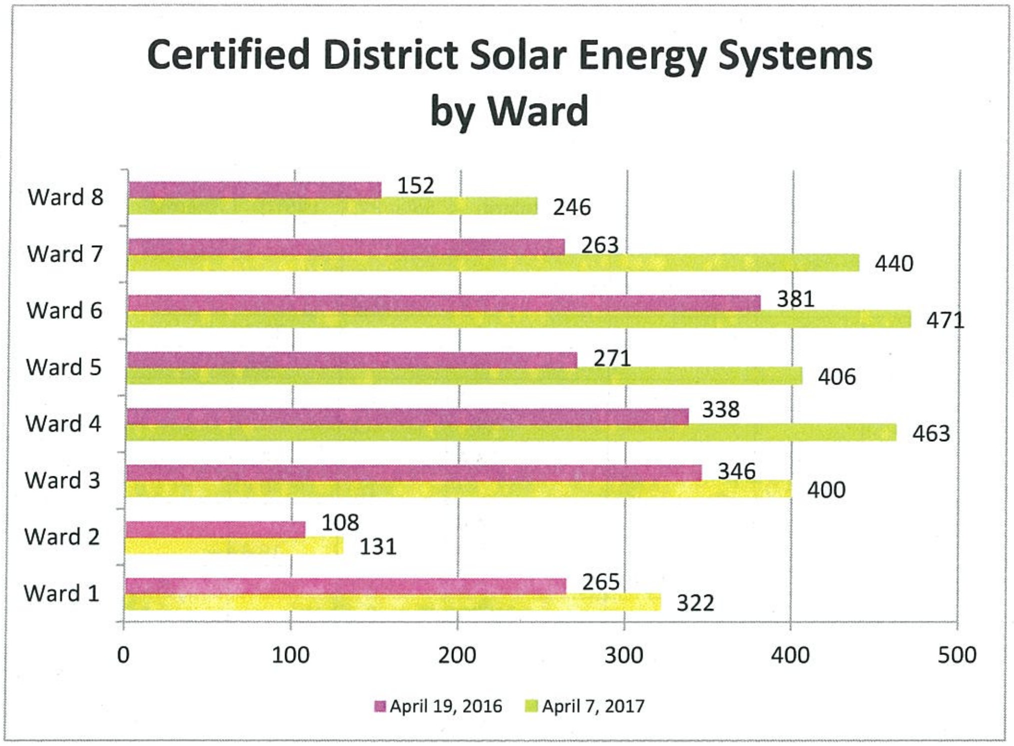
Note: Biomass includes black liquor and wood/wood waste.

The District has also made significant progress in certifying solar energy facilities for the RPS program. Currently, as of April 7, 2017, 5,164 solar energy systems—including solar photovoltaic and solar thermal—are eligible to participate in the District's RPS program. Within the District, there are currently 2,769 approved solar photovoltaic ("PV") systems and 110 solar thermal systems.[40] Outside of the District, there are six states with more than 100 eligible solar energy systems including Pennsylvania (928), Virginia (493), Maryland (237), North Carolina (156), Delaware (150), and Ohio (132). These six (6) states account for roughly 92 percent of the non-DC solar energy systems approved for the District's RPS program.

Solar energy systems can be found in all eight wards of the District. To date in 2017, the number of RPS-eligible solar energy systems has increased in all wards. The figure below shows where the systems certified for the District's RPS program are located:[41]

[40] The Commission provides monthly updates on solar energy system certifications and solar REC pricing, available at the following link: http://www.dcpsc.org/Electric/Renewable.asp

[41] This includes 6 federal facilities with a solar PV capacity of about 1.2 MW and 28 D.C. government facilities with a solar PV capacity of about 5.9 MW.



The total capacity associated for all solar energy systems is about 54.6 megawatts ("MW"), with about 33.8 MW located in the District as of April 7, 2017, compared to 19.2 MW located in the District as of April 19, 2016.[42] However, the current solar capacity is less than the 70.0 MW of estimated solar capacity necessary to meet the solar RPS requirement of 0.825 percent in 2016 and less than the 83.2 MW of estimated solar capacity necessary to meet the 0.980 percent in 2017. As noted above, many of these solar energy systems are certified in more than one jurisdiction, so it is difficult to determine with precision the resources that are fully available to meet the District's RPS requirement. However, the District's solar REC prices are the highest in the region, so holders of solar RECs have a significant financial incentive to sell them to suppliers who need to satisfy the solar requirement in the District. Specifically, the price of the District's solar RECs is very close to the $500 compliance fee. The table below shows the capacity of all of the District's certified renewable generators, by fuel type and location, as of April 7, 2017:

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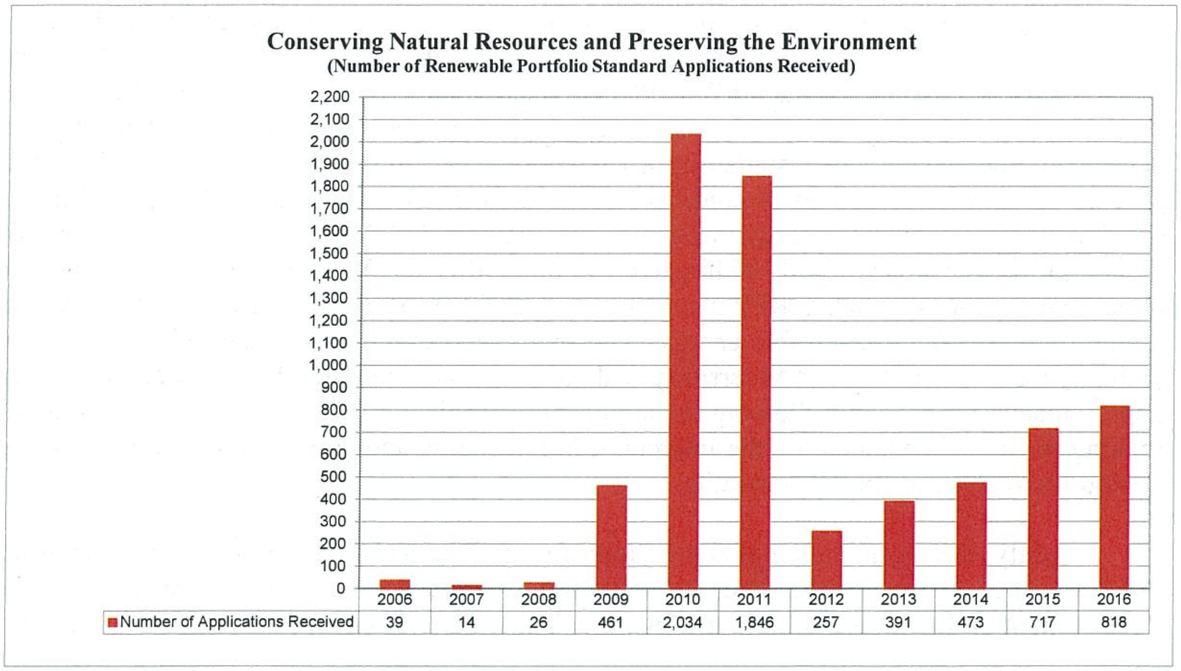
42 Within the District, there are 59 certified solar photovoltaic systems with a reported capacity of at least 100 kW. The largest system is at a federal facility that has a reported capacity of 611 kW.

Capacity (MW) of Renewable Generators Certified for the District's RPS Program by Fuel Type and Location (as of April 7, 2017)

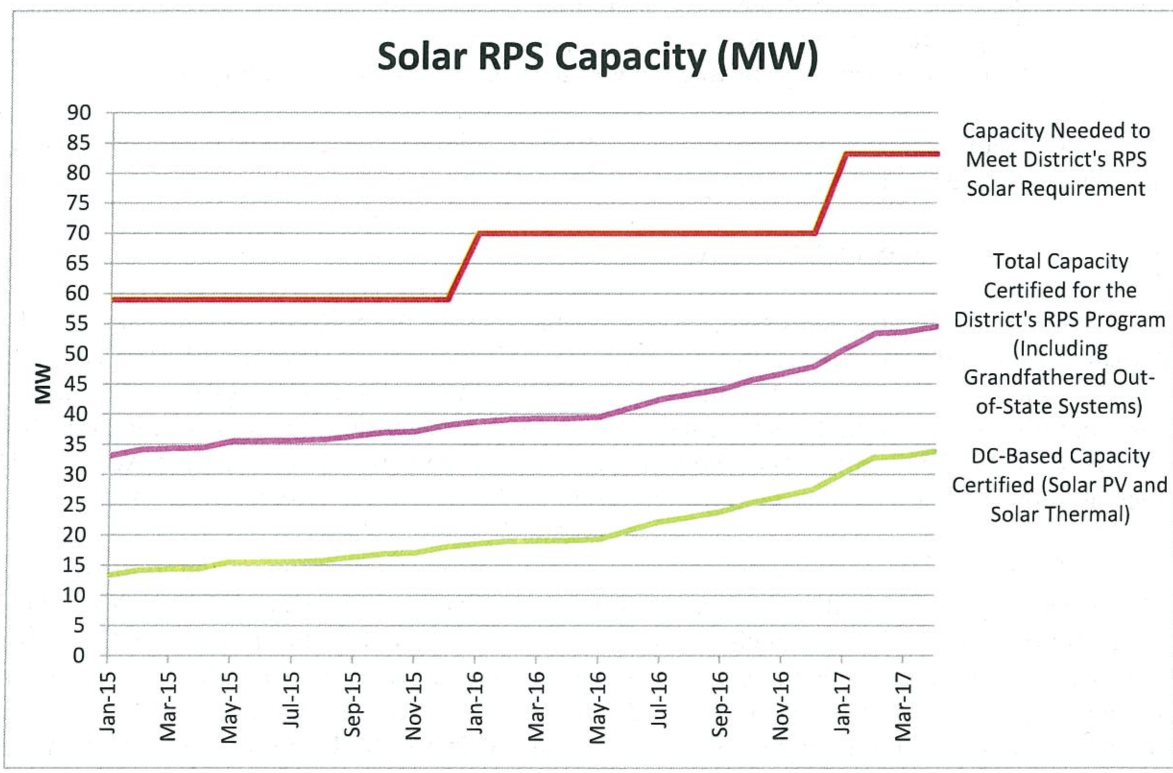
	Biomass	Hydroelectric	Methane from landfill or waste water treatment	Solar PV	Solar PV (NSTI)	Solar Thermal	Wind	Total
District of Columbia			10.0	28.6		5.2		43.8
Alabama	137.3							137.3
Delaware			7.4	1.2		0.0		8.6
Georgia	284.4				38.7			323.1
Iowa					2.0		201.7	203.6
Illinois		17.8	114.4	0.5			1,614.2	1,746.8
Indiana			47.2	0.2			1,482.4	1,529.8
Kentucky	148.0		18.4	0.2	14.1	0.0		180.6
Maryland	65.0	494.0		1.7	0.0	0.0		560.7
Michigan	103.0		33.0	0.0				136.0
Missouri			5.6		19.3		305.0	329.9
North Carolina		215.2	5.0	1.7		0.2		222.2
New Jersey				0.2				0.2
New York		34.8		0.4		0.0		35.2
Ohio	109.3	47.4	8.0	1.2	0.0	0.0	412.0	577.9
Pennsylvania		467.5	72.2	10.3		0.0	371.0	921.0
Tennessee	50.0							50.0
Virginia	398.7	147.2	94.1	2.2		0.4		642.6
Wisconsin	44.6	9.1		0.1				53.8
West Virginia		194.6		0.1		0.0	462.1	656.9
Total	1,340.3	1,627.6	415.3	48.7	74.1	5.9	4,848.3	8,360.2

Note: Biomass includes black liquor and wood/wood waste.

In 2016, the Commission received 818 renewable generator applications—primarily involving the certification of solar generators for the RPS program. As of April 7, 2017, the Commission has received 174 applications. The Commission continues to approve solar energy applications based on the existing laws and regulations. The chart below shows how the number of applications has changed over the years:



The chart below provides a comparison of the estimated MW of solar capacity needed to meet the increased solar requirement under the DGAA. As of April 7, 2017, the total capacity associated with the solar energy systems certified for the District's RPS program is about 54.7 MW, of which about 33.8 MW is located in the District.



In terms of the availability of other resources, as part of its merger commitments, Exelon shall, by December 31, 2018, develop or assist in the development of 7 MW of solar generation in the District outside of Blue Plains. In addition, Pepco shall support and expedite the interconnection for 5 MW of ground-mounted solar generation at Blue Plains that is developed, constructed and installed by a vendor selected by DC Water. Exelon also shall provide $5 million of capital to creditworthy governmental entities at market rates for the development of renewable energy projects in the District of Columbia. Moreover, Exelon or its non-utility subsidiaries will, within five (5) years after the Merger close, conduct one or more requests for proposals ("RFP") or other competitive process to solicit offers to purchase a total of 100 MW of renewable energy from one or more new or existing wind-generation facilities located within the PJM territory with an anticipated product delivery date beginning approximately three years following the applicable RFP date. There were also commitments relating to the enhancement of the interconnection process and support for customer-owned behind-the-meter distributed generation.

Lastly, the recent Value of Solar Study for the District of Columbia, released in April 2017 by the Office of the People's Counsel, mentions five primary barriers to the development of distributed solar in the District. These barriers include:

1. Access to suitable space, including real estate constraints such as the high proportion of renters; historic preservation guidelines that may restrict roof space; and the lack of open space for ground-mounted arrays.
2. Upfront costs and customer financing.
3. Interconnection processing time.
4. Program funding uncertainty, including variation in solar REC prices and funding for program incentives.
5. Ineffective price signals to compensate owners of solar generating systems.

The OPC Study provides recommendations to help address the challenges for stimulating distributed solar growth in the District.

V. Recent Activity and Next Steps

The Commission addressed various changes to the RPS Rules included in the RPS Expansion Amendment Act of 2016 in Order No. 18749 (released April 13, 2017). The rules will become effective upon publication of the NOFR that in the *D.C. Register*. In addition, the Commission is also addressing changes to its interconnection rules in a NOPR published on February 17, 2017 in the *D.C. Register,* as the RPS Expansion Amendment Act of 2016 increased the capacity of solar facilities qualified for SRECs in the District to 15 MW.

The Commission also continued to implement community net metering in the District. On December 13, 2013, the *Community Renewable Energy Amendment Act of 2013* (D.C. Law 20-0047 or "CREA"), which was enacted by the Council of the District of Columbia, became law. Among other things, CREA allows for the creation of community renewable energy facilities ("CREFs") of up to 5 MW wherein two or more "subscribers" can share the electricity produced by a single CREF. On April 23, 2015, the Commission voted to adopt the final rules implementing CREA in Order Nos. 17862 and 17863. The rules became final upon publication of the NOFR in the *D.C. Register* on May 8, 2015. On December 11, 2015, the Commission issued Order No. 18050, approving the CREF Documents submitted by Pepco and directing Pepco to make certain amendments to the CREF Documents, including the CREF Contact. On January 11, 2016, Pepco filed its Application for Reconsideration of Order No. 18050, and OPC filed its response on January 19, 2016. In Order No. 18135 (issued March 3, 2016), the Commission granted the motion of Pepco to reconsider the Commission's decision in Order No. 18050 and Pepco was directed to modify the CREF Contract consistent with this Order. With that Order, the Commission completed its legislatively assigned tasks for the implementation of CREA.

Subsequently, on August 18, 2016, the Council enacted the Community Renewable Energy Credit Rate Clarification Expansion Amendment Act of 2016. On October 8, 2016, the Act became effective. The Act amended Section 118 of the CREA and the definition for the term "CREF Credit Rate."[43] On October 28, 2016, the Commission published a NOPR amending Chapter 9 and updating the definition for CREF Credit Rate to comport with the Act. The change to the CREF Credit Rate was finalized on December 30, 2016, when a NOFR appeared in the *D.C. Register*.

In addition, pursuant to the requirements of the RPS Expansion Amendment Act of 2016, the Commission submitted its report to the D.C. Council in fulfillment of Section 2b of the Act (D.C. Code § 34-1432(f)) which provides that:

> No later than March 1, 2017, the Commission shall provide a report to the Council that includes:
>
> 1. An estimate of the amount of solar energy generated annually by solar energy systems in the District that could qualify to be used to meet the annual solar energy requirement, but for which renewable energy credits cannot be purchased by electricity suppliers to meet the solar energy requirement; and
> 2. A recommendation for how the Commission could adjust the annual solar requirement to account for the amount of solar generation identified in paragraph (1) of this subsection.

The Commission made use of its database of certified renewable facilities and Pepco's database of facilities that have been approved for interconnection with the distribution system. By comparing the solar photovoltaic ("PV") systems that have been interconnected to Pepco's distribution system with the solar PV application that have been submitted to the Commission

[43] As amended, the "CREF Credit Rate" means a credit rate applied to subscribers of community renewable energy facilities, which shall be equal to: (a) For residential subscribers, the full retail rate, which includes generation, transmission, and distribution charges for the standard offer service General Service Low Voltage Non-Demand Customer class or its successor, as determined by the Commission, based upon Section 118 of the CREA; and (b) For commercial subscribers, the standard offer service rate - including generation and transmission charges for the General Service Low Voltage Non-Demand Customer class or its successor, as determined by the Commission, based upon Section 118 of the CREA.

for certification and approved for the District's RPS program, any difference in capacity can be identified. In addition, the Commission considered information obtained from the Renewable Electric Plan Information System ("REPIS") database developed by the National Renewable Energy Laboratory ("NREL"). Based on this available information, the report indicated that an estimated 5,046 MWH (or 5,046 solar RECs) would not be available to suppliers to meet the District's solar energy RPS requirement at this time. Accounting for these unavailable solar RECs would lower the 2016 RPS requirement, for example, from 0.825% to 0.779% (an adjustment of 0.046%).

Going forward, the Commission will continue to certify generating facilities and update information on approved generators on the Commission's website. Through its website, the Commission is making forms and the rules available, to help facilitate the certification and compliance process. In addition, the Commission will continue to maintain a list of approved renewable generating facilities on the Commission's website. Moreover, the Commission has made available on its website fact sheets that explain net energy metering, which allows customer-owned generators (including renewable energy systems) to generate and sell excess electricity back to the grid, and the process for certifying a renewable energy system for the District's RPS program. The Commission's website also provides monthly updates on solar energy system certifications and solar REC pricing. Additional program information will also be made available as deemed appropriate. The Commission monitors the interconnections process to ensure that applications for the interconnection of renewable generating facilities in the District are made on a timely basis. Finally, we will continue to monitor the development of relevant Council legislation regarding RPS and goals for renewables in the District. As needed, the Commission will continue to adopt regulations or orders governing the implementation of the RPS.

Attachment 1

Renewable Portfolio Standards in Other States

***Renewable Portfolio Standards in Other States*[1]**

According to the Database of State Incentives for Renewable Energy ("DSIRE") and National Conference of State Legislatures ("NCSL"), 29 states and the District of Columbia have adopted RPS policies or mandates. In addition, nine states have renewable energy goals (see Figure 1). The 29 states include Arizona, California, Colorado, Connecticut, Delaware, Hawaii, Illinois, Iowa, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, Vermont, Washington, and Wisconsin. In 2015, Hawaii substantially increased its renewable energy requirements, while Vermont switched from a non-binding goal to an RPS mandate. On March 11, 2016, Oregon's Governor signed legislation that will effectively eliminate coal from the electricity supply of the state's major utilities by 2030. The law also increases the Oregon RPS from a pre-existing 25 percent by 2025 to 50 percent by 2040, with interim goals along the way, starting in 2025 with 27 percent. On October 8, 2016, the Renewable Portfolio Standard Expansion Amendment Act of 2016 became effective and increased the District of Columbia's RPS requirement to 50 percent by 2032. The District of Columbia joins California, Hawaii, New York, Oregon, and Vermont as states with RPS requirements of 50 percent or more.

In February 2015, West Virginia repealed its RPS standard, which was enacted in 2009. West Virginia had adopted an alternative and renewable energy portfolio standard that was unique to the state. Specifically, West Virginia's standard did not appear to require a minimum contribution from renewable energy resources, and it is feasible that the standard could have been met using only alternative resources and no renewable resources (as defined in the law). Thus, the renewable portion of the standard functioned more like a non-binding goal. Another distinguishing characteristic of West Virginia's standard was the use of the term "alternative energy resources," which was defined more broadly than definitions of alternative energy in other states. In particular, West Virginia's "alternative energy resources" included advanced coal technology, coal bed methane, natural gas, fuel produced by a coal gasification or liquefaction facility, synthetic gas, integrated gasification combined cycle technologies, waste coal, tire-derived fuel, pumped storage hydroelectric projects, and recycled energy.[2]

In May 2015, Kansas also took a major step when it switched from an RPS mandate to a non-binding goal. In June 2015, the Hawaii legislature updated legislation increasing the state's mandate to 100 percent in 2045—with interim requirements of 30 percent by 2020, 40

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[1] This section draws from material available at www.dsireusa.org (Database of State Incentives for Renewable Energy), Clean Energy States Alliance, Lawrence Berkeley National Laboratory, and the National Conference of State Legislatures.

[2] Recycled energy means useful thermal, mechanical or electrical energy produced from: (i) exhaust heat from any commercial or industrial process; (ii) waste gas, waste fuel or other forms of energy that would otherwise be flared, incinerated, disposed of or vented; and (iii) electricity or equivalent mechanical energy extracted from a pressure drop in any gas, excluding any pressure drop to a condenser that subsequently vents the resulting heat.

percent by 2030, and 70 percent by 2040. This makes Hawaii the first state with a 100 percent RPS requirement and is now considered a test bed for understanding how to safely and reliably integrate very high proportions of intermittent and distributed generation resources, such as solar, into the distribution grid. Vermont also passed a bill in June 2015, establishing an RPS requirement of 75 percent by 2032—with an interim requirement of 55 percent by 2017 and then increasing by an additional four (4) percent every three years until reaching the final requirement by 2032.

The 29 states include Pennsylvania's Alternative Energy Portfolio Standard, which allows non-renewable resources that the state considers to be "environmentally beneficial," such as waste coal.[3] Ohio also adopted an alternative energy—renewable and advanced—resource standard with an overall target of 25 percent by 2025.[4] However, the state has renewable resource benchmarks that begin in 2009 and increase annually towards an eventual target of 12.5% of retail electricity sales by 2024 and thereafter.[5]

In addition, nine states—Alaska, Indiana, Kansas, North Dakota, Oklahoma, South Carolina, South Dakota, Utah, and Virginia—have non-binding renewable energy goals. South Carolina was the latest state to establish a goal in 2014.[6] Utah also enacted legislation in March 2008 that contains some provisions similar to those found in renewable portfolio standards adopted by other states. However, certain provisions in the legislation may be more accurately described as a renewable portfolio goal.[7] Specifically, the legislation requires that utilities only need to pursue renewable energy to the extent that it is "cost-effective." The guidelines for determining the cost-effectiveness of acquiring an energy source include an assessment of whether acquisition of the resource will result in the delivery of electricity at

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3 The 8% in Figure 1 applies only to the Tier I resources under Pennsylvania's Alternative Energy Portfolio Standard. However, eligible Tier I resources also includes coal mine methane gas, which is not eligible under most RPS policies. Pennsylvania also has a Tier II that includes some nonrenewable resources such as waste coal and also takes into account integrated combined coal gasification technology. The Tier II requirement is 10%, yielding an 18% total from alternative sources.

4 Eligible renewable resources are defined to include the following technologies: solar photovoltaics (PV), solar thermal technologies used to produce electricity, wind, geothermal, biomass, biologically derived methane gas, landfill gas, certain non-treated waste biomass products, solid waste (as long as the process to convert it to electricity does not include combustion), fuel cells that generate electricity, certain storage facilities, and qualified hydroelectric facilities. Generally, advanced energy resources are defined as any process or technology that increases the generation output of an electric generating facility without additional carbon dioxide emissions. The definition of advanced energy resources explicitly includes clean coal, generation III advanced nuclear power, distributed combined heat and power (CHP), fuel cells that generate electricity, certain solid waste conversion technologies, and demand side management or energy efficiency improvements.

5 Only the renewable resource portion of Ohio's requirement is reflected in Figure 1 below.

6 In the 2009-2010 legislative session, the Alaska legislature enacted House Bill 306 with the goal that "the state receive 50 percent of its electrical generation from renewable energy sources by 2025." However, this language does not appear in codified statutes.

7 For purposes of preparing Figure 1 below, Utah's RPS program is considered to be a voluntary goal.

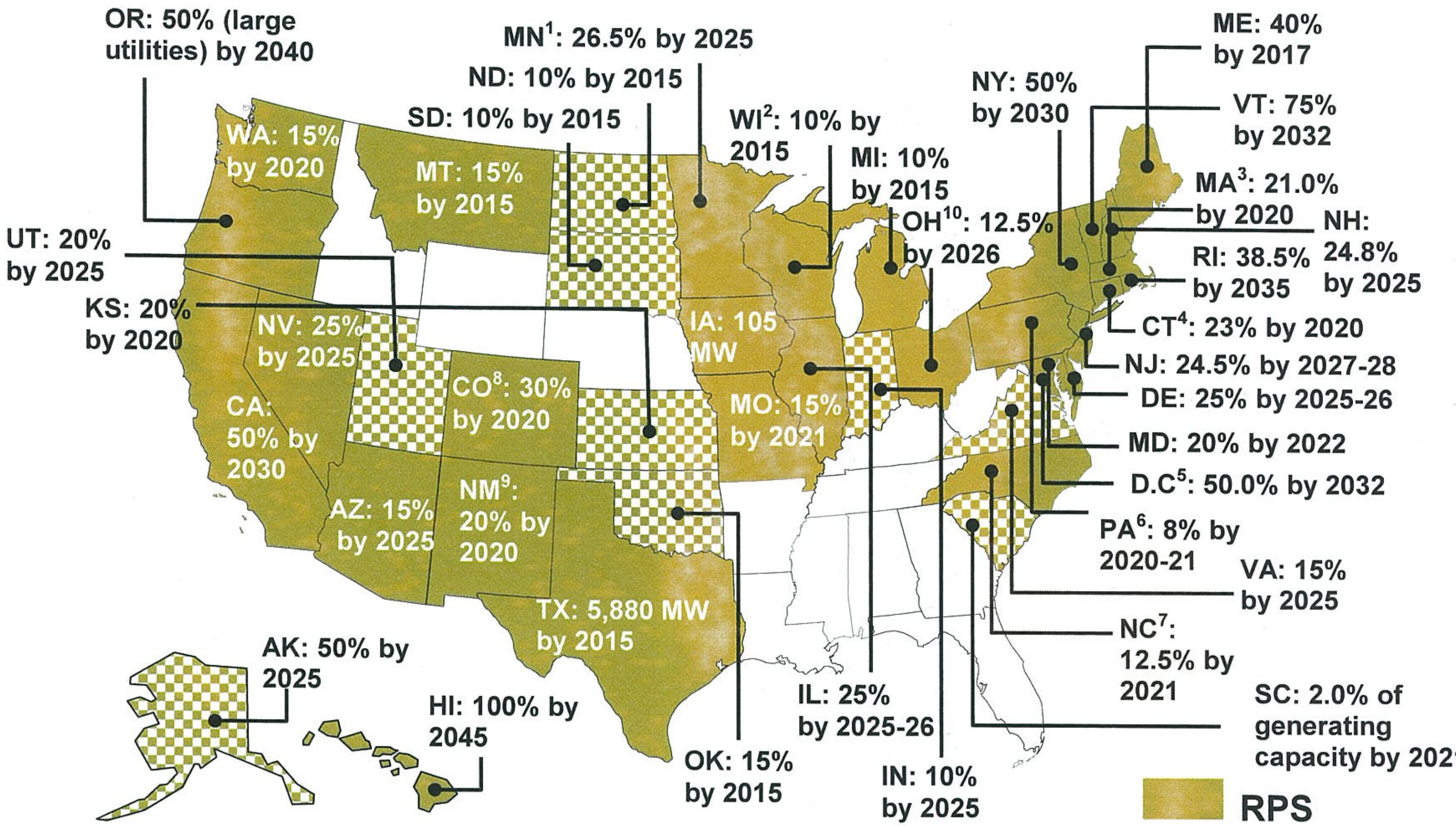
the lowest reasonable cost, as well as an assessment of long-term and short-term impacts, risks, reliability, financial impacts on the affected utility, and other factors determined by the Utah Public Service Commission. To the extent that it is cost-effective to do so, investor-owned utilities, municipal utilities and cooperative utilities must use eligible renewable resources to account for 20% of their 2025 adjusted retail electric sales. In addition, the first year of compliance is 2025 with no interim targets, but utilities must file progress reports during the interim period at specified times. The progress reports are supposed to indicate the actual and projected amount of qualifying electricity the utility has acquired, the source of the electricity, an estimate of the cost for the utility to achieve their target, and recommendations for a legislative or program change.

The following compares the District's RPS requirement to nearby states:[8]

- District – 50% by 2032 (the solar requirement increases to 5.0% by 2032)
- Delaware – 25% by 2025-26
- Maryland – 20% by 2022
- New Jersey – 24.5% by 2027-28
- North Carolina – 12.5% by 2021
- Pennsylvania – 8% by 2020-21
- Virginia – 15% by 2025

8 This does not account for differences in eligible resources, specific resource requirements, and other factors.

Figure 1: Renewable Portfolio Standards
(Percentage of Sales, except for Iowa and Texas)



[1] MN has a requirement of 31.5% by 2020 for Xcel Energy and 26.5% by 2025 for other investor-owned utilities. There is a 25% by 2025 requirement for other utilities.

[2] Statewide target is 10%, but requirements can vary by utility.

[3] 15% Class I (New Resources) plus additional 1% each year after 2020, 6.0% Class II (Existing Resources) by 2016.

[4] The 23% refers to Class I and II resources.

[5] Solar requirement increases to 5.0% by 2032.

[6] The 8% is for Tier I resources (including solar PV). PA also has a 10% requirement for Tier II resources that includes some nonrenewable resources.

[7] The 12.5% is for investor-owned utilities. Co-ops and municipals must meet 10% by 2018.

[8] The 30% is for investor-owned utilities. Co-ops serving 100,000 or more meters must meet 20% by 2020. Co-ops serving less than 100,000 meters and municipals must meet 10% by 2020.

[9] The 20% is for investor-owned utilities. Co-ops must meet 10% by 2020.

[10] OH also has a 12.5% Advanced Energy Resources requirement that includes advanced nuclear power, co-generation, and clean coal).

Sources: Database of State Incentives for Renewable Energy, Lawrence Berkeley National Laboratory, and National Conference of State Legislatures.

Attachment 2

List of Selected Commission Orders and Notices on the Implementation of the Renewable Energy Portfolio Standard

List of Selected Commission Orders and Notices on the Implementation of the Renewable Energy Portfolio Standard

Order No. 13566 (April 29, 2005): Invited interested parties to submit their views on twelve (12) RPS-related issues.

Order No. 13766 (September 23, 2005): Addressed various issues based on the comments filed in response to Order No. 13566. With respect to the process for implementing the Act, the Commission directed interested parties to form a RPS Working Group to examine in more detail certain issues related to the implementation of the REPS Act, and to develop a timeline and recommendations with respect to a two-phased approach to resolving those issues. The Commission also indicated that the PJM Environmental Information Service ("PJM-EIS") Generation Attribute Tracking System ("GATS") would be used in the implementation of the Act.

Order No. 13795 (October 24, 2005): Adopted the RPS Working Group's proposed procedural schedule recommended in the RPS Working Group Report (submitted October 11, 2005), including a timeline and designation of items, for addressing Phase I and Phase II issues—raised in Order No. 13766.

Order No. 13804 (November 10, 2005): Accepted in part and rejected in part comments filed by the parties in the RPS Working Group Report submitted on October 25, 2005. The Commission generally approved the method for certifying individual generators. The Commission directed the RPS Working Group to develop a list of comparable state certificates that would meet the District's RPS. The resulting list would help identify which facilities are in compliance with the District's RPS requirements. However, the Commission rejected the accrual of retroactive RECs created before January 1, 2006. The Commission noted that the intent of the REPS Act is to encourage the production and siting of renewable resources going forward, rather than looking back, which reduces the need for the use of retroactive RECs.

Order No. 13840 (December 28, 2005): Approved, in part, various rules addressing Phase I issues recommended in the RPS Working Group's third report (submitted November 23, 2005). Attachment A of the Order contains the interim rules that the Commission adopted. The interim rules, in part, established definitions for various terms consistent with the REPS Act, compliance requirements for electricity suppliers, generator eligibility, rules regarding the creation and tracking of RECs, and rules concerning the recovery of fees and costs.

Order No. 13860 (January 26, 2006): Generally accepted the recommendations presented in the RPS Working Group's report (submitted December 22, 2005) on comparable state certificates and related issues. The Commission pointed out that the use of the Tier I and Tier II eligibility matrices promotes a streamlined and simple process for the certification of renewable resources located outside of the District, consistent with Order No. 13766.

Order No. 13899 (March 27, 2006): Responded to Applications and/or Motions for Reconsideration and Clarification of Order No. 13840 filed by the Meadwestvaco Corporation, the Potomac Electric Power Company on behalf of the RPS Working Group, and jointly by Pepco Energy Services, Mirant Corporation, Washington Gas Energy Services, Inc., District of Columbia Energy Office, and Constellation. This Order, in part, amended the interim rules to indicate that retroactively created RECs must be tracked through GATS. In addition, with respect to the information to be included in the annual compliance report, the Commission amended the interim rules to indicate that suppliers purchasing RECs solely via bundled products are exempt from including the total price paid for Tier I, Tier II, and Solar Energy Credits in their report.

Order No. 14005 (July 24, 2006): Accepted in part and rejected in part, recommendations contained in the RPS Working Group report addressing Phase II issues, submitted on March 24, 2006. This Order further accepted in part and rejected in part recommendations contained in supplemental comments filed by the Office of the People's Counsel and in reply comments filed jointly by the Potomac Electric Power Company, Pepco Energy Services, Inc., and the District of Columbia Energy Office.

Order No. 14085 (October 13, 2006): Denied the Application for Reconsideration of Order No. 14005 filed by the MD-DC-VA Solar Energy Industries Association.

Order No. 14114 (November 13, 2006): Accepted in part and rejected in part, recommendations contained in the RPS Working Group report (September 15, 2006) regarding: (1) the use of engineering estimates to measure the output of small solar installations; (2) the District of Columbia's adoption of Behind-the-Meter rules and regulations used in other Mid-Atlantic States; and (3) the RPS Working Group's response to a hypothetical question involving renewable energy credit creation that was set forth in Order No. 13766.

Order No. 14225 (March 2, 2007): Accepted in part and rejected in part recommendations contained in the RPS Working Group report, addressing issues identified in Order No. 14114, submitted on December 13, 2006. In particular, the Commission amended the interim rules to address certain issues regarding behind-the-meter generation.

Order No. 14697 (January 10, 2008): Adopted Chapter 29 of Title 15 District of Columbia Municipal Regulations ("Final Rules"). The Final Rules became effective upon the publication of the Notice of Final Rulemaking in the *D.C. Register* on January 18, 2008.

Order No. 14782 (April 10, 2008): Adopted the Electricity Supplier 2007 Compliance Report Form and associated filing instructions for the District's RPS Program. Electricity suppliers were directed to use the form for the 2007 Compliance Reports due May 1, 2008.

Order No. 14798 (April 29, 2008): Directed on-site or behind-the-meter ("BTM") generators, certified by the Commission as eligible renewable generating facilities and required to file on-site or BTM generation reports under the Commission's rules, to file their reports with the Commission.

Order No. 14809 (May 12, 2008): Directed the RPS Working Group to file, consistent with the Commission's rules, an annual update to the Tier I and Tier II eligibility matrices.

Order No. 14885 (August 11, 2008): Directed certain electricity suppliers to file evidence with the Commission that each established Generation Attribute Tracking System accounts and that the renewable energy credits reported in their compliance reports have been properly retired.

Order No. 15077 (October 1, 2008): Denied Washington Gas Energy Services, Inc.'s request for a waiver of the 2007 compliance fee for solar renewable energy credits and directed the Company to file proof of payment of the 2007 compliance fee for solar renewable energy credits.

Order No. 15192 (February 18, 2009): Directed the RPS Working Group to review the available information regarding certain states and, if the RPS Working Group identifies any Tier I or Tier II renewable energy resources whose certification requirements may be comparable to the District's RPS program, to file an annual update. In identifying new resources, the Order noted that the RPS Working Group should be mindful of the fact that the Clean and Affordable Energy Act of 2008 has added additional certification requirements for certain solar energy facilities.

Order No. 15233 (April 7, 2009): Adopted amendments to the RPS rules, an Affidavit of Environmental Compliance, and a revised Electricity Supplier Annual Compliance Report Form.

Order No. 15561 (September 28, 2009): Adopted amendments to RPS rules consistent with the applicable sections of the Clean and Affordable Energy Act of 2008. In particular, the Commission added a new subsection detailing the requirements for meeting the solar portion of the RPS requirement. In addition, the amendments raised the compliance fees for tier one and solar energy Renewable Energy Credit ("SREC") shortfalls as well as change the definition of solar energy. The amendments also required additional documentation for applications for certification of solar thermal systems as District of Columbia renewable energy facilities.

Order No. 15581 (October 21, 2009): Denied Sol System's request to increase the derate factor used in estimating the output of a solar photovoltaic ("PV") system. The derate factor accounts for the inefficiencies inherent in converting direct current ("DC'") produced by a solar PV system to alternating current ("AC") used in homes or businesses. Specifically, the derate factor accounts for the inefficiency of the solar panels and inverter, as well as losses due to connections and wiring, among other factors. Pursuant to the Commission's rules, solar RECs are created and tracked through the PJM Environmental Information Services, Inc.'s Generation Attribute Tracking System ("PJM-EIS GATS"). PJM-EIS GATS applies a certain default derate factor utilizing PVWATTS, a performance calculator for PV systems developed by the National Renewable Energy Laboratory, which estimates the AC electricity produced by these PV systems. These estimates in turn are used to determine how many solar

RECs individual photovoltaic systems generate. Sol Systems offered no technical information of merit in support of its request.

Notice Regarding the Submission of Electricity Supplier Annual Compliance Report for the District of Columbia's Renewable Energy Portfolio Standard (March 23, 2010): Reminded electricity suppliers that they may not use the incineration of solid waste to meet more than 20 percent of the standard for tier two renewable sources. In addition, starting January 1, 2013, suppliers are prohibited from using RECs derived from solid waste incineration to meet any part of the Tier II standard.

Notice Regarding the Submission of Electricity Supplier Annual Compliance Report for the District of Columbia's Renewable Energy Portfolio Standard (March 18, 2011): Reminded electricity suppliers that they are obligated to submit their annual renewable energy portfolio standard compliance reports for calendar year 2010 by May 2, 2011[52] and that electricity suppliers shall meet the solar requirement by first exhausting all opportunity to purchase D.C. SRECs before purchasing non-D.C. SRECs.

Order No. 16528 (September 9, 2011): Denied all applications for certification of solar energy facilities that were not located within the District, nor in locations served by a distribution feeder serving the District, pending before the Commission on August 1, 2011.

Order No. 16529 (September 9, 2011): Decertified all solar energy facilities not located within the District or in locations served by a distribution feeder serving the District, and certified by the Commission between February 1 and August 1, 2011, as well as any solar facilities with a capacity larger than 5 MW regardless of the date certified. In addition, the clarified that any solar renewable energy credits generated by solar energy facilities decertified pursuant to this Order cannot be used to satisfy the solar portion of the District's RPS program for the 2011 compliance year nor any future compliance year.

Order No. 16680 (January 12, 2012): Denied SolTherm Energy, LLC's applications for recertification of 15 facilities, arguing that the applicability section of the permanent version of the legislation, the Distributed Generation Amendment Act of 2011 ("DGAA" or the "Act"), exempts contracts for the purchase and sale of solar renewable energy credits ("SRECs") from the decertification provision of the Act. In its Order, the Commission indicated that rather than grandfathering-in SRECs and/or SREC contracts, the DGAA effectively voided them after January 31, 2011. The Order mentions that the Council clarified the Act in both its emergency and permanent versions and expressly required the Commission to decertify any non-compliant facility certified between February 1, 2011 and the effective date of the Emergency Act, August 1, 2011. The Commission determined that SolTherm's interpretation of the Act would frustrate the Council's intent to render SRECs from non-D.C. facilities unmarketable—as SolTherm's facilities are located outside the District and are not in locations served by a distribution feeder serving the District. Therefore, the Commission concluded that it is statutorily precluded from recertifying them. In addition, SRECs

52 As May 1 fell on a Sunday, annual compliance reports were due the next business day, Monday, May 2, 2011.

extinguished by operation of law when the Commission decertified the SolTherm facilities cannot be rekindled under a provision clearly intended to apply only to energy supply contracts.

Order No. 16738 (March 15, 2012): Adopted the amended rules and revised annual compliance report form published in the January 13, 2012 Notice of Proposed Rulemaking. The proposed amendments to the RPS rules include, among other things, changes pursuant to the Distributed Generation Amendment Act of 2011.

Order No. 16787 (May 25, 2012): Directed three alternative electricity suppliers—Consolidated Edison Solutions, Liberty Power, and Noble Americas Energy Solutions—to comply with statutory limit on the use of municipal solid waste to meet the RPS requirement for Tier II resources, based on their 2010 compliance reports. The three suppliers were directed to either show cause why this notification of non-compliance is unwarranted or submit their respective payments for non-compliance payable to the Renewable Energy Development Fund.

Order No. 17062 (February 1, 2013): Adopted the RPS Working Group's proposed Tier I and Tier II eligibility matrices for 2011 as modified.

Order No. 17239 (September 6, 2013): Denied the Virginia Living Museum's revised application to expand its existing solar generating system as the second array is functionally separate from the existing array—being separately metered and located on two separate buildings, sharing no parts or components, and do not interact in any way. Given the information and argument before the Commission, there was no basis upon which to conclude that the second array is anything other than a new facility that is disallowed under the Distributed Generation Amendment Act of 2011, as it is not in a location served by a distribution feeder serving the District of Columbia.

Order No. 17349 (January 13, 2014): Adopted the RPS Working Group's proposed Tier I and Tier II eligibility matrices submitted for 2013. The proposed eligibility matrices do not include solar energy or solid waste among the eligible resources for the streamlined certification process. In addition, the RPS Working Group accounted for all nine (9) of the adjacent PJM states.

Order No. 17350 (January 13, 2014): Decertified two municipal solid waste facilities that were previously approved. After December 31, 2012, the incineration of solid waste is no longer eligible to generate RECs to be used to satisfy the Tier II portion of the District's renewable energy portfolio standard. The Commission indicated that RECs from these two facilities cannot be used to satisfy the Tier II portion of the RPS requirement for the 2013 compliance year, nor any future compliance year.

Order No. 17351 (January 10, 2014): Denied the Silicon Ranch Corporation's application for certification of a solar energy facility, with a capacity of least 30 MW, located in Georgia. In its Application, the Silicon Ranch Corporation indicated that it was seeking certification of the solar energy facility as a Tier I out-of-state resource, and it is not seeking certification to obtain SRECs. Based on its review of the Commission's RPS rules, the Applicant asserted that the District's solar carve out does not prevent outside of the District solar facilities like its own from being certified as a "generic" Tier I resource. By statute, Tier I renewable sources are clearly defined to mean one or more of the following types of energy sources: solar, wind, qualifying biomass, methane from the decomposition of organic materials, geothermal, ocean, and fuel cells producing electricity from qualifying biomass or methane. The Commission determined that since the statutory definition of a Tier I renewable source is based on the source used to produce energy, a Tier I renewable source cannot, therefore, be "generic." In addition, the applicant did not provide any supporting legal authority for the creation of a "generic" Tier I source. Nor does the statute authorize the Commission to certify a solar facility outside of the District which is not in a location served by a distribution feeder serving the District of Columbia and which is larger than 5 MW in capacity.

<u>Order No. 17379 (February 12, 2014)</u>: Directed the Potomac Electric Power Company ("Pepco") to incorporate the changes set out in this Order in its future Annual Interconnection Reports.

<u>Order No. 17393 (February 20, 2014)</u>: Denied the application for certification of the Welch/Molloy Residence's Solar Energy Facility as a Renewable Energy Standards Generating Facility because the solar energy facility is not located within the District or in a location served by a distribution feeder serving the District, pursuant to the DGAA.

<u>Order No. 17673 (October 24, 2014)</u>: Adopted a modified version of the NOPR published in the D.C. Register on June 27, 2014. The filing deadline for RPS compliance reports and fees in Sections 2901.7 and 2901.9 of the RPS Rules was moved from May 1 to April 1.

<u>Order No. 17794 (February 4, 2015)</u>: Addressed comments from interested persons and described changes to the NOPR published on September 12, 2014 amending Chapter 9, Rules and Regulations Governing Net Energy Metering ("NEM"), to implement those provisions of the Community Renewable Energy Amendment Act of 2013 ("CREA") regarding the community net metering program. A revised NOPR with the incorporated changes was published in the *D.C. Register* on January 30, 2015 for comment by interested persons.

<u>Order No. 17862 (April 24, 2015)</u>: Adopted revised rules and regulations governing Net Energy Metering ("NEM") to implement those provisions of the Community Renewable Energy Amendment Act of 2013 ("CREA") which establish the community net metering program.

<u>Order No. 17863 (April 24, 2015)</u>: Adopted amendments to Chapter 41, "District of Columbia Standard Offer Service ['SOS'] Rules," which were made to implement those provisions of the Community Renewable Energy Amendment Act of 2013 ("CREA") that affect SOS.

<u>Order No. 18050 (December 11, 2015)</u>: Approved the Potomac Electric Power Company's ("Pepco") Community Renewable Energy Facilities Documents ("CREF Documents") filed, pursuant to Chapter 9 of Title 15 of the District of Columbia Municipal Regulations

("DCMR") as well as the "Procedural Manual for Implementation and Administration of Community Renewable Energy Facilities" ("CREF Procedural Manual"). The Commission directed Pepco to amend the CREF Documents and the proposed CREF Procedural Manual in accordance with the directives of this Order.

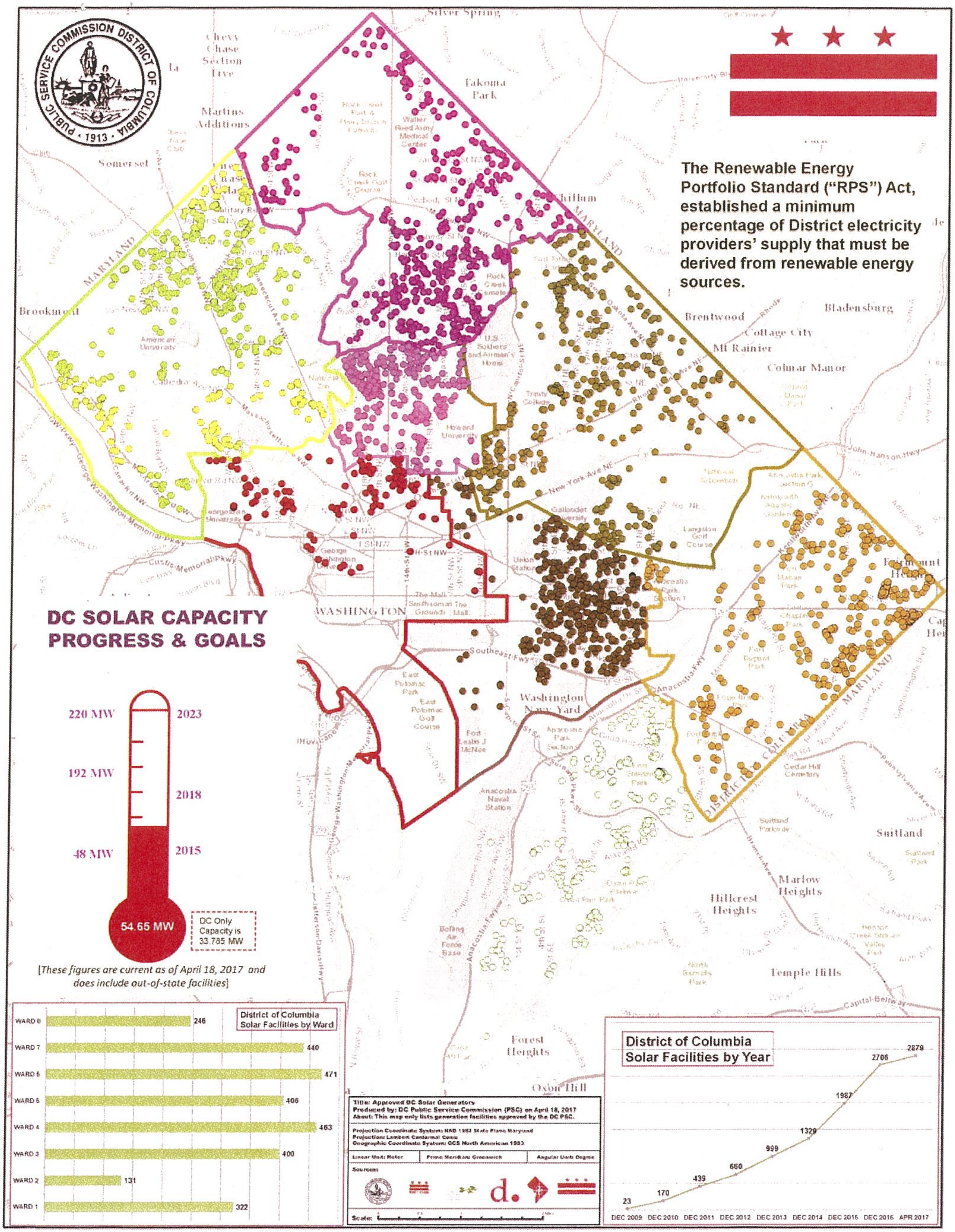
Order No. 18135 (March 3, 2016): Granted the motion of Potomac Electric Power Company ("Pepco") to reconsider the Commission's decision in Order No. 18050. Pepco was directed to modify the CREF Contract consistent with this Order.

Order No. 18705 (February 24, 2017): Approved the Potomac Electric Power Company's ("Pepco") Community Net Metering Rider ("Rider CNM"), Pepco's Community Renewable Energy Facility ("CREF") Contract and conditionally approved Pepco's proposed revised CREF Procedural Manual. The Commission directed Pepco to amend its proposed revised CREF Procedural Manual in accordance with the directives of this Order.

Order No. 18749 (April 13, 2017): Adopted amendments to Chapter 29, "Renewable Energy Portfolio Standard" ("REPS"), of Title 15 of the District of Columbia Municipal Regulations ("DCMR"), pursuant to D.C. Code § 34-802 and in accordance with D.C. Code § 2-505, that were made to implement those provisions of the Renewable Portfolio Standard Expansion Amendment Act of 2016 that affect the District of Columbia's REPS.

Attachment 3

Map of the Certified Solar Energy Systems in the District of Columbia


PUBLIC SERVICE COMMISSION DISTRICT OF COLUMBIA · 1913 ·
The Renewable Energy Portfolio Standard ("RPS") Act, established a minimum percentage of District electricity providers' supply that must be derived from renewable energy sources.
DC SOLAR CAPACITY PROGRESS & GOALS
220 MW
2023
192 MW
2018
48 MW
2015
54.65 MW
DC Only Capacity is 33.785 MW
[These figures are current as of April 18, 2017 and does include out-of-state facilities]
District of Columbia Solar Facilities by Ward
WARD 8 246
WARD 7 440
WARD 6 471
WARD 5 406
WARD 4 463
WARD 3 400
WARD 2 131
WARD 1 322
Title: Approved DC Solar Generators
Produced by: DC Public Service Commission (PSC) on April 18, 2017
About: This map only lists generation facilities approved by the DC PSC.
Projection Coordinate System: NAD 1983 State Plane Maryland
Projection: Lambert Conformal Conic
Geographic Coordinate System: GCS North American 1983
Linear Unit: Meter
Prime Meridian: Greenwich
Angular Unit: Degree
Sources:
Scale:
District of Columbia Solar Facilities by Year
DEC 2009 23
DEC 2010 170
DEC 2011 439
DEC 2012 660
DEC 2013 999
DEC 2014 1329
DEC 2015 1987
DEC 2016 2706
APR 2017 2879
Silver Spring
Chevy Chase Section Five
Takoma Park
Martins Additions
Somerset
Brookmont
Chillum
MARYLAND
Brentwood
Bladensburg
Cottage City
Mt Rainier
Colmar Manor
American University
Walter Reed Army Medical Center
Howard University
Trinity College
Gallaudet University
Langston Golf Course
National Arboretum
WASHINGTON
The Mall
Union Station
Washington Navy Yard
East Potomac Park
Anacostia Naval Station
Bolling Air Force Base
Fairmount Heights
Suitland
Marlow Heights
Hillcrest Heights
Temple Hills
Forest Heights
Oxon Hill
DISTRICT OF COLUMBIA
New York Ave NE
John Hanson Hwy
Southeast Fwy
Anacostia Fwy
George Washington Memorial Pkwy
Capital Beltway

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
1325 G STREET N.W., SUITE 800
WASHINGTON, D.C. 20005

ORDER

October 19, 2017

FORMAL CASE NO. 1130, IN THE MATTER OF THE INVESTIGATION INTO MODERNIZING THE ENERGY DELIVERY SYSTEM FOR INCREASED SUSTAINABILITY, Order No. 19143

I. INTRODUCTION

1. By this Order, the Public Service Commission of the District of Columbia ("Commission") invites the public to submit comment on Staff's Proposed Vision Statement for the modernizing the distribution energy delivery system for increased sustainability ("MEDSIS") Initiative or "MEDSIS Vision Statement." The Commission also invites public comment on whether any guiding principles should be included in the Commission's vision statement; whether a full assessment of the current capabilities and characteristics of the District's current energy delivery system is warranted at this time; and, whether, and to what extent, a consultant would be useful to help move MEDSIS forward more expeditiously. Initial comments on these matters as well as on the proposed MEDSIS Vision Statement are due within sixty (60) days of the date of this Order and reply comments are due thirty (30) days thereafter. The Commission also transfers the entire docket of *Formal Case No. 1143* to this proceeding.[1]

II. BACKGROUND

2. The investigation into modernizing the energy delivery system in the District of Columbia was initiated in response to intervenors' requests in both *Formal Case No. 1103*[2] and *Formal Case No. 1123*.[3] In consideration of intervenor requests, technological advancements in the energy industry, and changing consumer preferences, on June 12, 2015, the Commission issued Order No. 17912 which opened this proceeding to identify technologies and policies that can be implemented in the District to modernize the distribution energy delivery system for increased

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[1] *Formal Case No. 1143, In the Matter of the Commission's Consideration of a Demand Management Program for Electric Vehicle Charging in the District of Columbia* ("*Formal Case No. 1143*"), Potomac Electric Power Company's ("Pepco") Proposal for a Limited Demand Management Program for Plug-In Electric Vehicle Charging in the District of Columbia, filed April 21, 2017 ("Pepco's Proposed EV Program").

[2] *See Formal Case No. 1103, In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service* ("*Formal Case No. 1103*"), Order No. 17539, ¶ 120, rel. July 10, 2014 ("Order No. 17539").

[3] *Formal Case No. 1123, In the Matter of the Potomac Electric Company's Notice to Construct a 230kV/138 kV/13 kV Substation and Four 230 kV/138 kV Underground Transmission Circuits on Buzzard Point* ("*Formal Case No. 1123*"), Order No. 17851, ¶ 19, rel. April 9, 2015 ("Order No. 17851").

sustainability; and, in the near-term, to make the distribution energy delivery system more reliable, efficient, cost effective, and interactive.[4] The Order also established a series of workshops to be held in the proceeding; the first in October 2015, the second in November 2015, and the third on March 17, 2016.

3. At the conclusion of the third workshop, the Commission announced that staff would prepare a MEDSIS Report that would address the comments and make recommendations on the next steps. The staff prepared the report and, on January 25, 2017, the Commission issued the report for public comment.[5] By Order No. 18717, the Commission granted the District of Columbia Government's ("District Government") motion to extend the initial and reply comment period to April 10, 2017 and May 10, 2017, respectively.[6] On February 28, 2017, the Commission held a MEDSIS Town Hall Meeting to discuss the proposed pilot project parameters identified in the Staff Report. Finally, by Order No. 18812, the Commission granted Pepco's request to initiate a formal comment period on the OPC Value of Solar Report filed in the *Formal Case No. 1130* docket on May 19, 2017; initial and reply comments were due on July 12, 2017 and July 24, 2017, respectively.[7]

III. <u>DISCUSSION</u>

4. *Clean Energy DC*, the draft climate and energy plan for the District of Columbia, recommends, among other things, creating a vision of the District's future electricity system to be used to define grid capabilities and characteristics of the delivery system and characterize the transition required to achieve this vision.[8] Moreover, *Clean Energy DC* states, "As a first step, the District Government should clearly establish, reiterate, and quantify the District's objectives for grid modernization as they relate to its 2032 GHG reduction, energy use reduction, and renewable energy utilization targets, as well as the areas of efficiency, resilience, reliability, security,

[4] *Formal Case No. 1130*, *In the Matter of the Investigation into Modernizing the Energy Distribution System for Increased Sustainability*, Order No. 17912, rel. June 12, 2015.

[5] *Formal Case No. 1130*, Order No. 18673, rel. January 25, 2017.

[6] *Formal Case No. 1130*, Order No. 18717, ¶¶ 1, 7-8, rel. March 9, 2017.

[7] Initial comments on OPC's Value of Solar Study were filed by DC Solar United Neighborhoods and Potomac Electric Power Company. *See Formal Case No. 1130*, DC Solar United Neighborhoods Comments on People's Counsel's Value of Solar Study, filed July 11, 2017; *Formal Case No. 1130*, Potomac Electric Power Company Comments on People's Counsel's Value of Solar Study, filed July 12, 2017. Reply comments were filed by Department of Energy and Environment and Office of the People's Counsel. *See Formal Case No. 1130*, Department of Energy and Environment Reply Comments on People's Counsel's Value of Solar Study, filed July 24, 2017; *Formal Case No. 1130*, Office of the People's Counsel Reply Comments on Pepco's Comments on the Office of the People's Counsel's Value of Solar Study, filed July 24, 2017. The Commission notes that Staff has reviewed the comments submitted in response to OPC's Value of Solar Report and that the Commission will give the Report and its conclusions appropriate consideration in future solar-related matters before the Commission.

[8] Clean Energy DC, Draft October 2016 at p. 137, Department of Energy & Environment, https://doee.dc.gov/sites/default/files/dc/sites/ddoe/publication/attachments/Clean_Energy_DC_2016_final_print_single_pages_102616_print.pdf.

flexibility, and interactivity."[9] We believe that the Commission's vision must be compatible with the city's vision so that we can all move harmoniously toward the same goal, using our available resources as wisely as possible.

A. Vision Statement

5. The Commission commends Staff for undertaking the important task of crafting a vision statement as a guide to move us forward, particularly at this crucial time when so much of the infrastructure is being replaced. It is important that we give all stakeholders a meaningful opportunity to weigh in on the proposed vision statement before moving forward so we are putting the staff's proposal out for comment and, at the same time, offering some thoughts of our own.[10]

B. Guiding Principles and Objectives

6. The Public Service Commission of Maryland ("Maryland PSC") set forth guiding principles for the future of Maryland's electric distribution systems.[11] Additionally, regulators in Massachusetts, New York, Minnesota and Hawaii have similarly established guiding principles and convened stakeholder processes with regard to their respective grid modernization investigations.[12] We invite the public to include in its comments a discussion of whether any of these (or other) guiding principles should be included in the Commission's vision statement.

C. Energy Delivery System Assessment

7. Given the comments submitted on the MEDSIS Staff Report, it may be helpful for the Commission to undertake a comprehensive review of the District's current energy delivery system to determine its capabilities so all of us have a better idea of how to modernize the system. A cursory glance of the Commission's docket shows other pending proceedings that impact the

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[9] Clean Energy DC, Draft October 2016 at p. 138, Department of Energy & Environment, https://doee.dc.gov/sites/default/files/dc/sites/ddoe/publication/attachments/Clean_Energy_DC_2016_final_print_single_pages_102616_print.pdf.

[10] The Commission notes the MEDSIS Staff Report contained proposed Notice of Proposed Rulemakings ("NOPRs") on grid modernization-related definitions as well as amending the Commission's notice of construction ("NOC") rules. The Commission will soon release the NOPRs for public comment. However, the definitions are subject to further revision if future developments in the MEDSIS proceeding so warrant.

[11] *In the Matter of Transforming Maryland's Electric Distribution System to Ensure that Electric Service is Customer-Centered, Affordable, Reliable and Environmentally Sustainable in Maryland*, Maryland PSC Public Conference 44, Notice, January 31, 2017.

[12] *See, e.g.*, Massachusetts Department of Public Utilities Docket 12-76, Order No. 12-76-B, Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid, October 2, 2012; New York Public Service Commission Case No. 14-M-0101, Order Adopting Regulatory Policy Framework and Implementation Plan, February 26, 2015; Minnesota Public Utilities Docket No. 15-556, Commission Staff Report on Grid Modernization, March 24, 2016; Public Utilities Commission of Hawaii Docket No. 2016-0087, Order No. 34281 at 51, Dismissing Application Without Prejudice and Providing Guidance for Developing a Grid Modernization Strategy, January 4, 2017.

District's energy delivery system. For instance, Pepco is undergrounding electric powerlines[13] and constructing substations and transmission circuits.[14] Pepco is also proposing to construct underground transmission circuits to rebuild substations,[15] and has submitted a proposal for limited demand management for plug-in vehicle charging.[16] Washington Gas is engaged in an extensive pipe replacement effort[17] and a mechanical coupling replacement program.[18] As these efforts may ultimately pass on significant costs to ratepayers, the Commission believes it is important to undertake a holistic approach to the MEDSIS Initiative that considers everything that has been and is currently being undertaken with regard to the electric and natural gas delivery system. The Commission further believes that stakeholders deserve to know that future decisions with regard to modernizing the energy delivery system are prudent. Therefore, the Commission seeks stakeholder comments on whether a full assessment of the current capabilities and characteristics of the District's current energy delivery system is warranted at this time and whether it would be prudent to retain an independent consultant to conduct the assessment, using a portion of the $21.55 million Pepco and Exelon agreed pay into the *Formal Case No. 1130* MEDSIS Pilot Project Fund Subaccount.

D. Working Groups and Consultants

8. While the District was among one of the first jurisdictions to undertake a broad modernization initiative, focusing on both the electric and gas systems, since the release of the MEDSIS Staff Report, a number of states have taken actions that are worth noting. For instance, the Maryland PSC established six topics for consideration by stakeholder working groups led by Maryland PSC staff.[19] The New Hampshire Public Utilities Commission ("New Hampshire PUC"), which issued its final report on March 20, 2017, created a stakeholder grid modernization

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13 *See Formal Case No. 1145, In the Matter of Applications for Approval of Biennial Underground Infrastructure Improvement Projects Plan and Financing Orders.*

14 *See Formal Case No. 1123.*

15 *See Formal Case No. 1144, In the Matter of the Potomac Electric Power Company's Notice to Construct Two 230 kV Underground Circuits from the Takoma Substation to the Rebuilt Harvard Substation and from the Rebuilt Harvard Substation to the Rebuilt Champlain Substation.*

16 *See Formal Case No. 1143.*

17 *See Formal Case No. 1115, Application of Washington Gas Light Company for Approval of a Revised Accelerated Pipe Replacement Program.*

18 *See Formal Case No. 1027, In the Matter of the Emergency Petition of the Office of the People's Counsel for an Expedited Investigation of the Distribution System of Washington Gas Light Company; GT97-3, In the Matter of the Application of Washington Gas Light Company for Authority to Amend its Rate Schedule No. 6; and GT06-1, In the Matter of the Application of Washington Gas Light Company for Authority to Amend General Service Provision No. 23.*

19 *In the Matter of Transforming Maryland's Electric Distribution System to Ensure that Electric Service is Customer-Centered, Affordable, Reliable and Environmentally Sustainable in Maryland*, Maryland PSC Public Conference 44, Notice, January 31, 2017.

working group to create an open dialogue and reach consensus on key modernization topics.[20] The Rhode Island Public Utilities Commission ("Rhode Island PUC") opened Docket 4600, a stakeholder process to build consensus on issues related to the changing electric distribution system.[21] The Rhode Island PUC Docket 4600 Working Group issued its final report on April 5, 2017 and that report was accepted by the Rhode Island PUC on July 31, 2017.[22] The Commission notes that the Maryland PSC has retained consultants to analyze the benefits and costs of distributed solar energy resources in Maryland and to provide policy and technical consulting services to implement rate design pilot programs.[23] The Massachusetts Department of Public Utilities, New Hampshire PUC, and Rhode Island PUC also retained consultants to facilitate their respective stakeholder working group discussions. The Commission seeks stakeholder input on whether it would be prudent to retain an independent consultant, using a portion of the $21.55 million Pepco and Exelon agreed to pay into the *Formal Case No. 1130* MEDSIS Pilot Project Fund Subaccount, to act as a facilitator in stakeholder working groups or to handle certain aspects of the Commission's MEDSIS Initiative such as MEDSIS pilot programs.[24] Ideally, with input from stakeholders, the consultant would provide the Commission with consensus recommendations. We invite stakeholder comment on whether, and to what extent, a consultant would be useful to help move the MEDSIS Initiative forward more expeditiously.

E. Electric Vehicles

9. When the Commission opened this investigation, an examination of electric vehicles was among the various topics that were listed for consideration.[25] On April 21, 2017, Pepco filed a proposal seeking approval for a limited, voluntary demand management program for plug-in electric vehicle ("PIV") charging in the District of Columbia ("EV Program") consisting of five offerings with varying options and to allow Pepco to focus on expanding PIV use in the District of Columbia.[26] On April 27, 2017, the Commission opened *Formal Case No. 1143* to

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20 *Investigation into Grid Modernization*, New Hampshire PUC IR 15-296, Order No. 25, 877, April 1, 2016.

21 *In re: Investigation into the Changing Electric Distribution System and the Modernization of Rates in Light of the Changing Distribution System*, Docket No. 4600, Notice of Commencement of Docket and Invitation for Stakeholder Participation, March 18, 2016.

22 *In re: Investigation into the Changing Electric Distribution System and the Modernization of Rates in Light of the Changing Distribution System*, Docket No. 4600, Report and Order, July 31, 2017.

23 *See* Maryland PSC Order No. 86990, Case No. 9361 at A-19 (Merger Condition 14) (The Maryland PSC required Pepco Holdings, Inc., as a condition of the Exelon/PHI merger, to submit a "grid of the future" plan and commit $500,000 of non-ratepayer funds to support a consultant (or consultants) for this effort).

24 The Commission holds in abeyance any decision on the proposed pilot project parameters.

25 *Formal Case No. 1130*, Order No. 17912, rel. June 12, 2015.

26 *Formal Case No. 1143*, Potomac Electric Power Company's ("Pepco") proposal for a limited demand management program for plug-in electric vehicle charging in the District of Columbia, filed April 21, 2017 ("Pepco's Proposed EV Program").

consider Pepco's EV Program proposal and requested public comment on Pepco's proposal.[27] Some commenters indicated that the EV Program should be addressed in this proceeding rather than in a separate proceeding. Considering that the Commission included an examination of electric vehicles among the various topics that would be considered in this proceeding, we believe the more prudent and administratively efficient course of action is to transfer the entire docket of *Formal Case No. 1143* to this proceeding.

THEREFORE, IT IS ORDERED THAT:

10. The Commission Staff's proposed MEDSIS Vision Statement is accepted into the *Formal Case No. 1130* docket;

11. Initial comments on the Commission Staff's proposed MEDSIS Vision Statement are due sixty (60) days from the date of this Order and reply comments are due thirty (30) days thereafter;

12. Comments with regard to any principles and objectives the Commission should adopt to guide the modernization of the District's energy delivery system are due sixty (60) days from the date of this Order and reply comments are due thirty (30) days thereafter;

13. Comments on whether a full assessment of the current capabilities and characteristics of the District's current energy delivery system is warranted at this time and whether it would be prudent to retain an independent consultant to conduct the assessment, using a portion of the $21.55 million Pepco and Exelon agreed pay into the *Formal Case No. 1130* MEDSIS Pilot Project Fund Subaccount, are due sixty (60) days from the date of this Order and reply comments are due thirty (30) days thereafter;

14. Comments on whether the Commission should retain an independent consultant, using a portion of the $21.55 million Pepco and Exelon agreed pay into the *Formal Case No. 1130* MEDSIS Pilot Project Fund Subaccount, to act as a facilitator in stakeholder working groups or to handle certain aspects of the Commission's MEDSIS Initiative such as MEDSIS pilot programs are due sixty (60) days from the date of this Order and reply comments are due thirty (30) days thereafter; and

15. The entire docket of *Formal Case No. 1143* is transferred to *Formal Case No. 1130*.

A TRUE COPY: **BY DIRECTION OF THE COMMISSION:**

CHIEF CLERK: **BRINDA WESTBROOK-SEDGWICK**
COMMISSION SECRETARY

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[27] *Formal Case No. 1143,* Public Notice, rel. April 27, 2017.

The Public Service Commission of The District of Columbia

Formal Case No. 1130, Modernizing the Energy Delivery System for Increased Sustainability

Staff's Proposed MEDSIS Vision Statement

ISSUED: October 18, 2017

INTRODUCTION

In its adoption of the Retail Electric Competition and Consumer Protection Act of 1999 and the Retail Natural Gas Supplier Licensing and Consumer Protection Act of 2004, the Council of the District of Columbia (Council) envisioned the District of Columbia's ("District") energy delivery system as open, competitive, interactive, safe, and reliable. The District's energy delivery system has made great strides since restructuring and the Commission has and continues to update and expand upon the Council's vision for the District's energy delivery system. In furtherance of the Council's vision, the Public Service Commission of the District of Columbia (Commission) initiated the MEDSIS Initiative (Initiative) to address our role in ensuring the District's energy delivery system is modernized to meet the present and future energy needs of District ratepayers as well as the District's environmental protection and energy conservation goals.

Since the MEDSIS Initiative began in 2015, the Commission has worked diligently to make sure the foundation of the Initiative is solid and that the process is transparent, collaborative, and rooted in public engagement with a focus on information and data sharing between the Commission, utilities, government agencies, industry stakeholders, consumer advocacy groups, and individual citizens. To that end, the Commission: (1) held three public workshops between October 2015 and April 2016; (2) developed and issued, with an extended comment period, a detailed MEDSIS Staff Report in January of 2017, which, among other things, analyzed information gathered in the initial public engagement phase, identified regulatory barriers to the modernization process, provided proposed notice of proposed rulemakings (NOPRs) containing new and modified initiative-related definitions to enhance regulatory certainty; (3) highlighted questions related to microgrid development; and (4) held a MEDSIS Town Hall Meeting in February 2017 to hear public comment on the proposed Pilot Project Program Parameters, detailed in the MEDSIS Staff Report, which address how the $21.55 million in the MEDSIS Fund could be used to further the Initiative.

The extended public comment period on the MEDSIS Staff Report ended in May 2017. Commission Staff has thoroughly reviewed and considered the substantive comments filed by the public.[1] The comments were detailed and varied; a common thread expressed in several of the filings is the need for the Commission to develop a vision for the MEDSIS Initiative. Commission Staff agrees that development of a vision for modernizing the District's energy delivery system is necessary. The vision will not only aid continued public and stakeholder engagement in the process, but it will also provide a framework for the Commission to evaluate utility infrastructure spending proposals, the appropriateness of pilot projects requesting MEDSIS funding, as well as the value and potential impact of non-utility projects needing Commission approval. Therefore, with consideration of the wealth of information submitted to the Commission since the inception of the MEDSIS Initiative,[2] as well as consideration of the Commission's statutory mandate to ensure just and reasonable rates and the financial health of the District's utilities, Commission Staff proposes the following vision for modernizing the District's energy distribution system.

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[1] *See* Attachment A – Summary of Comments filed on the MEDSIS Staff Report.

[2] The MEDSIS Staff Report, public comments, stakeholder presentations, MEDSIS workshop materials, and all other MEDSIS-related information is publicly available on the MEDSIS webpage at www.dcpsc.org/medsis.

Staff recommends that the Commission release the proposed vision statement for public comment providing sixty (60) days for initial comments and thirty (30) for reply comments from the date of the Order.

COMMISSION STAFF'S PROPOSED VISION FOR A MODERN ENERGY DISTRIBUTION SYSTEM

MEDSIS Vision Statement

The District of Columbia's modern energy delivery system must be well-planned, encourage distributed energy resources, and preserve the financial health of the energy distribution utilities in a manner that results in an energy delivery system that is safe and reliable, secure, affordable, sustainable, interactive, and non-discriminatory.

WELL-PLANNED: With no large-scale generation in the District, the Commission must ensure that the distribution and transmission systems are strong and robust enough to withstand low probability, high impact events like storms, floods, and physical and cyber threats. To meet these needs, the District's modern energy delivery system must be developed in a strategic manner that is data-driven, incorporates advanced technologies, and is collaborative and open – allowing for consumer and stakeholder input. Therefore, utilities must:

- Develop detailed, data-driven Distribution and Integrated Resource Plans that, among other things: make infrastructure planning cost-effective; enable the optimal combination of distributed energy resources (DERs) with traditional capital investment by exploring non-wires alternatives; comply with legislatively mandated deployment of DER in the District; permit rational participation of consumers and distribution service providers; and plan for, track, and monitor DER penetration rates on the grid.

SAFE & RELIABLE: The Commission will ensure that utilities meet and improve safety and reliability performance and that the increasing volume of DERs interconnecting to the District's grid does not negatively impact the safety or reliability of the energy delivery system by:

- Requiring the continued investment in prudent infrastructure improvements to the energy system, like Pepco's reliability investments and Washington Gas' advance pipeline replacement program, so that the energy delivery system can meet the power needs of the District's current and future consumers.

- Reviewing and, where appropriate, updating the Commission's Electricity Quality of Service Standards (EQSS) and Natural Gas Quality of Service Standards (NGQSS) to ensure that the utilities are continually meeting and improving their safety and reliability performance.

- Updating and continually reviewing interconnection rules to facilitate the interconnection of DERs as well as all generation and storage options in a manner that does not compromise overall system safety and reliability.

- Where technically and economically feasible, encouraging the deployment of technologies that will not compromise system safety, will increase system reliability, and can accommodate two-way power flow like smart inverters, distributed automation, and sensors to better handle power fluctuations and outages.

- Enhancing data collection and real-time data sharing between utilities, third party suppliers, and stakeholders, like PJM, to increase system visibility, communication, and DER dispatchability, in a manner that increases the safety, reliability, and resiliency of the energy delivery system.

- Classifying DER and microgrid providers generating energy and serving more than one customer as subject to the Commission's authority thus enabling the Commission to protect District ratepayers, enforce the Consumer Bill of Rights (CBOR), and ensure the continued safe and reliable provision of energy service.

SECURE: The modern energy delivery system must be secure from both physical attacks to critical infrastructure components as well as from cybersecurity attacks that target energy information systems and private consumer information. Therefore, utilities and energy service providers must:

- Develop, utilize, and maintain robust physical and cybersecurity protections and risk management strategies that incorporate industry best practices like those established by the National Institute of Standards and Technology's (NIST) Framework for Improving Critical Infrastructure Cybersecurity.

- Ensure that the energy delivery system is resilient, uses modern grid security protocols, and is designed to resist, discourage, and rapidly recover from physical and cybersecurity attacks and system disruptions.

- Safeguard private and or confidential business data and consumer information from intentional or unintentional release or disclosure to untrusted environments.

AFFORDABLE: The Commission has a duty to ensure that rates for distribution service are just and reasonable. The Commission balances the desire of customers to keep rates down with the need to ensure that utilities remain financially healthy, able to attract investors, and pay for needed infrastructure maintenance and development. Balancing these interests, in the context of system modernization, becomes especially challenging when considering costly upgrades to the distribution system as well as potential ratepayer subsidization of costly renewable and DER technologies.

- The Commission recognizes that rapid technological change in the electric distribution industry increases the danger of "stranded assets" – capital investments that turn out to be unneeded. For this reason, before making investments in large capital projects, the utility must thoroughly examine the feasibility of non-wires alternatives as solutions to meet the stated investment objective at the lowest overall life-cycle cost. The utility must also undertake holistic planning approaches that fully examine technological options that can be deployed at a pace and scale that can meet policy objectives and customer expectations.

- In the long-term, the Commission expects that, under fair interconnection procedures, DER's will be able to stand on their own in the competitive marketplace without subsidies from distribution ratepayers. Therefore, benefits and costs of any proposals to use distribution rates to compensate new DERs must be weighed carefully.

- The Commission is committed to ensuring that ratepayers obtain maximum benefit from their over $90 million investment in Advanced Metering Infrastructure (AMI) by requiring the utility, to the extent economically and technically feasible, to maximize the use of AMI data in Distribution and Integrated Resource Planning, load forecasting, distribution system operations, and rate design as well as require activation of the Home Area Network[3] capabilities of the smart meters.

SUSTAINABLE: A sustainable energy delivery system will meet the energy needs of the present without compromising the ability of future generations to meet their own energy needs by focusing on the *triple bottom line*: environmental protection, economic growth, and social equality.

- **Environmental Protection:** Recognize the negative impact that energy usage and demand have on the environment and the human component of climate change. Protect the District's natural resources and assist the District Government in reaching its *Clean Energy DC*[4] goals by fostering the use of more efficient energy and renewable energy sources, DER technologies, and controllable demand alternatives to reduce greenhouse gas (GHG) emissions and overall energy consumption.

- **Economic Growth:** Foster economic growth in the District's energy markets by supporting innovation and making the District a desirable place for industry to invest by: (1) removing regulatory barriers that prevent the deployment of DER technologies in the District; (2) engaging industry and community stakeholders in the regulatory reform process; (3) promoting the deployment of pilot programs that will yield lasting economic benefits to District ratepayers; and (4) encouraging innovative business models and the use of scalable financial solutions to reach grid modernization goals.

- **Social Equality:** Recognize the positive impact that energy usage has on the daily lives of District residents. Ensure that, to the extent economically and technically feasible, all District ratepayers have equal access to energy efficiency programs, other DER programs, and modernization technologies approved and implemented by the Commission, as well as access to the Commission's regulatory process. Strengthen community involvement in reaching environmental protection and economic growth goals related to modernizing the

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3 A Home Area Network uses a low-power radio transmitter than can communicate with digital devices within the home to make use of energy consumption data from the smart meter.

4 The District Government, through the Department of Energy and Environment (DOEE), has established a "new climate and energy plan, with 55 actions in three major areas: Buildings, Energy Supply System, and Transportation." The Commission's work through MEDSIS aims to help the District meet its goal to reduce District-wide energy use by 50% (relative to 2012 levels) by 2032. To meet these energy usage reduction targets, the District is focused on reducing GHG emissions by cutting energy use, increasing renewable energy penetration, and reducing the District's reliance on fossil fuels. https://doee.dc.gov/cleanenergydc

District's energy delivery systems by: (1) encouraging and approving programs that fully consider, engage, and benefit all District ratepayers, especially the most vulnerable populations; (2) encouraging continued utility and stakeholder investment in educational programs and community outreach initiatives that explain how ratepayers can reduce their energy consumption and use energy more efficiently, including the role of various energy sources, distributed generation (DG), and DERs; and (3) working with utilities and industry stakeholders to develop ways to reduce the soft costs related to the deployment of photovoltaic (PV) systems and DERs in the District.

INTERACTIVE: As an increasing number of smaller scale and more localized resources come online the relationship between the energy distribution company, the consumer, and service providers will become increasingly complex and dynamic. New services will become available, energy and data will increasingly flow in multiple directions, and different types and scales of resources will enter the distribution system. A modern energy delivery system must become more interactive and flexible to accommodate these types of resources while maintaining system reliability and security. This interactivity is critical both in terms of managing the distribution system and in providing locational transparency and technical feasibility which will allow ratepayers, customer-generators, and DER providers to make informed energy choices. Therefore, the Commission:

- Recognizes the importance of the customer's ability to access and share energy data. Access to data empowers customers and third parties to utilize and develop new products and services. This includes activating the Home Area Network capability on customers' smart meters to realize additional benefits of existing AMI infrastructure and streamlining AMI data sharing through tools such as *Green Button Connect My Data* which can securely transfer AMI data to authorized third parties.

- Emphasizes the importance of improving and expanding consumer and stakeholder access to publicly available data related to distribution system constraints and technical capacity. Providing public access to Geographic Information Systems (GIS) such as hosting capacity maps, restricted circuits, and installed and pending solar projects provides critical distribution system information to customer-generators, community renewable energy facility owners, and DER providers.

- Encourages the interaction and communication between DERs, the distribution system, and the macro grid and that technologies that provide value to the distribution system, such as smart inverters, should be prioritized over technologies that merely benefit individual customers.

NON-DISCRIMINATORY: Nondiscrimination in the operation of the District's energy infrastructure is integral to the Commission's mandate to supervise energy utilities in the District of Columbia. Furthermore, since the restructuring of the energy markets, the need for the Commission to ensure that energy utilities operate in a nondiscriminatory manner has proliferated. Nondiscrimination covers both the technical operation of and the rates and fees charged for utilizing and accessing the energy utility infrastructure. The Commission will ensure that the District's modern energy system is non-discriminatory, open to competition, and provides for customer choice in accordance with District law by:

- Affording DER providers with a low-cost and streamlined interconnection process to facilitate customer generation. Encouraging continuous improvement and development of initiatives, like Pepco's *Green Power Connection*, that facilitate DER interconnection and build off past experience to reduce or eliminate barriers so that DERs can compete on a level playing field with wholesale energy.

- Unlocking customer and system data held by the incumbent utility in a controlled manner so that customers, DER providers, and third-party suppliers can provide targeted offerings to meet system needs and better serve the needs of customers.

- Pursuing policies that are technology neutral in both system operations and rate structure so that rates remain just and reasonable.

- Achieving the maximum benefits of competition and encouraging stakeholders to bring forward proposals for the competitive provision of services now included in the regulated monopoly distribution services.

ATTACHMENT A: SUMMARY OF THE COMMENTS ON THE MEDSIS STAFF REPORT

A. Summary of Initial Comments

A. D.C. Consumer Utility Board's Comments

1. On February 10, 2017, D.C. Consumer Utility Board ("DC CUB") submitted a letter supporting the "formation of a stakeholders working group [ ] to focus discussions on priority topics and to make recommendations is an appropriate and useful next step in the process."[5] DC CUB asserts that its "primary objective for this working group is to ensure that the views and goals of community stakeholders are well represented in shaping the overarching goals and principles and vision for MEDSIS." DC CUB recommends that a working group consider grid modernization efforts of New York, California, Connecticut, Massachusetts, Minnesota, and Hawaii. DC CUB further asserts that a "perennial concern is that the voice of community stakeholders is inadequately represented before the PSC because of the immense mismatch of resources available to community-based civic organizations in comparison to the for-profit utilities and businesses. For this reason [DC CUB] would seek a larger proportion of seats at the table be set aside for representatives from community-based organizations, including ANCs and civic/citizen organizations."[6]

2. DC CUB asserts that "the first objective for any stakeholder working group must be to make recommendations on the final scope and topics, including goals, principles and a vision for MEDSIS . . . [and that] no action defining or initiating a pilot program funding process [ ] should occur until the PSC receives the stakeholder working group recommendations (unanimous, or majority-minority) . . ."[7] DC CUB also recommends that using an independent third party to design the smart grid "would serve to substantially balance the resources that are available among parties." DC CUB concludes that the "competing demands on PSC staff time would make such a dedicated effort difficult for the PSC to provide in-house, [therefore,] this is an appropriate use for the MEDSIS fund."[8]

B. DC Solar United Neighborhood

3. On March 6, 2017, DC Solar United Neighborhoods ("DC SUN") submitted initial comments addressing issues raised in the February 28, 2017 MEDSIS Town Hall. DC SUN supports the overall goal of this proceeding—to explore ways to modernize the District's energy delivery system so as to increase sustainability, reliability, and the integration of solar and other Distributed Energy Resources ("DERS").[9] DC SUN suggests that the Commission launch this

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5 DC CUB's Comments at 1.

6 DC CUB's Comments at 1.

7 DC CUB's Comments at 2.

8 DC CUB's Comments at 2.

9 DC SUN's Comments at 3.

process by providing a statement of guiding principles in the form of fundamental policy objectives and define the concept of MEDSIS prior to any consideration of the pilot and demonstration project selection process.[10] DC SUN recommends that the Commission adopt the following guiding principles at the outset, which will help set the course for the proceeding;

1. Consumers should have the right to access all retail electricity services, including clean energy resources, real-time usage data, and dynamic pricing;

2. Individual consumers, businesses, and communities (not just private developers, government, and utilities) should have the right to aggregate consumer electricity services and implement DG microgrids;

3. New and improving technologies are driving fundamental change in DC's electric distribution system, and changes to the regulatory structure, projects or programs are required to ensure the seamless integration of technologies that will result in clear benefits – including cost reductions – for DC's ratepayers;

4. The distribution utility must be held accountable to consumers for specific performance goals, which could include goals concerning support for alternative energy, reliability, and customer service;

5. Electric distribution companies and cooperatives must serve as impartial grid operators, particularly when non-regulated affiliates are market participants;

6. Distribution utility revenues must be based on the quality, efficiency, and reliability of the utility's distribution service, not on electricity consumption; and

7. Materials should be created and disseminated that describe the MEDSIS process in language that is accessible as possible to the public.[11]

4. DC Sun also suggests that the Commission specifically articulate its vision of a MEDSIS by defining what "modernizing" the grid means as it relates to the specific goals the Commission seeks to achieve in this proceeding. DC Sun believes a modern energy delivery system should:

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[10] DC SUN's Comments at 3.

[11] DC SUN's Comments at 4.

1. Reduce the environmental impact of electricity and natural gas generation and usage;

2. Improve energy efficiency and demand management;

3. Permit the use of diverse energy sources—specifically, the grid should accommodate the integration of DG and other DERs;

4. Improve reliability and resilience;

5. Eliminate the significant amount of waste that occurs with the current system;

6. Support growth in low income resiliency programs that benefit community stakeholders;

7. Support the creation of community owned and managed micro-grids; and

8. Give consumers greater control over where their electricity comes from and how it's managed.[12]

C. Raymond Stanton

5. On March 7, 2017, Mr. Stanton submitted a public comment in support of MEDSIS.[13] He agrees that the Commission is doing good work and stated that "low-income access to solar is improving" and that "modernization has far to go."[14]

D. ThinkEco

6. On March 24, 2017, ThinkEco submitted comments supporting the Commission's plan in Section VII of the Report and offers their experience to aid any Commission stakeholder proceeding, in the design and implementation of new technology pilots or demonstration projects.[15] ThinkEco is the leading utility provider for demand- side management ("DSM"), energy efficiency ("EE") and demand response ("DR") for all non-central air conditioning ("AC") units, for residential, low income, multifamily and small business market segments.[16] In general, ThinkEco believes that all DSM program customer education and marketing that can be done before actual program implementation is beneficial to future program participation and

12 DC SUN's Comments at 5.

13 Raymond Stanton's Comments.

14 Raymond Stanton's Comments.

15 ThinkEco's Comments.

16 ThinkEco's Comments at 1.

performance and also believes that having marketing goals per rate class is even better. ThinkEco emphasizes the linkage between variable rates, new technology and savings performance is important, so customers understand they can have more impact (savings) when the two levers are employed together.[17]

7. ThinkEco also asserts that in their experience of designing and managing residential DSM programs in many jurisdictions across the US, collaborative planning and design sessions with stakeholders and the Commission participating, yields the best program results.[18] Regarding best practices for marketing DSM programs, the company employs traditional and non- traditional marketing techniques, such as email and direct mail, website and print, phone apps, as well as social media (Facebook and Twitter). ThinkEco has recently introduced a Points & Rewards platform which is a customer engagement tool offered across their utility program universe, which has shown great results in increased customer engagement, DSM participation, and program satisfaction.[19]

E. <u>NRG Energy, Inc.</u>

8. On April 7, 2017 NRG Energy, Inc. ("NRG") submitted comments supporting the Report's approach to ensuring that the underlying regulations are clear and will facilitate consumer and third party investments and actions to implement DER, and the proposed pilot project grant program.[20] NRG is the nation's largest independent power producer, with a diverse resource mix that includes approximately 50,000 megawatts of both renewable and conventional generation, including approximately 15,000 megawatts located in the PJM Interconnection.[21] NRG believes that the MEDSIS initiative is a positive step toward their vision of a "four-product" future consisting of four major elements; renewables, storage, controllable demand and fast-ramping gas.[22]

9. As a competitive supplier of electricity and supplier/aggregator of DER solutions, NRG asserts that the Report correctly concludes that utility ownership of DERs should be extremely limited.[23] From a competitive standpoint, NRG asserts that it is "clear that utilities do not belong in the DER market and it is also inappropriate for utility-affiliated competitive suppliers to compete for DER projects because that prospect would make it highly likely that some potential competitors would forego the District's electricity marketplace altogether, diminishing the range of choices available to customers and thwarting the potential for MEDSIS to achieve its

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[17] ThinkEco's Comments at 1.

[18] ThinkEco's Comments at 1.

[19] ThinkEco's Comments at 1.

[20] NRG's Comments.

[21] NRG's Comments at 2.

[22] NRG's Comments at 3.

[23] NRG's Comments at 4.

objectives."[24] NRG suggests that the most prudent course for the District and its regulated utilities is to be extremely careful to deploy utility investment only toward those functions that are uniquely and specifically related to the mission of the regulated monopoly delivery service, and to encourage consumers and third parties to provide the investment in DERs and other services that competitive suppliers are capable and eager to provide.

10. NRG supports the Report's proposed pilot project grant program as a means to encourage near-term deployment of a variety of DER technologies and business models in a variety of use cases but as currently structured, the program appears to impose a heavy regulatory and reporting burden on projects, which may deter some project proponents, and will lead to unnecessarily high costs.[25] NRG recommends that the final grant program design be more carefully calibrated to ensure that it contains only the minimal regulatory oversight and data reporting needed, and that any incremental costs associated with satisfying grant requirements that would not occur in a commercial project are covered by grant funding, in keeping with the intent that projects funded through this program are intended to be the basis for market-based expansions going forward, which will be governed by commercial agreements among counterparties as opposed to being subject to a highly regulated structure.[26]

11. NRG also recommends that the final grant program include an explicit recognition that the objective of all pilot projects should be to expand and become self-sufficient market-based DER offerings requiring all projects to identify regulatory or other barriers that need to be addressed to enable the demonstrated DER and its associated business model to fully monetize their capabilities and be successful on a commercial basis. NRG asserts that the PJM wholesale markets provide a significant source of long-term value and revenue, and as such suggests that the grant program should generally favor projects that will access PJM markets to earn revenues, as these projects are more likely to find a near-term path to financial sustainability.[27] The Commission should also include in the structure of the grant program consideration of how project proponents will be able to scale the projects up beyond the initial demonstrations, and that the Commission will facilitate regulatory changes identified by project proponents to enable that scaling.[28]

12. The Report recommends that three types of projects not be eligible for MEDSIS Pilot Project grant funding and NRG supports the exclusion of energy efficiency and utility-sponsored projects from the grant program.[29] However, NRG believes that the Commission should clarify what constitutes an "unproven" technology, and ensure that late-stage developmental technologies that have been proven on the bench but not necessarily in commercial operation can

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24 NRG's Comments at 4.

25 NRG's Comments at 6.

26 NRG's Comments at 6.

27 NRG's Comments at 6.

28 NRG's Comments at 6.

29 NRG's Comments at 7.

participate.[30] An objective distinction between "proven" and "unproven" technologies would ensure that proposed DER devices and systems meet safety and other basic requirements, while not precluding innovative applications of technologies that are not yet in common use.[31]

13. NRG suggests that the Commission clarify and specify its requirements for sponsor funding at each stage, including whether there is a requirement for sponsor funding in the Feasibility Study phase, and whether the specification of "a majority" require that 50.1% of the project costs in the later stages is sponsor-funded. In addition to the grant funding, NRG recommends that the Commission consider facilitating additional support that these early-stage demonstrations may require in order to secure financing and proceed to implementation.[32] And last, a matter that the Report appears to be silent on, NRG recommends that scheduling and dispatch control of the pilot project DERs rest with the project proponent, subject to voluntary agreement with the utility or a third-party aggregator.[33]

F. <u>GRID2.0 Working Group</u>

14. On April 7, 2017, GRID2.0 Working Group submitted comments stating that the Report is "strong in a narrow range of issues . . . however it is deficient in important respects"[34] Grid 2.0 reasserts eleven principles that should be incorporated into the goals for MEDSIS which are as follows:

1. Solutions should be technology neutral.

2. MEDSIS should optimize tariff structures to enable and expedite technology adoption and other desirable policy prescriptions.

3. Policy prescriptions should align utility incentives to public interest outcomes as identified in DC statutes and the DC Sustainability Plan,

4. Growth in energy demand is no longer the key dynamic around which the grid should be designed. Reduction of CO2 intensity in the power supply should be among the key dynamics identified for grid design.

5. Optimization of DER on the distribution, transmission, and generation elements of the District's electric grid should be a value function of location; set by the PSC, and periodically balanced as necessary.

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[30] NRG's Comments at 7.

[31] NRG's Comments at 7.

[32] NRG's Comments at 7.

[33] NRG's Comments at 8.

[34] GRID2.0's Comments at 2.

6. MEDSIS should articulate a pathway toward net zero energy demand/use in DC.

7. MEDSIS should reduce energy demand burden for lower income DC Residents.

8. Substantive stakeholder involvement in the utility planning process – independent of the PSC and docketed cases.

9. Energy democracy should be a hallmark of grid design such that DER and innovation distribute wealth and benefits to both DC citizens and the grid, and are integrated within the current system without bias.

10. Characterization of the Energy Services Platform Provider should address what role the distribution utility should play in load management and DER, and whether this role should be opened to competitive bidding.

11. Active public-sector involvement in PSC cases should be enabled through a fund to support expert and professional assistance.[35]

15. GRID2.0 believes that any deficiencies in the Report can be advanced and completed through implementation of the stakeholder working group recommended by Commissioner Beverly but recommend that the working group must be held to milestones and a timeline as there can be no other way that fairly considers the merits and legitimate claims of competing interests.[36] In addition, GRID2.0 states that sustainability is not defined and that it is not obvious that there is unanimity on the measurable outcomes of "sustainability."[37] GRID2.0 offers brief replies to the following points as requested on pg. vii the Report:

- *Staff has appropriately set out the scope of the Commission's jurisdiction* – In part, however, the PSC's avoidance of issues, such as tariffs, leaves open a large range of issues for which there is no description of the PSC's authority.
- *Staff's discussion of microgrids in the District in relation to the Commission's jurisdiction and other statutory and regulatory requirements is correct* – see above, this also requires further discussion.

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[35] GRID2.0's Comments at 1-2.

[36] GRID2.0's Comments at 2-3.

[37] GRID2.0's Comments at 2.

- *The proposed pilot project grant funding parameters are appropriate* – possibly, but this initiative is premature in advance of stakeholders' agreement on the goals of MEDSIS and thus the scope and objectives of the pilot projects. This should not be presumed by the PSC staff. It should be a description of a (short & succinct) process of discovery.
- *The proposed implementation timetable is appropriate* – disagree, as the stakeholder process needs to be incorporated on the front end.
- *Additional information needs to be provided in the Annual MEDSIS Status Report, besides what is proposed in Table 8* – reserve response for a later date following stakeholder working group meetings.[38]

G. Alevo USA Inc.

16. On April 10, 2017, Alevo USA Inc. ("Alevo"), a U.S.-based manufacturer, project developer and systems integrator of lithium-ion batteries with experience installing grid-scale battery projects filed comments on the report applauding the Commission on their work developing a strategy for Grid modernization.[39] Alevo first encourages the Commission to inquire how energy storage might be more cost-effective than traditional distribution investments in the District of Columbia.[40] Alevo asserts that at the distribution level, energy storage technology can help integrate renewables, ensure power quality and provide backup power to customers on critical circuits, among many other uses.[41] The technology can also be utilized behind the meter to help electric customers optimize their electric bills and bridge the gap to backup generators used for mission critical infrastructure.[42] Alevo encourages the Commission to encourage stakeholders to develop a framework that can be utilized to evaluate the cost-benefit of all proposed distribution investment such that it can be compared to potentially more cost-effective non-traditional technologies.[43] Alevo also recommends that the Commission consider battery flammability in developing use cases for battery storage within the District. Given D.C. being a highly-populated city adjacent to critical infrastructure, it would be prudent for the Commission to consider the flammability of energy storage devices to be deployed due to the well-documented risks of certain battery chemistries. [44]

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38 GRID2.0's Comments at 3.

39 Alevo USA Inc.'s Comments ("Alevo's Comments").

40 Alevo's Comments at 2-3.

41 Alevo's Comments at 3.

42 Alevo's Comments at 3.

43 Alevo's Comments at 3.

44 Alevo's Comments at 3.

17. Last, Alevo suggests that the Commission encourage Pepco to develop an integrated strategy that will determine the most cost-effective distribution grid for ratepayers in the District of Columbia. They assert that by completing an Integrated Distribution Plan (IDP), Pepco will be able in real time to determine the optimal combination of distributed energy resources (DERs) with traditional investment that will lead to a flexible, resilient, safe and cost-effective grid.

H. Department of Energy and Environment by Office of the Attorney General

18. On April 10, 2017, the District's Department of Energy and Environment ("DOEE") filed comments on the Report expressing its concern for the lack of progress and clear direction for MEDSIS as outlined in the Report.[45] DOEE states that the Report lacks a vision of what a modernized system should look like for the District, fails to lay out a roadmap for modernizing the system and that more sufficient guidance from the Commission is needed to achieve modernization of the system and accomplish key District legislative mandates and executive orders.[46]

19. DOEE has laid out key issues along with its recommendations in its comments. First, DOEE expresses that the Report lacks a vision and a roadmap and recommend that the Commission develop a vision and a roadmap through a stakeholder process facilitated by an independent grid modernization expert.[47] To address these key issues of a vision and a roadmap, DOEE recommends convening a stakeholder workshop, in agreement with Commissioner Beverly's statement, and given the complexity of this work, the Commission should hire an independent expert on modernization for facilitation. Second, DOEE asserts that the Commission should consider data-driven resource planning and evaluation and recommend developing a distribution resource planning process and develop a process for soliciting and evaluating non-wires alternatives with respect to infrastructure planning, based on the consensus of stakeholders and the Commission.[48] DOEE goes on to state that the distribution system plan should include all the information necessary for stakeholders to review and provide input on, and the Commission to make findings on, the distribution utility's plan for investing in DERs and distribution infrastructure for the next five years.

20. Then, DOEE asserts that the Report unnecessarily limits the scope of topics ripe for discussion in this proceeding and recommends the Commission allow the stakeholders and Staff to discuss all necessary concepts and tools for furthering the work of FC 1130.[49] Next, DOEE states that key concepts and tools must be explored and piloted and recommend the Commission identify key concepts, analyses, and projects to achieve modernization of the District's energy delivery system. This list should include the following: scenario and alternatives analysis using

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45 DOEE's Comments.

46 DOEE's Comments at 1.

47 DOEE's Comments at 11.

48 DOEE's Comments at 15.

49 DOEE's Comments at 20.

grid modeling, DER aggregation, time-varying rates, performance-based incentives, district energy including microgrids, and energy storage including battery storage.[50] And Last, DOEE asserts that the Report's recommended action items are inadequate and therefore recommend that the Commission expand the list of action items to include those recommended by DOEE and those in Commissioner Beverly's Statement, as well as provide an implementation timeline.[51]

I. Center for Renewables Integration

21. On April 10, 2017, The Center for Renewables Integration ("CRI") is a nonprofit team of energy professionals that works to provide state policymakers with the information needed to put rules, regulations and market mechanisms in place that support a rapid pace of renewables deployment, enabled by battery storage and advanced controls. CRI submitted comments generally applauding the Report and in general support of the definitions of technologies in the Draft NOPR proposed for inclusion.

22. Regarding the Report's Grant Funding Qualification Parameters, CRI agrees with Staff that the Commission should set priorities for the pilot project program, and submits that the policy priorities emphasized above are particularly important given the District's aggressive goals for solar power deployment established in the District's Renewable Portfolio Standard (RPS). CRI believes that MEDSIS should place significant emphasis on enabling high penetration solar given the District's aggressive RPS goals as the Districts 2032 requirement that 5% of the City's generation come from solar facilities located within the District or in locations served by a distribution feeder serving the District, does not represent the full potential for solar deployment.[52] CRI also suggests that the Commission place a priority on secure, and accessible, data modeling, collection and analysis regarding District's distribution grid and having a common model to use to analyze the data and evaluate the results will help ensure the success of the pilots. Ideally, at the end of the MEDSIS pilot phase, CRI hopes that enough data will have been collected from the pilots to inform long-term policy decisions that will enable the District to achieve the MEDSIS goals. To achieve that outcome, CRI asserts that the Commission will need to ensure that each set of pilot projects is designed to test for specific outcomes and gather objective data – both on the technical performance of DER as well as their cost and value.

23. CRI recommends that the Commission dedicate a portion of the MEDSIS funds to create "simulation projects" on individual distribution circuits that would aggregate high-penetration solar together with battery storage, smart inverters and distributed energy resource management systems. CRI also recommends, that MEDSIS pilot funds be used to gather data that can inform future ratemaking decisions. In particular, CRI recommends that the Commission undertake economic evaluations that include investigating "local distributed generation capacity value" of DER, pilot that specifically include projects that provide solutions for distributed voltage control and reactive power management, evaluate the role of time-of-use retail rates in advancing DER adoption and implementing pilots that specifically target placing storage at different point on

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[50] DOEE's Comments at 21.

[51] DOEE's Comments at 27.

[52] CRI's Comments at 5.

the distribution grid with the explicit objective of determining the economic value of the storage at those various locations.[53]

24. CRI concurs with Staff's recommendations on interconnection issues that should be addressed but suggests, however, that additional issues should be addressed as well.[54] Specifically, CRI recommends that interconnection guidelines should include explicit provisions relating to smart inverters, and that the evaluations performed in Pepco's interconnection process should begin to incorporate analysis of the potential impacts of storage, smart inverters and DERMS on increasing hosting capacity and lowering interconnection costs.

25. CRI recommends that Pepco begin to evaluate the potential impacts on its evaluation criteria and its hosting capacity maps of the deployment of storage, smart inverters and DERMS because the use of these companion technologies will be needed to increase hosting capacity.[55] Additionally, CRI recommends that the Commission also require Pepco to study the alternatives for DERMS, separate and apart from any testing. To conclude, CRI recognizes that the Commission does not have the ability to dictate the electricity products that PJM designs, but suggests that the Commission consider exploring with other PJM state Commissions, whether the California Independent System Operator ("CAISO") experienced with high-penetration solar and the duck curve warrants exploring the need for fast ramping generation services in PJM.[56]

J. PJM Interconnection LLC

26. PJM Interconnection, LLC ("PJM"), the Regional Transmission Organization (RTO) that coordinates the movement of wholesale electricity in all or parts of thirteen states and the District, submitted comments on April 10, 2017 generally looking forward to collaborating with the Commission and Pepco in MEDSIS.

27. In order to maximize the benefits of DERs, PJM would welcome the opportunity to work with the District and Pepco to consider how the location and operation of both dispatchable and non-dispatchable DERs may be made known to PJM, and to consider whether and how PJM may be able to call upon dispatchable DERs (through Pepco or other aggregator) if such resources could alleviate reliability issues on the wholesale grid.[57]

28. PJM asserts that any ability to receive telemetered output data (even aggregated data) through coordination with Pepco (and the other EDCs across the PJM region) or the resource developers/aggregators would greatly enhance PJM's forecasting capabilities and benefit reliability, market and transmission build out efficiency. PJM therefore encourages the Commission to consider how additional information and data may be provided to PJM to achieve

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53 CRI's Comments at 7-10.

54 CRI's Comments at 10.

55 CRI's Comment's at 12.

56 CRI's Comment's at 13.

57 PJM's Comments at 3.

the reliability and efficiency benefits. PJM also urges the Commission to consider revising its rules in the future so that ride- through functionality is required and suggests that one approach to this may lie in a future revision of the IEEE 1547 standard.[58] PJM would welcome the opportunity to work with the Commission and stakeholders to study any revised IEEE 1547 standard and to craft a DER interconnection rule that includes both voltage and frequency ride through.

29. PJM welcomes the opportunity to work with the Commission and stakeholders on the MEDSIS Pilot Project program and encourages the Commission and pilot project review board to look favorably upon proposed projects that seek to provide reliability benefits to the bulk power system through greater visibility and situational awareness of their operation, as well through utilization of smart inverter technology.[59] PJM also requests, to the extent that the Commission decides to convene a working group or establish a stakeholder Board, that the Commission invite PJM's participation and suggests that the Commission draw upon their expertise and experience in integrating all types of generation and storage resources as it evaluates an integration and operational plan to maximize the benefits of the District's DER deployment.[60]

K. <u>DC Climate Action</u>

30. DC Climate Action ("DCCA") filed its comments on April 10, 2017 agreeing that the Report has many strengths but focuses its comments on aspects that can be improved, the process and the substance. In terms of the process, DCCA agrees with Commissioner Beverly's suggestion of a working group to engage in a reasoned discussion of the substantive issues raised in the comments on the Staff Report, and to agree on ways to resolve those issues.[61] DCCA asserts that stakeholders would bring different perspectives, knowledge, and interests to the table that can be expected to fill the identified gaps in the Report through constructive dialogue and generate new ideas and solutions. [62] DCCA believes that such a working group should be given three to four months to resolve the identified issues or report the different arguments and positions.[63]

31. DCCA has many concerns regarding the substance of the Report. First DCCA welcomes framing of the MEDSIS goals provided by Commissioner Beverly's statement in which he states that "the MEDSIS proceeding should be directly aligned with and in support of the District's executive policy and legislative mandates" which deal with clean energy and reduction of carbon emissions.[64] DCCA states that the Report is uneven in its reference to these mandates and that the sustainability goal that they address, and the mandates by which they address it, should be treated consistently as a guide star in choices on distribution system modernization.

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58 PJM's Comments at 5.

59 PJM's Comments at 5.

60 PJM's Comments at 5.

61 DCCA's comments at 1.

62 DCCA's comments at 2.

63 DCCA's comments at 2.

64 DCCA's comments at 2.

32. DCCA believes that the Report is unclear on how to choose among potential pilot projects, which is an issue that should be on the agenda of the proposed working group and that project selection criteria should make it clear that pilot projects are for learning what we do not already know. [65] Also, DCCA asserts that Pilot projects that use software systems to help managers (including utilities and regulators) make choices on policies or investments should also be considered and that the pilot project sub-account should be open to selective reviews of what has been learned already from other jurisdictions' work on distribution modernization.[66]

33. Furthermore, DCCA suggests that the criteria for project selection should also include the potential for synergies between different pilots. DCCA believes that the Report's proposal that pilot projects be required to fit into the existing long-term plans of our electric and gas utilities should be relaxed or clarified to say that pilot projects must offer a better way to address a problem that the District and its utilities face. DCCA also recognizes that the Report could not address certain important issues regarding rate design, regulatory models, and system planning and design, but it should, however, make provision in the MEDSIS strategy for these areas to be considered, because they affect greatly the optimal distribution modernization path.[67]

34. DCCA goes on to suggest that the Report offer more discussion of the District's special characteristics that give it jurisdictional advantages as well as more detail on the opportunities enabled by new technologies to improve power distribution system efficiency for energy savings and cleaner energy including Volt/VAR Optimization, Advanced ("Smart") Inverters and Gas Distribution system planning. [68]

L. Apartment & Office Building Association

35. On April 10, 2017, The Apartment and Office Building Association of Metropolitan Washington, ("AOBA"), filed comments supporting the efforts of the Commission but with some concerns about the Report. AOBA is concerned that there is an absence of data regarding the costs of MEDSIS initiatives discussed in the Staff's Report and therefore encourage the Commission, stakeholders and the District of Columbia Government to develop budgets for the proposed initiatives and recommendations in the Report and determine with specificity, how the initiatives are financed, who pays and the impact on consumers.[69] AOBA is also concerned that ratepayers will burdened with higher utility rates in order to transform the electric distribution system and DOEE's Clean Energy DC and Climate Ready DC reports are important barometers on the scope of the core issues of concern to AOBA and its members. AOBA asserts that "there

65 DCCA's comments at 3.

66 DCCA's Comments at 4.

67 DCCA's Comments at 5.

68 DCCA's Comments at 5-8.

69 AOBA's Comments at 2-3.

is a clear need for the Commission to prevent escalation of utility rates, and to hold harmless ratepayers who remain committed to the electric grid."[70]

M. Constellation Companies and Exelon Generation Company, LLC

36. On April 10, 2017, Exelon Generation Company, LLC ("ExGen"), Exelon Microgrid, LLC, along with the following ExGen subsidiaries: Constellation NewEnergy, Inc., Constellation Energy Power Choice, LLC, Constellation Energy Nuclear Group, LLC, and BGE Home Products & Services, LLC ("Constellation") (collectively, "Constellation/ExGen") filed its comments on the Report applauding the Commission's investigation into MEDSIS. Given that ExGen is a wholesale supplier, the Constellation entities provide competitive retail services and that the bulk of the Report focuses on the delivery system, the comments submitted were "narrowly focused on a few issues that impact the abilities of ExGen to continue to ensure the adequacy and availability of a sustainable generation supply and of Constellation to continue to partner with the District's customers to deliver innovative competitive products that are reliable, efficient and cost-effective."[71]

37. Constellation/ExGen asserts that the Commission should not restrict from the procurement process, pilot projects proposed and led by unregulated subsidiaries and affiliates of regulated utilities. Instead, all market participants should be eligible to participate on a level playing field for pilot project initiatives to lead to innovative and cost-effective results. Constellation/ExGen appreciates the Staff Report's recognition that MEDSIS should not come at the expense of important policies such as retail choice, however, given the complexity associated with ensuring retail choice in each of the several microgrid types discussed in the Staff Report, Constellation/ExGen acknowledged that this issue will require continued stakeholder deliberation. Constellation/ExGen encourages stakeholders to recognize the value associated with allowing the end use customer to choose to participate or not in a microgrid when possible.

N. The Microgrid Resources Coalition by Drinker, Biddle and Reath

38. On April 10, 2017, the Microgrid Resources Coalition ("MRC") filed comments "strongly support[ing] the Staff and Commission's efforts to explore a modernized grid through a stake-holder process" however highlighting the need to protect microgrid development models supported by existing regulations while exploring new frameworks. The MRC is a consortium of microgrid owners, operators, developers, suppliers, and investors "formed to advance microgrids through advocacy for laws, regulations and tariffs that support their access to markets, compensate them for their services, and provide a level playing field for their deployment and operations."[72]

39. The MRC encourages the Commission to explore regulatory frameworks that foster the development of microgrids, and other advanced DER. MRC asserts that this exploration should include examining the development of distribution grid sensory measurement and control

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70 AOBA's Comments at 10.

71 Constellation/ExGen's Comments at 3.

72 The MRC's Comment's at 3.

infrastructure to enable distributional utilities to coordinate the procurement of services from flexible and dispatchable distribution level resources to provide ratepayers more reliable and dynamic services.[73] The MRC stresses the importance of maintaining what works under the current framework as the Commission explores its evolution. The MRC is concerned that the Report takes a limited view of the potential benefits of microgrids and should offer more recognition of the value microgrids are able to provide to the broader grid and therefore encourages Staff and the Commission to recognize that the same operational flexibility that provides benefits to their hosts makes microgrids uniquely suited to create efficiencies for the grid. The MRC also notes that microgrids are economically feasible given that a microgrid will allow for far more monetizable value than simply supplying less expensive commodity power.

O. Environmental Defense Fund

40. On April 10, 2017, Environmental Defense Fund ("EDF") filed comments on the Report commending the Commission's work and encouraging the Commission to craft a path towards grid modernization that is responsive to the unique characteristics of D.C.'s energy market and that builds on the foundation laid by D.C.'s energy policies and goals.[74]

41. EDF believes that further guidance and transparent information-gathering is needed to give all stakeholders an opportunity to meaningfully engage on how grid modernization can be leveraged to help achieve D.C.'s energy objectives. EDFrecommends that the Commission initiate a robust stakeholder engagement process to develop definitions, scope, key questions and principles in alignment with Commissioner Beverly's statement on a collaborative or stakeholder working group.[75] EDF also believes that one common constructive foundation is the formulation of guiding principles and goals in the path towards grid modernization and further asserts that having a framework in place that clarifies principles and goals is critical because it also informs how regulators and stakeholders can identify and prioritize technologies, functions, and capabilities the future grid should offer to meet D.C.'s grid modernization objectives.[76] EDF then goes on to suggest that it would be in the interest of all stakeholders, to collaboratively develop a set of comprehensive metrics closely tied to policy goals that track and assess the progress made on objectives linked to on-going grid modernization investments.

42. EDF's comments also offer an overview of a selection of common grid modernization components; Customer Engagement and Data Access and Volt/VAR optimization ("VVO").[77] EDF explains that engaging all customers is crucial to optimizing the use of smart technology investments and to harnessing a modernized electric grid and that VVO has been an

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[73] The MRC's Comments at 3-4.

[74] EDF's Comments.

[75] EDF's Comments at 4-5.

[76] EDF's Comments at 5.

[77] EDF's Comments at 6.

integral component of grid modernization efforts across the country and therefore should have been mentioned in the report.[78]

P. United States General Services Administration

43. The U.S. General Services Administration ("GSA") filed comments on April 10, 2017 concurring with the Report's basic recommendations, and urging the Commission to develop a framework and schedule for conducting the contemplated rulemakings. GSA believes that the Reports does not recommend specific policy options for the Commission, appears to be designed primarily to move the MEDSIS process forward, and sets forth indefinite timelines for completing the recommended actions.[79]

Q. Mission: data Coalition

44. The Mission: data Coalition ("Mission: data"), a national coalition of over 40 technology companies delivering consumer focused data-enabled energy savings for homes and businesses, submitted comments on April 10, 1017. Overall, Mission: data is pleased that the Report discussed third party access to meter data, however, believes that the discussion was brief and therefore offered two points in support of data access so that customers can realize tangible benefits of the Advanced Metering Infrastructure (AMI) investments in the District. First, Mission: data strongly recommends that the Commission require periodic certification of Pepco's Green Button Connect My Data ("GBC") implementation. Mission: data asserts that the GBC standard is expected to be updated once every two or three years, so certification need only be completed on that timeframe, after a new standard is released.[80] Second, Mission: data asserts that DER providers must be able to trust the reliability of Pepco's GBC service and therefore, the Commission should consider a reliability, or "uptime," requirement in this proceeding.

45. Furthermore, Mission: data believes the Home Area Network ("HAN") for accessing real-time meter readings should be addressed in this case because it is integral to DER service delivery in the District and since real-time meter information is going to be utilized most heavily by DER providers.

R. Sunrun Inc.

46. On April 10, 2017, Sunrun Inc. ("Sunrun"), a residential solar provider operating in Washington, D.C. and numerous locations across the country, filed comments supporting the report's recommended actions. Sunrun asserts that although PV systems and energy storage are both separately listed, a system that includes both – otherwise known as solar plus storage – is not included. Sunrun's only recommendation regarding the MEDSIS Pilot Projects is for purposes of clarity, that Staff include solar plus storage systems in the list of DERs as it would be ideal for Pilot Project eligibility.

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78 EDF's Comment at 7.

79 GSA's comments at 7.

80 Mission: Data's Comments at 2.

S. Enerblu Grid Services, Inc.

47. On April 10, 2017, Enerblu Grid Services ("EGS") filed comments "strongly urg[ing] the Commission to proceed rapidly with implementation of the MEDSIS Pilot Project program as it is described in the staff report."[81] EGS believes that no benefit will be gained by postponing this vital MEDSIS component; on the contrary, delays at this stage in the proceeding will increase the risk of the losing critical elements of momentum and stakeholder focus.[82]

T. Office of the People's Counsel

48. The Office of the People's Counsel for the District of Columbia ("OPC") filed comments on April 10, 2017, asserting that it is "imperative that the Commission take a holistic approach to developing grid modernization programs and enacting rules through this case, which … addresses the panoply of issues impacting the District's energy delivery system by being informed through the participation of all relevant stakeholders.[83]

49. OPC submits, the Commission must: (1) provide a comprehensive roadmap for grid modernization to make way for efficient, cost effective and inclusive measures/programs; (2) encourage robust stakeholder dialogue and involvement in this proceeding, such that it will be reflective of the needs and desires of all DC communities (including low-income residents) to partake in renewable energy options; and (3) make prudent use of all resources dedicated to pilot projects and initiatives created through this proceeding to ensure equitable/affordable cost recovery for grid modernization.[84] To help achieve these objectives OPC agrees with Commissioner Beverly's recommendation that a MEDSIS working group or stakeholder board be established.[85]

50. OPC further asserts that the Commission must first address pending litigation impacting the MEDSIS Proceeding because the issues are very interrelated.[86] OPC also believes that the interconnection issues for all sizes of campus-style Behind Behind-the-Meter Microgrids need to be addressed. OPC also asserts that detailed distributed resource planning will be critical to the success of MEDSIS initiatives[87] and that the Commission should consider economic aspects, including rate-design, impacts of all MEDSIS Initiatives.[88]

81 EGS's Comments.

82 EGS's Comments at 1.

83 OPC's Comments at 2.

84 OPC's Comments at 2.

85 OPC's Comments at 2.

86 OPC's Comments at 13.

87 OPC's Comments at 15.

88 OPC's Comments at 16.

U. <u>WGL Energy Services, Inc.</u>

51. WGL Energy Services, Inc., a retail gas and electricity marketer and WGL Energy Systems, Inc., a provider of design build, energy savings, solar, fuel cell and combined heat and electric plant services (together "WGL Energy") submitted comments on April 10, 2017 supporting the Commission's work with MEDSIS. WGL Energy strongly supports the development and deployment of microgrids in the District as a way to enhance the resiliency and reliability of electric power supplies during macro grid outages as well as a way to economically and reliably serve consumers and businesses during normal weather periods.[89] WGL Energy also supports Commission policies and rules that encourage the deployment of microgrid projects, preserve and foster competitive energy markets in the District and introduce new opportunities for leveraging distributed energy technologies to provide consumers in the District with clean energy services at competitive prices.[90]

52. WGL Energy first asserts that localized generation and independent delivery systems allow microgrids to operate independently in Island Mode Operation when the macrogrid is down. WGL Energy goes on to state that the recommended actions in the MEDSIS Report raise issues that the Commission and the parties can address in future rulemakings and proceedings and provided comments on specific recommendations. WGL Energy strongly supports customer choice and believes it has provided significant benefits to consumers and businesses in the District but submits that Commission should recognize that microgrid service is a competitive alternative.[91] Because of its expertise and jurisdiction over regulated electric companies, WGL Energy would support a Commission role for insuring the safety and reliability of private microgrids, while the responsibility for the reliability of the local distribution grid would remain with the utility including requiring the microgrid provider to comply with interconnection standards established by the utility's tariff and to pay appropriate interconnection charges.[92]

53. WGL Energy further suggests that a licensed retail supplier of renewable microgrid generation would have to comply with the requirements of the District's RPS law, D.C. Code § 34-1431 *et seq*., and would continue to be required to comply with the Commission's fuel mix and emissions reporting requirements to customers.[93] WGL Energy disagrees that private sector microgrid operators should pay separate assessments for their microgrid operations and activities and does not believe that consumers of services from private microgrid providers would be subject to Commission consumer-protection processes and requirements, but should require a dispute resolution process that may also be agreed to submit to the Commission for review.[94]

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[89] WGL Energy's Comments at 4.

[90] WGL Energy's Comments at 4.

[91] WGL Energy's Comments at 6.

[92] WGL's Comments at 8-9.

[93] WGL's Comments at 9.

[94] WGL's Comments at 9-10.

54. WGL Energy asserts that there are clear benefits of having distributed sources of energy, including microgrid generation, provide ancillary services to wholesale electricity markets administered by PJM.[95] Section 4002 of the Small Generator Interconnection Rules (15 D.C.M.R. §4002) currently contains requirements for inverters to protect against the negative impact of two-way power flow between the small capacity generator and the distribution system. These requirements, according to WGL Energy, may serve as the basis for, or complement the development of, standard interconnection procedures that WGL Energy recommended in its MEDSIS workshop comments where it noted that there are no standard interconnection procedures for connecting microgrids or energy storage systems to the larger electric distribution grid in the District.

55. WGL Energy believes that in the development of microgrid policies and rules and any pilots, the Commission should not allow electric utility ownership of generation because if the utility could own generation with regulated cost recovery or otherwise recover microgrid generation costs from all distribution customers, competitive providers could not possibly compete with such a structure. WGL Energy submits there is no public policy reason for allowing the electric utility in the District to again own generation and that the Commission should not alter the current construct where the electric utility does not own generation and only provides electric supply as a default service through Standard Offer Service pursuant to competitive wholesale bid procedures that are well-established.[96]

56. WGL Energy suggests that the Commission establish a timeframe for the issuance of ATOs that is tracked by the Commission and create a process to mitigate delays either by imposing penalties or using other mechanisms. This process should also govern Pepco service change activities, including interconnection studies, service change requests, performance of service connections, and similar activities as the timely performance of these activities benefits both the private sector microgrid or distributed generation developer and the community at large.

V. <u>Potomac Electric Power Company</u>

57. On April 10, 2017, Potomac Electric Power Company ("Pepco") filed its comments in strong support of the Commission's MEDSIS vision.[97] Pepco asserts that there are five key concepts that it believes should be incorporated in the Commission's consideration and implementation of the Report.

58. First, Pepco suggests that a governance framework that recognizes different levels of regulatory oversight for sustainable DERs is appropriate.[98] Second, the Commission should ensure that the MEDSIS Initiative remains flexible and able to take into account developments

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95 WGL's Comments at 10.

96 WGL Energy's Comments at 13.

97 Pepco's Comments.

98 Pepco's Comments at 5-6.

occurring in other Commission proceedings and existing Pepco projects, as well as the results of early MEDSIS pilot funding and advancements in technologies.[99] Third, as the Commission considers the architecture of the future grid, the Commission should keep in mind that Pepco, with its existing infrastructure and experience, is best situated and qualified to operate and maintain an increasingly complex electrical system for reliability and resiliency, to securely manage two-way communications and distribute key information about system needs, and to administer customer data and key market Platforms.[100]

59. Next, the Commission should ensure that all users pay their fair share of the costs of maintaining and investing in that system and also ensure that the pricing of electric energy, distribution, transmission, and increasing grid services reflect actual costs and economic value, and encourage the development of new rate structures to ensure fair compensation.[101] Furthermore, Pepco asserts that the Commission must ensure that Pepco is compensated for the true cost of the electric distribution grid and the services provided as Pepco is entitled to fair and timely cost recovery of investments in MEDSIS.[102] Pepco also suggested that the Commission consider the effects of proposals in the context of the District's increased renewable portfolio standard ("RPS") requirements

60. In addition to the foregoing general comments made on the Report, Pepco proposes specific comments and recommendations on several issues. Pepco recommends that the Commission address several significant policy questions related to microgrid development, ownership and control and that the Commission should clarify that new rate designs are appropriately considered in a manner that would inform the MEDSIS proceeding, with rate impacts addressed in the evaluation of potential pilot projects. Pepco generally supports the preliminary framework for selecting, implementing and tracking potential pilot projects outlined in the Report, however, it recommends that the Commission adopt Commissioner Beverly's proposal to establish a Stakeholder Advisory Board and ensure that the Stakeholder Advisory Board has the opportunity to provide input.

61. In terms of Microgrids, Pepco asserts that a model where it owns, operates and maintains all distribution facilities serving customers within the footprint of an area microgrid would be optimal for advancement of District micro grids in light of its existing infrastructure and regulation by the Commission.[103] Also, to ensure safety and reliability, Pepco believes that both campus and area microgrids should be subject to review and approval under the Commission's small generator interconnection rules or, if applicable, PJM interconnection requirements.[104] Pepco further believes that Campus microgrid customers should be responsible for all costs

99 Pepco's Comments at 6.

100 Pepco's Comments at 7.

101 Pepco's Comments at 8.

102 Pepco's Comments at 9.

103 Pepco's Comments at 25.

104 Pepco's Comments at 25.

incurred to construct, interconnect, operate and maintain a campus microgrid, including upgrades to Pepco's distribution system to enable microgrid functionality and similarly, all costs associated with an area microgrid's DER and control systems should be recovered from the microgrid operator and the customers within the microgrid footprint.[105] Pepco goes on to suggest that the Commission consider the extent to which Pepco should be required to invest in distribution system upgrades to supply energy to microgrid customers if microgrid generation is not available when needed and the extent to which all customers, or only microgrid customers, should pay for such upgrades.

62. In terms of reliability and customer service, Pepco agrees that the EQSS and the CBOR should apply to microgrid distribution facilities; however, it asserts that data related to area microgrid operations during island mode should be excluded from the calculation of Pepco's reliability performance indices under the EQSS since the level of service provided to customers during such periods will be entirely dependent upon the performance of the microgrid's DER.[106] Furthermore, regardless of the ownership structure, microgrid operators should adhere to the design and safety standards applicable to the current electric distribution system, and those standards should apply to behind-the-meter microgrid infrastructure.[107] Pepco agrees with Staff's conclusion that the Company is not precluded from owning generation and that there is no need for Commission action regarding Pepco' s ownership of DERs where the generation from such facilities is used by Pepco to support the reliability of the distribution system.

63. In terms of the economic aspects of MEDSIS, Pepco states that the Commission may also want to give consideration to other options, including; Connection Charges, Standby Charges, Time of Use Distribution Rates, Critical or Dynamic Peak Pricing/Incentive Payments. Pepco supports the consideration of alternative rate designs in conjunction with MEDSIS pilot projects, at a minimum and believes that the integration of alternative rate designs with DER technologies should be an important consideration in the Commission's evaluation of potential pilot designs and funding.[108]

64. Pepco generally supports Staff's proposed pilot feasibility process and also supports Commissioner Beverly's recommendation to expand stakeholder input in the MEDSIS Initiative by establishing a Stakeholder Advisory Board. Pepco recommends that the Commission should ensure that the Stakeholder Advisory Board has the opportunity to provide input at key stages in the MEDSIS pilot funding process, including: (1) development of the competitive solicitation process; (2) evaluation of pilot proposals and project selection; and (3) ongoing monitoring and evaluation of funded pilot projects.[109]

65. Pepco also supports the Report's recommended use of a standard competitive solicitation process as the framework for the MEDSIS pilot funding process however, believes that

105 Pepco's Comments at 25.

106 Pepco's Comments at 27.

107 Pepco's Comments at 27.

108 Pepco's Comments at 32.

109 Pepco's Comments at 33.

the Commission should ensure that the pilot funding process is designed to facilitate dialogue between Commission Staff and the Stakeholder Advisory Board and provide the Commission with meaningful and timely recommendations in an efficient manner. In this regard, Pepco proposes that the Commission engage an independent consultant to develop and issue requests for proposals, subject to public review and comment, based on the funding parameters approved by the Commission.[110] With respect to grant eligibility, Pepco recommends that the Commission clarify that Pepco may also apply for MEDSIS pilot project funding independently or in partnership with third parties.[111]

W. Georgetown University Department of Energy & Utilities

66. On May 5, 2017, Georgetown University ("Georgetown") submitted comments on the Report after having participated in the MEDSIS Town Hall. Georgetown presented its planned microgrid initiatives on campus and identified ways in which it sought to work in support of MEDSIS.[112] Georgetown presented its comments in terms of support or disagreement with previously submitted comments by other parties.

67. Georgetown "strongly endorses the comments on Enerblu Grid Services, urging the PSC to rapidly proceed with the pilot project described in the MEDSIS Report and warning that there is nothing to be gained from postponing this vital component of MEDSIS" and further agree with Enerblu's comments that "the grant funding process outlined by the Commission staff already provides for an open and transparent means of project selection, with ample opportunity for stakeholder involvement.[113]

68. Georgetown also endorses the comments submitted by the Microgrid Resources Coalition, specifically in terms of procurement services and elaborates on certain suggestions. Georgetown believes it is important to mandate transparency by requiring that the utility publish real time information on grid congestion and sustainability and reliability concerns; to require multiple potential solutions and by considering private sector proposals alongside utility rate-based investments; to establish a local distribution grid market for third party assets to participate in the delivery of capacity and reactive power and to engage market participants by encouraging incremental innovation.[114] Georgetown also asserts that it does not, however, concur with the MRC agreement with the Staff report that aggregated distributed generation and non-contiguous microgrids should be ignored under the MEDSIS initiative because in some instances, it could be useful to the economics and purposes of the overall microgrid initiative to cross a public right of way.[115]

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110 Pepco's Comments at 33-34.

111 Pepco's Comments at 33-34.

112 Georgetown University's Comments.

113 Georgetown's Comments at 4.

114 Georgetown's Comments at 5.

115 Georgetown's Comments at 5.

69. Georgetown agrees with the MRC and the Report, which notes that "microgrid designs frequently include energy storage components, which may be used to deliver ancillary services to the grid in non-islanded mode" but also with the MRC comments disagreeing with the Report conclusion that "the storage capacity required to provide such ancillary services is likely to be larger than what is required to support islanding of the microgrid."[116] Like MRC, Georgetown does not see a basis for this conclusion. Georgetown also agrees that ancillary service provision is not reliant on energy storage and that other kinds of generation can also participate effectively in ancillary markets and look forward to exploring these technologies in the District.[117]

X. SunPower's Comments

70. On May 1, 2017, SunPower submitted its comments on the Report. SunPower, is a U.S.-based global technology company involved in every step of the solar system supply chain, with over 6,500 employees worldwide the world's highest efficiency solar photovoltaic panel technology, and an extensive national dealer network mostly consisting of locally-owned small businesses.[118] SunPower states that in the District it is developing commercial-scale solar projects in addition to supporting dealer companies actively developing residential and small commercial solar projects.[119]

71. Overall, SunPower focused on a NOPR in Attachment E to the Staff Report, specifically, SunPower supports adopting a definition of "Electrical Company" that clarifies that the term expressly excludes any person or entity distributing electricity from a behind-the meter generator to a single retail customer behind the same meter. SunPower believes this will clarify the difference between public utility entities and distributed generation systems.[120] SunPower also agrees with Staff's belief that the term electrical company should not be, nor was "intended to apply to renewable energy providers selling power to a single behind-the-meter customer."[121] Lastly, SunPower asserts that it recognizes that this recommended action would not change the dynamics of the District's renewable energy market, but it does provide legal clarification for renewable energy developers, such as SunPower, who would be interested in financing and building projects in the District.[122]

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116 Georgetown's Comments at 8.

117 Georgetown's Comments at 8.

118 SunPower's Comments at 1.

119 SunPower's Comments at 1.

120 SunPower's Comments at 1.

121 SunPower's Comments at 2.

122 SunPower's Comments at 2

B. Summary of Reply Comments

A. The GridWise Alliance

72. On May 10, 2017, The GridWise Alliance ("GridWise") submitted reply comments to the MEDSIS Staff Report with several recommendations.[123] GridWise points out the need for the Commission to identify its goals and objectives of its grid modernization evolution at the outset of this process and in addition, goals should then be aligned with policy objectives and rate structures – and other components of this overall process – which will help achieve results and avoid unintended consequences and help maintain a reliable and secure grid.[124] GridWise also expresses that having a framework in place that clarifies principles and goals is critical and short-, medium-, and long-term planning also are essential in developing the path forward, as is an open platform grid architecture that can accommodate a range of technologies and capabilities.[125] GridWise suggests that developing and implementing metrics to measure and verify progress toward achieving established goals are important, as well.

73. GridWise asserts that costs incurred to transform to an integrated, modern grid, and to maintain the grid, should be "allocated and recovered responsibly, efficiently, and equitably;" and, policy and regulatory frameworks should be developed to achieve these objectives.[126] Such models should take into account: market structure, regulatory barriers, and other such key considerations. GridWise supports a gradual transition to more dynamic rates, though urges a move toward more dynamic rates as soon as is practicable for that portion of customers for which it makes sense to do so. Also, GridWise believes that Time-of-Use rates should be flexible enough to accommodate changing characteristics of supply and demand over time and that both effective customer education and transparency will be critical to the success and adoption of any new rate structures. Furthermore, GridWise has developed policy principles that also represent a consensus of the cross-section of its membership, from which are drawn the following that pertain to rate design.

B. Constellation Companies and Exelon Generation Company, LLC

74. On May 10, 2017, Constellation/ExGen filed its Reply Comments in response to Comments filed on the Report. In their reply comments, Constellation/ExGen reaffirms its positions on the issues raised in its Initial Comments and seeks only to reply to certain related comments.

75. First, Constellation/ExGen seeks to reply to comments concerning proposed eligibility requirements for participation in the MEDSIS Pilot Program Fund procurement process that would unnecessarily prevent the program from reaching its full potential by restricting

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[123] GridWise's Reply Comments at 1.

[124] GridWise's Comments at 2.

[125] GridWise's Comments at 2

[126] GridWise's Comments at 3.

affiliates of utilities from participating.[127] Constellation/ExGen reiterates that the Code of Conduct governing utilities and their affiliates is in place to ensure a level playing field between utility affiliates and other market participants. And regarding the MEDSIS Grant Pilot Program, "because the Staff Report anticipates that the Commission, with the assistance of an advisory board, (and not the utility) will select the MEDSIS Pilot Project grant recipients, and selection criteria and parameters for a procurement process have been outlined, there is no rational basis to exclude participation by affiliates."[128]

76. Second, Constellation/ExGen highlighted in its Initial Comments the need for further stakeholder deliberation with regard to how to ensure that consumers can experience the benefits of microgrids without frustrating the intent of the District's retail choice mandate. Therefore, Constellation/ExGen asserts that determining policies to further microgrid development in the context of the District's competitive market mandate will be necessary as the Commission considers how best to categorize and oversee microgrid development in the District.[129]

C. <u>WGL Energy Services, Inc.</u>

77. On May 10, 2017, WGL Energy filed its Reply Comments in response to Comments filed on the Report.[130] WGL Energy reiterated that it supports the Staff's Recommendation that the Commission establish a robust stakeholder engagement process to identify and resolve the many issues that grid modernization will raise. WGL Energy believes a Stakeholder Advisory Board is a sound mechanism to provide input to the Commission on important issues and that the Commission can resolve issues on which a consensus cannot be reached and the Stakeholder Advisory Board can facilitate consensus where possible and identify non-consensus issues for the Commission to resolve in a timely manner.[131]

78. Given the wide-ranging unresolved issues indicated in the parties' comments, WGL Energy agrees with Grid 2.0 and others that pilot programs for microgrids are premature at this time as there is no MEDSIS vision for formulating valid pilot programs and furthermore agrees that the Commission should hold off on pilot programs until the stakeholder collaborative can weigh in on the parameters of the programs.[132] Also, MRC submitted comments encouraging the Commission to explore regulatory frameworks that will foster microgrid development and other DER and MRC supports a core proceeding to address the foregoing. WGL Energy supports MRC's position and believes that institution of the NOPRs recommended by Staff and a stakeholder process is consistent with MRC's position. WGL Energy also supports a stakeholder

127 Constellation/ExGen's Reply Comments at 2.

128 Constellation/ExGen's Reply Comments at 2.

129 Constellation/ExGen's Reply Comments at 4.

130 WGL Energy's Reply Comments.

131 WGL Energy's Reply Comments at 10.

132 WGL Energy's Reply Comments at 13.

integrated distribution system planning process that will enable Pepco to account for DER and non-wires projects that the market will bring to the District.[133]

79. WGL Energy agrees with Pepco's actions to modernize its distribution grid. WGL also agrees with MRC that the potential benefits of microgrids far outweigh potential negative impacts. Importantly, the electric utility can identify and resolve any potential negative impacts of microgrids, just as it does now when connecting behind the meter renewable generation to the grid today, if reasonable microgrid interconnection rules and procedures are adopted.[134] WGL Energy agrees that microgrid development should not adversely affect the Commission's successful retail choice program but that the definitions of an electric company and an electricity supplier should facilitate the advancement of microgrids with potential sales to multiple customers in the District, consistent with WGL Energy's prior comments.[135]

80. In its comments, Pepco asserts that the Commission's Electricity Quality of Service Standards ("EQSS") and the Consumer Bill of Rights should apply to microgrid distribution facilities in front of the customer's retail meter and WGL Energy does not fully agree with these views.[136] WGL Energy believes that the EQSS performance metrics just do not work for a microgrid serving significantly smaller customer bases, and therefore those metrics would require a substantial re-working to be equitably applied to such smaller systems.

81. WGL Energy does not support Staffs recommendation that unproven technology be excluded from pilot programs. Nor does WGL Energy support limiting the corporate structures that can provide these benefits. Any concerns that the Commission may have about cross subsidization or financial capabilities can be addressed through other regulatory approaches such as affiliate codes of conduct. Furthermore, WGL Energy sees no reason to exclude energy efficiency projects within the context of grid modernization. WGL Energy does not support the exclusion of electric utility affiliates from pilot programs.[137]

D. Potomac Electric Power Company

82. On May 10, 2017, Pepco filed its Reply Comments in response to Comments filed on the Report.[138] Pepco first discusses the proposals by several Commenters for additional stakeholder processes, the usefulness of the key concepts set forth in Pepco's April 10 initial comments in assessing future MEDSIS developments and then responds to specific issues in the Staff Report addressed by Commenters.

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133 WGL Energy's Reply Comments at 14.

134 WGL Energy's Reply Comments at 21.

135 WGL Energy's Reply Comments at 22.

136 WGL Energy's Reply Comments at 23.

137 WGL Energy's Reply Comments at 26.

138 Pepco's Reply Comments.

83. Pepco reasserts that initiating another stakeholder process creates significant risk of further delay in achievement of the purposes of MEDSIS already established by the Commission. Pepco believes that the Report provides the right approach to advancing the MEDSIS Initiative as the expedited notice and comment rulemaking process and detailed pilot program developed by Staff-combined with the MEDSIS pilot funding created through the Exelon-PHI Merger will accelerate the deployment of actual projects that can provide "real world" data and "proof of concept" evidence, which all stakeholders can build upon.[139] Pepco supports creation of a Stakeholder Advisory Board, with participation by community groups and specific responsibilities regarding recommendations for MEDSIS pilot program criteria and project selection, and suggests that in making recommendations regarding the MEDSIS pilot program, the Stakeholder Advisory Board should be free to consider all issues pertaining to the pilots.[140]

84. In its initial comments, Pepco identified six key concepts that various Commenters agree on the importance of many (if not all) of these key concepts, and therefore Pepco believes that those concepts should be adopted by the Commission. The six key concepts are (1) Application of different levels of regulatory oversight based on DER characteristics is appropriate; (2) The MEDSIS Initiative should remain flexible; (3) Core functions of the distribution system should remain with Pepco as the electric utility; (4) All users of the electric distribution system should pay their fair share of costs; (5) Pepco is entitled to fair and timely cost recovery of investments in modernizing the electric grid and implementing MEDSIS; and (6) Compliance with renewable portfolio standard ("RPS") requirements as MEDSIS advances.[141] Pepco believes that the key concepts identified can serve as useful criteria for use by the Commission and other stakeholders in the course of the MEDSIS Initiative in evaluating the merits of pilot projects and potential changes to the Commission's regulations.[142]

85. Pepco believes that it is appropriate for the Commission to provide some guidance in MEDSIS on microgrid issues for the MEDSIS pilot process and for those stakeholders who are considering the development of microgrids within the District. Pepco asserts that the Commission should support the development of public-purpose microgrids by Pepco in which both utility and third-party owned DERs can participate and in addition, the Commission should consider establishing acceptable parameters of service agreements between customers and microgrid operators in which the parties negotiate commercial terms for micro grid end-use services and address Pepco requirements.[143]

86. In regard to the economic aspects of MEDSIS, Pepco believes that concern regarding the absence of MEDSIS cost data, is premature and Pepco expects that the Commission will need to take affirmative steps to properly allocate the costs of grid modernization among

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139 Pepco's Reply Comments at 6.

140 Pepco's Reply Comments at 7.

141 *See* Pepco's Comments at 5-10.

142 Pepco's Reply Comments at 10.

143 Pepco's Reply Comments at 16.

customers through new rate options that reflect the full cost of a customer's use of the distribution system, which will be best addressed in future proceedings.[144]

87. On April 17, 2017, OPC released a "Value of Solar" ("VOS") study for the District, and while Pepco has not reached conclusions regarding the OPC VOS study, Pepco asserts that the Commission's analysis must include not only the value of solar but also a comparison of that value to the value that can be achieved through advanced grid infrastructure, energy efficiency, and other DER as well as more granular consideration of equitable allocation among communities and customers with varying levels of impediments to DER deployment. Pepco encourages the Commission to establish a schedule for comments on the OPC VOS study as part of MEDSIS, including a technical conference in which OPC's calculations and assumptions can be examined in detail before comments are submitted to the Commission.[145]

88. Pepco agrees with the Commission's MEDSIS Pilot Funding Process as is currently and therefore asserts that the Commission should refrain from adopting any limitations on the pilot process at this stage of the MEDSIS initiative. Pepco believes that further consideration of distribution system planning and modeling processes as well as revisions to interconnection regulations should await the Commission's resolution of those issues in other proceedings.[146]

E. DC Climate Action

89. On May 10, 2017, DCCA submitted reply comments in response to Comments filed on the Report. In regard to the Multi-Party Stakeholder process, DCCA wishes to emphasize "that this multi-party stakeholder group would develop governing principles with which 'concepts' such as those enumerated by Pepco in their Comments" and that the working group would help to ensure that best practices in other jurisdictions are given full consideration for adaptation to the District's circumstances. [147]

90. DCCA agrees with the concern of OPC in its initial comments on the Report, regarding the possibility of inadequate consumer protections should the Commission employ light touch regulation to facilitate rapid deployment of DERs in the District, and suggests that this possibility would have to be examined carefully along with potential protections.[148] DCCA also agrees with OPC, that "'detailed distributed resource planning will be critical to the success of MEDSIS initiatives' and that 'the criteria used for analysis of the electric grid capacity with DER [is] a critical issue moving forward.'" DCCA believes that these criteria should be established by the stakeholder group.[149]

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144 Pepco's Reply Comments at 19.

145 Pepco's Reply Comments at 20.

146 Pepco's Reply Comments at 23.

147 DCCA's Reply Comments at 1.

148 DCCA's Reply Comments at 2.

149 DCCA's Reply Comments at 2

91. DCCA asserts that to permit broad participation in the planning and development of DERs including microgrids, access to data by stakeholders is crucial, and DCCA agrees with the DCG's comments regarding data sharing. It also supports the opinion articulated by Georgetown in its Comments expressing that the Commission should mandate transparency and making existing and potential value streams available to the public to ensure competition on an equal playing field between third parties and public utilities.[150] Furthermore, DCCA believes that issues relating to the modernization of gas distribution systems (for natural gas, renewable methane) were underdeveloped in the Staff Report.

C. Additional Comments filed in MEDSIS Docket

Commission Staff notes that the following comments were also filed in the MEDSIS docket after the closing of the comment period on the MEDSIS Staff Report:

- September 6, 2017 – Comments of Raymond Nuesch on behalf of Community Power Network. In his comments, Mr. Nuesch urged the Commissioners to "move ahead with the MEDSIS process so that all D.C. ratepayers can benefit from a low-cost, reliable, and renewable energy system." Mr. Nuesch further asserted that "[t]he MEDSIS proceeding is our opportunity to develop an electric grid that benefits everyone in D.C." and that he is "disappointed that to date, so little has come from the process," noting that "[t]he Commission has committed to a process to re-write the rules of the grid, but so far [has] failed to deliver on that promise." Mr. Nuesch concludes: "It is time for the Commission to initiate a stakeholder process to establish rules, working groups, and a completion deadline that will more the process forward."[151]

- September 8, 2017 – Joint Comments of DC Consumer Utility Board ("DC CUB") and GRID2.0 Working Group ("Grid2.0") filed in FC1130 and FC1144. DC CUB and Grid2.0 assert that with "the Notice of Construction (NOC) detailed in FC 1144 it would appear that Pepco is not able to wait until a resolution of FC 1130 (MEDSIS) . . . Pepco's proposed $420M investment in the electric distribution grid will guarantee rate increases for DC rate-payers for some years to come. Neither the Commission nor smartgrid advocates are well positioned at this time to know what percentage of Pepco's proposed capital grid project might have been met more efficiently by smartgrid strategies such as demand-side management and distributed energy resources." DC CUB and Grid2.0 goes on to assert, "[a]lthough the NOC by Pepco doesn't completely obviate the utility of MEDSIS, it does successfully set aside any value that might flow from it in the near term . . . This is in some measure the result of the Commission's very slow response to the challenge of smartgrid technology." DC CUB and GRID2.0 recommend the idea

[150] DCCA's Reply Comments at 3.

[151] Community Power Network's Comments, filed September 6, 2017.

proposed by Commissioner Beverly to establish a "stakeholder committee to explore consensus options for advancing MEDSIS . . .[should] be employed to aid in defining how best to shape the 1130 RFP for smartgrid pilots." DC CUB and Grid2.0 conclude that "FC 1144 would need to be suspended until the completion of the 1130 stakeholder and pilot project" process.[152]

- September 28, 2017 – Comments of Mr. Glenn Griffin urging the Commission "to move ahead with the MEDSIS process so that all D.C. ratepayers can benefit from a low-cost, reliable, and renewable energy system. Mr. Griffin further asserted that "[t]he MEDSIS proceeding is our opportunity to develop an electric grid that benefits everyone in D.C." and that he is "disappointed that to date, so little has come from the process," noting that "[t]he Commission has committed to a process to re-write the rules of the grid, but so far [has] failed to deliver on that promise." Mr. Griffin concludes: "It is time for the Commission to initiate a stakeholder process to establish rules, working groups, and a completion deadline that will more the process forward."[153]

- October 10, 2017 – Comments of Mr. Roger Horton and Mr. Daniel Woodward urging the Commission "to move ahead with the MEDSIS process so that all D.C. ratepayers can benefit from a low-cost, reliable, and renewable energy system. Mr. Horton and Mr. Woodward further assert that "[t]he MEDSIS proceeding is our opportunity to develop an electric grid that benefits everyone in D.C." and that they are "disappointed that to date, so little has come from the process," noting that "[t]he Commission has committed to a process to re-write the rules of the grid, but so far [has] failed to deliver on that promise." Mr. Horton and Mr. Woodward conclude: "It is time for the Commission to initiate a stakeholder process to establish rules, working groups, and a completion deadline that will more the process forward."[154]

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[152] Comments of DC CUB and GRID2.0, filed September 8, 2017.

[153] Glenn Griffin's Comments, filed September 28, 2017.

[154] Mr. Horton and Mr. Woodward's Comments, each filed October 10, 2017.

Public Service Commission

of the

District of Columbia

Bi-Annual Report on Fuel Mix

July 3, 2017

Executive Summary

The Retail Electric Competition and Consumer Protection Act of 1999 requires the Public Service Commission of the District of Columbia ("Commission") to report to the Council of the District of Columbia ("District Council") every two years, beginning July 1, 2003, on fuel mix information for the electricity sold in the District of Columbia ("District"), the amount of electricity sold in the District that comes from renewable sources, and on the feasibility of requiring each licensed electricity supplier doing business in the District to provide a minimum percentage of electricity sold from renewable sources.[1] To collect the information necessary for this report, the Commission has adopted fuel mix disclosure regulations that require suppliers serving load in the District to report their most current fuel mix statistics supplied by the Regional Transmission Organization ("RTO") that provides service to the District, i.e. PJM Interconnection, L.L.C. ("PJM"). Twenty-eight (28) of the thirty-seven (37) electricity suppliers (including Pepco) serving customers in the District reported their fuel mix statistics to the Commission by the June 1, 2017 due date—with a total of thirty-three (33) reports filed by June 19, 2017. These reports are related to the PJM System Fuel Mix for 2016, which follows:

Fuel Source	Share
Coal	34.3%
Nuclear	34.7%
Natural gas	26.3%
Oil	0.2%
Total Renewables	4.5%
Total	100.0%

In 2016, the share of natural gas used to provide electricity increased to 26.3 percent from 23.0 percent in 2015, while the share of coal decreased to 34.3 percent from 36.6 percent in 2015. The share of renewable resources also continues to rise, although its share of generation still remains relatively small—around 4.5 percent in 2016 compared to 4.3 percent in 2015—with wind energy representing the largest share with 2.2 percent, followed by hydroelectric power at 1.0 percent.

The impact of renewable resources is not easily accounted for in the fuel mix reporting. The renewable resources component in the fuel mix for any particular year may be different from the same component in the RPS report for that same year because of the manner in which the RPS requirement is implemented. In particular, pursuant to the Commission's RPS rules, RECs are valid for three years from the date of generation. To the extent that an electricity supplier meets its RPS compliance requirement using RECs from a year different from the fuel mix reporting period, the renewable component should not be reflected in the report due to the difference in the date of generation.[2] In addition, District

1 D.C. Code § 34-1517(c) (2).

2 For example, if the fuel mix reporting period is for calendar year 2016 and the electricity supplier acquired some RECs associated with generation in 2015 to comply with the renewable portfolio standard, then the supplier's fuel mix report should not count the renewable resources associated with generation in 2015. The

consumers may enter into purchase power agreements for renewable resources that may not be directly reflected in the fuel mix reported by suppliers.

The District Council also enacted the Omnibus Utility Amendment Act of 2004 that, among other things, requires the Commission to determine the feasibility of an electricity supplier to disclose every six months emissions on a pound per megawatt-hour basis and the fuel mix of the electricity sold by that supplier in the District.[3] In September 2008, the Commission adopted final rules that require the electricity suppliers to file reports showing their emissions in pounds per megawatt-hour for carbon dioxide, nitrogen oxide and sulfur dioxide. The 2016 emissions disclosure available from PJM-EIS show a decrease in the amount of emissions from carbon dioxide, nitrogen oxide, and sulfur dioxide, compared to 2015. Based on the PJM System Fuel Mix, the 2015 and 2016 emissions are as follows:

Emissions (lbs. per MWH)

	2015	2016
Carbon dioxide	1014.29	992.04
Nitrogen oxide	0.78	0.75
Sulfur dioxide	1.61	1.32

The fuel mix and emissions information can help the District's customers make more informed choices when selecting their electricity supplier and help the District community monitor the environmental impacts of the fuel choices that are being made. This is becoming more important as residential consumers continue to choose alternative electricity suppliers. Currently, about 15 percent of the District's residential customers receive electricity supplied by an alternative supplier. The Commission will continue to monitor the fuel mix and emission reports to ensure that the information is being properly disclosed and to improve upon the reporting.

only RECs that should be included in the fuel mix report would be those renewable resources associated with generation in 2016.

[3] D.C. Code § 34-1504(c) (2)(A).

I. Introduction

The Retail Electric Competition and Consumer Protection Act of 1999 requires the Commission to report to the District Council every two years, beginning July 1, 2003, on fuel mix information for the electricity sold in the District. In the next section, Section II, we describe the reporting requirements for fuel mix and emissions that the Commission has implemented in the District. In Section III, we provide information on the PJM Interconnection's ("PJM")—the Regional Transmission Organization ("RTO") that coordinates the delivery of wholesale electricity to the District—fuel mix and renewable resources.[4] Finally, Section IV summarizes the Commission's ongoing activities. Selected orders relating to the Commission's rules on fuel mix and emissions reporting are included in Attachment 1.

II. Reporting Requirements for Fuel Mix and Emissions

A. Fuel Mix

Section 34-1517(c)(2) of the D.C. Code states that before July 1, 2003, and every two (2) years after that date, "the Commission shall provide a report to the Council on the overall fuel mix of the electricity sold in the District of Columbia, the amount of electricity sold in the District of Columbia which comes from renewable energy sources, and on the feasibility of requiring each licensed electricity supplier doing business in the District of Columbia to provide a minimum percentage of electricity sold from renewable energy sources."[5] In addition, Section 34-1517(b) of the D.C. Code states that every six (6) months, "each licensed electricity supplier doing business in the District of Columbia shall report to the Commission on the fuel mix of the electricity sold by the electricity supplier, including categories of electricity from coal, natural gas, nuclear, oil, hydroelectric, solar, biomass, wind, and other resources, and on the percentage of electricity sold by the electricity supplier which comes from renewable energy sources."

In Order No. 12765, issued June 13, 2003, the Commission adopted interim fuel mix disclosure regulations and approved the Retail Competition Working Group's recommendation that suppliers serving load in the District should report the most current PJM-supplied or self-determined fuel mix statistics by June 1 and December 1 of each year. In addition, the Commission directed suppliers to report to their District customers the fuel mix information in the June and December billing cycles of each year. Subsequently, in Order No. 13391, issued September 21, 2004, the Commission directed active suppliers to file a June fuel mix report that includes information for the previous calendar year and a December fuel mix report that covers the period January through June of the current year.

B. Emissions Disclosures

On January 31, 2005, the District Council enacted the Omnibus Utility Amendment Act of 2004, which became effective on April 12, 2005.[6] The Omnibus Act, among other things,

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4 This information is provided through PJM Environmental Information Services, Inc. ("PJM-EIS"), which was formed to provide environmental and emissions attributes reporting and tracking services to its subscribers. PJM-EIS owns and administers the Generation Attribute Tracking System ("GATS").

5 The Commission provides an annual report to the District Council on the electricity suppliers' compliance with the District's Renewable Energy Portfolio Standard.

6 *See* D.C. Law 15-342, Omnibus Utility Amendment Act of 2004.

amended several sections of the Electric Restructuring Act and required the Commission to determine the feasibility of an electricity supplier to disclose every six months emissions on a pound per megawatt-hour basis and the fuel mix of the electricity sold by that supplier in the District. In Order No. 13589, issued May 19, 2005, the Commission determined that the emissions information required by law is available from PJM. In addition, the Commission concluded that since suppliers are already providing the fuel mix information, it would be administratively efficient to require electricity suppliers to disclose the emissions information at the same time that they provide their fuel mix report. Based on information readily available from PJM, the Commission directed that electricity suppliers report on carbon dioxide, nitrogen oxide, and sulfur dioxide emissions by June 1 and December 1 of each year. Active electricity suppliers were also directed to provide this emissions information to their customers.

The Commission finalized the interim disclosure requirements in a rulemaking process. A Notice of Proposed Rulemaking ("NOPR") appeared in the *D.C. Register* on July 11, 2008, proposing rules governing the submission of fuel mix and emission disclosure reports by the Potomac Electric Power Company ("Pepco") and electricity suppliers and replacing the interim regulations recommended by the Retail Competition Working Group and later adopted by the Commission in Order No. 12765 (issued June 13, 2003), as well as other Commission directives. No comments were filed in response to the NOPR. A Notice of Final Rulemaking appeared in the *D.C. Register* on September 12, 2008, adopting the rules that appeared in the NOPR. The rulemaking notices are also included in Attachment 1. As a result of the final rules, electricity suppliers will provide more supplier-specific information about their fuel mix and will supply data about carbon dioxide, nitrogen oxide and sulfur dioxide emissions in pounds per megawatt hour. In the past, electricity suppliers generally submitted the PJM system mix information, which offers no differentiation among suppliers.

III. Fuel Mix, Renewable Resources and Emissions Disclosures

Figure 1 below provides the fuel mix available in the PJM region for 2012 through 2016.[7] Figure 1 also provides a perspective on the share of renewable resources in the PJM region associated with the generation of electricity. Based on Figure 1, the overall renewable resources in the PJM region in 2016 represents more than four percent of the available fuel resources.[8]

Figure 2 below provides additional details about the renewable resources in the PJM System Mix from 2012 – 2016. As of 2016, wind energy accounts for the largest share among renewable resources, about 2.2 percent. Among other renewable resources, hydroelectric power represents the second largest resource in 2016 and comprises roughly one percent. Hydroelectric power is counted as a Tier II resource under the District's renewable energy portfolio standard.[9] Methane gas and wood-related fuels account for approximately 0.3 and 0.2 percent, respectively, in 2016.[10] Overall, Tier I related resources—such as methane gas, solar and wind—still

[7] The PJM system mix represents the distribution of generating resources used to produce electricity in the PJM region and is used as a proxy to represent the fuel mix for the District of Columbia. A certificate is created for each megawatt hour of electricity generated. Suppliers may claim certificates from specific generators. Unclaimed certificates represent the residual mix of generation.

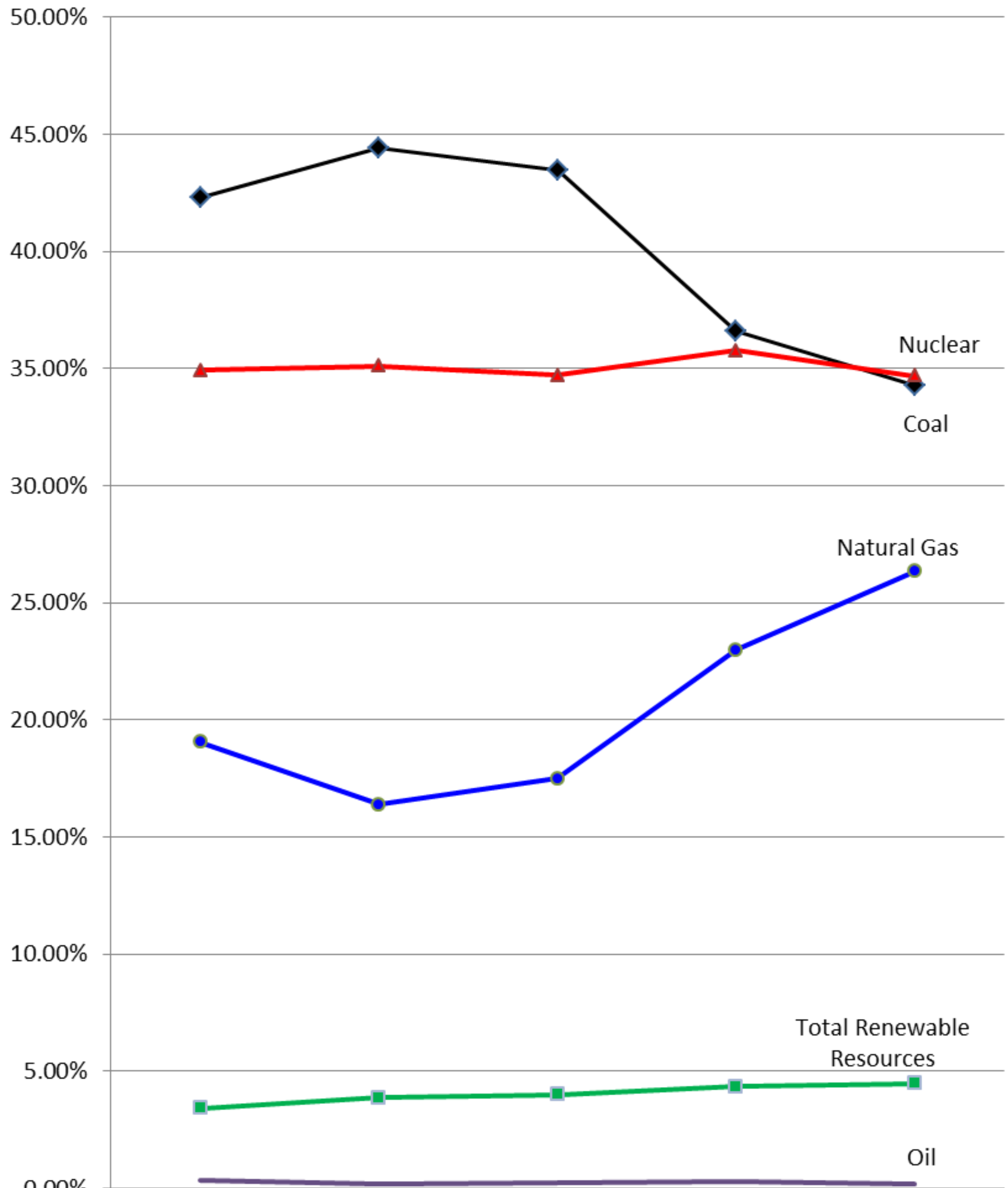
[8] The District's Renewable Energy Portfolio Standard requirement for 2017 calls for 13.5 percent from Tier I resources, with 0.98 percent from solar energy resources, and 1.5 percent from Tier II resources.

[9] Municipal solid waste is no longer eligible to meet the District's RPS requirement as of 2013.

[10] Coal mine methane gas is not generally eligible under most RPS policies.

represent a very small share of the current fuel mix in the PJM system—about 2.7 percent in 2016.

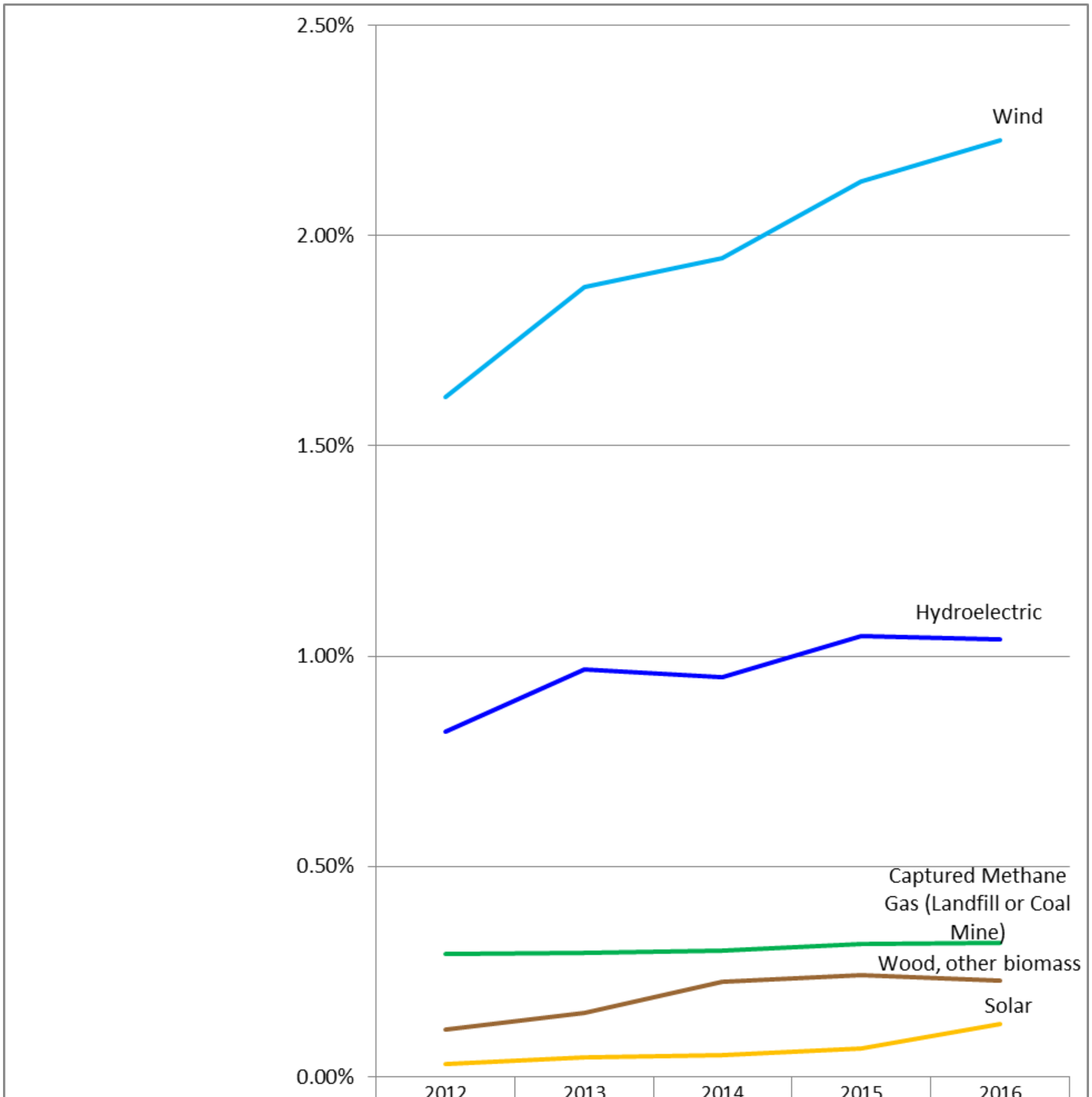
Figure 1: PJM System Fuel Mix
2012 - 2016



	2012	2013	2014	2015	2016
Coal	42.28%	44.43%	43.49%	36.58%	34.26%
Nuclear	34.93%	35.12%	34.72%	35.77%	34.70%
Natural Gas	19.06%	16.39%	17.51%	22.98%	26.34%
Oil	0.33%	0.19%	0.25%	0.28%	0.20%
Total Renewable Resources	3.40%	3.86%	4.01%	4.35%	4.46%

Source: PJM-EIS GATS

Figure 2: Renewable Resources in PJM System Mix
2012 - 2016



	2012	2013	2014	2015	2016
Captured Methane Gas (Landfill or Coal Mine)	0.29%	0.29%	0.30%	0.32%	0.32%
Solar	0.03%	0.05%	0.05%	0.07%	0.13%
Wind	1.62%	1.88%	1.95%	2.13%	2.23%
Wood, other biomass	0.11%	0.15%	0.23%	0.24%	0.23%
Hydroelectric	0.82%	0.97%	0.95%	1.05%	1.04%

Source: PJM-EIS GATS

* These percentages do not include solid waste, which is no longer considered a renewable resource for RPS purposes.

PJM has also begun to incorporate the impact of distributed solar photovoltaic ("PV") generation into its long-term load forecast. PJM uses the behind-the-meter ("BTM") solar PV data from its Generation Attributes Tracking system—adjusting for various factors—to remove the solar generation impact from its load forecast. This distributed solar impact is separate from the solar generation that is being transmitted in the wholesale market.

The District Council enacted the *Renewable Energy Portfolio Standard Act* ("REPS Act"), on January 19, 2005, which established a renewable energy portfolio standard ("RPS") that sets the minimum percentage of a District electric provider's supply source that must be derived from certain types of renewable energy resources beginning January 1, 2007.[11] The RPS minimum requirements, among other things, were amended by the Clean and Affordable Energy Act ("CAE Act") of 2008.[12] Subsequently, the District Council adopted new legislation, the *Distributed Generation Amendment Act of 2011* ("DGAA"), which substantially increased the RPS requirement for solar energy—up to 2.5 percent by 2023, compared to the previous requirement of 0.4 percent by 2020.[13] In addition, the DGAA generally prohibited certifying solar energy systems located outside the District of Columbia for RPS purposes. However, through the enactment of the *Fiscal Year 2015 Budget Support Act of 2014*, solar energy resources from other states are now able to meet the Tier I portion of the RPS requirement, but not the District solar carve-out requirement.

The enactment of the *Renewable Portfolio Standard Expansion Amendment Act of 2016* raised the RPS requirement to 50.0 percent from Tier I resources by 2032, with not less than 5.0 percent from solar energy. In addition, among other things, the 2016 Act amended the solar compliance fee and kept it at 50 cents per kilowatt-hour ("kWh") shortfall through 2023, before decreasing to 5 cents per kWh by 2033. Previously, the solar compliance fee was set to begin decreasing in 2017.[14] The 2016 Act also enables 15 MW solar energy systems in the District or in a location served by a distribution feeder serving the District, and no cap on the size of solar installations owned by District agencies, to be eligible for certification. The latter change has the potential to accelerate the number of DC-based solar renewable energy credits ("RECs") that may be available to suppliers for compliance purposes in the upcoming years.

The impact of renewable resources is not easily accounted for in the fuel mix reporting. The renewable resources component in the fuel mix for any particular year may be different from the same component in the RPS report for that same year because of the manner in which the RPS requirement is implemented. In particular, pursuant to the Commission's RPS rules, RECs are valid for three years from the date of generation. To the extent that an electricity supplier

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[11] Renewable energy resources are separated into two categories, Tier I and Tier II, with Tier I resources including solar energy, wind, qualifying biomass, methane, geothermal, ocean, and fuel cells, and Tier II resources including hydroelectric power other than pumped storage generation, other qualifying biomass, and waste-to-energy. Minimum percentage requirements are specified for Tier I and Tier II resources, but Tier I resources can be used to comply with the Tier II standard. In addition, a minimum requirement is carved out specifically for solar energy.

[12] The RPS requirement increased to 20 percent by 2020, up from 11 percent by 2022.

[13] On August 1, 2011, the Distributed Generation Emergency Amendment Act of 2011 became law (*See* D.C. Act 19-126). The permanent version of this legislation, the Distributed Generation Amendment Act of 2011, became law on October 20, 2011 (*See* D.C. Law 19-0036).

[14] Under the DGAA, the solar energy compliance payment was set to decrease from 50 cents per kWh in 2016 to 35 cents in 2017; then 30 cents in 2018; then 20 cents in 2019 through 2020; then 15 cents in 2021 through 2022; until reaching 5 cents in 2023 and thereafter.

meets its RPS compliance requirement using RECs from a year different from the fuel mix reporting period, the renewable component should not be reflected in the report due to the difference in the date of generation.[15] In addition, District consumers may enter into purchase power agreements for renewable resources that may not be directly reflected in the fuel mix reported by suppliers.

The District has made significant progress in certifying renewable energy facilities for the RPS program. As of June 1, 2017, 5,482 renewable energy systems—including solar photovoltaic ("PV") and solar thermal—have been certified and are now eligible to participate in the District's RPS program. Solar energy systems account for the vast majority of these approved renewable systems—5,304 as of June 1. Within the District, as of June 1, there are currently 2,908 certified solar PV systems and 110 certified solar thermal systems. There continues to be out-of-District solar energy systems certified for RPS purposes, with 2,286 systems still "grandfathered" into the RPS program under the DGAA or in a location served by a feeder serving the District.[16] The total capacity associated with these solar energy systems is about 58.5 megawatts ("MW"), of which about 37.6 MW is located in the District. This is well below the 83.2 MW of estimated solar capacity necessary to meet the current statutory RPS requirements of 0.98 percent in 2017.

Table 1 below shows the emissions disclosures from 2012 through 2016 based on the PJM System Fuel Mix:

Table 1: PJM System Mix Emissions
2012 - 2016
(lbs. per MWH)

	2012	2013	2014	2015	2016
Carbon Dioxide	1,091.68	1,111.80	1,107.77	1,014.29	992.04
Nitrogen Oxide	0.95	0.95	0.9	0.78	0.75
Sulfur Dioxide	2.4	2.21	2.23	1.61	1.32

Source: PJM-EIS GATS

The reported emissions have improved over time, mainly due to the switch from coal to natural gas as noted above. The District's Clean Energy Plan calls for reducing greenhouse gas emissions by 50 percent below 2006 levels by 2032, and 80 percent below 2006 levels by 2050. The District's Sustainable DC Plan also identified two additional targets: (1) increase the use of renewable energy to 50 percent; and (2) reduce energy use by 50 percent by 2022.[17]

15 For example, if the fuel mix reporting period is for calendar year 2016 and the electricity supplier acquired some RECs associated with generation in 2015 to comply with the renewable portfolio standard, then the supplier's fuel mix report should not count the renewable resources associated with generation in 2015. The only RECs that should be included in the fuel mix report would be those renewable resources associated with generation in 2016.

16 This does not include solar energy resources that are eligible to meet the Tier I requirement only and not the solar carve-out.

17 District Department of Energy and Environment, *Clean Energy DC: A Climate and Energy Plan for the District of Columbia* (October 2016, Summary Report).

IV. Commission's Ongoing Activities

The Commission continues to monitor the fuel mix and emissions reports that are submitted by retail electricity suppliers and Pepco every six months. The Commission will address, as appropriate, any issues arising from the recent fuel mix and emission filings for June 2017. The Commission staff also continues to monitor the regional GATS collaborative process, as appropriate, through PJM-EIS meetings. As needed in the future, the Commission will revise the regulations or issue orders to ensure that electricity suppliers disclose the fuel mix and emissions information consistent with District law and the Commission's rules. The Commission will continue to consider ways to improve upon the reporting of the fuel mix and emissions information.

Attachment 1

Commission Orders and Rulemakings on Fuel Mix

945 - E - 1032

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
1333 H STREET, N.W., SUITE 200, WEST TOWER
WASHINGTON, D.C. 20005

ORDER

June 13, 2003

FORMAL CASE NO. 945, IN THE MATTER OF THE INVESTIGATION INTO ELECTRIC SERVICE MARKET COMPETITION AND REGULATORY PRACTICES, ORDER NO. 12765

I. INTRODUCTION

1. By this Order, and for the reasons set forth in more detail below, the Public Service Commission of the District of Columbia ("Commission") approves and adopts proposed *interim* fuel mix disclosure regulations as amended, and *interim* reporting format submitted by the Retail Competition Working Group ("Working Group").[1] The Commission also approves and adopts the June 1 and December 1 timeframes for suppliers to provide fuel mix data to the Commission pursuant to Sections 34-1517(b) and 34-1504 (c)(2)(B) of the District of Columbia Retail Electric Competition and Consumer Protection Act of 1999 ("Act").[2] The Commission directs that fuel mix information shall be reported to customers in the District of Columbia within the June and December billing cycles of each year pursuant to Section 34-1504(c)(2)(C) of the Act. Finally, the Commission directs the Working Group to submit recommendations on specific issues listed in ordering paragraph 13 within 10 days of this Order.

2. This particular phase of the proceeding fulfills three of the Commission's statutory obligations under the Act: (1) to establish feasibility criteria regarding an individual supplier's duty to disclose its fuel mix under Section 34-1504 (c)(2)(A)(ii) of the Act,[3] (2) to provide, *inter alia,* a report to the District of Columbia City Council on the overall fuel mix of electricity sold to customers in the District of Columbia;[4] and (3) to require the electricity

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1 For purposes of this filing, the Working Group consists of PEPCO, the Office of the People's Counsel, Pepco Energy Services, Inc., Constellation NewEnergy, and Washington Gas Energy Services.

2 *See* §34-1517 (b) and §34-1504(c) (2) (C); and *see generally,* D.C. Code, 2001 Ed. §§ 34-1501 – 1520.

3 *See* D.C. Code, 2001 Ed. § 34-1504(c)(2)(A)(ii) which provides that the Commission shall make a determination of feasibility pursuant to subsection (c)(2)(A)(i) of this section within 6 months after the date an electricity supplier receives a license pursuant to § 34-1505.

4 *See* D.C. Code, 2001 Ed § 34-1517(c) (2) of the D.C. Code, which states in part, "[b]efore July 1, 2003, and every 2 years after that date, the Commission shall provide a report to the Council on the overall fuel mix of the electricity sold in DC, the amount of electricity sold in DC which comes from renewable energy sources. . ." The report to the Council should contain whether it is feasible to require licensed electricity suppliers to provide a minimum percentage of electricity sold from a renewable energy source. In order for the Commission to "track" this kind of information, the Commission requires all electricity suppliers to report their fuel mix to the Commission every 6 months after January 1, 2002. *See also* § 34-1517 (b) of the Act.

suppliers to disclose to customers every 6 months, fuel mix of electricity sold in the District of Columbia.[5] These mandates are part of the Commission's efforts to restructure the District of Columbia's electricity market pursuant to the Act.

II. BACKGROUND

3. By Order No. 12003, the Commission directed the Working Group to submit proposed criteria relating to the feasibility of fuel mix reporting to customers.[6] The Commission also reminded licensed suppliers in that Order, that they still bear the independent responsibility of reporting their fuel mix data to the Commission under Section 34-1517 of the District of Columbia Code.[7] The Working Group submitted proposed criteria regarding the feasibility of requiring individual electricity suppliers to disclose fuel mix information, every six months, to their customers for the electricity they sell in the District of Columbia.[8] Specifically, the Working Group proposed that the Commission adopt a regulation, which states that it is feasible for a licensed supplier to disclose its *actual* fuel mix, provided that the electricity supplied in the District of Columbia is from generation purchased under contract from specified resources or unit or system contracts. The Working Group recommended, however, that such a disclosure is not possible if the electricity supplied in the District of Columbia is purchased from the PJM Interconnection, L.L.C. ("PJM") spot market or a contract for unspecified resources.[9]

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5 *See* D.C. Code, 2001 Ed § 34-1504 (c) (2) (C) which states in part, if the Commission determines that it is not feasible for an electricity supplier to disclose the fuel mix of electricity sold by the supplier in the District of Columbia, "the Commission, by regulation or order; shall require the electricity supplier to disclose to its customers every 6 months a regional fuel mix average." *See also* D.C. Code, 2001 Ed § 34-1504 (c) (2) (B) which states that if the Commission determines that it is feasible for an electricity supplier to disclose the fuel mix it sells in the District, then a supplier must disclose every 6 months its fuel mix of electricity, including categories of electricity from coal, natural gas, nuclear energy, oil, hydroelectric, solar, biomass, wind and other sources.

6 *See Formal Case No. 945, In the Matter of the Investigation into Electric Service Market Competition and Regulatory Practices*, Order No. 12003, rel. May 17, 2001.

7 In order for the Commission to discharge its statutory duty to "track the fuel mix of the electricity sold in the District of Columbia and the amount of electricity from renewable sources sold in the District of Columbia," we deem it necessary, regardless of what a particular supplier's customer disclosure might cover (*i.e.*, fuel mix for electricity sold in the District of Columbia or regional fuel mix average), for **each licensed electricity supplier to** report their fuel mix **to the Commission** every 6 months after January 1, 2002. *See* § 34-1517 (b) of the District of Columbia Code. (emphasis added for clarity).

8 *See Formal Case No. 945, In the Matter of the Investigation into Electric Service Market Competition and Regulatory Practices*, Letter from the Retail Competition Working Group to Jesse P. Clay, Jr., Commission Secretary, filed June 22, 2001. The letter stated that the Working Group had been informed that PJM was in the process of testing a new fuel mix tracking system that may "enable more accurate reporting of fuel mix information."

9 *Id.* (The letter attached proposed regulations submitted by Working Group, entitled "Regulations re: Feasibility of Fuel Mix Disclosure.)

4. The Commission concluded in Interim Order No. 12065,[10] issued July 18, 2001, that the Working Group's proposed criteria were consistent with the requirements of the Act and would promote the public interest by requiring individual suppliers to disclose fuel mix information to consumers. The proposed criteria were found to be in the public interest because individual suppliers have the opportunity to assess in advance, based on their procurement activity, the feasibility of disclosing the fuel mix of electricity that is sold in the District, including the origins of the electricity (*i.e.*, coal, natural gas, and nuclear resources) and the percentage of the electricity that is sold from renewable energy sources. The proposed criteria contemplate that electricity suppliers can purchase the electricity to be sold in the District of Columbia using four types of contracts and one market source.[11]

5. Based on the Working Group's report, the Commission adopted three interim regulations ("criteria") regarding the reporting of electricity fuel mix in Order No. 12065. First, the Commission directed individual electricity suppliers that procure electricity through contracts, which specify the origins of that electricity as being from specified resources, specified units, or a specified system, to disclose the fuel mix of the electricity sold in the District of Columbia. Second, the Commission's Order provided that, on an interim basis, individual electricity suppliers are not required to disclose the fuel mix of the electricity sold in the District, provided that the procured electricity is derived through purchases from the PJM spot market, or a contract from unspecified sources.[12] The Commission emphasized that this exemption was temporary, until such time as fuel mix disclosure becomes feasible. Third, the Working Group was directed to submit comments on the method by which suppliers should disclose their fuel mix to District customers and to report on PJM's progress in establishing its new fuel mix tracking system. The Commission ordered that its interim criteria remain in effect, until a PJM tracking system is established, in order to accurately report fuel mix information.

III. MAY 15, 2003 WORKING GROUP REPORT RECOMMENDATIONS:

6. The Commission issued Order No. 12533[13] on August 12, 2002, which directed the Working Group to submit for the Commission's consideration, proposed interim regulations, including reporting standards and procedures that will govern the disclosure of data by suppliers of the fuel mix sold in the District of Columbia. The Order further directed the Working Group

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10 *See Formal Case No. 945, In the Matter of the Investigation into Electric Service Market Competition and Regulatory Practices,* Order No. 12065, rel. July 18, 2001.

11 These categories include:

a) contracts that specify that the electricity is generated from specified resources (e.g., fuels, hydro, etc.);
b) contracts that specify that the electricity is generated from a specified unit(s);
c) contracts that specify that the electricity is generated from a specified system(s);
d) purchases from the PJM spot market; and
e) contracts for electricity from unspecified resources.

12 *Id.*

13 *See Formal Case No. 945, In the Matter of the Investigation into Electric Service Market Competition and Regulatory Practices,* Order No. 12533 at 6-7, rel. August 12, 2002.

to provide recommendations on certain specific issues such as the fuel mix reporting format and on consumer bills, promulgation of enforcement rules, the timeframe for disclosure of fuel mix, and an implementation plan for reporting.[14] Because the Working Group did not respond to all of the Commission's questions, the Commission again, in Order No. 12705, directed the Working Group to prepare and file an *updated* comprehensive fuel mix data report.[15] The Working Group filed its report on May 15, 2003,[16] which included a status report on fuel mix reporting in the District of Columbia, interim regulations, and interim reporting format.

7. Overall, the Working Group states that the fuel mix disclosure standards and procedures under development by PJM, met the requirements under the Act. The Working Group represents that the proposed interim regulations provide sufficient flexibility to incorporate the current average PJM control area data as well as any future improvements as to providing zone-specific fuel mix data. Alternatively, suppliers may submit self-generated disclosure information at any time in lieu of those provided by PJM.[17]

8. The Commission believes that because the interim regulations are not final rules, and PJM is still in its developmental stages, it is more beneficial to electricity suppliers to have an interim "model" to guide them in their fuel mix data disclosure reporting than not. Attachment B to the Working Group report represents PJM's fuel mix data reporting format. We agree with the Working Group that the format is consistent with other jurisdictions in the control area, and provides renewable energy resource information mandated by the Act. The Commission adopts the format in Attachment B.

9. The Working Group attached proposed regulations to its report:[18] The Commission approves the proposed interim regulations as amended. First, the word "energy" found in (a), should be replaced with "electricity," to maintain uniformity and consistency in the provisions. Secondly, the Commission amends the Working Group's proposed interim regulations to read as follows (revisions in **bold**):

> "On June 1 and December 1 of each year, each licensed supplier doing business in the District of Columbia, and the Electric company as the provider of Standard Offer Service for the District of Columbia, shall report to the

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14 *Id.* The specific issues were: fuel mix reporting formats, timeframe for disclosure of fuel mix, and an implementation plan for reporting.

15 *See Formal Case No. 945, Phase II, In the Matter of the Investigation into Electric Service Market Competition and Regulatory Practices*, Order No. 12705, rel. April 16, 2003.

16 *See Formal Case No. 945, Phase II, In the Matter of the Investigation into Electric Service Market Competition and Regulatory Practices*, Status Report on Fuel Mix Reporting, filed May 15, 2003.

17 *See Formal Case No. 945, Phase II, In the Matter of the Investigation into Electric Service Market Competition and Regulatory Practices*, Status Report on Fuel Mix Reporting, filed May 15, 2003.

18 *See Formal Case No. 945, Phase II, In the Matter of the Investigation into Electric Service Market Competition and Regulatory Practices*, Attachment A—Proposed Regulations, filed May 15, 2003.

Commission on the fuel mix of the electricity sold in the District of Columbia by the electricity supplier or the Electric Company.

> (a) For the electricity sold by an electricity supplier or the Electric Company that is from a specific generation resource, the electricity supplier or the Electric Company shall use the specific fuel mix from that generation resource in its fuel mix report to the Commission.
>
> (b) For the electricity sold by an electricity supplier or the Electric Company that is not from specific generation resources, the electricity supplier or the Electric Company shall use the average fuel mix statistics for all generation resources provided by PJM in its fuel mix report to the Commission.

The fuel mix information provided to the Commission shall be in a format consistent with that provided by PJM." **In addition to the fuel mix report provided to the Commission, fuel mix information shall be reported to customers of the District of Columbia within the June and December billing cycles of each year."**

The inclusion of this language fulfills our duty under Sections 34-1504(c)(2)(B) and 34-1504(c)(2)(C) of the Act to require electricity suppliers to report regional fuel mix to customers every 6 months.

10. Because the Working Group did not provide responses to all of the specific issues detailed in Order No. 12533, the Commission, once again, directs the Working Group to respond to those questions listed in paragraph 13 of the Order within 10 days of the date of this Order.[19] Additionally, the Commission believes that because the interim regulations are not final rules, and PJM is still in its developmental stages, it is more beneficial to electricity suppliers to have an interim "model" to guide them in their fuel mix data disclosure reporting than not. Attachment B to the Working Group report represents PJM's fuel mix data reporting format. We agree with the Working Group that the format is consistent with other jurisdictions in the control area, and provides renewable energy resource information. The Commission adopts the format in Attachment B.

11. With respect to these timeframes for reporting fuel mix data to the Commission, the Commission also approves the Working Group's recommendations that suppliers serving load in the District of Columbia report to the Commission and customers, the most current PJM-supplied or self-determined fuel mix statistics on June 1 and December 1 of each year. The Commission supports a uniform, single fuel mix reporting system that will support compliance and verification of electric generation attributes. This system will ensure accurate accounting

19 *See Formal Case No. 945, Phase II, In the Matter of the Investigation into Electric Service Market Competition and Regulatory Practices*, Order No. 12533 at 6-7, rel. August 12, 2002.

and reporting, and facilitate efficient and transparent transaction among market participants. Further, PJM's Generation Attributes Tracking System (GATS) will be flexible enough to accommodate varied and changing policies and programs here in the District of Columbia.

THEREFORE, IT IS ORDERED THAT:

12. Consistent with the guidance set forth in this Order, and until such time as the PJM GATS is finalized, the Commission approves and adopts the following:

(a) the interim fuel mix disclosure regulations as amended herein;

(b) the interim reporting format used by PJM (Attachment B);

(c) the fuel mix information shall be reported to customers of the District of Columbia within the June and December billing cycles of each year, pursuant to Sections 34-1504(c)(2)(B) and 34-1504 (c)(2)(C) of the Act; and

13. The Working Group shall provide recommendations on the following issues within 10 days of this Order:

(a) Should the Commission promulgate enforcement rules and penalties for the failure to comply with the reporting requirements as set forth in the Act? And, if suppliers violate the disclosure requirements under the Act, what penalties should be assessed? Is the Commission the appropriate regulatory entity to audit electricity suppliers' compliance with environmental disclosure requirements?

(b) How should fuel mix be reported on the consumer's bill?

(c) Whether the renewable energy resources listed in PJM's average fuel mix statistics format (Attachment B of the Working Group report) are consistent with the definitions of the renewable sources under Section 34-1517(a) in the Act.[20] If the definitions are inconsistent, how or should they be reconciled?

A TRUE COPY:

CHIEF CLERK

BY DIRECTION OF THE COMMISSION:

Sanford M. Speight

SANFORD M. SPEIGHT
ACTING COMMISSION SECRETARY

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[20] The Working Group shall define the following sources of energy under D.C. Code, 2001 Ed. §34-1517(a): solar; wind; tidal; geothermal; biomass; hydroelectric facilities; and digester gas.

945-E-1194

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
1333 H STREET, N.W. 2ND FLOOR, WEST TOWER
WASHINGTON, D.C. 20005

ORDER

September 21, 2004

FORMAL CASE NO. 945, IN THE MATTER OF THE INVESTIGATION INTO ELECTRIC SERVICE MARKET COMPETITION AND REGULATORY PRACTICES, Order No. 13391

I. INTRODUCTION

1. By this Order, the Public Service Commission of the District of Columbia ("Commission") requires Washington Gas Energy Services, Inc. ("WGES") and Baltimore Gas and Electric Home ("BGE Home") to file fuel mix reports pursuant to Order No. 12765. The Commission also requires PEPCO Energy Services, Inc. ("PES") to file a supplemental report to advise the Commission whether its customers received bill insert notification of its fuel mix. Finally, the Commission reminds all electric suppliers of their obligation to file a fuel mix report with the Commission in June and December of each year.

II. BACKGROUND

2. By Order No. 12003, the Commission directed the Formal Case No. 945 Working Group ("Working Group")[1] to submit proposed criteria relating to the feasibility of fuel mix reporting to customers.[2] In that Order, the Commission also reminded licensed suppliers that they still bear the independent responsibility of reporting their fuel mix data to the Commission under D.C. Code § 34-1517.[3] The Working Group submitted proposed criteria regarding the feasibility of requiring individual electricity suppliers to disclose fuel mix information every six months to their customers for the electricity they sell in the District of Columbia.[4] Specifically, the Working Group

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1 The participating members of the Working Group are PEPCO, the Office of the People's Counsel, Constellation NewEnergy, Inc. and PEPCO Energy Services, Inc.

2 *See Formal Case No. 945, In the Matter of the Investigation into Electric Service Market Competition and Regulatory Practices ("F.C. 945"),* Order No. 12003, rel. May 17, 2001.

3 In order for the Commission to discharge its statutory duty to track the fuel mix and the amount of electricity from renewable sources sold in the District of Columbia, we deem it necessary, regardless of what a particular supplier's customer disclosure might cover (*i.e.*, fuel mix for electricity sold in the District of Columbia or regional fuel mix average), for each licensed electricity supplier to report its fuel mix to the Commission every six months after January 1, 2002.

4 *See F.C. 945*, Letter from the Retail Competition Working Group to Jesse P. Clay, Jr., Commission Secretary, filed June 22, 2001. The letter stated that the Working Group had been informed

proposed that the Commission adopt a regulation which states that it is feasible for a licensed supplier to disclose its actual fuel mix, provided that the electricity supplied in the District of Columbia is from generation purchased under contract from specified resources, unit, or system contracts. The Working Group suggested, however, that such a disclosure is not possible if the electricity supplied in the District of Columbia is purchased from the PJM Interconnection, L.L.C. ("PJM") spot market or under a contract for unspecified resources.[5]

3. By Interim Order No. 12065, the Commission concluded that the Working Group's proposed criteria were consistent with the requirements of the Act and would promote the public interest by requiring individual suppliers to disclose fuel mix information to consumers.[6] The proposed criteria were found to be in the public interest because individual suppliers have the opportunity to assess in advance, based on their procurement activity, the feasibility of disclosing the fuel mix of electricity that is sold in the District, including the origins of the electricity (i.e. coal, natural gas, and nuclear resources) and the percentage of the electricity that is sold from renewable energy sources. The proposed criteria contemplated that electricity suppliers could purchase electricity to be sold in the District of Columbia using four types of contracts and one market source.[7]

4. Based on the Working Group's criteria, by Interim Order No. 12065, the Commission adopted three interim regulations regarding the reporting of electricity fuel mix.[8] First, the Commission directed individual electricity suppliers who procure electricity through contracts that specify the origins of the electricity as being from specified resources, specified units, or a specified system, to disclose the fuel mix of the electricity sold in the District of Columbia. Second, the Commission's Order provided that, on an interim basis, individual electricity suppliers are not required to disclose the fuel mix of the electricity sold in the District if the procured electricity is derived through purchases from the PJM spot market, or under a contract from unspecified sources.[9] The

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that PJM was in the process of testing a new fuel mix tracking system that may enable more accurate reporting of fuel mix information.

5 *Id.* Attached to the letter were proposed regulations drafted by the Working Group, entitled "Regulations re: Feasibility of Fuel Mix Disclosure."

6 *F.C. 945*, Order No. 12065, rel. July 18, 2001.

7 These categories include:

a) contracts that specify that the electricity is generated from specified resources (e.g., fuels, hydro, etc.);
b) contracts that specify that the electricity is generated from a specified unit(s);
c) contracts that specify that the electricity is generated from a specified system(s);
d) purchases from the PJM spot market; and
e) contracts for electricity from unspecified resources.

8 *See F.C. 945*, Order No. 12065, rel. July 18, 2001.

9 *Id.*

Commission emphasized that this exemption was temporary, until such time as fuel mix disclosure becomes feasible. Third, the Working Group was directed to submit comments on the method by which suppliers should disclose their fuel mix to District customers and to report on PJM's progress in establishing its new fuel mix tracking system. The Commission ordered that its interim criteria remain in effect until a PJM tracking system is established in order to accurately report fuel mix information.

5. By Order No. 12533, the Commission further directed the Working Group to submit, among other things, proposed interim regulations.[10] The Commission approved the proposed regulations, as amended, by Order No. 12765.[11] The regulations set forth, among other things, the December and June fuel mix reporting requirements.

6. On June 23, 2003, the Working Group submitted a Fuel Mix Working Group Report in compliance with Order No. 12765. The report responded to three key questions raised by the Commission in that Order: (1) Whether the Commission should promulgate enforcement rules and penalties for the failure to comply with the reporting requirements as set forth in the Act; (2) How fuel mix should be reported on a customer's bill; and (3) Whether the renewable energy resources listed in PJM's average fuel mix statistics format (Attachment B of the Working Group report) are consistent with the definitions of the renewable sources under Section 34-1517(a) the Act. In response to the first issue, the Working Group does not believe there is any need for the Commission to promulgate enforcement rules and penalties, inclusive of the amount of any penalty, for the failure to comply with the fuel mix reporting requirements. In response to the second issue, the Working Group concludes that for residential and small commercial customers, the electricity supplier should report on its fuel mix in a mailing to each of its customers. In response to the third issue, the Working Group believes that the renewable resources listed in PJM's average fuel mix statistics are consistent with the definitions of the renewable resources under D.C. Code § 34-1517(a)(2001 ed.).

7. On December 1, 2003, PEPCO filed its fuel mix report in compliance with Order No. 12765 and also included its fuel mix information in the bill insert for its December billing cycle.[12] On December 4, 2003, PES reported on its fuel mix of electricity sold in the District of Columbia for the twelve months ending October 31, 2003.[13] Constellation NewEnergy filed a fuel mix report which indicated that it does not purchase unit-specific energy and attached the most recent PJM Regional Average

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10 *See F.C. 945*, Order No. 12533, rel. August 12, 2002.

11 *See F.C. 945*, Order No. 12765, rel. June 13, 2003.

12 *See F.C. 945*, Regional Fuel Mix Data for Potomac Electric Power Company, filed December 1, 2003. We note that on June 14, 2004, PEPCO also filed its required June fuel mix report. No other party filed a June report as required by the regulations.

13 *See F.C. 945*, Compliance Filing of PEPCO Energy Services, Inc., filed December 4, 2003.

Disclosure Label in compliance with Section 117(b) of the 1999 Act.[14] No other electric suppliers filed their fuel mix reports.

III. DISCUSSION

8. We agree with the Working Group that each electricity supplier to residential and small commercial customers in the District should report its fuel mix in a mailing to its customers and that the renewable resources listed in PJM's average fuel mix statistics are consistent with the definitions of the renewable resources under D.C. Code § 34-1517(a). However, we reserve judgment on the necessity to promulgate enforcement rules and penalties until we have given suppliers one more opportunity to file their fuel mix reports for December 2003 and June 2004.

9. Our records indicate that WGES and BGE Home are active suppliers of electricity to District consumers and have not filed fuel mix reports for December 2003 and June 2004. By this Order, we remind all active suppliers that they are required to file fuel mix reports with the Commission in June and December of each year and to disclose such information to customers every six months. All active suppliers shall have 45 days from the date of this order to file any overdue fuel mix reports.

10. We note that PJM data for a current year is not available until December of that year and covers only the period January to June. Complete data for the year is not available until the following June but does not segregate out data for the previous July – December period. For that reason, we modify the fuel mix reporting requirements to be consistent with PJM's publication practices. Accordingly, active suppliers shall file their December fuel mix report for the period January – June of that year. Active suppliers shall file a June fuel mix report that includes information for the previous calendar year.

11. Finally, we note that in PES's December 4, 2003 filing, PES failed to mention whether it included its fuel mix report in mailings to its consumers. We direct PES to file a supplemental report within 10 days from the date of this Order stating whether it has provided this notice to its customers as required by Order No. 12765.

THEREFORE, IT IS HEREBY ORDERED THAT:

12. All active electric suppliers shall have 45 days from the date of this Order to file the overdue fuel mix reports;

13. All future fuel mix reports shall be filed in accordance with Order No. 12765, as modified by this Order; and,

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14 *See F.C. 945*, Constellation NewEnergy, Inc.'s Fuel Mix Reporting, filed December 4, 2004. The data attached to Constellation's filing was described as the "most recent" fuel mix average, but the data was from 2002. Constellation's filing was not in compliance with Order No. 12765 because it contained outdated fuel mix data. However, Constellation is not required by Order No. 12765 to report its fuel mix to the Commission or to its D.C. customers because it does not have any D.C. customers at this time.

14. PES is directed to file a supplemental fuel mix report within 10 days from the date of this Order stating whether it mailed its fuel mix report to its customers.

A TRUE COPY: **BY DIRECTION OF THE COMMISSION:**

Sanford M. Speight

CHIEF CLERK **SANFORD M. SPEIGHT**
ACTING COMMISSION SECRETARY

945 - E - 1280

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
1333 H STREET, N.W., 2nd FLOOR, WEST TOWER
WASHINGTON, D.C. 20005

ORDER

May 19, 2005

FORMAL CASE NO. 945, IN THE MATTER OF THE INVESTIGATION INTO ELECTRIC SERVICE MARKET COMPETITION AND REGULATORY PRACTICES, Order No. 13589

I. INTRODUCTION

1. By this Order, the Public Service Commission of the District of Columbia ("Commission") directs all active electricity suppliers to disclose their emissions information semi-annually as required by D.C. Law. Suppliers are to file this information by June 1 and December 1 of each year along with their fuel mix information.

II. BACKGROUND

2. All electricity suppliers are currently disclosing their fuel mix information by filing it with the Commission by June 1 and December 1 of each year as well as reporting this information to their customers.[1] On January 31, 2005, the District of Columbia City Council enacted the Omnibus Utility Amendment Act of 2004 ("Omnibus Act").[2] The Act became effective on April 12, 2005 and, in part, requires the Commission to direct each electricity supplier to disclose emissions information regarding carbon dioxide, nitrogen oxide, sulfur dioxide, and any other pollutant that the Commission deems appropriate, for electricity sold in the District of Columbia.[3] According to the Act, the Commission must determine whether it is feasible for the supplier to disclose this information every six months and may direct suppliers to provide this information either by rule or by order.[4]

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1 *See Formal Case No. 945, In the Matter of the Investigation into the Electric Service Market Competition and Regulatory Practices*, Order No. 12765 rel. June 13, 2003.

2 Omnibus Utility Amendment Act of 2004, Pub. L. No. 15-342 (2005). The Omnibus Act became effective on April 12, 2005. The Omnibus Act superseded the "Omnibus Utility Emergency Amendment Act of 2005" which was passed in January 2005.

3 Omnibus Act at Sec. 304.

4 *Id.*

III. DECISION

3. The Commission determines that the emissions information required by law is readily available from the PJM Interconnection ("PJM"), the regional transmission organization that includes the District of Columbia. Inasmuch as suppliers are already providing fuel mix information every six (6) months, we believe that it would be administratively efficient to require suppliers to disclose the additional emissions information at the same time, and in the same report, that they disclose their fuel mix. Because information on additional pollutants is not readily available from PJM, we determine that expanding the list of pollutants is infeasible at this time. Consequently, we direct all electricity suppliers to provide their emissions data for carbon dioxide, nitrogen oxide, and sulfur dioxide by June 1 and December 1 of each year.[5]

THEREFORE, IT IS ORDERED THAT:

4. All active electricity suppliers are directed to provide their emissions information by June 1 and December 1 of each year to their customers and the Commission.

A TRUE COPY: **BY DIRECTION OF THE COMMISSION:**

CHIEF CLERK **CHRISTINE D. BROOKS**
COMMISSION SECRETARY

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5 Because the PJM Generation Attribute Tracking System ("GATS") is currently not in operation, suppliers can use information from PJM's fuel mix/emission disclosure label for their June 1, 2005 filing. PJM's Fuel Mix Disclosure Label includes information on the suppliers' fuel mix and emissions.

945-E-1898 AH

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
1333 H STREET, N.W., SUITE 200, WEST TOWER
WASHINGTON, DC 20005

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... OF COLUMBIA ... SERVICE COMMISSION

NOTICE OF PROPOSED RULEMAKING

FORMAL CASE NO. 945, IN THE MATTER OF THE INVESTIGATION INTO ELECTRIC SERVICES MARKET COMPETITION AND REGULATORY PRACTICES

1. The Public Service Commission of the District of Columbia ("Commission"), pursuant to its authority under D.C. Official Code § 34-1504(b) (2007 Supp.), hereby gives notice of its intent to adopt Chapter 42 of Title 15 DCMR, in not less than thirty (30) days after publication of this Notice of Proposed Rulemaking ("NOPR") in the *D.C. Register*.[1]

2. The proposed regulations establish the Commission's rules governing the submission of Fuel Mix and Emissions Disclosure Reports. These proposed rules replace the Interim Regulations recommended by the Retail Competition Working Group and later adopted by the Commission in Order No. 12765.[2]

CHAPTER 42 FUEL MIX AND EMISSIONS DISCLOSURE REPORTS

Section
4200 APPLICABILITY
4201 FUEL MIX AND EMISSIONS DISCLOSURE REQUIREMENTS
4202 WAIVER
4206-4298 [RESERVED]
4299 DEFINITIONS

4200 APPLICABILITY

4200.1 This Chapter establishes the Public Service Commission's ("Commission") regulations governing the disclosure of fuel mix and emissions applicable to an Electricity Supplier as provided in D.C. Official Code §§ 34-1504(c)(2) and 34-1517(b)-(c).

1 D.C. Official Code § 34-1504(b) (2007 Supp.).

2 *Formal Case No. 945, In The Matter Of The Investigation Into Electric Services Market Competition And Regulatory Practices*, Order No. 12765, rel. June 13, 2003.

4201 FUEL MIX AND EMISSIONS DISCLOSURE REQUIREMENTS

4201.1 Each active District of Columbia Electricity Supplier and the Electric Company shall report every six (6) months the fuel mix of electricity sold and the emissions produced in accordance with D.C. Official Code §§ 34-1504(c)(2)(A)(i) and 34-1517(b).

4201.2 Each active Electricity Supplier and the Electric Company must submit a semi-annual Fuel Mix and Emissions Report ("Fuel Mix Report") to the Commission on June 1 and December 1. The June 1 report shall provide fuel mix and emissions information for the prior calendar year. The December 1 report shall provide fuel mix and emission information for the period January through June of the current year.

4201.3 Each Fuel Mix Report must contain the following information in accordance with D.C. Official Code §§ 34-1504(c)(2)(A)(i) and 34-1517(b):

(a) The percentage of electricity generated from the following energy sources:

(1) Coal;

(2) Oil;

(3) Natural gas;

(4) Nuclear;

(5) Solar;

(6) Wind;

(7) Biomass;

(8) Captured methane gas from landfill gas or wastewater treatment plant;

(9) Water, including hydroelectric and ocean;

(10) Geothermal;

(11) Municipal solid waste; and

(12) Other.

(b) The emissions in pounds per megawatt-hour of:

(1) Carbon dioxide;

(2) Nitrogen oxides; and

(3) Sulfur dioxide.

4201.4 In the Fuel Mix Report, the percentages for § 4201.3(a)(5) through (11) above should also be added together and designated as the "Renewable Energy Resources Subtotal."

4201.5 For electricity sold by an Electricity Supplier or the Electric Company that is from a specific generation resource, including any renewable energy credits associated with generation in the reporting period, the Electricity Supplier or the Electric Company shall include the specific generation resource in its Fuel Mix Report.

4201.6 For electricity sold by an Electricity Supplier or the Electric Company that is not from specific generation resources, the Electricity Supplier or the Electric Company shall include the PJM Environmental Information Services, Inc. ("PJM EIS") average residual fuel mix statistics, by generation resource, in its Fuel Mix Report. Pursuant to § 4201.2 for the Fuel Mix Reports to be submitted by December 1 covering the time period January through June of the current year, Electricity Suppliers and the Electric Company may use estimates, if the actual numbers are unavailable, when reporting residual fuel mix statistics.

4201.7 A Fuel Mix Report shall be in a format similar to the information provided by the PJM EIS.

4201.8 Each Electricity Supplier and the Electric Company shall provide a Fuel Mix Report to its customers in the District of Columbia within the June and December billing cycles each year in accordance with D.C. Official Code §§ 34-1504(c)(2)(B)-(C) and consistent with § 4201.3 of this Chapter. The Fuel Mix Report submitted to the Commission shall indicate that the information is also being disclosed to customers.

4201.9 If an Electricity Supplier or the Electric Company fails to file a semi-annual Fuel Mix Report or to disclose the information to its customers as required by this Chapter and D.C. Official Code §§ 34-1504(c)(2)(B)-(C), that company may be subject to Commission action. In addition, pursuant to D.C. Official Code § 34-1508, failure to file a Fuel Mix Report or disclose information to customers may result in suspension or revocation of a license to supply electricity or imposition of a civil penalty up to $10,000 per violation.

4202 **WAIVER**

The Commission reserves the right to waive any provision of these rules for good cause shown.

4202-4298 (Reserved)

4299 **DEFINITIONS**

4299.1 For the purposes of this chapter:

"Biomass" means a solid, nonhazardous, cellulosic waste material that is segregated from other waste materials and is derived from any of the following forest-related resources, with the exception of old growth timber, unsegregated solid waste, or post-consumer waste paper: (a) mill residue, (b) precommercial soft wood thinning, (c) slash, (d) brush, (e) yard waste, (f) waste pallet, crate or dunnage, and (g) agricultural sources, including tree crops, vineyard materials, grain, legumes, sugar, and other crop by-products or residues.

"Commission" means the Public Service Commission of the District of Columbia.

"Electric company" means every corporation, company, association, joint-stock company or association, partnership, or person doing business in the District of Columbia, their lessees, trustees, or receivers appointed by any court whatsoever, physically transmitting or distributing electricity in the District of Columbia to retail electric customers. The term excludes any building owner, lessee, or manager who, respectively, owns, leases, or manages, the internal distribution system serving the building and who supplies electricity and other electricity related services solely to the occupants of the building for use by the occupants.

"Electricity supplier" means a person, including an aggregator, broker, or marketer, who generates electricity; sells electricity; or purchases, brokers, arranges, or markets electricity for sale to customers. The term excludes the following:

(a) Building owners, lessees, or managers who manage the internal distribution system serving such building and who supply electricity solely to occupants of the building for use by the occupants;

(b) Any person who purchases electricity for its own use or for the use of its subsidiaries or affiliates; or

(c) Any apartment building or office building manager who aggregates electric service requirements for his or her building or buildings, and who does not:

(1) Take title to the electricity;

(2) Market electric services to the individually-metered tenants of the building; or

(3) Engage in the resale of electric services to others;

(d) Property owners who supply small amounts of power, at cost, as an accommodation to lessors or licensees of the property; and

(e) A consolidator.

"Hydroelectric" means power produced through conventional hydroelectric turbines.

"Ocean" means power produced from currents, tides, waves, and thermal differences.

"PJM Environmental Information Services" means the wholly-owned subsidiary of PJM Technologies, Inc. that provides environmental and emissions attributes reporting and tracking services to its subscribers.

"Residual fuel mix" means the net amount of generation remaining after subtracting from the total generation occurring during a year any generation that has been removed through specific claims on such generation.

3. All persons interested in commenting on this proposed rulemaking may submit comments, in writing, no later than thirty (30) days after the date of publication of this NOPR in the *D.C. Register*. Persons interested in submitting reply comments may do so no later than forty-five (45) days after the date of publication of this NOPR in the *D.C. Register*. All comments and replies must be sent to Dorothy M. Wideman, Commission Secretary, Public Service Commission of the District of Columbia, 1333 H Street, N.W., Suite 200, West Tower, Washington, DC 20005. Copies of these proposed rules may be obtained, at cost, by writing to the Commission Secretary at the above address or on the Commission's website at www.dcpsc.org. Once the comment period has expired, the Commission will take final rulemaking action.

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RECEIVED PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
1333 H STREET, N.W., SUITE 200, WEST TOWER
WASHINGTON, DC 20005

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DISTRICT OF COLUMBIA PUBLIC SERVICE COMMISSION

NOTICE OF FINAL RULEMAKING

FORMAL CASE NO. 945, IN THE MATTER OF THE INVESTIGATION INTO ELECTRIC SERVICES MARKET COMPETITION AND REGULATORY PRACTICES

1. The Public Service Commission of the District of Columbia ("Commission") hereby gives notice, pursuant to Sections 2-505(a) and 34-1504(b) of the District of Columbia Official Code,[1] of final rulemaking action, adopting Chapter 42 of Title 15 DCMR governing Fuel Mix and Emissions Disclosure Reports. The Commission issued a Notice of Proposed Rulemaking ("NOPR") which was published in the *D.C. Register* on July 11, 2008, giving notice of the Commission's intent to adopt Chapter 42 of Title 15 DCMR.[2] No comments were filed in response to the NOPR.

2. As indicated in the NOPR, the proposed regulations establish the Commission's rules governing the submission of Fuel Mix and Emissions Disclosure Reports.[3] In addition, the proposed rules replace the Interim Regulations recommended by the Retail Competition Working Group and later adopted by the Commission in Order No. 12765.[4] The replacement of the Interim Regulations with permanent rules will facilitate the submission of Fuel Mix and Emissions Disclosure Reports by electricity suppliers and the Electric Company to the Commission consistent with the provisions of Section 34-1504 of the District of Columbia Official Code.[5] Accordingly, the Commission hereby adopts Chapter 42 of Title 15 DCMR governing Fuel Mix and Emissions Disclosure Reports as contained in the *D.C. Register* on July 11, 2008. The rules will become effective upon publication of this Notice of Final Rulemaking in the *D.C. Register*. Copies of the rules may be obtained by contacting Dorothy Wideman, Commission Secretary, Public Service Commission of the District of Columbia, 1333 H Street, N.W., 2nd Floor, West Tower, Washington, D.C. 20005. Copies may also be obtained from the Commission's website at www.dcpsc.org.

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1 D.C. Official Code §§ 2-505(a) (2001 Ed.) and 34-1504(b) (2008 Supp.).

2 55 *D.C. Register* 7572-7576 (July 11, 2008).

3 55 *D.C. Register* at 7572.

4 *Formal Case No. 945, In The Matter Of The Investigation Into Electric Services Market Competition And Regulatory Practices*, Order No. 12765, rel. June 13, 2003.

5 D.C. Official Code § 34-1504(b) (2008 Supp.).

Public Service Commission

of the

District of Columbia

Report Pursuant to the Renewable Portfolio Standard Expansion Amendment Act of 2016

March 1, 2017

Pursuant to the requirements of the Renewable Portfolio Standard Expansion Amendment Act of 2016 (D.C. Law 21-154, effective October 8, 2016) the District of Columbia Public Service Commission submits the following report to the D.C. Council. Specifically, this report is submitted in fulfillment of Section 2b of the Act (D.C. Code § 34-1432(f)) which provides that:

> No later than March 1, 2017, the Commission shall provide a report to the Council that includes:
>
> (1) An estimate of the amount of solar energy generated annually by solar energy systems in the District that could qualify to be used to meet the annual solar energy requirement, but for which renewable energy credits cannot be purchased by electricity suppliers to meet the solar energy requirement; and
>
> (2) A recommendation for how the Commission could adjust the annual solar requirement to account for the amount of solar generation identified in paragraph (1) of this subsection.

The report consists of a brief background section, a section addressing a method for making an annual estimate of the amount of District-based solar facilities for which renewable energy credits are not available for purchase, a section addressing a method for annually adjusting the solar requirement to include the capacity of these facilities, and a summary of the Commission's recommendations. The Commission is available to discuss any of the information and recommendations in the report with the Council.

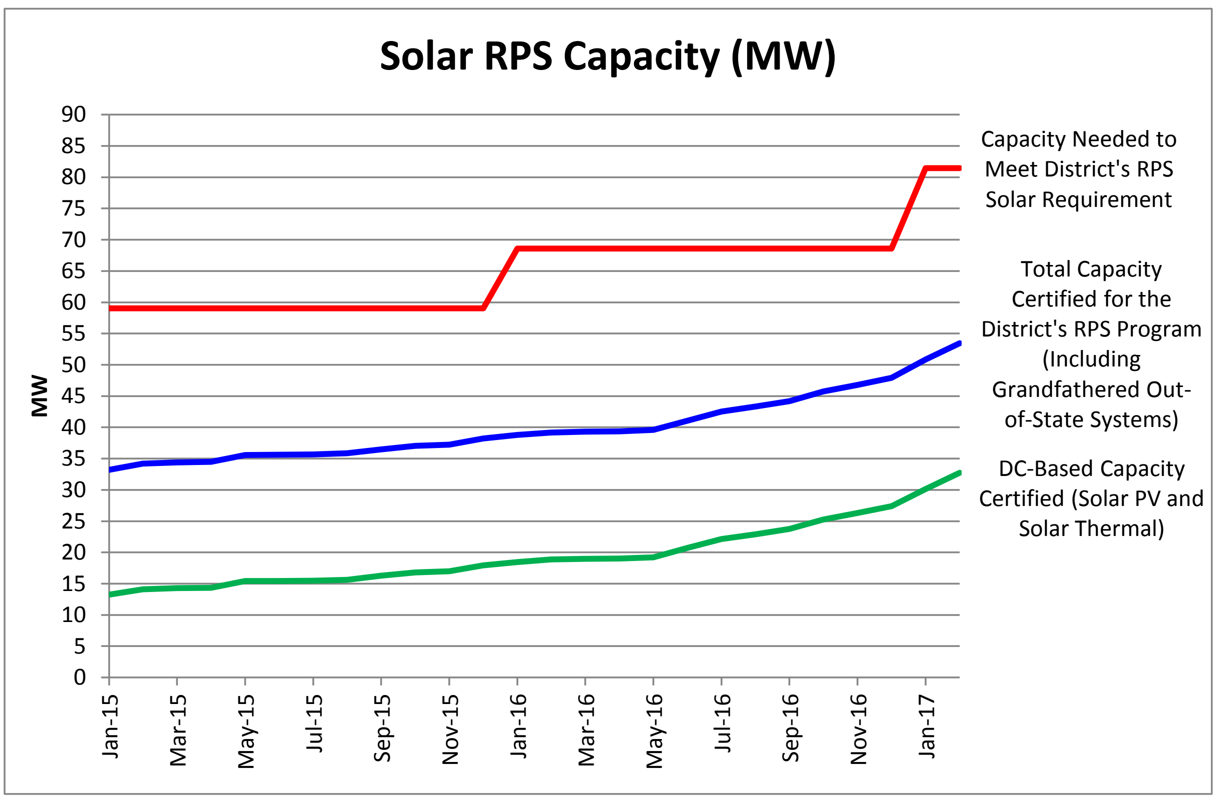
I. Background

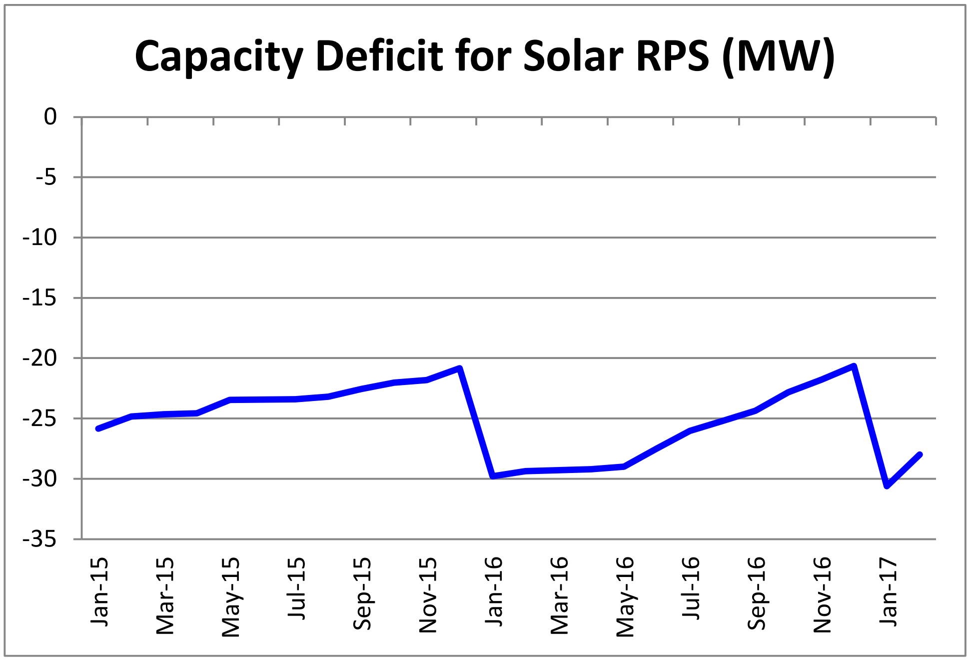
The Renewable Portfolio Standard law in the District requires each retail supplier of electricity licensed by the Commission to demonstrate that a certain percentage of the electricity sold to District customers is associated with renewable sources. The requirement also applies to the provider of default Standard Offer Service (SOS) for customers who do not purchase electricity from a licensed supplier. Under laws passed by the Council, the percentage of electricity required to come from renewable sources increases each year. Prior to enactment of the Renewable Portfolio Standard Expansion Amendment Act of 2016 the overall percentage of electricity sold to consumers in the District that each supplier was required to associate with renewable sources increased annually until it reached 20% in 2023. The 2016 Amendment Act extended the annual increases until reaching 50% by 2032.

In addition, within the required overall annual percentages, the RPS law includes a so-called "carve out" requirement for electricity from solar sources. Under the carve out provision prior to the Distributed Generation Amendment Act of 2011, suppliers had to first attempt to satisfy the requirement using facilities located in the District and could use solar associated with facilities located within PJM or a state bordering PJM if DC-based sources were not available. The 2011 amendment to the RPS law significantly changed this by requiring that, except for a small 20 MW of grandfathered facilities, the solar carve out could only be met using solar associated with facilities located in the District or on a feeder serving the District. The solar carve out percentage was set at amounts that increased annually to 2.5% by 2023. The 2016 Amendment Act retained the District based requirement and further increased the solar carve out annually until reaching 5% by 2032.

Retail suppliers can meet the RPS requirements in only one way—by the purchase of Renewable Energy Credits, or RECs, associated with facilities that have been certified by the Commission as eligible to participate in the RPS program. In the case of solar facilities eligible for the carve out, the Commission may only certify a facility if it is physically located in the District or on a feeder serving the District (i.e. a facility located in nearby areas of Maryland on a feeder that serves both jurisdictions). If RECs are not available for purchase, a retail supplier must meet the balance of the sales percentage requirement by the payment of an alternative compliance fee. The price of the fee for each category of renewable resource is set by the Council in the statute and the amount of the solar compliance fee was set to decline, in 2017, as the percentage requirement increased. However, the 2016 Amendment Act delayed the decline of the fee associated with the solar carve out and kept it at 50 cents per kilowatt-hour (kWh) through 2023.

While the number and capacity of District-based solar facilities certified by the Commission to sell solar RECs (SRECs) to retail suppliers for satisfaction of the District's Renewable Portfolio Standard requirement program has increased significantly over time, the amount of available SREC capacity is still well below the capacity required to meet the RPS requirement. The following charts display the continuing deficit.





In its comments on the proposed Amendment Act, the Commission expressed concern about the cost to consumers of the increase in the solar carve out and the maintenance of the higher solar alternative compliance fee for an additional seven years. Both the cost of the purchased SRECs and the price of the Alternative Compliance Fee are passed on to consumers by the retail suppliers and the SOS provider. The Commission estimated that the cost to consumers could reach over $100 million in 2023.

The Commission also noted that looking only at facilities that had been certified by the Commission for the sale of SRECs to retail suppliers did not give the full picture of the amount of electricity generated and consumed from solar resources located in the District, because it did not include facilities that were generating electricity from solar but were not certified for participation in the sale of SRECs. There are a number of reasons an owner of a solar facility might not certify its facility for the sale of SRECs. For example, if the SRECs are sold a building owner cannot count the solar facility for points in obtaining LEED, or Leadership in Energy and Environmental Design, certification—a significant consideration for commercial building owners. The Commission suggested that the Council might want to adjust the RPS requirement to account for these additional facilities. The Commission's comments led to the requirement in the 2016 Amendment Act for a report to the Council on how such a broader picture and adjustment might be accomplished.

II. Analysis

The Commission staff has considered various sources of information that are available to determine the total capacity of solar facilities located in the District. In addition to the Commission's database of certified facilities, Pepco maintains a database of facilities that have been approved for interconnection with Pepco's distribution system. This database includes all interconnected facilities, whether or not the owner has taken the second step of seeking certification for participation in the sale of SRECs. By comparing the solar photovoltaic (PV) systems that have been interconnected to Pepco's distribution system with the solar PV applications that have been submitted to the Commission for certification in the District's RPS program, the additional capacity can be identified.

In response to Order No. 18575 (issued October 17, 2016), in Formal Case No. 1050, Pepco provided information on the interconnection of systems through 2016. The solar PV systems included in Pepco's filing are reported to have a capacity of about 31,022 kilowatts (kW). As of February 1, 2017, the Commission has approved solar PV systems in the District with an estimated capacity of 27,582 kW. In addition, based on information obtained from the Renewable Electric Plant Information System (REPIS) database developed by the National Renewable Energy Laboratory (NREL), we adjusted the data to account for 356 kW of systems not contained in Pepco's interconnection database. This results in 3,795 kW of solar capacity that is "unaccounted" for in the District's RPS program.[1] This unaccounted for capacity can be converted into solar energy generation by using software, developed by NREL, called PVWatts®. Based on NREL's PVWatts® calculation, 1 kW of capacity produces about 1,329.5 kWh per year, or about 1.330 MWh per kW. Multiplying the latter number by the "unaccounted" for capacity of 3,795 kW yields roughly 5,046 unaccounted for renewable energy credits—1 REC is equal to 1 megawatt-hour (MWH) of electricity generation—which would be produced annually. This estimate satisfies the request in Item (1) of the Act above.

With respect to Item (2) of the Act, one can subtract the unaccounted for RECs from the estimated number of solar RECs needed to meet the RPS requirement in say 2016, for example, and estimate a new percentage requirement. The current solar requirement for 2016 is 0.825%. Based on Pepco's response to a Commission data request, the reported retail electricity sales for 2016 are 11,050,011.956 MWH and, after multiplying the previous solar requirement for 2016, yields a total number of required solar RECs of 91,162 (about 68.6 megawatts (MW) of solar capacity). Subtracting the unaccounted solar RECs from the required solar RECs yields a net amount of 86,116 solar RECs (roughly 64.8 MW).[2] This latter figure is equivalent to an RPS solar requirement of about 0.779% for 2016. Thus, if implemented, the unaccounted for solar RECs would produce a lower solar requirement that electricity suppliers would meet for the 2016 compliance year. This procedure would satisfy the request in Item (2) above.

The table below summarizes the two items (in bold) required, pursuant to the RPS Amendment Act of 2016. In particular, based on the available information, an estimated 5,046 MWH (or 5,046 solar RECs) would not be available to electricity suppliers to meet the District's solar energy RPS requirement at this time. Accounting for these unavailable solar RECs would lower the 2016 RPS requirement, for example, from 0.825% to 0.779% (an adjustment of 0.046%).

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[1] The Commission is also trying to make adjustments, as necessary, to account for any discrepancies between the data received from Pepco and the renewable portfolio standard ("RPS") applications submitted to the Commission in order to be certified for the RPS program.

[2] The adjustment of about 3.8 MW is roughly 5.5% of the 68.6 MW RPS solar requirement for compliance year 2016.

	MW	MWH
2016 RPS Requirement (0.825%)	68.6	91,162
Adjustment	**3.8**	**5,046**
2016 Revised RPS Requirement (0.779%)	**64.8**	**86,116**

III. Next Steps

Assuming that new legislation were to adopt the two requirements outlined in the Act, the remaining issues that would need to be addressed by the Commission are related to obtaining the data and the timing of informing the suppliers of the new solar requirement:

- First, the Commission would need the compliance year electricity sales and an update of interconnection approvals, which could be obtained from Pepco by mid-January.[3]
- Next, the process proposed in Section II would then be applied to the new data, producing a revised RPS requirement for the following compliance year.
- Subsequently, the Commission would inform the Council of the proposed adjustment—a 0.046% reduction in this example—in the annual report due to the Council on May 1. The proposed adjustment would also be put out for review and comment through the Commission's regular public process. The Commission would issue a decision annually by August 1 on any adjustment, which would then be applied to the next compliance year filing by electricity suppliers.[4] This schedule would give adequate opportunity for all interested persons to weigh in and comment on the proposed adjustment, and would inform suppliers of any adjustment prior to the start of a new compliance year.

[3] It is possible that Pepco's reported distribution sales may differ from the sales provided by electricity suppliers in their RPS compliance reports.

[4] Thus, following this example, the 0.046% reduction would be applied to the solar RPS requirement for the 2017 compliance year.

Question 31 - Attachment 13

Question 31: **Please list in decending order the top 25 overtime earners in your agency in FY17 and FY18, to date, if applicable. For each, state the employee's name, position number, position title, program, activity, salary, fringe, and the aggregate amount of overtime pay earned.**

Response FY17: **Please see reponse below:**

FY 2017

Employee Name	Postion Number	Position Title	Program	Activity	Salary	Fringe	Overtime Pay
Kenneth C Ford	00085491	Consumer Spec	Utility Regulation	Utility Regulation	58,679	11,971	$314.63
		Total					**$314.63**
Aaron-John Aylor	00041175	Staff Assistant	Utility Regulation	Utility Regulation	56,233	11,472	$330.36
		Total					**$330.36**
Amita Daves	00018979	Special Assistant	Agency Management	Personnel	72,528	14,796	$9.94
Amita Daves	00018979	Special Assistant	Agency Management	Training & Development	72,528	14,796	$9.94
Amita Daves	00018979	Special Assistant	Agency Management	Contracting & Procurement	72,528	14,796	$9.94
Amita Daves	00018979	Special Assistant	Agency Management	Property Management	72,528	14,796	$9.94
Amita Daves	00018979	Special Assistant	Agency Management	Information Technology	72,528	14,796	$9.94
Amita Daves	00018979	Special Assistant	Agency Management	Financial Management	72,528	14,796	$9.94
Amita Daves	00018979	Special Assistant	Agency Management	Legal	72,528	14,796	$9.94
Amita Daves	00018979	Special Assistant	Agency Management	Communications	72,528	14,796	$9.94
Amita Daves	00018979	Special Assistant	Agency Management	Customer Service	72,528	14,796	$9.94
Amita Daves	00018979	Special Assistant	Agency Management	Performance Management	72,528	14,796	$9.94
Amita Daves	00018979	Special Assistant	Utility Regulation	Utility Regulation	72,528	14,796	$397.49
		Total					**$496.89**
Margaret E Moskowitz	00018979	Sr. Consumer Services Spec	Agency Management	Communications	81,050	16,534	$143.53
Margaret E Moskowitz	00018979	Sr. Consumer Services Spec	Agency Management	Customer Service	81,050	16,534	$143.53
Margaret E Moskowitz	00018979	Sr. Consumer Services Spec	Utility Regulation	Utility Regulation	81,050	16,534	$430.59
Margaret E Moskowitz	00018979	Sr. Consumer Services Spec	Agency Management	Communications	81,050	16,534	$101.12
Margaret E Moskowitz	00018979	Sr. Consumer Services Spec	Agency Management	Customer Service	81,050	16,534	$101.12
Margaret E Moskowitz	00018979	Sr. Consumer Services Spec	Utility Regulation	Utility Regulation	81,050	16,534	$303.38
		Total					**$1,223.27**
Total Overtime for FY17							**$2,365.15**

FY 2018:

Aaron Aylor	00041175	Consumer Spec	Utility Regulation	Utility Regulation	65,443	13,350	$141.58
Total Overtime for FY18 (as of January 31, 2018)							**$141.58**

MEMORANDUM OF AGREEMENT

THIS AGREEMENT effective this 11th day of May, 2016 between the American Federation Of State, County And Municipal Employees, District Council 20, AFL-CIO ("AFSCME" or the "Union") and The Public Service Commission of the District of Columbia (the "Commission" or the "Employer").

WHEREAS, the Employer has recognized the Union as the sole and exclusive representative for employees with membership in the collective-bargaining unit of the American Federation of State, County and Municipal Employees, AFL-CIO, District of Columbia District Council 20, except for those employees specifically excluded in the Master Agreement;

WHEREAS, the Employer and Union have agreed on the non-compensation employment terms of the bargaining unit; the parties are desirous of establishing the compensation terms of the bargaining unit;

WHEREAS, the Government of the District of Columbia and certain labor organizations representing units of employees comprising Compensation Units 1 and 2, including AFSCME, have already negotiated and agreed to a compensation agreement titled "Compensation Agreement between the District of Columbia Government and Compensation Units 1 and 2, FY 2013 - FY 2017" ("Comp Plan"); and

WHEREAS, the Employer and the Union agree, the terms contained in the Comp Plan should be adopted as the compensation terms between the Union and the Employer.

NOW, THEREFORE, the Employer and Union agree:

1. The agreement titled "Compensation Agreement between the District of Columbia Government and Compensation Units 1 and 2, FY 2013 – FY 2017," shall apply to the bargaining unit except as modified by this Agreement.

2. Article 2 Metro Pass the Comp Plan shall be substituted and replaced with the following:
   "Article 2 Smart Benefits
   Bargaining unit employees shall receive the same Public Transit Fringe Benefit Programs ('SmarTrip") as all other employees of the Commission to subsidize all or part of the monthly transit costs of the employees between their residence and the Commission's offices on normal workdays."

3. This Agreement may only be modified upon mutual written agreement.

4. This Agreement shall be effective beginning July 1, 2016 and shall remain in full force and effect through September 30, 2017 provided that the parties may in writing mutually agree to extend this agreement.

IN WITNESS WHEREOF, the Employer and Union have signed this Agreement on the day and year first above written.

FOR THE PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

Betty Ann Kane, Chairman

FOR DISTRICT COUNCIL 20 AMERICAN FEDERATION OF STATE, COUNTY AND MUNICIPAL EMPLOYEES, AFL-CIO (AFSMCE)

Andrew Washington, Executive Director

Edward P. Ongweso, Ph.D

Anjanette L. Parker

John Howley

MASTER AGREEMENT

BETWEEN

THE AMERICAN FEDERATION OF STATE, COUNTY AND MUNICIPAL EMPLOYEES, DISTRICT COUNCIL 20, AFL-CIO

AND

THE PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

RECEIVED
DISTRICT OF COLUMBIA
PUBLIC SERVICE COMMISSION
2016 MAY -5 AM 10:36
OFFICE OF THE
COMMISSION SECRETARY

EFFECTIVE THROUGH SEPTEMBER 30, 2018

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PREAMBLE

The District of Columbia Comprehensive Merit Personnel Act (D.C. Law 2-139, Title I, Chapter 6, Subchapter 1, D.C. Official Code § 1-601.02) states that the Council of the District of Columbia declares that it is the purpose and policy of this act to assure that the District of Columbia Government shall have a modern flexible system of public personnel administration, which shall "provide for a positive policy of labor-management relations including collective bargaining between the District of Columbia and its employees . . . ."

The District of Columbia Comprehensive Merit Personnel Act (D.C. Law 2-139, Title 1, Chapter 6, Subchapter XVIII, (D.C. Official Code) Section 1-617.01) states [t]he District of Columbia Government finds and declares that an effective collective bargaining process is in the general public interest and will improve the morale of public employees and the quality of service to the public.

The District of Columbia Comprehensive Merit Personnel Act (D.C. Law 2-139, Title 1, Chapter 6, Subchapter XVIII, (D.C. Official Code) Section 1-617.01(b) provides for collective bargaining between the Mayor of the District of Columbia or any appropriate personnel authority and labor organizations accorded exclusive recognition for employee representation for employees of the District of Columbia Government.

Pursuant to the District of Columbia Comprehensive Merit Personnel Act (D.C. Law 2-139, Title 1, Chapter 6, Subchapter XVIII, (D.C. Official Code) Section 1-617.10), various local unions or District Council 20 of the American Federation of State, County and Municipal Employees, AFL-CIO, (herein "AFSCME" or the "Union") have been certified and/or recognized as the collective bargaining agent for certain employees of the Public Service Commission of the District of Columbia (hereinafter the "Commission" or the "Employer").

Accordingly, AFSCME and the Employer enter into this Agreement on , which shall have as its purposes:

1. Promotion of a positive policy of labor-management relations between the Employer and its employees;

2. Improvement of morale of employees in service to the Employer;

3. Enhancement of the quality of public service to the citizens of the District of Columbia;

4. Creation of a government that works better; and

5. Promotion of the rights of employees to express their views without fear of retaliation.

4/25/14
For Union AW For DCPSC

AFSCME and the Public Service Commission of the District of Columbia declare that each party has been afforded the opportunity to put forth all its non-compensation proposals and to bargain in good faith. Both parties agree that this Agreement is the result of their collective bargaining and each party affirms its contents as to the non-compensation terms of employment without reservation. This Preamble is intended to provide the background and purpose of the Collective Bargaining Agreement. Alleged violations of the Preamble per se will not be cited as contract violations.

ARTICLE 1
RECOGNITION

Section 1 — Recognition:

The Employer hereby recognizes as the sole and exclusive representative for the employees of the collective bargaining unit of the American Federation of State, County and Municipal Employees, AFL-CIO, District of Columbia District Council 20 (hereinafter referred to collectively as the "Union" or "AFSCME")

Section 2 - Bargaining Unit Description:

The Bargaining Unit shall be comprised of all professional and non-professional employees employed by the Employer, excluding all management officials, supervisors, confidential employees, employees engaged in personnel work other than in a purely clerical capacity and employees engaged in administering the provisions of Title 1, Chapter 6, subchapter XVII of the D.C. Official Code; and employees who are covered by another union's certification.

All Executive Assistants (Special Assistant II and III) to the Commissioners and the Executive Director, and the Staff Assistant in the Office of Human Resources, are excluded from the bargaining unit due to the nature of their job with the Employer, which includes access to personnel and confidential information.

Section 3 - Coverage:

AFSCME, the certified exclusive representative of all employees in the Bargaining Unit referenced above, shall be responsible for representing the interests of employees in the units without discrimination as to membership; provided, however, that a bargaining unit employee who does not pay dues or service fees may be required by the Union to pay reasonable costs for personal representation.

ARTICLE 2
MANAGEMENT RIGHTS

Section 1— Management Rights in Accordance with the Comprehensive Merit Personnel Act (CMPA):

For Union AW 4/25/14 For DCPSC

(a) Management's rights shall be administered consistent with D.C. Official Code §1-617.08, 2001 edition as amended.

(b) All matters shall be deemed negotiable except those that are proscribed by this subchapter. Negotiations concerning compensation are authorized to the extent provided in Sections 1-617.16 and 1-617.17 (as amended).

Section 2 - Impact of the Exercise of Management Rights:

Management rights are not subject to negotiations; however, in the Employer's exercise of such rights, the Union may request the opportunity to bargain the impact and effects of the exercise of management rights, where there has been an adverse impact upon employees regarding terms and conditions of employment.

ARTICLE 3
UNION RIGHTS AND SECURITY

Section 1 — Exclusive Agent:

The Employer shall not negotiate with any other employee organization or group with reference to terms and/or conditions of employment for employees represented by AFSCME. AFSCME shall have the right of unchallenged representation in its bargaining units for the duration of this Agreement in accordance with PERB Interim Rules, Section 502.9(b).

Section 2 — Meeting Space:

Upon request at least one day in advance, the Employer will provide meeting space as available for bargaining unit business. Except as provided elsewhere in this Agreement, meetings will be held on the non-work time of all employees attending the meetings. The Union will be responsible for maintaining decorum at meetings on the Employer's premises and for restoring the space to the same condition to which it existed prior to the meetings.

Section 3 — Access to Employees:

The Union shall have access to all new and rehired employees within its bargaining unit to explain Union membership, services and programs. Such access shall occur either during a formal orientation session or upon such employees' reporting to their work site within thirty (30) calendar days of employees' appointment or reappointment.

Section 4 - Dues Checkoff:

The Employer agrees to cause to be deducted union dues bi-weekly from the pay of employee members upon proper authorization. The employee must complete and sign Form 277 to authorize the withholding. The amount to be deducted shall be certified to the Employer in writing by the appropriate official of District Council 20. It is the responsibility of the employee and the Union to

For Union 4/05/16 For DCPSC

bring errors or changes in status to the attention of the Employer. Corrections or changes will be made at the earliest opportunity after notification is received but in no case will changes be made retroactively. Union dues withholding authorization may be cancelled upon written notification to the Union and the Employer within the thirty (30) calendar day period prior to the anniversary date of this Agreement. When Union dues are cancelled, the Employer shall withhold a service fee in accordance with Section 5 of this Article.

Section 5 - Service Fees:

In keeping with the principle that employees who benefit by the Agreement should share in the cost of its administration, the Union shall require that employees eligible to join the Union who do not pay Union dues shall pay an amount (not to exceed Union dues) that represents the cost of negotiation and/or representation. Such deductions shall be allowed when the Union presents evidence that at least 51% of the employees in the unit are members of the Union.

Section 6 — Cost of Processing:

The Employer shall cause to be deducted $.05 per deduction (dues or service fee) per pay period from each employee who has dues or service fees deducted. This amount represents the fair value of the cost to the Employer for performing the administrative services and is payable to the Office of Labor Relations and Collective Bargaining.

Section 7 - Hold Harmless:

The Union shall indemnify, defend and hold the Employer harmless against any and all claims, demands and other forms of liability, which may arise from the operation of this Article. In any case in which a judgment is entered against the Employer as a result of the deduction of dues or other fees, the amount held to be improperly deducted from an employee's pay and actually transferred to the Union by the Employer, shall be returned to the Employer or conveyed by the Union to the employee(s), as appropriate.

ARTICLE 4
LABOR-MANAGEMENT MEETINGS

Section 1— Labor-Management Partnerships:

Consistent with the principles of the D.C. Labor-Management Partnership Council, the parties agree to establish and support appropriate Labor-Management Partnerships to promote labor-management cooperation within a high-quality work environment designed to improve the quality of services delivered to the public.

The Commission's Partnership should ordinarily be made up of equal numbers of high-level officials of labor and management who will meet regularly to consider such issues as they choose to discuss. Decisions by the partnership shall be by consensus only.

For Union 4/05/16 For DCPSC

Section 2 — Labor-Management Contract Review Committee:

Appropriate high-level management and union representatives shall meet as necessary, at either party's request, to discuss problems covering the implementation of this Agreement. The findings and recommendations of the Contract Review Committee will be referred to the Chairman of the Commission (hereinafter the "Chairman") for action. The Chairman or his/her designee shall respond in writing to any written finding and recommendation of the committee within a reasonable period.

ARTICLE 5
DISCRIMINATION

Section 1 — General Provisions:

The Employer agrees that it will not in any way discriminate against any employee because of his/her membership or affiliation in or with the Union or service in any capacity on behalf of the Union. Each employee has the right, freely and without fear of penalty.

(1) To form, join and assist a labor organization or to refrain from this activity;

(2) To engage in collective bargaining concerning terms and conditions of employment, as may be appropriate under this law and rules and regulations through a duly designated majority representative; and,

(3) To be protected in the exercise of these rights.

Neither party to this Agreement will discriminate against any employee with regard to race, color, religion, national origin, sex, age, marital status, personal appearance, sexual orientation, family responsibilities, matriculation, physical handicap, political affiliation, or as otherwise provided by law.

Section 2 — Equal Employment Practices:

The Employer agrees to vigorously continue the implementation of its Equal Employment opportunity Program as approved by the Director, D.C. Office of Human Rights. For the purpose of this Agreement, the Employer's affirmative action plan will be observed. Any deviation of the plan shall be sent to the Union.

The Union shall designate an Affirmative Action Coordinator who shall, upon request, attend meetings of the Employer to discuss implementation of the affirmative action policies and programs.

For Union 4/05/16 For DCPSC

Vacancy Announcements for vacancies shall be posted at all work locations. One copy of the notice shall be supplied to appropriate Union Shop Stewards. For all purposes of this agreement, notice may be delivered electronically.

Section 3 — Discrimination Charges:

Any charges of discrimination shall be considered by the appropriate administrative agency having jurisdiction over the matter and shall therefore not be subject to the negotiated grievance procedure.

ARTICLE 6
UNION RIGHTS AND RESPONSIBILITIES

Section 1— Union Stewards:

Union Stewards shall be designated by the Union and shall be recognized as employee representatives. Union Stewards shall be employed at the same work area or shift as employees they are designated to represent. When a union steward is transferred by an action of management (not including promotion or transfer at the employee's request), the steward may continue to act as a steward for his/her former work site for a period not to exceed 45 days from original notification. The Union will supply the Employer with lists of stewards' names, which shall be posted on appropriate bulletin boards. The Union shall notify the Employer of changes in the roster of Stewards. Stewards are authorized to perform and discharge union duties and responsibilities, which may be assigned to them under the terms of this Agreement.

Section 2 — Performance of Duties:

Stewards shall obtain permission from their immediate supervisors prior to leaving their work assignments to properly and expeditiously carry out their duties during a reasonable amount of official time to be estimated in advance whenever possible. Before attempting to see an employee, the Steward will obtain permission from the employee's supervisor. Such permission will be granted unless the employee cannot be immediately relieved from his assigned duties, in which case permission will be granted as soon as possible thereafter. If the immediate supervisor is unavailable, permission will be requested from the next highest level of supervision. Requests by Stewards for permission to meet with employees and/or by employees to meet with Stewards will not require prior explanation to the supervisor of the problems involved other than to identify the area to be visited and the general purpose of the visit i.e., grievance investigation, labor-management meetings, negotiation sessions, etc.

A Steward thus engaged will report back to his/her supervisor on completion of such duties and return to their job. The employer agrees that there shall be no restraint, interference, coercion, or discrimination against a Steward in the performance of such duties.

Section 3 — Union Activities on Employer's Time and Premises:

For Union ______ For DCPSC ______

The Employer agrees that during working hours, on the Employer's premises and without loss of pay, in accordance with Article 6 of this Agreement, Union representatives shall be allowed to:

A. Post Union notices on designated Union bulletin boards (with a copy given to the Employer);

B. Attend negotiation meetings;

C. Transmit communications authorized by the District Council and Local Union or its officers to the Employer or his/her representative;

D. Consult with the Employer or his/her representative, District Council and Local Union Officers, other Union representatives or employers, concerning the enforcement of any provisions of this Agreement, and other Labor-Management activities. Official time does not include internal Union activities; and

E. Solicitation of Union membership and distribution of literature shall be confined to the non-working time of all employees involved and out of sight of the public.

Section 4 — Visits by Union Representatives:

The Employer agrees that representatives of the American Federation of State, County and Municipal Employees whether local, Union representatives, District council representatives, or International representatives shall have full and free access except in secured areas, to the premises of the Employer at any time during working hours to conduct Union business. Except for matters of an employee's discipline or an emergency, the Union shall give the Employer at least 24-hours advance notification to the appropriate supervisor of the facility to be visited to permit scheduling that will cause minimal disruption of the work activities.

Section 5 — Union Insignia:

The Employer agrees that the employee has a right to participate and identify with the Union as his/her representative in collective bargaining matters; therefore, the Employer agrees that such identification devices as emblems, buttons and pins supplied by the Union to the employees within the bargaining unit may be worn.

Section 6 — Official Time:

Union representatives who engage in labor management activities during working hours shall indicate on the "Official Time Report" the activity performed. See Appendix A. No Union representative will be disadvantaged in the assessment of his/her performance based on use of documented official time while conducting labor management business.

For Union 4/26/16 For DCPSC 4/25/16

ARTICLE 7
DISCIPLINE

Section 1:

Discipline shall be imposed for cause, as provided in the D.C. Official Code § 1-616.51 (2001 ed.).

Section 2:

For the purposes of this Article, discipline shall include the following:

a. **Corrective Actions:** Written reprimands or suspensions of nine (9) days or less;

b. **Adverse Actions:** Removal, suspension for more than nine (9) days; or a reduction in rank or grade or pay for cause.

Section 3:

Discipline will be appropriate to the circumstances, and shall be primarily corrective, rather than punitive in nature. After discovery of the incident, the investigations shall be conducted in a timely manner and discipline shall be imposed upon the conclusion of any investigation or the gathering of any required documents, consistent with the principle of progressive discipline.

Section 4:

If a supervisor has reason to discipline an employee, it shall be done in a manner that will not embarrass the employee before other employees or the public.

Section 5:

Unless there is a reasonable cause to believe that an employee's conduct is an immediate hazard to the Employer, the employee or other employees, or is detrimental to public health, safety or welfare, an employee against whom adverse action is proposed shall be entitled to at least fifteen (15) days advance written notice of proposed adverse action (or seven (7) days if corrective action is proposed). The notice will identify the causes and the reasons for the proposed action.

Section 6:

Recognizing that the Union is the exclusive representative of the employees in the bargaining unit, the Employer shall in good faith attempt to notify the Union of proposed disciplinary actions. Further, the Employer agrees to notify the employee of his or her right to representation in corrective or adverse actions. The material upon which the proposed discipline is based shall be made

For Union [initials] 4/25/14 For DCPSC [signature] 4-25-16 available to the employee and his/her authorized representatives for review. The employee or his/her authorized representative will be entitled to receive a copy of the material upon written request.

Any information that cannot be disclosed to the employee, his representative, or physician shall not be used to support the proposed action.

Section 7:

Except in the special circumstances referred to in Section 5 above, an employee shall be entitled to at least five (5) workdays to answer the notice of proposed corrective or adverse action. If the proposed action is removal, the employee shall upon request, be granted an opportunity to be heard prior to a final decision. This opportunity to be heard shall be afforded by a person designated by the Employer. This person shall not be in the supervisory chain between the proposing and/or deciding official(s) and shall not be subordinate to the proposing official. This person shall review the employee's answer, discuss the proposed action with the employee and/or his representative and appropriate representatives of the Employer and make a recommendation to the deciding official who will act upon the recommendation, as he/she deems proper.

Section 8:

The person proposing a disciplinary action shall not be the deciding official unless the proposing official is the Chairman of the Employer or its Chief Human Resource Officer.

Section 9:

Except in the special circumstances referred to in Section 5 above, an employee against whom a corrective or adverse action has been proposed shall be kept in an active duty status during the notice period.

Section 10:

The deciding official shall issue a written decision within forty-five (45) calendar days from the date of receipt of the notice of proposed action, which shall withdraw the notice of proposed action or sustain the proposed action in whole or in part. The forty-five (45) day period for issuing a final decision may be extended by agreement of the employee and the deciding official. If the proposed action is sustained in whole or in part, the written decision shall identify which causes have been sustained and which have been dismissed, describe whether the proposed penalty has been sustained or reduced and inform the employee of his or her right to appeal or grieve the decision, and the right to be represented. The final decision shall also specify the effective date of this action.

For Union AAW 4/25/16 For DCPSC 4/25/16

Section 11:

In any circumstance in which the Employer has reasonable cause to believe that an employee's conduct is an immediate hazard to the Employer, to the employee involved or other employees, or is detrimental to the public's health, safety or welfare; the Employer may place an employee on administrative leave with or without notice of the proposed action to the employee.

Section 12:

Notice of final decision, dated and signed by the deciding official, shall be delivered to the employee on or before the time the action is effective. If the employee is not in a duty status at that time, the notice shall be sent to the employee's last known address by certified or registered mail.

Section 13:

Except as provided in Section 14 of this Article, employees may grieve actions through the negotiated grievance procedure, or appeal to the Office of Employee Appeals (OEA) in accordance with OEA regulations but not both. Once the employee has selected the review procedure, that choice shall be the exclusive method of review.

Section 14:

The removal of an employee during his or her probationary period is neither grievable nor appealable and shall be done in accordance with the Employer's policies.

Section 15:

If a final decision is grieved through the negotiated grievance procedure a written grievance shall be filed with the deciding official within fifteen (15) workdays after the effective date of the action.

Section 16:

In appropriate cases, consideration shall be given to referring troubled employees to an employee assistance program sponsored by the Government of the District of Columbia.

Section 17:

Whenever an employee is questioned by a supervisor with respect to a matter for which a disciplinary action is intended against the employee, the employee may, upon request, consult with a union official or other representative. Upon such request, the supervisor will stop the questioning until the employee can consult with such representative, but in no event will such questioning be delayed beyond the end of the employee's following shift. When and if questioning is resumed, an employee may have a union official or other representative present.

For Union 4/25/16 For DCPSC 4.25.16

ARTICLE 8
TRAINING AND CAREER LADDER

Section 1— Basic Training:

Other than skills necessary to qualify for the position, the Employer agrees to provide, as appropriate, each employee with basic training or orientation for the safe and effective performance of his/her job. Training must relate to the employee's job function, subject to budget, and the Employer's preapproval, which shall not be unreasonably withheld. Such training shall be provided at the Employer's expense and, if possible, during the employee's regular workday. If the employee is required to participate in training outside of regular work hours, the employee will be compensated in accordance with the DPM Chapter 13. Continued training shall be within budgetary constraints.

Section 2 - Continued Training Opportunities:

The Employer will encourage and assist employees in obtaining career related training and education outside the Employer by collecting and posting current information available on training and educational opportunities. The Employer will inform employees of time or expense assistance the Employer may be able to provide.

Section 3 - Career Ladder:

The parties recognize and endorse the value of employee training and career ladder programs. Both parties subscribe to the principles of providing career development opportunities for employees who demonstrate potential for advancement. The feasibility of upward mobility and training programs for unit employees shall be a proper subject for labor-management meetings. Career ladder promotions when effected, shall be in accordance with DPM Chapter 8, Part II, Subpart 8, and Appendix A.

Section 4 - Experience Verification:

When an institution of higher learning provides credit for on-the-job experience, the Employer will, at the request of the employee, seek to provide pertinent information to verify the employee's experience with the Employer. The employee shall provide the relevant documents and information necessary for the release of the employee's information to the relevant institution.

Section 5 - Union Sponsored Career Advancement Programs:

Management and the Union support the objective of meaningful career advancement for employees through promotions, transfers and the filling of vacancies. In keeping with this objective, the Union will investigate and develop programs to enhance opportunities for career advancement such as: career counseling services; placement of career planning resource materials on site; correspondence course arrangements with area colleges, universities, vocational and technical schools; and workshops on resume writing and interview skills.

4/05/16
For Union AW For DCPSC AJ 4.25.16

Programs that are developed will be presented and discussed during appropriate labor-management committee meetings for review and consideration.

ARTICLE 9
SAFETY AND HEALTH

Section 1 - Working Conditions:

A. The Employer shall provide and maintain safe and healthful working conditions for all employees as required by applicable laws. It is understood that the Employer may exceed standards established by regulations consistent with the objectives set by law. The Employer will make every effort to provide and maintain safe working conditions. AFSCME will cooperate in these efforts by encouraging its members to work in a safe manner and to obey established safety practices and regulations.

B. Matters involving safety and health will be governed by the D.C. Occupational Safety and Health Plan in accordance with Subchapter XXI of the Comprehensive Merit Personnel Act (1980, as amended).

C. The Employer shall furnish and maintain each work place in accordance with standards provided within this Section.

Section 2 - Employees Working Alone:

Employees shall not be required to work alone in areas beyond the call, observation or periodic check of others where dangerous chemicals, explosives, toxic gases, radiation, laser light, high voltage or rotary machinery are to be handled, or in known dangerous situations whenever the health and safety of an employee would be endangered by working alone.

Section 3 - Corrective Actions:

A. If an employee observes a condition, which he or she, believes to be unsafe, the employee should report the condition to the immediate supervisor.

B. If the supervisor and employee agree that a condition constitutes an immediate hazard to the health and safety of the employee, the supervisor shall take immediate precautions to protect the employee.

C. If the supervisor and employee do not agree that a condition constitutes an immediate hazard to the health and safety of the employee, the matter may be immediately referred by the employee to the next level supervisor or designee. The supervisor or designee shall meet as soon as possible with the employee and his or her AFSCME representative, and shall make a determination.

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D. Employees shall not be required to operate equipment that has been determined by the Employer to be unsafe to use, when by doing so they might injure themselves or others.

Section 4 - Medical Service: On-the-Job Injury:

A. The Employer shall make first-aid kits reasonably available for use in case of on-the-job injuries. If additional treatment appears to be necessary, the Employer shall arrange immediately for transportation to an appropriate medical facility.

B. The need for additional first-aid kits will be an appropriate issue for Safety Committee determination. Recommendations of the Safety Committee will be referred to the Employer.

Section 5 - Safety Devices and Equipment:

When applicable, protective devices and protective equipment shall be provided by the Employer to be used by employees.

Section 6 - Safety Training

A. The Employer shall provide safety training to employees as necessary for performance of their job. Issues involving safety training may be presented to the Safety Committee established in Section 8(A).

B. The Employer shall provide CPR training to all employees who request such training.

Section 7 - Information on Toxic Substances:

Employees who have been identified by the Safety Committee and the Employer as having been exposed to a toxic substance (including, but not limited to asbestos) in sufficient quantity or duration to meet District Government standards shall receive appropriate health screening. In the absence of District Government standards, the Safety Committee and Safety Officer will refer to standards established by other appropriate authorities such as Occupational Safety and Health Administration (OSHA), National Institute for Occupational Safety and Health (NIOSH) or the Environmental Protection Agency (EPA).

Section 8 - Safety Committees:

A. A Safety Committee of three (3) representatives from AFSCME and three (3) representatives from the Employer is hereby established.

B. One (1) AFSCME and one (1) Employer representative shall each serve as co-chairpersons of the Committee. The Employer's Risk Management official shall serve on the Safety Committee as one of the Employer's representative.

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C. The Safety Committee shall:

1. Meet at least quarterly or as needed, unless mutually agreed otherwise. Prior to regularly scheduled monthly meeting, labor and management must submit their respective agendas to each other at least five (5) days in advance;

2. Conduct safety surveys, consider training needs, and make recommendations to the Employer;

3. Receive appropriate health and safety training.

D. Final reports or responses from the Employer shall be provided to the Safety Committee within a reasonable period of time on safety matters initiated by the Committee.

E. Safety Committees may be reorganized upon agreement of both parties.

Section 9 - Light Duty:

A. The Employer agrees to provide light duty assignments for Employees injured on the job to the extent that such light duty is available as follows:

1. To be eligible for light duty, the employee must be certified by the employee's attending physician. The certification must identify the employee's impairments and the type of light duty he or she is capable of performing.

2. The Employee will be given light duty assignments for which he or she is qualified, initially within his or her own unit. If light duty is not available within the unit, suitable work will be sought elsewhere within the Commission.

3. Light duty assignments shall not normally extend beyond 45 working days. However, if there are no other requests for light duty, this period may be extended until such time as another employee makes the request. Employees unable to perform their regularly assigned duties after the expiration of that time shall make application for disability compensation or exercise such other options as may be available to employees under the provisions of this Agreement or under law, and in accordance with paragraph 5 below.

4. Where there are more requests for light duty than there are light duty assignments, assignments shall be made in the order of earlier date of request.

5. When light duty is not available, an employee must return to full duty or seek compensation or retirement from appropriate channels, or other assistance as may be available in accordance with Section 9. In the event compensation or retirement is not approved,

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the employee may be required to take a fitness for duty examination and may be separated if (a) found unfit to perform or (b) found fit but refuses to report for full duty.

Section 10 - Excessive Temperatures in Buildings:

Employees, other than those determined by the Employer to be essential, shall be released from duty or reassigned to other duties of a similar nature at a suitably temperate site because of excessively hot or cold conditions in the building. This determination will be made by the Employer as expeditiously as possible and shall be based upon existing procedures. In lieu of dismissal, the Employer may reassign employees to other duties of similar nature at a suitably temperate site. The cost of authorized transportation will be assumed by the Employer. Administrative leave will be granted if authorized by the Chairman or his or her designee.

Section 11 - Employee Health Services:

Employees covered by this Agreement shall have access to employee health services provided by the Employer consistent with the Comprehensive Merit Personnel Act (D.C. Law 2-139).

Section 12 - Maintenance of Health Records:

Medical records of employees shall be maintained in accordance with the provisions of Chapter 31 of the D.C. Government regulations that maintain confidentiality of those records. Medical records shall not be disclosed to anyone except in compliance with applicable rules relating to disclosure of information. Copies of rules relating to medical information will be made available to AFSCME.

Section 13:

A. The Employer agrees to follow Mayor's order 87-95 regarding ergonomic policy for use of video display terminals (VDT).

B. Continuous users who operate a video display terminal for more than two continuous hours shall be allowed to move out of their chairs for brief periods to perform other tasks as specified by their supervisor.

C. If a pregnant employee, who is a continuous VDT user, submits a medical statement from her physician which recommends limiting her use of the VDT during the term of her pregnancy because of exposure to radiation, reasonable consideration will be given to providing the employee with other available duties, within the work unit, for which she is qualified and which her doctor certifies that she can perform.

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ARTICLE 10
GENERAL PROVISIONS

Section 1 — Work Rules:

Employees will be advised of verbal and written work rules, which they are required to follow. The Employer agrees that proposed new written work rules and the revision of existing written work rules that affect the bargain agreement shall be subject to notice and consultation with the Union.

Section 2 - Distribution of Agreement:

The Employer and Union agree to share equally in the cost of reproducing this contract for employees and supervisors. The parties shall mutually agree upon the cost and number of copies to be printed.

ARTICLE 11
BULLETIN BOARDS

The Employer agrees to furnish suitable Bulletin Boards and/or space to be placed at locations mutually acceptable to the Union and the Employer. The Union shall limit its posting of notices and bulletins to such Bulletin Boards.

ARTICLE 12
PERSONNEL FILES

Section 1 - Official Files:

The Employer shall cause to be maintained the official files of all personnel covered by this Agreement. Records of corrective actions or adverse actions shall be removed from an employee's official file in accordance with the DPM.

Section 2 - Right to Examine:

Each employee shall have the right to examine the contents of his/her personnel files upon request.

Section 3 — Right to Respond:

Each employee shall have the right to answer any material filed in his/her personnel file and his/her answer shall be attached to the material to which it relates.

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Section 4 - Right to Copy:

An employee may copy any material in his/her personnel file.

Section 5 — Access by Union:

Upon presentation of written authorization by an employee, the Union representative may examine the employee's personnel file and make copies of the material.

Section 6 — Confidential Information:

The Employer shall cause to be kept all arrests by the Metropolitan Police, fingerprint records, and other confidential reports in a confidential file apart from the official personnel folder. No person shall have access to the confidential file without authorization from the Employer's Chief Human Resources Officer.

Section 7 - Employee to Receive Copies:

A. The employee shall receive a copy of all material placed in his/her folder in accordance with present personnel practices. Consistent with this Article when the Employer sends documents to be placed in an employee's personnel folder which could result in disciplinary action or non-routine documents which may adversely affect the employee, the employee shall be asked to acknowledge receipt of the document. The employee's signature does not imply agreement with the material but simply indicates he/she received a copy.

B. If an employee alleges that he/she was not asked to acknowledge receipt of material placed in his/her personnel folder as provided in this section, the employee will be given the opportunity to respond to that document and the response will be included in the folder.

Section 8 — Access by Others:

The Employer shall inform the employee of all requests outside of the normal for information about him/her or from his/her personnel folder. The access card signed by all those who have requested and have been given access to the employee's file shall be available for review by the employee.

ARTICLE 13
SENIORITY

Section 1 - Definition:

Seniority means an employee's length of continuous service within job classification and function with the Employer from his/her date of hire for purposes of this Article only. Employees hired on the same day shall use alphabetical order of surname in determining seniority.

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Section 2 - Breaks in Continuous Service:

An employee's continuous service shall be broken by voluntary resignation, discharge for cause or retirement. If an employee returns to his former, or a comparable, position within one year, the seniority he had at the time of his/her departure will be restored but he/she shall not accrue additional seniority during his/her period of absence.

Section 3 - Seniority Lists:

The Employer shall provide the Union semiannually with list of names of employees represented by the Union. The list will be in seniority order as defined by Section 1 of this Article. The Employer shall supply the Union semi-annually with lists of new hires in bargaining unit positions and the names of unit employees who have left employment.

Section 4 - Reassignments:

A reassignment requested by an employee to a position in the same classification within the Commission may be effected by mutual agreement.

Section 5 - Promotions:

A. Whenever a job opening occurs, in any existing job classification or as the result of the development or establishment of a new job classification, a notice of such opening shall be posted on all bulletin boards or communicated electronically for ten (10) working days prior to the closing date. A copy of the notices of job openings will be given to the appropriate Union Steward at the time of posting.

B. During this period, employees who wish to apply for the open position or job including employees on layoff may do so. The application shall be in writing, and it shall be submitted to the appropriate Human Resources Office.

C. Management has the right to determine job qualifications, provided they are limited to those factors directly required to satisfactorily perform his/her job. Where all job factors are relatively equal, the employee with the greatest relevant seniority within the unit shall be promoted.

Section 6 - Change to Lower Grade:

A. The term "change to lower grade", as used in this provision means change of assignment from a position in one job classification to a lower paying position in the same job classification.

B. Demotions may be made to avoid laying off employees, to provide for employees who request a change to lower grade for personal convenience, or to change an employee to a lower grade when he/she is unable to perform satisfactorily the duties of his/her position.

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Section 7 - Individual Work Schedules:

Work schedule changes initiated by the Employer affecting an individual employee shall be in accord with seniority, except where specific skills are needed.

Section 8 - Pay for Work Performed in Higher Graded Position:

A. Employees detailed or assigned to perform the duties of a higher graded position for more than four (4) pay periods in any calendar year shall receive the pay of the higher graded position. Assignment to a higher graded position for periods of at least one (1) pay period shall count toward the accumulation of the four (4) pay period requirement. The applicable rate of pay will be determined by application of D.C. government procedures concerning grade and step placement for temporary promotions, and will be effective the first pay period beginning after the qualifying period has passed. An employee on detail to a lower graded position shall maintain the pay for his/her original position. Advance notice will be given to the Union of any detail exceeding one pay period.

B. This provision shall not apply to training programs.

C. Issues involving changed or additional duties assigned to an employee, within his/her present position, shall be considered in accordance with position classification procedures.

ARTICLE 14
INCLEMENT WEATHER CONDITIONS

Section 1 - Reporting Time:

A. During inclement weather where the Employer has declared an emergency, employees (other than those designated emergency employees) will be given a reasonable amount of time to report for duty without charge to leave. Those employees required to remain on their post until relieved will be compensated at the appropriate overtime rate or compensatory leave for the time it takes his/her relief to report for duty.

B. The Employer agrees to dismiss all non-emergency employees when early dismissal is authorized by higher officials during inclement weather.

ARTICLE 15
HOURS OF WORK

Section 1 - Workday:

Except as provided in this Article, the normal workday for full-time employees shall consist of eight (8) hours of work within a 24-hour period. The normal hours of work shall be consecutive except that they may be interrupted by a lunch period.

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Section 2 - Workweek:

Except as provided in this Article, the workweek for full-time employees shall normally consist of five (5) consecutive days, eight (8) hours of work, Monday through Friday, totaling forty (40) hours. Special schedules will be established for employees, other than employees in continuous operations, who are required to work on Saturday, Sunday or seasonal schedules as part of their regular workweek.

Section 3 - Continuous Operations and Shifts:

The workday for employees in 24-hour continuous operations shall consist of eight hours of work. Work schedules for employees assigned to shifts, showing the employee's workdays, and hours, shall be posted on appropriate bulletin boards. All employees shall be scheduled to work regular work shifts i.e., each work shift shall have a regular starting and quitting time.

Section 4 - Changes in Work Schedules:

Except in emergencies, regular work schedules shall not be changed without ten (10) working days advance notice.

Section 5 - Flexible/Alternative Work Schedules:

A. The normal work hours may be adjusted to allow for flexible/alternative work schedules, with appropriate adjustments in affected leave and compensation items (e.g., overtime, premium pay, compensatory leave, etc.). Such schedules may be appropriate where: (1) it is cost effective, (2) it increases employee morale and productivity, or (3) it better serves the needs of the public. The Union will be given advance notice (when flexible/alternative work schedules are proposed) and shall be given the opportunity to consult.

B. An alternative work schedule will provide that overtime compensation will not begin until the regularly scheduled workday or tour of duty has been completed. Other premiums will be based on the regularly scheduled workday of the employees. An alternative work schedule shall not affect the existing leave system. Leave will continue to be earned at the same number of hours per pay period as for employees on five (5) day, forty (40) hour schedules and will be charged on an hour-by-hour basis.

ARTICLE 16
ADMINISTRATION OF LEAVE

Section 1— General:

Employees shall be eligible to use leave in accordance with the personnel rules and regulations. Any request for a leave of absence shall be submitted in writing by the employee to his/her immediate supervisor. The request shall state the length of time off the employee desires, the type of leave requested and the reason for the request. An excused absence is an absence from duty without loss of pay and without charge to leave when such absence is authorized by statute or administrative discretion.

Section 2 - Annual Leave:

A. Normal Requests for Leave: A request for a short leave of absence, not to exceed three days, shall be requested in writing on the proper form and answered before the end of the work shift in which the request is submitted. A request for a leave of absence between four to seven days must be submitted five (5) calendar days in advance and answered within five days, except for scheduled vacations, as provided for in Section 2 of this Article. If the request is disapproved, the supervisor shall return the SF-71 with reasons for the disapproval indicated. Requests for annual leave shall not be unreasonably denied.

B. Emergency Requests: Any employee's request for immediate leave due to family death or sickness shall be granted or denied immediately.

C. Carryover: Annual leave, which is not used, may be accumulated from year to year. In general, the maximum allowable leave is thirty (30) days, unless the employee had a greater amount of allowable leave at the beginning of the leave year. Employees shall receive a lump sum leave payment for all accrued annual leave not used at the time of retirement, resignation or other separation from the employer, consistent with the negotiated Compensation Agreement.

D. Vacation Schedules: Every effort will be made to grant employees leave during the time requested. If the operations would suffer by scheduling all requests during a given period of time, a schedule will be worked out with all conflicts to be resolved by the application of seniority. After vacations are posted, no changes shall be made unless mutually agreeable or an emergency arises. Employees will be encouraged to schedule vacations through the year.

Section 3 - Sick Leave:

A. Requests:

1. Supervisors shall approve sick leave of employees incapacitated from the performance of their duties. Employees shall request sick leave as far in advance as possible prior to the start of their regular tour of duty on the first day of absence.

2. Sick leave shall be requested and approved in advance for visits to and/or appointments with doctors, dentists, practitioners, opticians, and chiropractors for the purpose of securing diagnostic examinations, treatments and x-rays.

3. Employees shall not be required to furnish a doctor's certificate to substantiate requests for approval of sick leave unless such sick leave exceeds three work days continuous duration. However, if Management has given written notice to an employee that there is a good reason to believe that the employee has abused sick leave privileges, then the employee must furnish a doctor's certificate for each absence from work, which is

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claimed as sick leave regardless of its duration. The Union will encourage employees to conserve sick leave for use during periods of extended illness.

4. Advance sick leave requests will be given prompt consideration by the Employer consistent with Section 3(b) of this Article when the following provisions are met:

> **(a)** The request must be submitted in writing and must be supported by acceptable medical certificates.
>
> **(b)** All available accumulated sick leave to the employee's credit must be exhausted. The employee must use annual leave he/she might otherwise forfeit.
>
> **(c)** In the case of employees serving under temporary appointments, or under probationary or trial periods, advance sick leave should not exceed an amount which is reasonably assured will be subsequently earned during such period.
>
> **(d)** The amount of sick leave advanced to an employee's account will not exceed 240 hours at any time. Where it is known that the employee is to be separated, the total sick leave advanced may not exceed an amount, which can be liquidated by subsequent accrual prior to the separation.
>
> **(e)** There must be a reasonable assurance that the employee will return to duty.

B. Advance Sick Leave: Advance sick leave may be granted to permanent or probationary employees in amounts not to exceed 240 hours. Furthermore, an employee may not be indebted for more than 240 hours of sick leave at any one time. Sick leave may be advanced to employees holding a limited appointment or one expiring on a specific date, but not in excess of the total sick leave that would accrue during the remaining period of such appointment. In either case the employee request must be supported by a statement from his/her physician attesting that the employee has a serious disability or ailment and is incapacitated for duty and stating the period of time expected to be involved. The request should be denied only if the requirements of Section 3 (a) and (b) are not met or there is a reason to believe that the employee will not return to duty or that he/she has abused the sick leave privilege in the past.

C. All accrued and accumulated sick leave must be exhausted before the advance sick leave is credited. Accrued and accumulated annual leave may remain standing to the credit of employees. The Employer will use its best efforts to answer an employee's request for advanced sick leave within fifteen (15) working days. However, an employee is responsible for applying advance sick leave in writing as far in advance as possible. If the request is denied, the reasons for such denial shall be given in writing. Further, the employee will be given consideration for LWOP consistent with the provisions of personnel rules and regulations.

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Section 4 — Other Paid Leave:

A. Military Leave: Full-time employees are entitled to leave as reserve members of the armed forces or as members of the National Guard to the extent provided in D.C. Official Code Section 1-612.03(m) and applicable rules and regulations., which provides in part the following:

1. Members of the D.C. National Guard are entitled to unlimited military leave without loss of pay for any parade or encampment with the D.C. National Guard when ordered by the Commanding General, excluding weekly drills and meetings.

2. Additional military leave with pay will be granted to full-time employees who are members of the reserve components of the Armed Forces or the National Guard for the purpose of providing military aid to enforce the law for a period not to exceed 22 workdays per calendar year.

B. Court Leave: Employees shall be granted leave of absence with pay anytime they are required to report for jury duty or to appear as a witness on behalf of the District of Columbia Government, or the Federal or a State or Local Government, in accordance with personnel rules and regulations.

C. Voting Leave: Where the polls are not open at least three hours either before or after an employee's regular hours of work, he/she may, upon request, be granted an amount of excused time which will permit him/her to report to work three hours after the polls open or leave work three hours before the polls close, whichever requires the lesser amount of time off. Leave for voting will be allowed in accordance with the personnel rules and regulations.

D. Funeral Leave: Funeral leave shall be granted in accordance with the District of Columbia Compensation Units 1 & 2 Agreement.

E. Civic Duty: Upon advance request and adequate justification employees required to appear before a court or other public body on public business in which they are not personally involved shall be granted leave of absence with pay unless paid leave is prohibited by Federal or District Regulations or Statutes.

F. Examinations: Employees shall be excused without charge to leave in accordance with personnel rules and regulations for the purpose of taking an employment medical examination and examination for induction or enlistment in the active Armed Forces, a District Government owned vehicle operator examination, a civil service examination or other examination which his/her the Employer has requested him/her to take in order to qualify for reassignment, promotion, or continuance of his/her present job, but not for the reserve Armed Forces. An employee shall also be excused without charge to leave for the purpose of taking an examination whenever, in the judgment of the Employer it will benefit thereby. Absence from duty in order to take an examination primarily for the employee's own benefit and not connected to the District Government must be requested in accordance with the general leave provisions.

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<u>Section 5: Leave Without Pay:</u>

A. **General:** Leave of absence without pay for a limited period may be granted at the supervisor's discretion for a reasonable purpose if requested in advance in writing.

B. **Union:** Employees elected to any Union office or selected by the Union to do work which takes them from their employment with the Employer shall at the written request of the employee and the Union be granted a leave of absence without pay; provided the written request states the purpose and duration of the absence, and is submitted thirty (30) calendar days in advance of the commencement of the desired period of absence. If the Employer indicates that the requested leave will unduly hamper its operations, it may offer an alternative for consideration by the Union.

C. The initial leave of absence shall not exceed one (1) year. Leaves of absence for Union officials may be extended for similar periods. No more than one employee from a bargaining unit shall be on such extended leave at the same time.

D. **Parenthood Leave:** Maternity leave before and following childbirth shall be granted at the request of the employee. The employee is obligated to advise her supervisor substantially in advance of the anticipated leave date. This period of absence shall be determined by the employee, her physician and her supervisor. Maternity leave is chargeable to sick leave or any combination of sick leave, annual leave, or leave without pay. Paternity leave may be granted for a period of up to two (2) weeks following childbirth, and may be extended at the supervisor's discretion. Such leave shall be a combination of annual leave or leave without pay.

E. Leave may be granted for a period of up to two (2) weeks to an employee who is adopting a child, with extensions made at the discretion of the supervisor. Such leave shall be a combination of annual leave or leave without pay.

F. **Union Officer Leave:** Attendance at Union sponsored programs may be approved annual leave or leave without pay in accordance with normal leave practices unless Administrative Leave has been approved.

G. **Educational Leave:** After completing one (1) year of service an employee upon request may be granted a leave of absence for educational purposes provided that successful completion of the course will contribute to the work of the Employer. The period of leave of absence may not exceed one (1) year, but may be extended at the discretion of the Employer. If an employee is returning from educational leave during which he/she has acquired the qualification of a higher rated position he/she shall not have lost any of his/her rights in being evaluated for the higher graded position.

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ARTICLE 17
ADMINISTRATION OF OVERTIME

Section 1: Distribution:

Overtime work shall be equally distributed among employees, when appropriate. Individual employee qualifications shall be considered when decisions are made on which employees shall be called for overtime work.

Section 2:

Management will solicit volunteers when overtime work is required. In the event a sufficient number of qualified volunteers are not available to perform in the job functions, overtime work will be assigned to equally qualified employees in inverse order of seniority, unless a different system is worked out on a local-by-local basis. Instances of hardship should be presented to the supervisor and shall be considered on a case-by-case basis.

ARTICLE 18
WAGES

Section 1:

The salaries and wages of employees shall be paid bi-weekly. In the event the scheduled payday is a holiday, the preceding day shall be the payday. If, for any reason, an employee's paycheck is not available on the prescribed day, or if it does not reflect the full amount due, that employee will be paid as quickly thereafter as is possible, and under no circumstances will he or she be required to wait until the next regular payday.

Section 2:

If an employee's paycheck is delayed, the employee shall immediately notify his/her supervisor. The supervisor shall initiate efforts to obtain a supplemental payment. Supplemental payments will not effectuate normal payroll deductions. Appropriate payroll deductions will be deducted from the employee's subsequent paycheck. (Except DHS, see Attachment 6.)

ARTICLE 19
REDUCTION-IN-FORCE

Section 1: Definition:

The term reduction-in-force, as used in this Agreement means the separation of a permanent employee, his/her reduction in grade or pay, or his/her reduction in rank because of (a) reorganization, (b) abolishment of his/her position, (c) lack of work, (d) lack of funds, (e) new equipment, (f) job consolidation or (g) displacement by an employee with greater retention rights who was displaced because of (a) through (f) above.

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Section 2: Consultation:

The Employer agrees to consult in advance with the Union prior to reaching decisions that might lead to a reduction-in-force in the bargaining unit. The Employer further agrees to minimize the effect and such reduction-in-force on employees and to consult with the Union toward this end.

Section 3: Procedure:

A reduction-in-force will be conducted in accordance with the provisions set forth in the Comprehensive Merit Personnel Act [(CMPA), D.C. Official Code § 1-624].

Section 4: Impact and Effects Bargaining:

In the event of a reduction-in-force, the Employer shall, upon request, provide the Union with appropriate information to insure that the Union can engage in impact and effects bargaining over the reduction-in-force.

Section 5: Review of Procedures:

In the event of reduction-in-force, the affected employee will receive credit for his/her performance in accordance with the Comprehensive Merit Personnel Act, [D.C. Official Code Ann., Title 1, Section 1-624 (2001 Edition)].

ARTICLE 20
CONTRACTING OUT

Section 1:

During the term of this Agreement the Employer shall not contract out job positions traditionally performed by employees covered by this Agreement, except where manpower (including expertise and technology) and/or equipment is not available to perform such work, when it is determined by the Employer that budgetary conditions exist requiring contracting out, or when it is determined by the Employer that emergency conditions exist requiring such contracting out (provided however that the contracting out is for a period of time that the emergency exists). The Employer shall consult with the Union prior to any formal notice to contract out a bargaining unit job.

Section 2:

When there will be adverse impact to bargaining unit employees, the Employer shall consult with the Union thirty (30) days prior to final action, except in emergencies. The Union shall have full opportunity to make its recommendations known to the Employer who will duly consider the Union's position and give reasons in writing to the Union for any contracting out action. The Employer shall consult with the Union to determine if the needs of the Employer may be met by means other than contracting out work traditionally performed by bargaining unit employees.

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ARTICLE 21
STRIKES AND LOCKOUTS

Section 1 - Definition:

The term strike as used herein means any unauthorized concerted work stoppage or slowdown.

Section 2 - Strikes:

It shall be unlawful for any employee or the Union to participate in, authorize or ratify a strike against the District.

Section 3 - Lockouts:

No lockout of employees shall be instituted by the Employer during the term of this Agreement except that the Employer in a strike situation retains the right to close down any facilities to provide for the safety of employees, equipment or the public.

Section 4 - Other Considerations:

At no time however, shall employees be required to act as strikebreakers.

ARTICLE 22
GRIEVANCE PROCEDURES

Section 1:

Any grievance or dispute that may arise between the parties involving the application, meaning or interpretation of this Agreement, shall be settled as described in this Article unless otherwise agreed to by the parties.

Section 2 - Procedure:

This procedure is designed to enable the parties to settle grievances at the lowest possible administrative level. Therefore, grievances should be filed at the lowest level where resolution is possible. Accordingly, a grievance may be filed at the Step in the grievance procedure where the alleged action, which precipitated the grievance, occurred.

Step 1: The employee and/or the Union shall take up the grievance or dispute with the employee's immediate supervisor as soon as is practicable, but no later than fifteen (15) working days from the date of the occurrence or when the Union and/or the employee first had knowledge of or should have known of the occurrence. The supervisor shall attempt to address the matter and shall respond to the Steward as soon as is practicable, but not later than fifteen (15) working days after the receipt of the grievance.

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Step 2: If the grievance has not been settled, it shall be presented in writing by the employee and/or the Union to the second level supervisor within ten (10) working days after the Step 1 response is due or received, whichever is sooner. The written grievance shall be clearly identified as a grievance submitted under the provisions of this Article, and shall list the contract provision violated, a general description of the incident giving rise to the grievance, the date or approximate date and location of the violation and the remedy sought. The second level supervisor shall respond to the Union and/or employee in writing within ten (10) working days after receipt of the written grievance.

Step 3: If the grievance is still unresolved, it shall be presented by the employee and/or the Union to the Chairman on or his/her designated representative, in writing within fifteen (15) working days after the Step 3 response is due or received, whichever is sooner. The Chairman, or his/her designated representative shall respond in writing (with a copy to the Local President) within fifteen (15) working days after the receipt of the written grievance.

Step 4: If the grievance is still unresolved, the Union may, by written notice, request arbitration within twenty (20) days after the reply at Step 4 is due or received, whichever is sooner.

Section 3 - Union Participation:

A. The Employer shall notify the Union in writing of all grievances filed by the employees, all grievance hearings and determinations when such employees present grievances without the Union. The Union shall have the right to have a representative present at any grievance hearing and shall be given forty-eight (48) hour notice of all grievance hearings.

B. Any grievance of a general nature affecting a large group of employees and which concerns the misinterpretation, misapplication, violation or failure to comply with the provisions of the Agreement shall be filed with the Chairman or Director of Human Resources.

Section 4 - Who May Grieve:

Either an employee or the Union may raise a grievance, and if raised by the employee, the Union may associate itself therewith at any time if the employee so desires. Whenever the Union shall raise or is associated with a grievance under this procedure, such a grievance shall become the Union's grievance with the Employer. If raised by the Union, the employee may not thereafter raise the grievance him/herself, and if raised by the employee, he/she may not thereafter cause the Union to raise the same grievance independently.

Section 5 - Selection of the Arbitrator:

A. The arbitration proceeding shall be conducted by an arbitrator to be selected by the Employer, through the Office of Labor Relations and Collective Bargaining, and by the Union as soon as possible after notice of intent to arbitrate is received. If the parties fail to select an arbitrator, the Federal Mediation and Conciliation Service (FMCS) or the American Arbitration Association (AAA) shall be requested to provide a list of seven (7) arbitrators from which an arbitrator shall be selected within seven (7) days after receipt of the list by both parties.

B. Both the Employer and the Union may strike three (3) names from the list using the alternate strike method. The party requesting arbitration shall strike the first name. The arbitration hearing shall be conducted pursuant to the American Arbitration Association guidelines unless modified by this Agreement.

Section 6 - Decision of the Arbitrator:

The decision of the arbitrator shall be final and binding on the parties and shall not be inconsistent with the terms of this Agreement. The arbitrator shall be requested to render his/her decision in writing within thirty (30) days after the conclusion of the arbitration hearing.

Section 7 - Expenses of the Arbitrator:

Expenses for the arbitrator's services and the proceeding shall be borne equally by the Employer and the Union. However, each party shall be responsible for compensating its own representatives and witnesses. If either party desires a record of the arbitration proceedings, it may cause such a recording to be made, providing it pays for the record and make copies available without charge to the other party and the arbitrator.

Section 8 - Time Off For Grievance Hearings:

The Employee, Union Steward and/or Union representative shall upon request, be permitted to meet and discuss grievances with designated management officials at each step of the Grievance Procedure within the time specified consistent with Section 3 of Article 6 on Union Stewards.

Section 9 — Time Limits:

All time limits set forth, in this Article may be extended by mutual consent, but if not so extended, must be strictly observed. If the matter in dispute is not resolved within the time period provided for in any step, the next step may be invoked.

Section 10:

Matters not within the jurisdiction of the Employer will not be processed as a grievance under this Article unless the matter is specifically included in another provision of this Agreement, or any compensation agreement executed between the parties.

Section 11:

A. The parties agree that a process of grievance mediation may facilitate satisfactory solutions to grievances prior to arbitration. Therefore, on an experimental basis and when mutually agreed to by the parties, a mediator may be selected and utilized to facilitate settlements. The mediator may not impose a settlement on the parties, and any settlement reached will not be precedential unless otherwise agreed to by the parties on a case-by-case basis.

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B. Grievances may be combined for the purpose of mediation upon mutual agreement by the parties.

ARTICLE 23
EMPLOYEE RIGHTS

Employees of the Unit shall have and shall be protected in the exercise of the right, freely and without fear of penalty or reprisal, to form, join and assist the Union or to refrain from any such activity. Except as expressly provided herein, the freedom shall be recognized as extending to participation in the management of the Union and acting for it in the capacity of a union representative, including representation of its views to the officials of the Mayor, D.C. Council or Congress.

ARTICLE 24
NEW TECHNOLOGY AND EQUIPMENT

Section 1:

When the Employer introduces new equipment or technological changes on an experimental basis the Employer will notify the Union upon introduction as to where the experiment is being conducted and its nature and intended duration. The Employer will provide a 60 day notice if the experiment is to be instituted permanently.

Section 2:

The Employer shall provide any reasonable training for affected employees to acquire the skills and knowledge necessary for new equipment or procedures. The training shall be held during working hours, when reasonably available. The Employer shall bear the expense of the training.

Section 3:

If training is required for employment and the training is held outside the employee's normal tour of duty, the employee shall receive compensatory time.

ARTICLE 25
JOB DESCRIPTIONS

Each employee within the unit shall receive a copy of his/her current job description upon request. When an employee's job description is changed, the employee and the Union shall be provided a copy of the new job descriptions.

ARTICLE 26
SAVINGS CLAUSE

In the event any Article, Section or portion of the Agreement shall be held invalid and unenforceable by any court or higher authority of competent jurisdiction, such decision shall apply only to the specific Article, Section, or portion thereof specified in the decision, and upon issuance

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of such a decision, the Employer and the Union agree to immediately negotiate a substitute for the invalidated Article, Section or portion thereof.

ARTICLE 27
DURATION AND FINALITY

Section 1 - Duration of Agreement:

This Agreement shall be implemented as provided herein subject to the requirements of Section 1715 of the CMPA (Section 1-617.15(a), D.C. Official Code, 2001 Edition). This Agreement shall be effective as of the day of final approval, and shall remain in full force and effect for three years from the final approval date. Should either party desire to renegotiate, renew, extend or modify this Contract, notice will be given in writing in accordance with the requirements of the Comprehensive Merit Personnel Act. This Agreement shall remain in full force and effect during the period of negotiations.

Section 2 - Finality:

This Agreement was reached after negotiations during which the parties were able to negotiate on any and all negotiable non-compensation issues, and contains the full agreement of the parties as to all such non-compensation issues that were or could have been negotiated. The Agreement shall not be reconsidered during its life unless by mutual consent or as required by law.

[THIS SPACE IS INTENTIONALLY LEFT BLANK]

4/25/16
For Union ______ For DCPSC ______ 4.25.16

On this day of May 11, 2016 and in witness to this Agreement, the parties hereto set their signatures.

FOR THE PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

Betty Ann Kane, Chairman

FOR DISTRICT COUNCIL 20 AMERICAN FEDERATION OF STATE, COUNTY AND MUNICIPAL EMPLOYEES, AFL-CIO (AFSMCE)

Andrew Washington, Executive Director

Edward P. Ongweso, Ph.D

Anjanette L. Parker

John Howley

For Union AW 4/25/16 For DCPSC 4.25.16

APPENDIX A

For Union AJW 4/25/16 For DCPSC 4.25.16

OFFICIAL TIME REPORT **REPORTING PERIOD (each pay period)**

OFFICIAL TIME SPENT ON LABOR-MANAGEMENT ACTIVITIES **FROM:** **TO:**

Name of Union Representative (Last Name, First, Middle Initial) **Name of Supervisor Submitting Report**

Organization (Agency, Division, Branch)

Representational Functions of Official Time (Activity) as identified in the Agreement. [See Reverse Side]

DATE	Requested Time		Activity (1-8) Identify all that apply	Supv. Approving Initials	Actual Time		Total Time Used	Union Rep. Initial	Supv. Approving Initials
	FROM: am/pm	TO: am/pm			FROM: am/pm	TO: am/pm			