Testimony
of
Betty Ann Kane, Chairman
Public Service Commission of the District of Columbia

before the
Committee on Transportation & the Environment
Council of the District of Columbia

On Bill 22-904, the CleanEnergy DC Omnibus Amendment Act of 2018

October 9, 2018

Good afternoon Chairman Cheh and members of the Committee on Transportation and the Environment. I am Betty Ann Kane, Chairman of the District of Columbia Public Service Commission. I am pleased to be here today to present testimony on Bill 22-904, the CleanEnergy DC Omnibus Amendment Act of 2018. This legislation would make significant changes to existing law governing the District's Renewable Portfolio Standards ("RPS") requirements for retail suppliers who sell electricity to residential, commercial, governmental and institutional customers in the District. The Commission licenses those suppliers, certifies facilities as eligible to sell renewable energy credits ("RECs") for use by retail suppliers, and oversees and enforces supplier compliance with the RPS law. The bill would also significantly increase the fees required to be paid into the Sustainable Energy Trust Fund ("SETF") by natural gas and electricity customers in the District. Finally, the bill would make major changes in the method established by the Commission for procurement of electricity for customers who buy their electricity through the Standard Offer Service ("SOS") Program. About 30% of all electricity sold in the District, including 85% of the electricity bought by residential customers, is through the SOS Program.

The Public Service Commission was established in 1913 and was re- affirmed in the Home Rule Charter as an independent agency of the District government. The statutory responsibility of the Commission is to ensure that all utility companies and competitive electricity, natural gas, and telecommunications suppliers operating in the District provide services that are safe and reliable, at just and reasonable rates. In making its regulatory decisions, the Commission is also required, pursuant to language added by the Council to the Clean and Affordable Energy Act of 2008 to take into consideration the "economy of the District, the conservation of natural resources, and the preservation of environmental quality." Bill 22-904 would "clarify" this factor by adding a specific reference to "effects on global climate change and the District's public climate commitments."

The Commission agrees with the importance of considering environmental quality, including climate change, in decisions about energy supply and delivery. Indeed, the Commission has been involved in facilitating distributed generation, renewable energy, especially DC based rooftop solar facilities, energy efficiency and conservation programs for many years. Among our recent initiatives are the establishment of a Working Group to improve the interconnection process for larger and community solar installations and the development of an automated online application process for certification of renewable energy generating facilities that will make it easier and faster to have an application approved. The Commission has adopted a very strong Vision Statement in Formal Case No. 1130 on Modernizing the Energy Delivery System for Increased Sustainability ("MEDSIS"): "The District of Columbia's modern energy delivery system must be sustainable, 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 interactive and non-discriminatory." Our Guiding Principles to implement this Vision comprise a triple bottom line: environmental protection, economic growth, and social equality.

For environmental protection we specifically "recognize the negative impact that energy use 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 goals by fostering the use of more efficient energy and renewable energy resources, DER technologies, and controllable demand alternatives to reduce greenhouse gas ('GHG') emissions and overall energy consumption."

Phase two of MEDSIS is in full gear with six working groups from a wide variety of stakeholders participating on tasks including Data Information and Access, Non-wires Alternatives to Grid Investments, Future Rate Design, Customer Impact, Microgrids, and Pilot Projects. The Smart Electric Power Association has been engaged to guide the groups to recommendations by the summer of 2019. The Commission's approval of the Pepco-Exelon merger included $21 million from Exelon to fund pilot projects arising from MEDSIS, as well as $5 million for renewable energy projects for low and moderate income multi-family housing and a commitment from Exelon to purchase 100 megawatts ("MW") of wind power from existing or new wind generation facilities to serve District customers. The Commission's approval of the merger of Washington Gas with AltaGas also included $4.2 million for energy efficiency and energy conservation initiatives for multi-family housing projects.

The Commission worked closely with the Council Chairman and members to help shape the District's first RPS law in 2005 and we look forward to continuing to work with you in any amendments to the RPS or other energy legislation. That said, we must state that while Bill 22-904 reflects a sincere desire to continue the progress that the District has made in facilitating clean and renewable energy use by District residents, businesses and institutions, the bill as written presents significant policy issues, as well as concerns related to cost, implementation and enforcement. Based on our experience, our knowledge of the energy market, and our statutory responsibilities, the Commission is pleased to share those concerns as outlined below.

However, as background to our comments about Bill 22-904, it is important to recognize that there is a downside to mandating the use of renewable energy sources. The cost of compliance with RPS requirements has been growing. Indeed, the cost of RPS compliance now represents as much as 12% of the cost of Standard Offer Service from this year's procurement. This is an increase from 10% last year. Aside from the cost of energy and capacity, the cost of RPS compliance is the largest cost, and increasing. Our consultants have prepared this pie chart to show the impact of the requirement that an increasing percentage of electricity be sourced from renewable sources (see Attachment 1).

ISSUE 1: LONG-TERM PURCHASE AGREEMENTS AND THE REC AND ENERGY MARKETS

When the DC Council enacted the electricity market restructuring legislation in 1999 it substituted electricity supply purchase from a competitive market for traditional command-and-control rate-of-return regulation. The basic idea was to shift the risk of generation investment and operation from ratepayers to entrepreneurs who were willing to bear the risks of funding and operating electric generating facilities. For the District and other restructured jurisdictions in the PJM Interconnection ("PJM") region this has proven to be a boon in that we have not been saddled with legacy investments which prohibit, or at least severely impede, moving to new cleaner and lower cost generating technologies. The GHG emission rates in the PJM region are presently about half what they were ten years ago. Also, without restructuring and reliance on the PJM wholesale electricity market it is doubtful that the phenomenal growth in customer-owned renewable electricity generation in the District would have been as smooth and extensive has it has been. Under vertically integrated rate-of-return regulation such customer generation would have been seen as unwelcome direct competition to Pepco's generation investments. It is because of our restructuring and reliance on the PJM market that the District can contemplate legislation such as the "CleanEnergy DC Omnibus Amendment Act of 2018".

However, the bill would move the purchase of electricity supply for the District away from market-based solutions and towards long-term bilateral contracts. Such contracts remove a transaction from the market to a private two-party transaction. The primary result is a transfer of risk from entrepreneurs to the general body of ratepayers. Such contracts also lock-in a specific type and generation of technology and prohibits the District from benefitting from cost reducing advancements in renewable electricity generation over the length of the contract in much the same way that the District has been legislatively prohibited from benefitting from the large cost reductions associated with utility-scale solar electricity generation.

The bill affects both electricity generated from a renewable energy source and renewable energy credits ("RECs") created by the renewable energy generation source. RECs are the bundle of the environmental attributes of electricity from a renewable generation source. The scheme adopted by the District and most other jurisdictions with Renewable Energy Portfolio Standards ("RPS") was to separate the environmental attributes of generation from the energy attributes of the generation and trade each attribute in a separate market. There is a market for environmental attributes that is part of the PJM Generation Attributes Tracking System ("GATS") and markets for electricity supply, the PJM energy market and the PJM capacity market. For the District and other PJM jurisdictions with RPSs the generation and environmental attributes have been unbundled. That means that simply purchasing electricity from a generator that employs a renewable technology does not mean that the purchaser is purchasing renewable energy unless the environmental characteristics, i.e. RECs, and energy components, i.e. MWh, have specifically been recombined as part of a contractual arrangement. Thus, electricity from a renewable generation technology that is purchased pursuant to a long-term agreement without re-bundling the energy and environmental components has no specific inherent environmental characteristics. This is called null energy and cannot be used to claim that a purchaser or user is consuming renewable energy.

Section 101(d-1) would require that beginning on January 1, 2022, each electricity supplier serving customers in the District must meet the annual RPS, under §34-1431-1440, by obtaining "at least 70% of its renewable energy credits from renewable sources with which the supplier has a long-term purchase agreement." The bill defines "Long-term purchase agreement" as "an agreement between an electricity supplier and an electricity generator for the purchase of electricity or renewable energy credits over a term of at least 7 years."

Since Section 101 (d-1) amends the current DC Code provision related to the purchase of RECs, we interpret the phrase "with which the supplier has a long-term purchase agreement" to here mean a long-term agreement for the purchase of the RECs, and does not apply to the method of purchase in the electricity supply/capacity market. In other words, the bill would not require all electricity suppliers to use long-term purchase agreements to purchase energy supply from renewable energy sources. Section 101(d-1), as currently worded, requires that electricity suppliers can only purchase RECs using a long-term contract with the renewable electricity generation source, which creates the RECs. The current market for RECs is carried out through multiple means, but primarily through GATS, FLETT Exchange, aggregators, brokers, marketers, solar developers and other third parties, not through bilateral contracts between retail energy suppliers and renewable energy generators. Relatively few owners of rooftop solar generation sell their RECs directly to a retail supplier. Most long-term forward agreements are used primarily as a form of financing for a renewable energy generation facility construction project. In addition, solar RECs ("SRECs") have only a small price differential between the price of SRECs and the alternative compliance fee ("ACF"), under the §34-1434(c), this small difference may prompt some electricity suppliers to simply pay the ACF rather than commit to long term REC contracts with DC solar electricity facility owners. This would tend to decrease the actual use of solar energy in DC as measured by the RPS.

Requiring long term purchase agreements for RECs and SRECs could be a death knell for the SREC market in the District. As of October 1st, there are 3,881 solar photovoltaic facilities in the District certified to sell SRECs, 115 certified thermal photovoltaic facilities, and 2,471 certified grandfathered facilities outside of the District. While some of these are leased systems the total number of solar energy facility owners is still several thousand. Requiring electricity suppliers to enter into long-term bilateral contracts with individual owners of renewable generation systems is simply unworkable.

In addition, many owners of solar energy generation facilities do not own the rights to the SRECs generated by their facilities. The SRECs for these facilities have been sold forward for future RPS compliance years to finance the solar generation project. As currently drafted, under B22-904 these forward sold SRECs would be stranded and of no value to the current, non-generation, owners. This would also have the effect of eliminating the use of forward selling SRECs to finance the construction of renewable energy projects in the District. This would have the effect of significantly reducing the number of new renewable energy projects undertaken in the District.

ISSUE 2: ADDITIONAL REQUIREMENTS IMPOSED ON THE SOS PROGRAM

Section 102(c), mandates that electricity suppliers which participate in the SOS Program for default customers that do not obtain electricity supply for competitive electricity suppliers, pursuant to §34-1509(c), must obtain specific percentages of their annual supply from tier one renewable sources pursuant to long-term purchase agreements for a term of at least seven (7) years beginning on January 1, 2020. Thus, the requirement for electricity suppliers to use long term purchase agreements to obtain electricity from a tier one renewable source will not apply to electricity suppliers that offer supply in the competitive market to non-SOS Program customers.

While the Commission doesn't regulate the rates for the 42 certified electricity suppliers in the District's competitive supply market and, thus, does not have data on the historical prices for such or data on the use of long-term electricity supply purchase agreements, it does have data on the annual contract bids for electricity supplied in the SOS Program for default residential and commercial customers. Overall, SOS represents about 25% of the electricity sold in the District. And 75% of the SOS supply is bought by residential customers. Currently, 83.5 % of the electricity supply (MWH) for residential and 14% of the electricity supply for commercial customers is provided by the SOS Program. Thus, the impact of requiring only electricity suppliers that win SOS Program supply contracts to use long term purchase agreements to obtain electricity from a tier one renewable source will primarily be borne by residential and small commercial SOS Program customers. The 86% of commercial load that does not acquire electricity supply from the SOS Program will remain free to purchase electricity that is not subject to this additional restriction.

Column one in the attached chart shows the average year 1 winning prices for electricity supply to residential customers (see Attachment 2). Column two in the chart shows the current year price averaged with the prices for the preceding two years, thus, showing the average price for three years. Column three assumes that the contracts would have been for a seven-year supply with the price based on the current year SOS contract and the prices for the SOS contacts for the previous six years (as shown in column one). The accompanying graph illustrates the differences between the historical one-year SOS contract prices and the hypothetical three-year and seven-year price based on historical one-year SOS contract data (see Attachment 2). In general, the historical SOS Program data demonstrates that long-term seven-year SOS bids are expected to be better than three-year bids when electricity supply prices are rising. However, when electricity prices are declining, as they have done for each of the past eight years except for one the long-term seven-year SOS Program supply bids will be more expensive. Thus, we should assume that the rates for SOS Program residential and commercial customers will increase.

The proposed legislation would require all future SOS Program electricity supply contractors to obtain eighty percent of electricity supply from renewable generation sources and for a term of seven, rather than three, years by January 1, 2022. Based on information filed by competitive energy providers and their marketing materials, electricity from renewable supply sources offered to residential customers in the District is significantly more expensive than electricity from non-renewable or mixed supply sources. Long-term energy supply contracts are often more expensive in the final years of the term because of the uncertainty of regulatory and financial risk. In other words, long-term purchase agreements do not always ensure that rates will be reasonable. Finally, enactment of this legislation would make the District unique nationally by requiring SOS Program default electricity suppliers to obtain specific percentages of their annual supply from tier one renewable sources pursuant to long-term purchase agreements for a term of at least seven years. This unprecedented requirement in a competitive bidding process could have a chilling effect on the number of electric suppliers that would otherwise want to submit competitive bids for the SOS Program supply contracts. We are concerned that this could rapidly lead to having a monopoly supplier for all of the residential, small commercial and large commercial SOS Program supply contracts and resulting increases in SOS Program rates.

The Commission has been aware that the Department of Energy and Environment ("DOEE") has previously suggested that the Commission consider long term contracts for SOS supply. As part of its Biennial Review of the SOS program in Formal Case No. 1017 the Commission issued an order on August 9, 2018 requesting comment on using long-term Power Purchase Agreements ("PPAs") for SOS Program supply (see Attachment 3). The Commission requested comments in response to 11 issue areas that are set forth in the Order. On September 6, 2018, the Commission adopted an Order that granted a request from the Office of People's Counsel ("OPC") that requested additional time to file comments on the basis that both OPC and DOEE had retained outside consultants which are each undertaking studies regarding the potential advantages and disadvantages of incorporating long-term PPAs for renewable energy and long-term purchase agreements for RECs into the SOS procurement process. Pursuant to this Order, public comments are due to the Commission on November 9, 2018 and reply comments are due to the Commission on December 21, 2018. The Commission expects that the information from the DOEE and OPC studies, as well as public comments on these studies would also be useful to the Committee as it evaluates whether to proceed with this bill's mandatory use of long-term purchase agreements for renewable electricity supply by SOS Program participants and for RECs by all electricity suppliers.

ISSUE 3: LIMITING ELIGIBLE RECs TO THE PJM INTERCONNECTION REGION STATES

B22-904 amends the geographic area from which RECs may be purchased by electricity suppliers to meet the annual RPS requirements from the PJM Interconnection Region or from a state adjacent to the PJM Interconnection region to only states within the PJM Interconnection Region (Delaware, District of Columbia, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia). Thereby, eliminating Alabama, Arkansas, Georgia, Iowa, Mississippi, Missouri, New York, South Carolina, and Wisconsin from the certified renewable electricity generator states where RECs may be purchased. As other states in the PJM Interconnection Region decide to amend their RPS to 100% by 2032, as is proposed in B22-904, there will be greater demand for RECs in these states, thus, increasing REC prices and the resulting flow-through costs to electricity suppliers and their customers.

Decreasing the size of the geographic area where electricity suppliers can purchase RECs to meet the DC RPS will likely increase the cost of electricity supply to DC electricity customers. The attached chart (see Attachment 4) quantifies that there are currently 121 DC certified tier one renewable sources that are in states adjacent to the PJM Interconnection region which accounts for nearly 16 percent of the total DC certified tier one renewable source capacity. The second chart in Attachment 4 demonstrates that 60 percent of the RECs used to comply with the 2017 RPS were sourced in the State of Missouri, one of the Non-PJM Interconnection region states. This chart also documents that in 2017, 83 percent of the RECs used to comply with the DC RPS came from tier one renewable electricity sources located in the Non-PJM Interconnection region states. Frankly, it is unclear whether there are enough certified tier one renewable electricity sources in the PJM Interconnection region states to make up for the lost 83 percent of RECs from the Non-PJM states to meet the increasingly stringent RPS in 2019, 2020 and beyond. Iowa, for example, has the second highest amount of currently installed wind production, second only to Texas, and both Iowa and Missouri are predicted to be significant sources of growth in wind for sale over the next decade. Attachment 5 provides maps from the federal Department of Energy that show installed and projected wind capacity. You will note that the eastern states have a much lower actual and potential wind capacity. Limiting the geographic area eligible for REC participation will limit the supply of RECs, while at the same time the legislation would significantly increase the required demand for RECs.

Furthermore, it is not evident whether reducing the number of certified renewable electricity generator states where RECs may be purchased by electricity suppliers is beneficial to attaining the bill's Clean Energy goals. From a practical standpoint there is the problem of what to do with already certified tier 1 generation that is in the states adjacent to PJM. Would these facilities have to be decertified, as were solar facilities outside DC were in 2008 when the DC SREC requirements were created or would they be grandfathered. In the last ten years the RPS program has used grandfathering three times. Grandfathering is necessary to avoid interference with existing contracts, as well as to avoid further uncertainty in the market. However, grandfathering also presents additional challenges in reporting, monitoring compliance and making predictions.

ISSUE 4: LONG-TERM PURCHASE AGREEMENT DEADLINES

B22-904 also prescribes that electricity suppliers that win SOS Program contracts through the auction process conducted under Commission rules and oversight will be required to obtain at least 26% of the supplier's electric supply through long-term purchase agreements beginning on January 1, 2020. As a practical matter the January 1, 2020 implementation deadline presents two significant additional problems for the operation of the SOS Program.

First, Pepco, as the Commission's designated SOS Program Administrator, entered into contracts pursuant to the December 2016 and January 2017 SOS Program supply auctions for four blocks of electricity supply for three-year terms for residential and small commercial SOS Program customers beginning in June 2017. (All SOS Program supply contracts are subject to the Commission's approval.) And, Pepco entered into three-year term contracts for two electricity supply blocks procured in December 2017 and two blocks procured in January 2018 for residential and small commercial SOS Program customers beginning in June 2018. Obviously, subjecting the electricity suppliers that are under existing SOS Program supply contracts to a requirement that they obtain 26% of their electricity supply through long-term purchase agreements from renewable electricity sources beginning on January 1, 2020 will necessitate the Commission to renegotiate current SOS Program supply contracts which will, probably, significantly increase the cost of electricity supply to the SOS Program's residential and small commercial customers if such contracts are not grandfathered.

Second, on October 1, 2018 Pepco released the Request for Proposal to electricity suppliers for procurement of electricity supply blocks for the SOS Program residential, small, and large commercial customers beginning on June 1, 2019. (The SOS Program for large commercial customers is for a 12-month term: June 1, 2019 – May 31, 2020.) The SOS Program's First Tranche supply auction for qualified electricity suppliers is scheduled for December 3, 2018. The SOS Program's Second Tranche supply auction is scheduled for January 7, 2019. The uncertainty about whether this bill's requirement that SOS Program electricity suppliers obtain 26% of their electricity supply through long-term purchase agreements from renewable electricity sources beginning on January 1, 2020 will have a significant disruptive impact on the SOS Program supply auctions in December and January. This uncertainty could result in significantly higher auction bid prices than would otherwise occur absent this legislation. Obviously, that will result in increased SOS Program prices to DC ratepayers.

ISSUE 5: ENFORCEMENT

D.C. Code Section 34-1434 sets forth the required annual compliance reporting to the Commission for electricity suppliers to demonstrate compliance with the applicable RPS, including acquisition of the required number of RECs. This section also sets forth the alternative compliance fee amount that the supplier must pay to DOEE if it has not complied with the annual RPS.

However, Bill 22-904 does not enact a similar reporting requirement for electricity suppliers to the Commission to report to the Commission to ensure compliance with the new requirement that beginning on January 1, 2022, three years from now, that RECs long-term purchase agreement RECs. Furthermore, there is no penalty provision in the bill of an alternative compliance fee-type of provision to apply in the event that an electricity supplier fails to meet the 70 percent REC long-term purchase agreement requirement specified in section 101(c)(3).

The omission of authorization for the Commission to specify compliance reporting requirements and to assess penalties for non-compliance are major deficiencies in the legislation.

ISSUE 5: SETF COLLECTIONS

Section 201(b) sets forth an annual increase in the SETF fee from Fiscal Year 2020 through Fiscal Year 2032 and every year thereafter. Attachment 6 provides estimated annual SETF fee collections from electric and gas customers for these years and shows the disbursements to the DC Sustainable Energy Utility ("SEU") and the Green Bank as prescribed under the legislation. As you will see the amount of the SETF fees collected annually from gas customers will more than triple from under $4 million to $13 to $14 million and nearly double for electricity customers from $16 - $17 million to over $30 million in FY 2020. These are significant increases in the costs paid by residential and small and large commercial customers. They constitute additional rate increases that in many instances are larger than the rate increases that the Commission, after full hearing and deliberation, has approved in recent years. When added to the other costs associated with this legislation that we have outlined, the Commission is concerned that they will have a major negative impact on the affordability of electricity and gas service and supply for DC ratepayers. Finally, if you review the last column on the far right of this chart you will see that there will be an average of $12 million annually for a total of $156.6 million in surplus SETF funds after payments to the DC SEU, DOEE and the Green Bank. The Commission questions whether such surpluses will prove too tempting and been diverted, as has unfortunately happened in the past, to pay for services and budget shortfalls unrelated to the purpose of this legislation.

CONCLUSION

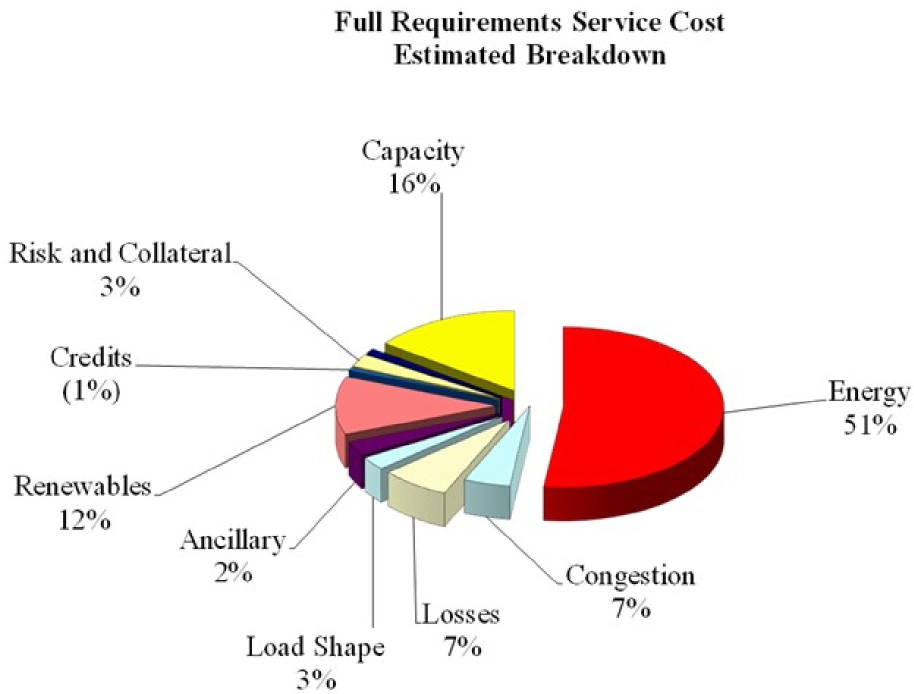
The Commission is supportive of the intent of the legislation and of the Council and Executive Branch to address climate change factors. However, there are many questions about the practicality, market impact, and costs to electricity customers associated with mandating long-term purchase agreements for electricity from renewable sources and for RECs. We all need to receive and review the DOEE and OPC studies and public comments on the advantages and disadvantages of requiring long-term purchase agreements for electricity supply from renewable sources as part of the SOS Program before mandating the use of such long-term purchase agreements for SOS Program customers. We need to hear from the electricity suppliers. And, we need to take time to consider additional pathways.

In the bigger picture, the Commission also urges a serious look at sources other than gas and electric ratepayers as the captive source to pay for meeting climate change and sustainability initiatives. Unfortunately, except for a new tax on fuel oil, and a potential change in the excise tax for clean fuel vehicle registration, all of the new required costs of Bill 22-904 would be financed through surcharges, fees and REC purchases that are imposed on the energy distribution and energy supply bills paid by DC ratepayers. While it is true that there will be costs to owners of buildings of 10,000 square feet or more to meet the Building Energy Performance Standards that would be imposed in Title III, there is a phase in time line, there will be "multiple compliance pathways" established by DOEE, and there will be exemption criteria for owners that "demonstrate financial distress, change of ownership, vacancy, major renovation, pending demolition, or other circumstances determined by DOEE." There will also be a required "incentive and financial assistance program for qualifying owners and affordable housing providers." Building performance standards are a very important part of reducing energy use and, thereby, addressing climate change. Assistance is good also. The cost to building owners for meeting the standards that will be developed is not prescribed in the bill—even the fines for noncompliance are to be determined later by DOEE—and there is no prescribed cost to a vehicle owner of the proposed changes to the excise tax, only that the total be revenue neutral to the District—and again an exemption for financial hardship. However, for gas and electric ratepayers between now and 2032 the surcharges and fees are prescribed by the bill and they will be costly-- with no exemptions, no assistance, and no "multiple pathways."

We cannot keep going back to ratepayers and piling more and more mandatory charges on top of their bills—ratepayers are not a bottomless source. This burden also competes with the need to pay hundreds of millions of dollars for significant investments in reliability and modernization, including the DC PLUG that is putting key electric feeders underground and the Project Pipes which is replacing aging gas mains and connections, as well as critical ongoing maintenance and repairs; changes to safely service electric vehicles and public transportation; and technology and upgrades to continue to accommodate increased distributed energy generation and two-way interconnection. All of these projects will of course continue to receive full review and consideration by the Commission to determine the need and the most cost-effective method of achieving them. But there are limits. The transformers have to work and the gas pipes can't leak.

Thank you and we would be happy to answer any questions.

ESTIMATED PRICE BREAKDOWN FOR DC SOS 2018-2021 RESIDENTIAL CONTRACTS



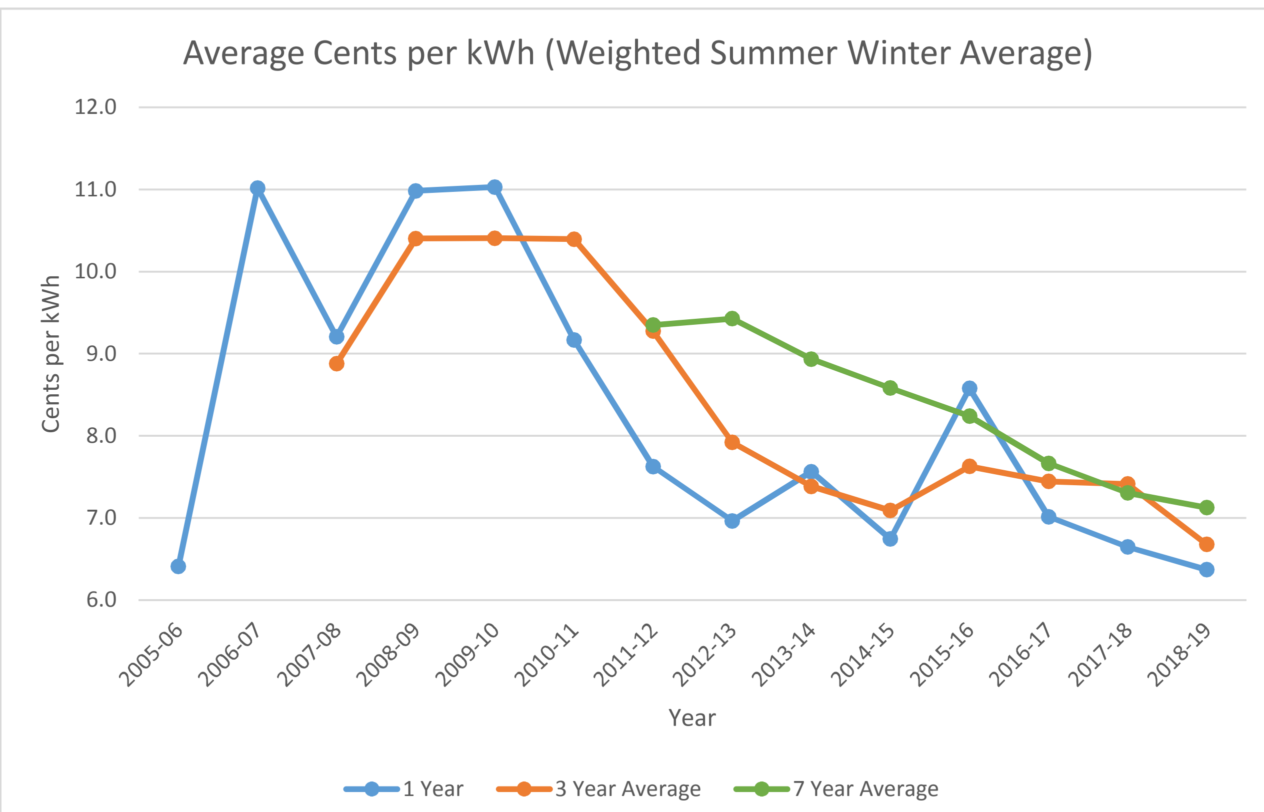
Winning SOS Price - Annual, 3-Year, and 7-Year Average

Summer and Winter (Weighted average)

	1 Year	3 Year Average	7 Year Average
2005-06	6.4		
2006-07	11.0		
2007-08	9.2	8.9	
2008-09	11.0	10.4	
2009-10	11.0	10.4	
2010-11	9.2	10.4	
2011-12	7.6	9.3	9.3
2012-13	7.0	7.9	9.4
2013-14	7.6	7.4	8.9
2014-15	6.7	7.1	8.6
2015-16	8.6	7.6	8.2
2016-17	7.0	7.4	7.7
2017-18	6.6	7.4	7.3
2018-19	6.4	6.7	7.1

Weighted average is 7 months for Winter and 5 months for Summer
All values are cents per kWh

Data Source: Annual SOS filing. For 2018-2019, see Feb. 12, 2018 filing, page 1 of Attachment B, residential class, in excess of 30 kWh.



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

ORDER

August 9, 2018

FORMAL CASE NO. 1017, IN THE MATTER OF THE DEVELOPMENT AND DESIGNATION OF STANDARD OFFER SERVICE IN THE DISTRICT OF COLUMBIA, Order No. 19431

I. INTRODUCTION

1. By this Order, the Public Service Commission of the District of Columbia ("Commission") initiates the 2018 Biennial Review of Standard Offer Service ("SOS").

II. BACKGROUND

2. By statute, the Commission may conduct competitive bid procedures for the selection of a retail electricity supplier or suppliers to provide SOS for the District of Columbia; or authorize the electric company, Potomac Electric Power Company ("Pepco" or "Company"), to conduct competitive bid procedures to obtain third-party contracts to provide SOS for the District; or both.[1] In 2004, the Commission adopted a wholesale model in which Pepco, as the SOS Administrator, conducts competitive bidding to obtain third-party contracts to provide SOS for the District.[2] The Commission periodically reviews the process for providing SOS in the District and determines whether any changes or adjustments to SOS are needed based on this review.[3] This process is referred to as the Biennial Review.

III. DISCUSSION

3. In 2017, the Commission completed its most recent Biennial Review and made substantive changes to the SOS bidding process based on those findings.[4] The Commission also identified issues to be considered further in the next Biennial Review to be conducted in 2018 including: 1) what is a reasonable margin or return for Pepco to earn as the SOS Administrator and what is the relationship between this return and its cash

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[1] D.C. Official Code § 34-1509 (d) (1) (2010 Repl.).

[2] *Formal Case No. 1017, In the Matter of the Development and Designation of Standard Offer Service in the District of Columbia* ("*Formal Case No. 1017*"), Order No. 13118, rel. March 1, 2004.

[3] 15 DCMR § 4102.2 (2015).

[4] *Formal Case No. 1017*, Order No. 18829, rel. July 7, 2017 ("Order No. 18829"); *Formal Case No. 1017*, Order No. 19106, rel. Sept. 13, 2017 ("Order No. 19106").

working capital;[5] 2) whether to eliminate the adder;[6] and 3) whether to eliminate the minimum stay provision for commercial customers.[7] In addition, during the last Biennial Review, the District of Columbia Department of Energy and Environment ("DOEE") suggested the inclusion of Purchase Power Agreements ("PPAs") in the SOS procurement process.[8]

A. What is a Reasonable Margin or Return for Pepco as the SOS Administrator and What is the Relationship Between this Return and its Cash Working Capital?

4. The Commission previously determined that Pepco is entitled to a margin as, *inter alia*, Pepco should be compensated for the risks associated with serving as the SOS administrator.[9] However, the Commission indicated that in the next Biennial Review it would review the issue of what is a reasonable return for Pepco to earn as the SOS Administrator and the relationship between this margin and cash working capital.[10] The Commission has not reconsidered this issue since the establishment of the margin 14 years ago.[11] The margin is part of the Administrative Charge which also includes incremental costs, uncollectible costs, and the adder.[12]

5. In Pepco's latest retail SOS rate filing submitted on February 12, 2018, the Company noted that it made an annual return of approximately $6 million for its services as the SOS Administrator for the SOS service year ending May 31, 2017, while Pepco's incremental costs for administering SOS were around $900,000.[13] This filing appears to suggest that cash working capital is being treated as an expense for which Pepco is being

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5 Order No. 18829, ¶ 148

6 Order No. 19106, ¶ 6.

7 Order No. 19106, ¶¶ 9-10.

8 See Order No. 18829, ¶ 17. In Order No. 18829, the Commission also noted that, while Pepco, in its comments filed as part of the Biennial Review process, had described some of the procedures it employs to avoid potential conflicts of interest otherwise ensure that Exelon Generation Company, LLC does not receive any competitive advantage as an Exelon affiliate when bidding in the District of Columbia's SOS auction, the Commission needed greater detail regarding Pepco's safeguards. The Commission, therefore, directed Pepco to file a detailed description of these procedures. Order No. 18829, ¶¶ 93, 391. Pepco filed its response on August 21, 2017. *Formal Case No. 1017*, Letter from Peter E. Meier, Vice President Legal Services, Inc., Pepco, to Brinda Westbrook-Sedgwick, Commission Secretary (Aug. 21, 2018). No comments were filed in response to Pepco's filing. The Commission has reviewed this filing and determined that no additional safeguards are required at this time.

9 Order No. 18829, ¶ 147 (internal citations and quotation marks omitted).

10 Order No. 18829, ¶ 148.

11 *See generally Formal Case No. 1017,* Order No. 13268, ¶¶ 25-71, rel. Aug. 19, 2004 ("Order No. 13268").

12 Order No. 13268, ¶ 3 (citation omitted).

13 *Formal Case No. 1017,* Pepco's Refiled Retail Rates, Including Administrative Charges, for SOS, Attachment D, at 2, filed February 12, 2018 ("Pepco's 2018 Refiled Retail Rates").

reimbursed annually.[14] If the Commission were to reduce the current level of the margin by, for example, having the margin calculated as a percentage of Pepco's incremental costs for administering SOS, this could lower the price of SOS and could make it more difficult for competitive electricity suppliers to compete in the D.C. market. As part of the last Biennial Review, the Commission determined that the margin should no longer be calculated on a per kWh volumetric basis and should, instead, be an annual fixed charge.[15] Given this historical experience and perspective, the Commission is interested in information supporting a conclusion that Pepco's margin is reasonable or, in the alternative, what evidence supports a conclusion that the margin should be modified.[16] Therefore, the Commission as part of the 2018 Biennial Review, invites comments on the following issue:

- What is the appropriate return for Pepco to earn as SOS Administrator? What should be the relationship between this return and cash working capital?[17]

B. Whether to and Why Eliminate the Adder?

6. The original purpose of the adder was to reflect the retail electricity suppliers' marketing costs in SOS rates in order to ensure that the suppliers are not placed at a competitive disadvantage.[18] Subsequently, the Commission determined that removing the adder will lower costs for SOS customers and eliminate a subsidy going to retail shopping customers from SOS ratepayers.[19] Thus, in Order No. 18829, the Commission directed Pepco to remove the adder from SOS rates beginning with the June 1, 2018, to May 31, 2019, service year.[20] On August 7, 2017, the Retail Energy Supply Association ("RESA") challenged the Commission's rationale for eliminating the adder and filed an Application for Reconsideration of Order No. 18829, asking that "the Commission reconsider its decision to eliminate the adder."[21] The Commission agreed that the better course of action would be to defer this issue to the next Biennial Review so the Commission

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14 Pepco's 2018 Refiled Retail Rates, Attachment D.

15 Order No. 18829, ¶¶ 1, 143, and 393.

16 The Maryland Public Service Commission recently initiated an investigation regarding what an appropriate level of margin was for Baltimore Gas and Electric Company to receive as SOS administrator. *See* www.psc.state.md.us/search-results/?keyword=9221&x.x=17&x.y=14&search=all&search=case.

17 In preparing comments on this issue, interested persons are encouraged to examine the Commission initial consideration of this issue in 2004. *See generally Formal Case No. 1017*, Order No. 13268, ¶¶ 25-71, rel. August 19, 2004.

18 Order No. 18829 at 28 (citation omitted in original). The adder consists of the fixed overall Administrative Charge minus incremental costs, uncollectible costs and the margin. *See* Order No. 13268, ¶ 72.

19 Order No. 18829, ¶ 126.

20 Order No. 18829, ¶¶ 1, 127, and 394.

21 *Formal Case No. 1017,* Retail Energy Supply Association's ("RESA") Application for Reconsideration, filed August 7, 2017 ("RESA's Application").

could explore the matter in more depth and develop a more complete record before making a decision that could negatively impact competition.

7. Like the margin, the adder was established 14 years ago.[22] Given this lapse of time and potential changes in the competitive marketplace, commenters should consider what evidence suggests that the adder has accomplished what it was designed to do. That is to reflect retail electricity suppliers' marketing costs in SOS rates to ensure that these electricity suppliers are not placed at a competitive disadvantage. The alternative is for commenters to consider what evidence supports the elimination of the adder. We encourage commenters to review the Commission's previous consideration of this issue in Order Nos. 18829 and 19106.[23] Commenters are requested to support their positions as to whether to retain or eliminate the adder with a numerical analysis and/or other empirical evidence. As indicated above, this could lower the price of SOS and could make it more difficult for competitive electricity suppliers to compete in the D.C. market. Interested persons may want to consider this possibility, when commenting on whether the adder should be eliminated. Therefore, consistent with its decision in Order No. 19106, the Commission invites comments on the following issue:

- Should the adder be eliminated? If so, why; if not, why not.

C. Whether to and Why Eliminate the Minimum Stay Provision?

8. In Commission Order No. 18829, the Commission initially decided not to abolish the 12-month minimum stay provision that requires a commercial customer to remain on SOS for a minimum of 12 months when switching from a competitive electricity supplier to SOS, because the goal of the provision is to allow SOS suppliers to better manage migration between SOS service and third party suppliers and the Commission did not see the benefit of eliminating the minimum stay provision and, thereby, creating more uncertainty for SOS suppliers which could result in higher prices being bid.[24] On Reconsideration, RESA requested that the Commission reverse its decision.[25] The Commission, in Order No. 19106, did not reverse its initial decision having determined that the "present record is too thin to support a change in policy at this time."[26] However, the Commission indicated that the issue could be revisited during the next Biennial Review.

9. Again, the Commission is interested in knowing whether there have been changes in the marketplace over the last 14 years that would warrant a change in policy to eliminate the minimum stay provision. When commenting, proponents of this provision should provide evidence that the minimum stay has, in fact, allowed SOS suppliers to better manage migration and thereby avoid bidding higher SOS prices. Opponents, by contrast,

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22 *See generally* Order No. 13268, ¶¶ 72-108.

23 *See* Order No. 18829, ¶¶ 110-127; Order No. 19106, ¶¶ 4-6.

24 Order No. 18829, ¶ 281.

25 RESA's Application at 10.

26 Order No. 19106, ¶ 10.

should provide evidence that this has not been the case and the minimum stay provision should now be eliminated. Commenters are encouraged to review the Commission's previous consideration of this issue in Order Nos. 18829 and 19106.[27] Therefore, as part of the 2018 Biennial Review, the Commission invites comments on the following issue:

- Should the 12-month minimum stay provision for commercial customers be eliminated? If so, why; if not, why not.

D. Should Purchase Power Agreements ("PPAs") be used in the SOS Procurement Process?

10. During the last Biennial Review comment period, commenters were asked whether Pepco should continue as the SOS administrator and whether there were other aspects of the SOS program that should be changed in light of competitive developments in D.C., DOEE suggested that the Commission consider procuring electricity for SOS through long-term PPAs for renewable energy. According to DOEE, PPAs can provide affordable electricity, price stability, and reduce Green House Gas ("GHG") emissions.[28] The Office of the People's Counsel agreed with DOEE.[29] RESA, Direct Energy, Exelon Generation Company, LLC, and WGL Energy Services opposed the introduction of PPAs into the SOS procurement process.[30] Subsequently, Mayor Muriel Bowser pledged that the District will achieve its goal of GHG neutrality by 2050.[31] Moreover, the most recent draft of "Clean Energy DC's: District of Columbia Climate and Energy Plan" suggests that, in "transitioning to a low-carbon District", one tool to help achieve this goal is the use of PPAs to buy renewable energy when procuring electricity for SOS.[32] Therefore, the Commission seeks to obtain additional information about the potential advantages and disadvantages of incorporating PPAs for renewable energy and long-term purchase agreements for Renewable Energy Credits ("RECs") into the SOS procurement process.

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27 *See* Order No. 18829, ¶¶ 258, 259, 265, 277, and 281; Order No. 19106, ¶¶ 7-10.

28 *See* Order No. 18829, ¶ 17.

29 *See* Order No. 18829, ¶ 58.

30 *See* Order No. 18829, ¶¶ 68, 266, 267, and 278-280. RESA and WGES argued that these PPAs could or would adversely affect retail electricity services competition. *See* Order No. 18829, ¶¶ 68 and 280. Direct Energy and ExGen argued that the price of electricity procured through long-term PPAs could end up being significantly higher than future prices of electricity, hurting consumers. *See* Order No. 18829, ¶¶ 266 and 267. Direct Energy also argued that such contracts could result in stranded costs. *See* Order No. 18829, ¶ 266.

31 On December 4, 2017, Mayor Muriel Bowser pledged at the inaugural North American Climate Summit, to make Washington, DC carbon-neutral and climate resilient by 2050, and to implement a roadmap to reduce greenhouse gas emissions by 100 percent. *See* https://doee.dc.gov/release/mayor-bowser-commits-make-washington-dc-carbon-neutral-and-climate-resilient-2050.

32 Department of Energy & Environment, Government of the District of Columbia, *Clean Energy DC: The District of Columbia Climate and Energy Plan (Draft)*, October 2016, at 33, 41.

11. Accordingly, as part of the 2018 Biennial Review, the Commission invites comments on the following issues:

- Should a certain percentage of the SOS load be procured through long-term PPAs for renewable energy generation ("clean energy PPAs")? If so, what should that percentage be? What percentage of the SOS load should continue to be procured through the Wholesale Full Requirements Service Agreement?

- Should the clean energy PPAs supply energy for all customers classes – Residential, Small Commercial, and Large Commercial – or only some classes?

- What is the optimum contract term for clean energy PPAs? 5 or 10 years or longer? Should there be one contract term for all clean energy PPAs or a mix of contract terms?

- What renewable sources should be included in long-term clean energy PPAs? Wind and solar only, or should additional sources such are biomass and hydro or other Tier One resources be considered?

- What would the impact of the implementation of clean energy PPAs be in terms of the estimated reduction of GHG?

- Assuming less than 100 percent of the SOS is procured through clean energy PPAs, what impact, if any, will the use of PPAs have on the bid prices for the remainder of the SOS load?

- States can procure their SOS energy and RECs (including solar renewable energy credits (SRECs)) to meet their Renewable Energy Portfolio Standards in a bundled fashion or purchase them separately. Which method is more economical for long-term purchase agreements? Which method will better promote the goal of reducing GHG? Will the use of clean energy PPAs for SOS energy bundled with RECs and SRECS have any impact on the retail market for RECs and SRECs?

- If, as part of the procurement of SOS generation, the clean energy PPAs are entered into with extremely low per kWh prices, how would this affect competition between SOS and competitive electricity suppliers?

- How can the Commission avoid a scenario where clean energy PPAs are entered into for what may turn out to be at rather high prices, especially in the out years, and a large proportion of SOS customers migrate to competitive electricity suppliers as a result? (Under this scenario, substantially more generation would be procured than what is needed, resulting in excess generation being sold at a loss and thus increasing the remaining SOS customers' costs per kWh of electricity.)

- Would the use of long-term clean energy PPAs for SOS procurement be viewed by the credit agencies (Moody's, S&P, and Fitch) as an increase in Pepco's debt and, thereby, adversely impact Pepco's credit worthiness? If yes, could this be avoided by Pepco restructuring its position as the SOS administrator or by the use of a third-party entity as the SOS administrator?

- Would clean energy PPAs constitute an out-of-market financial subsidy to renewable energy generation facility owners that sell wholesale electricity supply services in PJM's markets? And, if yes, would such subsidies have an adverse impact on the PJM capacity market's ability to promote robust supply competition and the selection of the least-cost supply resources?

Interested persons commenting on whether long-term PPAs for renewable energy should be employed to supply all or part of the District's SOS load are encouraged to provide specific examples of where such PPAs have been successful or unsuccessful.

12. Finally, the Commission invites comment on any other recommended changes to the SOS program in light of competitive developments in the District of Columbia.

THEREFORE, IT IS ORDERED THAT:

13. Interested parties shall have 30 days from the date of this Order to file comments and 45 days to file reply comments.

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

Brinda Westbrook-Sedgwick

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

Tier I Certified Resources in Non-PJM States*
(in megawatts (MW))

State	Methane from landfill	Solar PV	Solar PV (NSTI)	Solar Thermal	Wind	Wood Waste	Grand Total
AL						49.80	49.80
GA			159.13				159.13
IA	1.60		1.99		274.55		278.14
MO	5.60		19.34		451.00		475.94
NY		0.40		0.00			0.40
SC	30.80						30.80
WI		0.14					0.14
Total	**38.00**	**0.54**	**180.46**	**0.00**	**725.55**	**49.80**	**994.36**

*The 994.36 MW of Tier I related resources in Non-PJM States is approximately 16% of the total Tier I resources currently certified for the District's RPS program.

Tier I Certified Resources in Non-PJM States*
(number of facilities)

State	Methane from landfill	Solar PV	Solar PV (NSTI)	Solar Thermal	Wind	Wood Waste	Grand Total
AL						1	1
GA			42				42
IA	1		1		17		19
MO	1		6		6		13
NY		28		1			29
SC	6						6
WI		11					11
Total	**8**	**39**	**49**	**1**	**23**	**1**	**121**

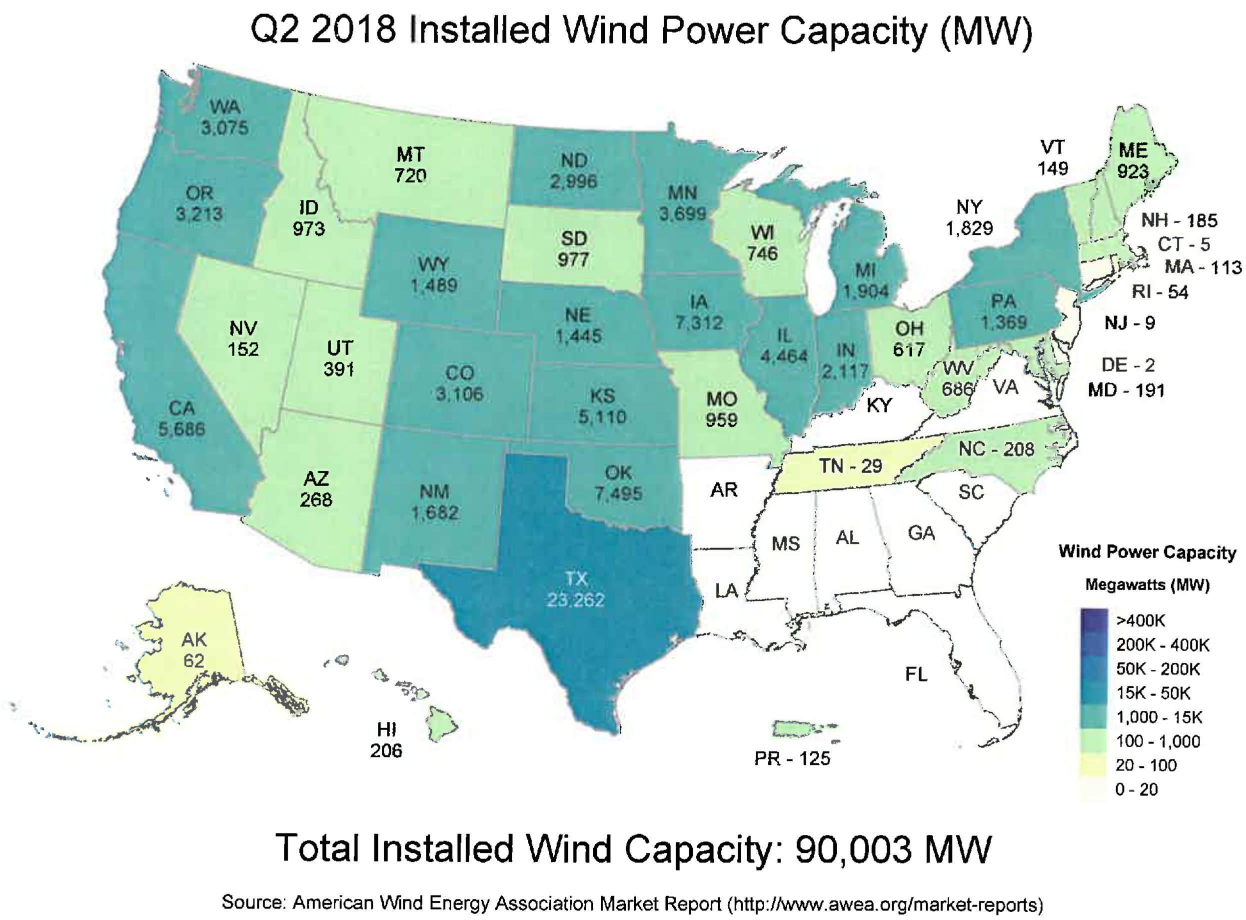
*The 121 Tier I related facilities in Non-PJM States is approximately 2% of the total Tier I resources currently certified for the District's RPS program.

Tier I RECs Used for 2017 RPS Compliance by Jurisdiction

State	Amount Retired	Percent of Total
District of Columbia	19,622	1.6%
Alabama	78,160	6.2%
Delaware	643	0.1%
Georgia	74,761	6.0%
Iowa	113,597	9.1%
Illinois	9,625	0.8%
Indiana	164,718	13.1%
Kentucky	67	0.0%
Maryland	1,054	0.1%
Michigan	16	0.0%
Missouri	756,404	60.3%
North Carolina	2,197	0.2%
New Jersey	63	0.0%
New York	184	0.0%
Ohio	489	0.0%
Pennsylvania	10,219	0.8%
South Carolina	16,596	1.3%
Tennessee		
Virginia	1,330	0.1%
Wisconsin	97	0.0%
West Virginia	4,502	0.4%
Total	1,254,344	100.0%

PJM States	214,545	17%
Non-PJM States	1,039,799	83%

ATTACHMENT 5



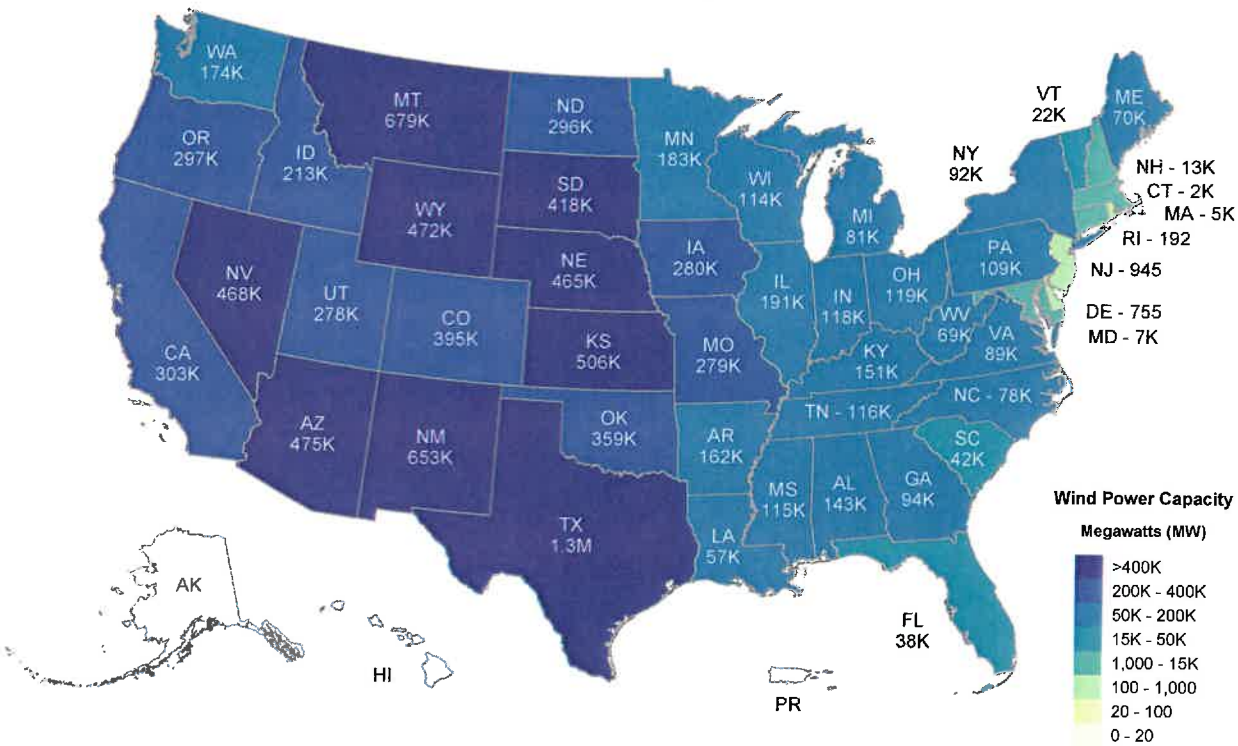
Year

1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018

Installed Wind Capacity

This map shows the maximum potential output from wind power given the number of installations in a state. The U.S. Department of Energy WINDExchange initiative tracks installed capacity as wind energy's market share of the nation's electricity mix increases from nearly 6% to what is possible to achieve as described in the Wind Vision (http://www.energy.gov/windvision)—20% by 2030 and 35% by 2050. The American Wind Energy Association reports installed capacity in their market reports (http://www.awea.org/Resources/Content.aspx?ItemNumber=875&navItemNumber=621) and projects database (http://www.awea.org/Resources/Content.aspx?ItemNumber=5728&navItemNumber=5776). The Energy Department's annual Wind Technologies Market Report (https://www.energy.gov/windreport) provides information about wind power capacity additions and forecasts.

U.S Potential Wind Capacity in Megawatts (MW) at 80 Meters



Total Potential Wind Capacity: 10,640,080 MW

Source: AWS Truepower, NREL

◉ **Capacity** ○ **Generation**

Potential Wind Capacity

Wind power capacity potential reflects the amount of wind power that is technologically possible to have installed in a given region. We would not expect this potential to be fully utilized, but it is indicative of the physical limits of the assumed technology. For example, between 2016 installed capacity that is close to 75,000 MW and potential capacity--what is technologically possible at 80-meters—is 10,600,000 MW. To get a sense for your location, compare a state's current installed capacity to what it technologically possible. Wind power capacity potential is estimated assuming that all available land area, after legal and technical exclusions are applied, is populated with wind turbines at a density of 3 megawatts per square kilometer. For additional detail on exclusions and methods for determining resource potential see Lopez et al (2012) (http://www.nrel.gov/docs/fy12osti/51946.pdf) and the *Wind Vision Report (http://energy.gov/eere/wind/maps/wind-vision)*.

ATTACHMENT 6

SETF ESTIMATED CONTRIBUTIONS 2020 - 2032 (Prepared by DC SEU/DC PSC)

Year	MMcf Natural Gas "Volumes Delivered to Consumers" *Source: EIA Natural Gas Consumption by End Use - D.C.*	Therm Sales	MWh Sales *Source: EIA Electricity Sales - D.C.*	kWh Sales	Gas Rate	Electric Rate	SETF Collection Gas	SETF Collection Electric	SETF Collection Total	DCSEU	Current DOEE Expenses	Surplus	Green Bank	Surplus after Green Bank
2014	32,543	325,507,701	11,193,589	11,193,589,000	$ 0.0140	$ 0.0015	$ 4,557,108	$ 16,790,384	$ 21,347,491					
2015	31,419	314,265,018	11,291,233	11,291,233,000	$ 0.0140	$ 0.0015	$ 4,399,710	$ 16,936,850	$ 21,336,560					
2016	27,987	279,936,823	11,394,003	11,394,003,000	$ 0.0140	$ 0.0015	$ 3,919,116	$ 17,091,005	$ 21,010,120					
2017		279,936,823	10,916,449	10,916,449,000	$ 0.0140	$ 0.0015	$ 3,919,116	$ 16,374,674	$ 20,293,789					
2018				-	$ 0.0140	$ 0.0015	$ -	$ -	$ -					
2019				-	$ 0.0140	$ 0.0015	$ -	$ -	$ -					
2020		306,569,847		11,198,818,500	$ 0.0452	$ 0.0029	$ 13,841,629	$ 32,494,492	$ 46,336,120	$ 20,000,000	$ 1,500,000	$ 24,836,120	$ 15,000,000	$ 9,836,120
2021		305,803,423		11,170,821,454	$ 0.0452	$ 0.0028	$ 13,807,025	$ 31,086,050	$ 44,893,075	$ 20,000,000	$ 1,500,000	$ 23,393,075	$ 15,000,000	$ 8,393,075
2022		305,038,914		11,142,894,400	$ 0.0452	$ 0.0027	$ 13,772,507	$ 30,086,929	$ 43,859,436	$ 20,000,000	$ 1,500,000	$ 22,359,436	$ 10,000,000	$ 12,359,436
2023		304,276,317		11,115,037,164	$ 0.0452	$ 0.0026	$ 13,738,076	$ 28,891,872	$ 42,629,948	$ 20,000,000	$ 1,500,000	$ 21,129,948	$ 10,000,000	$ 11,129,948
2024		303,515,626		11,087,249,571	$ 0.0452	$ 0.0025	$ 13,703,731	$ 27,702,602	$ 41,406,332	$ 20,000,000	$ 1,500,000	$ 19,906,332	$ 10,000,000	$ 9,906,332
2025		302,756,837		11,059,531,447	$ 0.0452	$ 0.0024	$ 13,669,471	$ 26,519,097	$ 40,188,569	$ 20,000,000	$ 1,500,000	$ 18,688,569	$ 10,000,000	$ 8,688,569
2026		301,999,945		11,031,882,619	$ 0.0452	$ 0.0023	$ 13,635,298	$ 25,341,338	$ 38,976,635	$ 20,000,000	$ 1,500,000	$ 17,476,635		$ 17,476,635
2027		301,244,945		11,004,302,912	$ 0.0452	$ 0.0022	$ 13,601,209	$ 24,169,301	$ 37,770,510	$ 20,000,000	$ 1,500,000	$ 16,270,510		$ 16,270,510
2028		300,491,833		10,976,792,155	$ 0.0452	$ 0.0021	$ 13,567,206	$ 23,002,966	$ 36,570,172	$ 20,000,000	$ 1,500,000	$ 15,070,172		$ 15,070,172
2029		299,740,603		10,949,350,174	$ 0.0452	$ 0.0020	$ 13,533,288	$ 21,842,311	$ 35,375,599	$ 20,000,000	$ 1,500,000	$ 13,875,599		$ 13,875,599
2030		298,991,252		10,921,976,799	$ 0.0452	$ 0.0019	$ 13,499,455	$ 20,688,408	$ 34,187,863	$ 20,000,000	$ 1,500,000	$ 12,687,863		$ 12,687,863
2031		298,243,773		10,894,671,857	$ 0.0452	$ 0.0018	$ 13,465,706	$ 19,537,960	$ 33,003,666	$ 20,000,000	$ 1,500,000	$ 11,503,666		$ 11,503,666
2032		297,498,164		10,867,435,177	$ 0.0452	$ 0.0016	$ 13,432,042	$ 17,518,306	$ 30,950,348	$ 20,000,000	$ 1,500,000	$ 9,450,348		$ 9,450,348
TOTAL							**$ 177,266,642**	**$ 328,881,631**	**$ 506,148,273**	**$ 260,000,000**	**$ 19,500,000**	**$ 226,648,273**	**$ 70,000,000**	**$ 156,648,273**

Blue = Estimates

Electricity and Gas assumed annual reduction rate: 0.25% 0.9975

Sources:
https://www.eia.gov/electricity/data/eia861m/index.html
https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SDC_a.htm

Years 2014-2017 Actuals
Years 2020-2032 Estimates