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GOVERNMENT OF THE DISTRICT OF COLUMBIA
OFFICE OF THE ATTORNEY GENERAL

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Public Advocacy Division
Social Justice Section

ELECTRONIC FILING

August 14, 2020

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

Re: Rulemaking No. RM40-2020-01: In the Matter of 15 DCMR Chapter 40, District of Columbia Small Generator Interconnection Rules

Dear Ms. Westbrook-Sedgwick:

On behalf of the Department of Energy and Environment, please find enclosed their Reply Comments in response to the Notice of Proposed Rulemaking first appearing in the D.C. Register on April 10, 2020 in the above captioned matter. If you have any questions regarding this filing, please do not hesitate to contact the undersigned.

Respectfully submitted,

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of 15 DCMR Chapter 40 – District of Columbia Small Generator Interconnection Rules	)))))	**RM40-2020-01**

DEPARTMENT OF ENERGY AND ENVIRONMENT'S
REPLY COMMENTS IN RESPONSE TO PROPOSED RULEMAKING RM40-2020-01

Pursuant to the Public Service Commission of the District of Columbia's ("Commission") Public Notice published in the District of Columbia Register on May 22, 2020,[1] the Department of Energy and Environment (DOEE), on behalf of the District of Columbia Government (the District), respectfully submits these reply comments on the April 10, 2020 Notice of Proposed Rulemaking (NOPR) published by the Commission in the above-captioned proceeding.

I. BACKGROUND

The NOPR amends the Small Generator Interconnection Rules (SGIR) in Chapter 40 of Title 15 of the District of Columbia Municipal Regulations (DCMR). The stated purpose of the NOPR is to address the following: (1) distribution system upgrade costs for Community Renewable Energy Facilities (CREF); (2) timelines for small generator interconnection; and (3) a timeframe for advanced inverter deployment and the implementation of the *IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces* (IEEE 1547-2018 Standard). The NOPR follows a series of meetings by the RM-9 Stakeholder Working Group to discuss the above topics, although the working

[1] Vol. 67 – No. 21, 005448.

group did not reach consensus on these matters. The NOPR originally requested comments on the proposed amendments to the SGIR within 30 days of their publication in the District of Columbia Register; however, the Commission by Public Notice twice extended the deadline for comments until July 15, 2020.[2] In addition to DOEE, Centers for Renewable Integration (CRI), Joint Solar Advocates (JSA), Potomac Electric Power Company (Pepco), and DC Climate Action (DCCA) filed sets of initial comments to the NOPR.[3] DOEE submits the following reply comments.

II. CONTEXT: THE DISTRICT'S CLIMATE GOALS AND MANDATES

DOEE believes that the outcome of this proceeding, and the streamlining of Distributed Energy Resources (DER) interconnection and DER integration in general, are essential and may determine the success or failure of the District's local solar policy and grid modernization goals. DOEE appreciates the chance to react to the initial comments filed by CRI, JSA, Pepco, and DCCA in this matter. In addition to the need for streamlined interconnection processes to meet the District's solar carve-out under the Renewable Portfolio Standard, (RPS)[4] DOEE has outlined the importance of streamlined DER interconnection to these goals in the following documents and filings:

- <u>Clean Energy DC</u>

The Clean Energy DC (CEDC) Plan is the District's climate and energy action plan. The CEDC calls for: "updating interconnection studies and procedures for DER based on revised

[2] RM40-2020-01, Public Notices issued May 14, 2020, and May 22, 2020.
[3] In addition, the D.C. Water & Sewer Authority filed a Motion for Leave to File Comments and Comments on July 17, 2020, however, as of the filing of these Reply Comments, the Commission has not yet ruled on this motion.
[4] The Clean Energy Omnibus Amendment Act of 2018, pg. 2-3

planning methods and to accommodate an expanded volume of requests."[5] DOEE envisions updated interconnection studies and procedures as part of a larger framework of integrated distribution resource planning to enable an effective grid modernization that can accommodate a significant amount of cost-effective DER.

- Formal Case No. 1050 - *In the Matter of the Investigation of the Implementation of Interconnection Standards in the District of Columbia*

In Formal Case No. 1050, DOEE filed comments calling for additional transparency in interconnection costs, a strict 20 business day timeline for Pepco to issue Authorizations To Operate (ATO), and improvements to Pepco's hosting capacity analysis.[6]

- Formal Case No. 1130 - *In the Matter of the Investigation of the Implementation of Interconnection Standards in the District of Columbia*

DOEE has been an active participant in Formal Case No. 1130, and has called for: (1) streamlining the interconnection process; (2) improvements to Pepco's hosting capacity analysis methodology; (3) creating a public interconnection queue; (4) new rules governing storage and systems with islanding capability; (5) automated and fast track interconnection; and (6) standardized interconnection agreements for microgrids.[7] DOEE has also provided analyses and briefings by national experts on grid modernization, describing streamlined, transparent, and accessible interconnection of DER as a fundamental building block of grid modernization.[8]

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[5] DOEE, *Clean Energy DC: The District of Columbia Climate and Energy Action Plan*, p. 173

[6] Written Statement of District Department of the Environment Director Tommy Wells, at pg. 4 (July 21, 2015); Comments by the Department of Energy and Environment on behalf of the District of Columbia Government, at pgs. 1-2 (October 22, 2018).

[7] District of Columbia Department of Energy and Environment, "*Formal Case No. 1130:* "Initial Comments on Staff Proposed Opinion and Order in Response to Order No. 19984." Pg. 6, 15-18.

[8] See, for example, an excerpt from Paul De Martini & Lorenzo Kristov, "Distribution Systems in a High Distributed Energy Resources Future", p.8, October 2015, Lawrence Berkeley National Laboratory, https://emp.lbl.gov/sites/default/files/lbnl-1003797.pdf

III. SUMMARY OF DOEE'S INITIAL COMMENTS

As DOEE stressed in its Initial Comments in this proceeding, DOEE supports continual updates and improvements to the SGIR that are paired with adequate enforcement to ensure that DER interconnection and integration continues apace to put the District on track to meet its decarbonization and solar-driven economic development goals. DOEE asks the Commission to reject proposed changes to the SGIR that would delay the achievement of these goals, such as Pepco's proposal to require projects larger than 250 kW to go through a Level 4 interconnection (and therefore, a supplemental review), or Pepco's proposal to alter the "DC – CREF" tariff in a manner that directly conflicts with the District's climate goals and falls outside the scope of an interconnection rulemaking.

For ease of organization, DOEE has divided its Reply Comments into four sections: (1) transparent and non-discriminatory access to the Electric Distribution System (EDS); (2) streamlining of interconnection processes and timelines; (3) modernization; and (4) responses to proposals that would delay or otherwise harm DER integration. Based on DOEE's initial filings, together with the input of comments from other stakeholders, DOEE has provided a redline of the SGIR in the NOPR as Attachment A.

IV. TRANSPARENT AND NON-DISCRIMINATORY ACCESS TO THE ELECTRIC DISTRIBUTION SYSTEM (EDS)

This section will focus on responses to parties' comments regarding transparent and non-discriminatory access to the EDS, which will include the following topics: (A) public queue, and (B) cost sharing and transparency.

A. Public Queue

As DOEE stated in its Initial Comments, the public queue is required to facilitate fair, non-discriminatory access to the EDS, by ensuring that all developers have access to the same information. This practice is standard in a number of states, including California, New York, Massachusetts, and Hawaii. The use of a public queue is also recommended as a best practice by the Interstate Renewable Energy Council (IREC). As the National Renewable Energy Laboratory (NREL) notes:

> Publicly-available data that depict a utility's interconnection application queue can be used by developers to understand a project's position in the overall queue as well as the volume of other projects requesting interconnection at a particular location. Queuing data that include location at the circuit level could also help developers assess the likelihood that upgrades will be needed to accommodate new distributed capacity on a circuit.[9]

Given that EDS upgrade costs have been difficult for solar developers to predict, providing access to public queue data listed in the NOPR would help developers make educated decisions *in advance* of filing an interconnection application.

1. The public queue does not require Pepco to share information about customers.

Pepco, in its initial comments to this NOPR, expressed concern that a public queue would be unlawful and against Commission regulation: "The public queue proposed in the 2020 NOPR would force Pepco to choose between violating a District law and violating Commission regulations. Moreover, Pepco would be forced to choose between violating this regulation and violating 15 D.C.M.R. §308, which contains the same disclosure restrictions as the District

[9] National Renewable Energy Laboratory, *Review of Interconnection Practices and Costs in the Western States*, April 2018. pg. 37

law."[10] Pepco cites examples of interconnection data that were ordered by the Commission to be submitted confidentially, including: "a list of the names, locations, fuel types, and kW capacities of the Level 2, Level 3 and 4 facilities approved during a reporting year."[11]

Pepco goes on to state, "[t]he Commission's direction to now provide this same information in a public queue is inconsistent with the law and with Commission precedent." DOEE disagrees, finding that the public queue does not require the "same information" since it does not require the names or locations of customers.

DOEE finds Pepco's interpretation of both D.C. Code § 34-1507 and 15 DCMR § 803 to be overly broad. D.C. Code § 34-1507 states that:

> Unless a customer consents in writing, a market participant or the electric company may not disclose information that: (A) Is about the customer; and (B) Was supplied to the market participant or electric company by the customer.[12]

However, none of the twenty (20) items listed in Attachment 1 of the NOPR represent information that is "about the customer." While the examples of confidential filings that Pepco provided contain customer information such as name and location, the public queue would require neither. The public queue would contain a list of DER projects pending interconnection and their attributes, with the feeder as the most granular locational information available. For illustrative purposes, DOEE provides an example of what the District of Columbia public queue would look like in Attachment B.

Regarding DCMR § 803, the regulation reads:

> A Utility … shall not disclose information that reveals the status of the Account of any individual Customer without the Customer's consent or upon dictate of lawful authority;
> ….

[10] Pepco Initial Comments, pg. 11
[11] Pepco Initial Comments, pg. 11
[12] District of Columbia Municipal Code § 34–1507

> Unless a Customer consents…the Utility…may not disclose or use Customer information or the Customer's use of service (types and amounts) except to the Commission and in accordance with the Utility['s]...Privacy Policy.[13]

The public queue would not require the collection or dissemination of information that reveals the status of a customer's account, customer identifying information, or a customer's energy consumption data. As such, the public queue does not violate any provision of an existing Commission regulation. If the Commission does find any of the items in the public queue to constitute a type of protected customer information, then those items should be provided in aggregate or as a range of values, thereby preventing the item from becoming a customer identifying information.

2. The public queue should not be costly to maintain.

Another concern that Pepco raised with the public queue is the issue of cost: "the public queue is duplicative and an unnecessary cost to customers."[14] DOEE disagrees with Pepco that a simple spreadsheet would be costly to maintain, especially compared to the suite of complex mapping tools that Pepco currently hosts on its website.

Additionally, Pepco states: "Of the 20 items requested in the public queue, Pepco already provides that information in a form that complies with District law for almost all of them."[15] Since Pepco already collects and disseminates much of the information requested, it should not be a cost-intensive process to compile this information into a single spreadsheet.

[13] District of Columbia Municipal Regulations Title 15, Chapter 3, §803
[14] Pepco Initial Comments, pg. 2
[15] Pepco Initial Comments, pg. 3

3. The public queue is not duplicative.

DOEE appreciates the work that Pepco has done to make more information available to DER developers and the public. Pepco mentions in its comments several mapping tools that are available, tracking tools for developers once projects are already working their way through the interconnection process, and required reporting to the Commission.[16] However, DOEE notes that these datasets and reports are not a substitute for a public queue. The purpose of such a queue is to add a level of transparency to the interconnection process, by allowing symmetrical access to information about projects in the queue at the feeder level to aid in project siting and estimating interconnection costs. This type of information, in order to have an impact, must be available to developers *before* they apply to interconnect to the EDS.

4. As an alternative, the Commission could host and maintain the public queue.

Given Pepco's discomfort with hosting the public queue, DOEE would like to recommend as a potential alternative that the Commission host the queue on its website and require Pepco to report the required information on a monthly basis.

B. Cost Sharing and Transparency

Cost transparency was a topic of significant discussion in the RM-9 Working Group meetings. DOEE believes that additional transparency will improve the interconnection process by avoiding costs for upgrades that may be unnecessary and will also improve the predictability of necessary interconnection costs.

[16] Pepco Initial Comments, pg. 2-10

1. The Interconnection Facilities Matrix should be completely separate from the SGIR and should be updated no more than annually.

DOEE stated in its Initial Comments:

> DOEE disagrees with the way in which the design of the interconnection process in this NOPR has been based on the Interconnection Facilities Cost Matrix. Rather, DOEE strongly believes that the interconnection procedures and timelines should be based on the safety and reliability of the system, not the availability of up-front, and, at this time, arbitrary, cost estimates.[17]

DOEE reiterates this point because DOEE and other stakeholders will not have a chance to review or comment on this cost matrix, which will be hosted on Pepco's website. Therefore, Pepco's proposal creates arbitrary interconnection rules that are grounded in opaque cost estimates instead of DER and EDS technical attributes and operating criteria. Moreover, it is fundamentally unfair to build interconnection rules based on cost estimates that are non-transparent, unpredictable, and unavailable for review.

While the Interconnection Facilities Cost Matrix should not be part of the SGIR, DOEE certainly welcomes the additional predictability that could be provided by Pepco hosting a fixed-cost menu on its website for interconnection facilities (or even for EDS upgrades) to provide cost certainty for DER interconnection.

However, in Pepco's initial comments, it has proposed the following: "Pepco has added the words "at least" next to "annually" to allow flexibility in case the Interconnection Facilities Cost Matrix were to need to be updated more than one time in a year."[18] Therefore, Pepco's proposed change would appear to reduce the transparency of the SGIR even further if it continues to include timelines based on the Interconnection Facilities Cost Matrix. If the matrix can be updated at any time, the added potential for variability in both prices and the facilities

[17] DOEE Initial Comments, pg. 6
[18] Pepco Initial comments, pg. 15

included within the matrix removes any additional cost certainty from the inclusion of the matrix in the first place. The interconnection process should not be dependent upon opaque and unpredictable cost estimates shown on Pepco's website that are subject to change and for which there is no Commission oversight or opportunity for informed stakeholder review for reasonableness and accuracy.

DOEE notes that there are guides that may be helpful. NREL has a database of interconnection costs available that may help Pepco and solar developers to quickly estimate the cost of various interconnection facilities and upgrades.[19] In addition, the California Public Utility Commission (CPUC) issued Decision 16-06-052 on June 23, 2016 regarding the development of a "Unit Cost Guide" for each investor-owned utility. The CPUC Order included the following language:

> The Utilities will update their Cost Guides annually. Prior to posting updates to the Cost Guide, the Utilities will meet and confer with stakeholders to obtain comment on proposed revisions pursuant to a schedule set forth in the Principles. Overall, the Cost Guides developed by the Utilities will not replace any project-specific study costs, but rather, the Cost Guide is intended to be used as a point of reference for projects that are considering the existing study processes.[20]

It is important to note that while these Unit Cost Guides are a tool for increasing transparency, they are not intended to alter the interconnection process and timelines. The list of items included covers typical types of facilities and upgrades that could be required for interconnecting DER, including equipment such as transformers and automatic reclosers. An example of the Unit Cost Guide for Southern California Edison is included as Attachment C for reference.[21]

[19] https://www.nrel.gov/solar/distribution-grid-integration-unit-cost-database.html
[20] CPUC Decision 16-06-052, at pg. 7 (*rel.* June 23, 2016).
[21] https://www.sce.com/sites/default/files/inline-files/Attachment%20A%20-%20Unit%20Cost%20Guide%202019.pdf

2. Cost letters should be itemized.

A crucial step for increasing cost transparency and predictability will be the itemization of cost letters, according to the language in the original NOPR. In Pepco's initial comments, the company stated: "Pepco's systems do not permit itemized breakout of these costs or any of the other costs listed in the 2020 NOPR."[22] DOEE does not find this statement to be an adequate reason to prevent more transparency and predictability. A cost estimate is merely a sum of the cost estimate of each constituent item. It strains credulity that providing this one additional layer of information cannot be "permitted". Interconnection Customers have a right to know the unit cost figures of equipment for which they are paying.

3. The Commission should adopt the New York model or a similar framework for the cost sharing of EDS upgrades.

In filing initial comments, both Pepco and JSA raised concerns that the cost-sharing framework for CREFs in the NOPR would not achieve equitable results. The JSA stated: "As currently proposed, those proposing interconnections early in the year would be rewarded while others would not be able to benefit. It is not a practical mechanism for equitable distribution of charges."[23] Pepco also stated:

> By capping the aggregate amount of cost that can be socialized, the first movers receive the benefit of the socialized costs, leaving those who enter the queue later with no benefit of cost socialization (i.e., they must pay for their entire project). Therefore, the Commission should either remove the cap all together or should have a per project cap on the amount that would be socialized without limiting the aggregate amount that can be socialized.[24]

DOEE agrees with Pepco and JSA on this point regarding early movers.

[22] Pepco Initial Comments, pg. 19
[23] JSA Initial Comments pg. 10
[24] Pepco Initial Comments pg. 12

As DOEE noted in multiple RM-9 Stakeholder Working Group meetings as well as in its Initial Comments, there are other, more equitable cost allocation models available, such as the model used by New York:

> In the New York model, the Interconnection Customer who triggers the upgrade pays 100% of the cost, and "the share of the costs paid by subsequent developers would be calculated as the ratio of the total upgrade cost compared to the total AC watts the upgrade serves." A model based on this premise of post-upgrade allocation would promote a non-discriminatory approach.[25]

DOEE believes the New York allocation model or a similar model to be a more equitable approach than the model proposed in the NOPR. The New York model or a similar approach allows upgrade costs to be allocated based on the amount of hosting capacity that is unlocked through the upgrade so that the costs can be distributed in a pro-rated manner.

DOEE is willing to support a portion of cost share with ratepayer for CREF upgrades, if (1) significant improvements are made in the transparency and predictability of how the costs are allocated, including the implementation of the public queue; (2) a technical justification for any upgrades *and* interconnection facilities are provided ; and (3) itemized cost letters are provided.

V. STREAMLINING OF INTERCONNECTION PROCESS AND TIMELINES

This section will focus on responses to parties' comments regarding the streamlining of interconnection processes and timelines, which includes the following topics: (A) virtual CREFs, and (B) reporting and timeline enforcement.

[25] DOEE Initial Comments pg. 10

A. Virtual CREFs

The RM-9 Stakeholder Working Group discussed the need for “virtual” CREFs (VCREF), which follow the same billing procedures as a typical CREF while avoiding the need for interconnection facilities. This should help to streamline the interconnection procedures while simultaneously reducing costs for the interconnection of CREFs, thereby helping the District meet its climate goals and mandates. A VCREF that does not require EDS upgrades will likely need only a Customer Generation Meter for interconnection, which should allow the project to proceed through a streamlined timeline.

The Commission should reject Pepco’s proposal to require projects requiring only additional metering equipment to go through an extended interconnection timeline, as this would prejudice VCREFs. DOEE agrees with JSA that VCREFs are “the fastest and most efficient method for CREF interconnection.”[26] DOEE has submitted previous filings supporting VCREFs, asking the Commission to expedite their implementation.[27] In the current iteration of the SGIR, there are three types of interconnection timelines facing a Level 2 interconnection project: (1) projects requiring neither interconnection facilities nor EDS upgrades; (2) projects requiring interconnection facilities only; and (3) projects requiring EDS upgrades. The timelines for Approval to Install (ATI) associated with each of these project types are listed in the chart below, for each of the (1) current SGIR, (2) NOPR, and (3) DOEE’s proposed changes:

Project Type	**Current Rules – Days to ATI**	**NOPR – Days to ATI**	**Proposed by DOEE**
1 – No Facilities, No Upgrades	15	15	15
2 – Facilities Only	15	25	15
3 – Upgrades Required	30	25	25

[26] JSA Initial Comments, pg. 2
[27] DOEE “Comments in Response to Proposed Rulemaking RM-09-2020-01,” at pgs. 2-3 (March 13, 2020).

A VCREF requiring only the installation of a Customer Generation Meter should benefit from a 15-day timeline for ATI, regardless of the timeline scenario adopted, since a Customer Generation Meter does not qualify as an interconnection facility. DOEE agrees with Pepco on this point:

> Similarly, Pepco modifies the definition of Interconnection Facilities to make clear that both the Utility Distribution Usage Meter and the Utility Distribution Generation Meter are not Interconnection Facilities.[28]

Therefore, the Commission should reject Pepco's proposal to force projects requiring merely a generation meter to go through an extended interconnection timeline, which would unfairly prejudice VCREFs and other simple projects that require only generation metering in order to be interconnected.

DOEE does note, however, that the capabilities of DER interconnected with inverter systems can be equipped with sensors and metering technology that are certified as revenue-grade.[29] Therefore, DOEE does not support the name change from "Customer Generation Meter" to "Utility Distribution Generation Meter." Additionally, the District of Columbia's CREF statute explicitly requires CREF developers to own and install a "production meter." The statute reads:

> (H) The amount of electricity generated each month available for allocation as subscribed or unsubscribed energy shall be determined by a revenue quality production meter installed and paid for by the owner of the community renewable energy facility. It shall be the electric company's responsibility to read the production meter."[30]

Therefore, to require utility ownership of the generation meter for CREFs would contradict D.C. Code § 34–1518.01.

[28] Pepco Initial Comments, pg. 15.
[29] For more detail, see section 6.B.i of this document.
[30] D.C. Code § 34–1518.01.

B. Reporting and Timeline Enforcement

Consistent improvement in the interconnection process in the District of Columbia will require reducing the amount of time that it takes from a project's initial interconnection application to the point where the interconnection is finalized and the system is operating.

1. ATO timelines should be clear and enforced.

DOEE supports JSA's assertion that clear timelines should be in place for invoicing and for ATOs. JSA stated in its Initial Comments:

> [T]here should be a timeline for the issuance of an invoice after the Interconnection Customer signs the cost letter. This time should not exceed two (2) business days. After the invoice is paid, there should be a timeline for interconnection and the issuance of Authorization to Operate. This should be twenty (20) business days after the required documentation in section 4005.4(e) is submitted to the EDC.[31]

DOEE agrees with JSA and recommends that the Commission adopt this language. DOEE has filed comments previously in Formal Case No. 1050 requesting a clear timeline for ATOs of 20 business days.[32]

2. Reporting and enforcement should be required for timelines at each interconnection level.

In JSA's Initial Comments, the group stated that the "requirement for corrective action plans should be expanded beyond the ATI timelines for Level 1 applications. This should be a requirement for all interconnection levels and not only for Authorizations to Operate, but also for Approval to Install."[33] DOEE agrees with JSA and requests that the Commission adopt this recommendation.

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[31] JSA Initial Comments, pg. 10

[32] District of Columbia Department of the Environment, "*Formal Case No. 1050*: Written Statement of District Department of the Environment Director Tommy Wells" July 21 2015. pg. 4

[33] JSA Initial Comments, pg. 6-7

DOEE also asks the Commission to immediately appoint a staff member as the Interconnection Ombudsperson to provide oversight of the interconnection process, including audits of past interconnection documentation, enforcement of timelines, and dispute resolution. In addition to the Massachusetts example provided by DOEE in its Initial Comments, both New York and California have appointed ombudspersons for dispute resolution or complaints in the interconnection process.[34]

DOEE has also recommended in its Initial Comments and in Formal Case No. 1130 to preserve Level 1 interconnections as fast-track only, with any modifications to the process requiring a project to go through Level 2, as a first step to moving Level 1 towards a fully automated interconnection process.[35]

VI. MODERNIZATION

This section will focus on responses to parties' comments regarding grid modernization, which includes the following topics: (A) IEEE 1547-2018 Standard implementation, and (B) communications technologies. DOEE notes that this NOPR does not address the required changes to the SGIR to integrate microgrids (i.e., clear rules for battery storage and islanding), which will need to be undertaken in Formal Case Nos. 1050 and 1163.

[34] Both state utility commissions appoint one ombudperson per investor-owned utility
[35] DOEE Initial Comments, pg. 22-23

A. IEEE 1547-2018 Standard Implementation

DOEE looks forward to working with the Commission, Pepco, and other stakeholders to implement the IEEE 1547-2018 Standard, including the near-term goal of developing default autonomous inverter settings profiles before January 1, 2022.

1. MDV-SEIA and Pepco should be named as co-organizers of the IEEE 1547-2018 Standard educational workshops along with Commission Staff.

The Commission, in Order No. 20364, stated:

> The Commission directs the Staff in conjunction with Pepco to hold educational workshops within 120 days from the date of this Order…relative to the status and progress of the standards' implementation, to inform stakeholders of developments in the implementation of these standards.[36]

DOEE looks forward to participating in the educational workshops. DOEE staff have already participated, along with Commission staff, in an educational workshop held by MDV-SEIA on December 5, 2019, which drew upon considerable technical expertise. CRI noted in its supplemental comments:

> The Commission should note in this regard, that CRI has been participating in forums and discussions on Advanced Inverter deployment in the District sponsored by …MDVSEIA. The Commission-ordered workshops can build upon MDVSEIA's work, and CRI hopes that Staff will engage stakeholders active in the MDVSEIA process in planning the new workshops.[37]

Given the significant work that MDV-SEIA has done to date on the IEEE 1547-2018 Standard implementation, DOEE agrees with CRI that MDV-SEIA is an important entity to organize the educational workshops alongside Pepco and Commission Staff.

[36] Formal Case No. 1130, ¶ 77 (*rel.* June 5, 2020).
[37] At pg.4 (July 14, 2020).

2. The Commission should establish the DOEE-requested Advanced Inverter Technical Stakeholder Working Group "AIWG".

In Order No. 20364, the Commission left the door open for the creation of a stakeholder working group: "Upon the completion of the educational workshop on IEEE 1547-2018 Standards, the Commission will consider the need for a technical conference or working group as deemed appropriate."[38] DOEE reiterates its request from its Initial Comments for the creation of the AIWG and adoption of the proposed scope of work for the working group.

DCCA, JSA, and CRI in their initial comments each underlined the need for stakeholder participation. DCCA stated in its initial comments:

> DCCA supports the roll-out date but believes that the Commission should include a robust stakeholder process starting immediately (in 2020) to ensure that the settings profile chosen aligns with the District's public climate and energy policies and goals, and that the inverter deployment supports other District-specific needs such as the development of a healthy renewables industry sector.[39]

DOEE supports the comments of DCCA, CRI, and JSA, noting that the creation of the AIWG and stakeholder engagement in the process is critical. While DOEE believes this pathway proposed by DCCA, CRI, and JSA (which is based on the Maryland process) to be acceptable, DOEE requests that the Commission adopt a process that is Commission and stakeholder-driven. The Commission, together with the AIWG, should draft and adopt the autonomous inverter settings profiles for the District of Columbia for each relevant feeder/circuit type. A Commission and stakeholder driven-engagement process could help assure that all input is adequately evaluated and taken into consideration. This process is in line with the National Association of Regulatory Utility Commissioners (NARUC) resolution published on February 12, 2020. The NARUC resolution includes the following language:

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[38] *Supra* note 36.
[39] DCCA Initial Comments, pg. 5

> Whereas IEEE 1547-2018 highlights responsibilities, including determination of performance categories, of State regulators and other authorities governing interconnection requirements;
>
> ….
>
> Whereas successful State implementation of the updated IEEE 1547-2018 will benefit from stakeholder engagement, including electric distribution system operators, DER customers and developers, and bulk power system operators, and identifying and engaging such subject matter experts may take significant lead-time.[40]

IREC also underscored the need for regulator coordination with stakeholders:

> State regulators will play an important role in adopting and implementing the new standards, helping ensure that all interests are balanced."[41] IREC also notes: "State implementation of IEEE Std 1547™-2018 will benefit from fair, balanced and transparent stakeholder processes to ensure that the perspectives of all impacted stakeholders, including consumers adopting DERs, are accounted for and reflected.[42]

DOEE also recommends that the Commission look to the California Smart Inverter Working Group as a model, which was created as a joint California Energy Commission and CPUC initiative.[43]

3. The Commission should adopt the proposed objectives for advanced inverter settings in the NOPR.

DOEE is concerned with Pepco's interpretation of the IEEE 1547-2018 Standard and advanced inverter capabilities in Pepco's initial comments in this proceeding, particularly with the following language: "The reason for having advanced inverters is to give the utility the ability to curtail generation in order to avoid violations."[44] DOEE finds this framing of IEEE

[40] NARUC, "Resolutions Passed By NARUC Board of Directors 2020 Winter Policy Summit" pgs. 1-2
[41] IREC, "Smart Inverter Update: New IEEE 1547 Standards and State Implementation Efforts," July 23 2018: https://irecusa.org/2018/07/smart-inverter-update-new-ieee-1547-standards-and-state-implementation-efforts/
[42] IREC, *Making the Grid Smarter: Primer on Adopting the IEEE 1547™-2018 Standard for Distributed Energy Resources*, pg. 4
[43] https://www.cpuc.ca.gov/General.aspx?id=4154
[44] Pepco Initial Comments, pg. 17

1547-2018 Standard-compliant advanced inverters to be fundamentally incorrect and inconsistent with the purpose of the IEEE 1547-2018 Standard. The Standard provides for significant *autonomous* functions that inverter-based DER systems can provide. The adoption of these autonomous inverter settings profiles will allow inverter-based systems to provide support to the EDS by reacting to local measurements of voltage and frequency. DOEE notes that there are several jurisdictions where the reactive power capabilities and voltage regulation performance of advanced inverters are specified as part of the Advanced Inverter Operating Requirements of their respective interconnection rules, including California, Hawaii, and Minnesota.[45] While the advanced inverters also have the ability to allow for control functionalities, DOEE has recommended that the Commission focus on autonomous functionalities between now and January 1, 2022, to ensure that DER interconnected to the District of Columbia's EDS after that point in time will be able to provide these grid support services and expanded hosting capacity. At that point, additional work will need to be done to determine under what conditions an EDC can implement DER control functionalities and the appropriate contractual language, consumer protections, and tariffs required in these instances.

DOEE disagrees with Pepco's proposed changes to the advanced inverter objectives in Pepco's Initial Comments:

> Pepco proposes that the primary objective is "to help support reliability of the system while minimizing the curtailment of real power." By changing the focus of this objective, more customers will be able to interconnect solar projects, and solar hosting capacity will be increased. If the smart inverter functions can only be used when the system is experiencing violations (abnormal operating conditions), the

[45] (1) CPUC Rule 21 Hh(2), Smart Inverter Generating Facility Design and Operating Requirements, https://www.cpuc.ca.gov/Rule21/; (2) HIPUC Rule 14H, Appendix I Distributed Generating Facility Interconnection Standards Technical Requirements, 4A - Advanced Inverter Generating Facility Design and Operating Requirements, https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/generate-your-own-power; (3) Minnesota Technical Interconnection and Interoperability Requirement (TIIR), https://mn.gov/puc/assets/TIIR%20w%20CORRECTED%20Interim%20Implementation%20Guidance_tcm14-431321.pdf.

> system will be operating on the edge of stability and very close to voltage violations, not a robust scenario that can support greater hosting capacity.[46]

DOEE believes that Pepco's proposed changes would skew the focus of the implementation of the IEEE 1547-2018 Standard towards curtailment at the expense of the numerous other support functions inverters can provide that may be used to increase hosting capacity (i.e. voltage/frequency ride-through, voltage/frequency regulation). The original NOPR correctly points out that performance categories must be established for both normal and abnormal operations. As IREC notes:

> IEEE Std 1547™-2018 identifies two performance categories relevant to DER grid functionality: the Normal Operating Performance Category and the Abnormal Operating Performance Category. The Normal Operating Performance Category specifies how the DER should perform with regards to voltage control during normal grid operations. The Abnormal Operating Performance Category specifies DER performance during a grid disturbance.[47]

DOEE disagrees with Pepco's framing of the NOPR's objectives, finding that the Commission's original language addresses both normal and abnormal operating conditions. However, Pepco's focus on curtailment at the expense of voltage/frequency ride-through and voltage/frequency regulation results in a narrowly focused generation curtailment strategy instead of one that embraces grid modernization and the grid support functions that advanced inverters can provide under normal operations. This stance taken by Pepco demonstrates a lack of understanding of advanced inverter capabilities that will limit the uptake of renewable energy in the District of Columbia.

DOEE finds that Pepco's mischaracterization of the IEEE 1547-2018 Standard further underscores the need for the Commission to develop District of Columbia default inverter

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[46] Pepco Initial Comments, pg. 16
[47] IREC, *Making the Grid Smarter: Primer on Adopting the IEEE 1547™-2018 Standard for Distributed Energy Resources*, pg. 13

settings that are appended to the SGIR. The first step in the implementation of IEEE Standards will be to deal with the default autonomous settings for inverters that will allow for increased hosting capacity in the interim, while additional regulations are put in place for overseeing control functionalities.

DOEE strongly urges the Commission to maintain the full objectives of IEEE 1547-2018 Standard implementation in the NOPR, and to reject Pepco's proposed alterations that unnecessarily reduces the public benefits of the IEEE 1547-2018 Standard.

4. Inverter settings profiles should be specific to the feeder/circuit type.

DCCA, CRI, and JSA each called for specific language to be added as a tertiary objective: "The tertiary objective is to differentiate requirements between radial circuits, area networks, and spot networks where necessary to maximize DER deployment opportunities and to support achievement of the primary and secondary objectives."[48] DOEE agrees with DCCA, CRI, and JSA, and finds that a Commission-convened AIWG is the correct forum to continue this discussion. In its Initial Comments, DOEE similarly stated that required inverter settings profiles should be developed for "both radial and network (including spot network) distribution circuits."[49]

5. The Commission should amend the waiver language in 4002.1.

In its initial comments, DCCA points out the following:

> We note the waiver in the first sentence of "4002.1" ("Unless waived by the EDC") and assume that it applies only to sub item ".1" of "4002" and does not apply to item "4002.7" on "Advanced Inverters", and that the language in the respective

[48] CRI Supplemental Comments pg. 5; DCCA Initial Comments pg. 6; JSA Initial Comments Pg. 6
[49] DOEE initial comments, pg. 18

> items presents no contradiction. If this is not the case, the Commission might consider wording clarification to avoid possible confusion.[50]

DOEE agrees with DCCA and asks the Commission to amend the waiver for clarity. DOEE notes that any waiver of the IEEE 1547-2018 Standard by the EDC for an individual DER system should require technical justification.

B. Communications Technologies

As DOEE noted in its Initial Comments, there are ongoing issues with telemetry requirements which are hampering interconnection of solar facilities in the District of Columbia. DOEE presented an interim solution in its Initial Comments. Additionally, DOEE wishes to note that the IEEE 1547-2018 Standard has a standardized communication protocol which can be addressed by the AIWG and implemented over time. IREC provides a useful summary of what will be required for the implementation of the Communications portion of the IEEE 1547-2018 Standard:

> Transitioning to IEEE Std 1547™-2018 compliant local DER communications interfaces will require time for widespread deployment of communications infrastructure by grid operators or third parties, and consideration of related issues, including cybersecurity and standardization of communication network performance requirements. The ease and cost of implementing new communication protocols will be highly dependent on the availability of existing infrastructure and a utility's existing capabilities.
>
> For states where the utility may have outdated or inefficient communications systems, regulators will need to carefully consider the cost impact (to all ratepayers and/or to individual DER customers) of updating and/or revamping existing systems to allow for more sophisticated communications to occur with DERs in order to utilize the IEEE Std 1547TM-2018 required capabilities.
>
> To ensure transparency and alignment with IEEE Std 1547TM-2018, states may want to evaluate the deployment of communications and controls infrastructure in

[50] At pg. 3 (July 15, 2020).

> the context of existing or planned Smart Grid, Grid Modernization, Distribution Resource Plan, and/or Integrated Resource Plan proceedings."[51]

1. Telemetry, like other interconnection facilities, should require a technical justification and why IEEE and UL compliant inverter-based systems cannot provide the required information to the EDC.

JSA outlined some of the issues that solar developers have been facing with respect to telemetry requirements in their initial comments:

> Pepco has been requiring telemetry and communications equipment to be installed on systems that are larger than 250 kilowatts on Distribution Automation ("DA") feeders. These requirements have not been justified to developers or customers, nor do they seem to be supported by the language in 4005.2(b), and add a tremendous cost to a solar facility. The Joint Solar Advocates call for the Commission to compel Pepco to provide justification for these requirements and convene stakeholders to address alternate solutions to the perceived issues with these types of interconnections.[52]

DOEE agrees with JSA that a technical justification should be provided for the requirement of Pepco's telemetry solution, including why inverter systems cannot provide the required data visibility. DOEE notes that, currently, commercially available inverter systems feature communications and sensing capabilities that would avoid the need to integrate utility telemetry equipment into proposed customer generating facilities. DOEE believes that Pepco is improperly imposing its telemetry equipment on generator facilities when commercially available alternatives exist that are more cost effective without detrimentally impacting grid reliability. An example diagram[53] of inverter system topology is included in the figure below, where sensors (1) monitor PV system performance, (2) monitor/control battery functions, and (3)

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[51] IREC, *Making the Grid Smarter: Primer on Adopting the IEEE 1547™-2018 Standard for Distributed Energy Resources*, pg. 21

[52] At pg. 7 (July 15, 2020).

[53] There are several manufacturers that carry these systems that are currently available for installation: (1) https://www.pika-energy.com/files/manuals/pika_islanding_inverter_installation_manual-21.pdf; (2) https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall_2_AC_BU_NA-EN_Installation_Manual.pdf; (3) https://www.solaredge.com/us/solaredge/downloads/download/498957A.

monitor/control grid injection. DOEE notes that the backup gateway can monitor multiple current transformer (CT) points and actuate accordingly. The inverter system depicted features the *certified* communications functionalities and monitoring capabilities that Pepco requires at a significantly lower cost.

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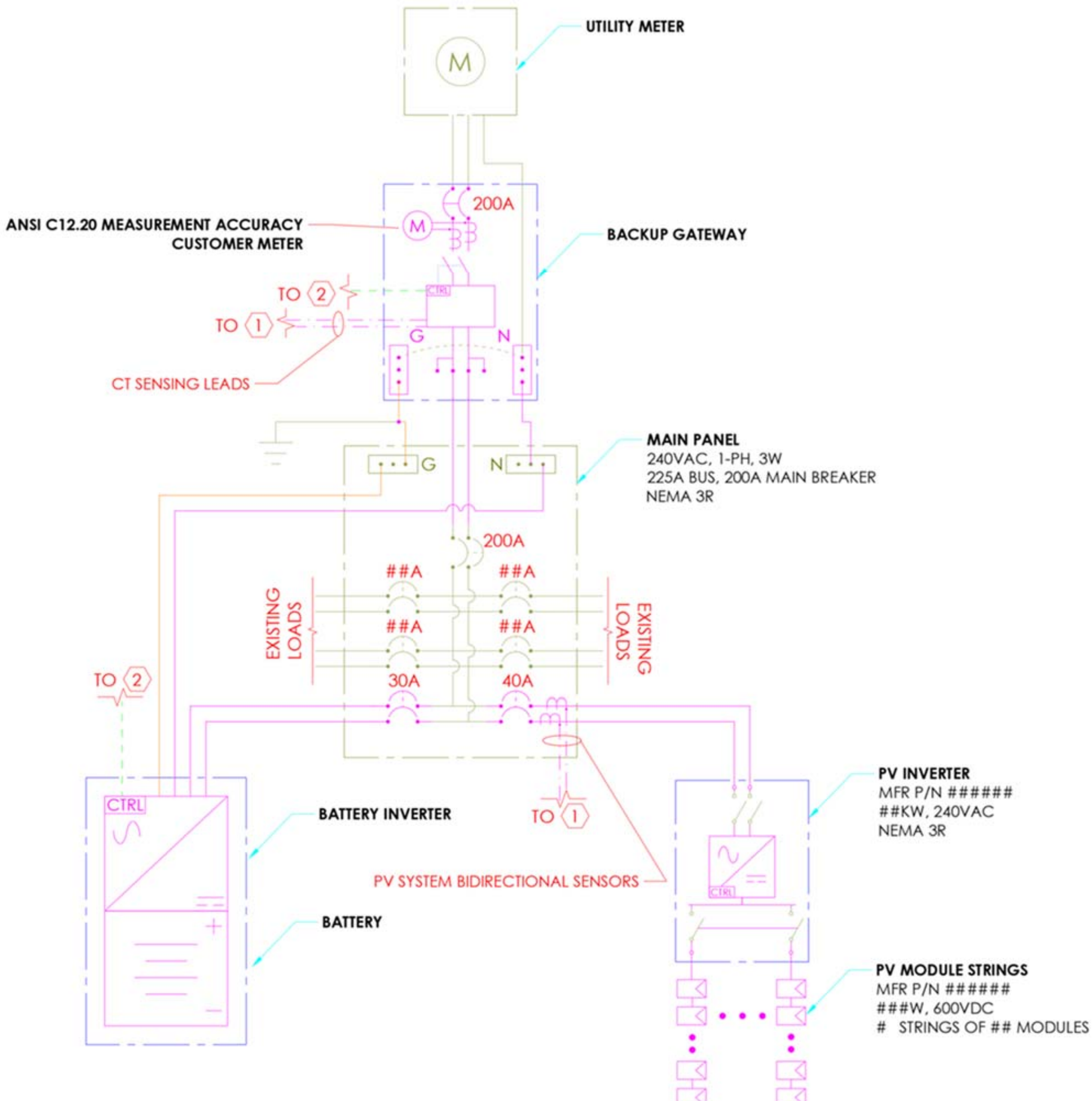

UTILITY METER
M
200A
ANSI C12.20 MEASUREMENT ACCURACY
CUSTOMER METER
M
BACKUP GATEWAY
TO 2
TO 1
CTRL
G
N
CT SENSING LEADS
MAIN PANEL
240VAC, 1-PH, 3W
225A BUS, 200A MAIN BREAKER
NEMA 3R
G
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200A
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##A
##A
##A
EXISTING LOADS
EXISTING LOADS
30A
40A
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TO 1
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BATTERY INVERTER
BATTERY
PV SYSTEM BIDIRECTIONAL SENSORS
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VII. RESPONSES TO PROPOSALS THAT WOULD DENY OR OTHERWISE HARM DER INTERCONNECTION

This section will focus on responses to proposals by Pepco in its initial comments which would represent a step backward in the process of implementing DER in the District of Columbia. This list of proposals includes: (A) treatment of CREFs as customers; (B) additional delays in interconnection timelines; and (C) changes to size requirements.

A. Treatment of CREFs as Customers

Pepco has put forth a proposal that would treat CREFs as customers, rather than as generators. DOEE believes that this proposal is inconsistent with the purpose of the CREF legislation. DOEE requests that the Commission reject Pepco's proposal.

1. The Commission should strike Pepco's comments regarding changes to the "DC-CREF" tariff because this proposal was submitted outside of a tariff proceeding.

Pepco has submitted plans to amend its "DC – CREF" tariff within their initial comments to this NOPR.[54] Amending a tariff falls outside of a rulemaking on the interconnection rules. Pepco's redline of the NOPR provided with their initial comments did not provide any additional language in the SGIR regarding customer charges for CREFs, because this issue is not pertinent to interconnection. These proposed changes to Pepco's "DC-CREF" tariff should not be taken under consideration by the Commission in this proceeding, and would require a Notice of Proposed Tariff.

[54] Pepco Initial Comments, pg. 21-22

2. CREFs are generators, not customers.

In Pepco's initial comments, they referred to CREFs as customers: "CREFs are a customer on the system, either by agreement with the CREF Owner or with the Subscriber Organization if the CREF owner and the Subscriber Organization are separate entities."[55]

DOEE disputes this framing by Pepco, because CREF facilities are not customer-generators in the way that Net Energy Metering systems are. CREFs are fully exporting systems, and the energy exported becomes the property of the SOS administrator.[56] They function more akin to independent power producers than to customers. The District Council defined CREFS in the following manner: "Community Renewable Energy Facilities are (CREFs) are facilities that generate electricity from a Tier 1 renewable source."[57] It is clear from this characterization that the CREF legislation intended for CREFs to act as generators, rather than customers. The District Council made clear that the enabling legislation for these renewable generators would help the District to comply with its local solar carve-out under the RPS: "[T]he Community Renewable Energy Act of 2013 is an important tool that will allow for the creation of CREFs thereby incentivizing the growth in the District's solar capacity."[58] In addition to CREFs being a critically important tool in meeting the District's mandated local solar carve-out, these facilities are the only way for residents who rent or lack adequate roof area to access local solar generation. A policy that would hurt the CREF market would increase the barriers to solar access and have a disproportionate impact on the District's most underserved residents, who are less likely to have access to single-family rooftop solar.

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[55] Pg. 21 (July 15, 2020).
[56] District of Columbia Municipal Regulations, Title 15, Chapter 9, § 906.4
[57] Council of District of Columbia Committee on Government Operations, "Report on Bill 20-0057, The Communities Renewable Energy Act of 2013." July 2 2013. https://lims.dccouncil.us/downloads/LIMS/29213/Committee_Report/B20-0057-COMMITTEEREPORT.pdf
[58] *Ibid.*

Additionally, customer charges are paid to maintain the system by the CREF subscribers, so charging a new customer charge would be double-counting. DOEE also believes that adding an unjustified customer charge to CREFs would work against the District's goal of meeting its local solar carve-out under the RPS. The Pepco proposal to potentially charge a monthly tariff according to the MGT-LV class would result in a customer charge of $456.76 per month,[59] which has the potential to harm the District of Columbia's CREF market. DOEE finds that Pepco's proposal is prejudicial to CREFs and should be rejected.

3. Pepco's characterization of the Maryland community solar tariff is misleading.

Pepco stated in its initial comments to this NOPR:

> Currently, the bill for a CREF owner/Subscriber Organization in the District is generated and then is manually zeroed out so that District of Columbia CREFs do not pay a customer charge. This is inconsistent with other Pepco Holdings jurisdictions—such as Pepco Maryland—where the community solar owner/Subscriber Organization pays a customer charge for use of the Pepco system and services.[60]

DOEE believes that simply harmonizing billing with other Pepco Holdings jurisdictions is not an appropriate justification for adding a customer charge in the District of Columbia. Additionally, the Maryland Pepco Tariff Book does not support Pepco's initial comments. Pepco's "MD-CS" Tariff in Maryland includes the following language about billing for CREFs, which are referred to as CSEGs in Maryland:

> For billing of any net consumption by a CSEGS, the CSEGS is subject to all tariff provisions applicable under the schedule they are placed. In determining the

[59] Pepco DC Tariff Book, pg. R-6.6, https://www.pepco.com/MyAccount/MyBillUsage/Documents/Pepco%20DC%20PEPRADR%20-%20RAD%20Surcharge%20Annual%20True-up-%20effective%20%207.10.17.pdf

[60] Pg. 21

> appropriate Tariff Schedule for a CSEGS, the billing demand will be based on the rated capacity$_{AC}$ of the CSEGS's inverter.[61]

According to this Tariff book, most recently updated on July 16, 2020, a CREF in Maryland would only be billed as a customer in the event that it had net consumption in a given month, which would require the CREF to be fully offline and net consumption as a result of the powering of on-site metering or other facilities. Pepco's Maryland Tariff Book is included as Attachment D.

B. Additional Delays in Interconnection Timelines

DOEE has been clear that it will not support changes to the SGIR that result in additional delays or extended timelines for interconnection. Pepco's proposal to delay delivery of the interconnection agreement until Pepco has submitted a final cost letter would unnecessarily delay DER interconnection.

Pepco has proposed in its initial comments to hold off on the provision of the interconnection agreement until after a final cost letter is produced, which is 60 business days in the NOPR. DOEE has requested this be reduced to 30 business days. Pepco filed the following language in its initial comments:

> Currently, the section states that Pepco should provide the agreement within three days of the Approval to Install. This works well for projects to which the Interconnection Facilities Cost Matrix applies because there are no design changes beyond the Approval to Install, and the final cost letter is issued with the Approval to Install. Under other circumstances, however, the Approval to Install is issued in advance of the final cost letter. Until the final cost letter is issued, designs can change, and the agreement technically would not be final. Pepco has changed

[61] Pepco Maryland Tariff Book Pepco MD Tariff Book, schedule "MD -CS" effective October 19, 2018. Tariff Book 159th version updated online July 16, 2020.
https://www.pepco.com/MyAccount/MyBillUsage/Documents/MD%20Pepco%20Current%20Rate%20Schedule%20effective%2009012020%20SOS%20Type%20II.pdf

> "Approval to Install" to "final cost letter" to ensure that the executed agreement is provided when the agreement is final (with the final cost letter).[62]

This amounts to another unilateral regulatory proposal from Pepco that would change interconnection timelines dependent on the availability of cost information, rather than the safety and reliability of the EDS. The ATI should be provided along an interconnection agreement and initial cost estimate for projects requiring facilities or upgrades, complete with any construction milestones. To push off the provision of this agreement until the final cost letter would introduce impermissible additional delays to interconnection of DER in the District of Columbia based on factors not related to safety or reliability. DOEE disputes Pepco's assertion that "designs can change" after ATI has been issued. At that point, Pepco should not be changing design or operating requirements of the interconnection of a system, and the SGIR as written does not provide for a change to system design after ATI has been issued.

DOEE requests that the Commission reject Pepco's proposed delay in the provision of the interconnection agreement and milestones.

C. Changes to Size Requirements

Pepco has submitted a proposal in its Initial Comments to this NOPR to change system size requirements.

1. Pepco's proposal to alter the maximum system size allowable through the Level 2 interconnection is arbitrary and will delay interconnection of projects larger than 250 kW in the District.

In Pepco's initial comments, it has submitted a proposal as follows:

> [M]odify the chart, as shown below, because the regulations, as shown in the 2020 NOPR, disadvantage small customers. The standards below are the Company's

[62] Pg. 18

> current standards created based on experience in the PHI system and will provide greater opportunity for small systems to interconnect with the distribution system.[63]

The modifications to the chart change the basis of eligibility for a Level 2 interconnection from line capacity to circuit voltage. This represents a move away from determining interconnection based on actual hosting capacity of a line to one that is based on voltage levels that are subject to Pepco's discretion. Under this proposal, no project in the District of Columbia greater than 250 kW would be eligible to interconnect as a Level 2 project and would be forced to go through a Level 4 interconnection (and therefore a lengthy supplemental review process that would delay interconnection by a period of months).

System size eligibility under a Level 2 interconnection is currently between 1-2 MW in the District of Columbia, depending on the line capacity, with the recognition that projects more than 2.5 miles from a substation may need to be smaller due to more limited hosting capacity at greater distances from the substation. This proposal from Pepco would, in addition to reducing the size of solar projects that can interconnect reasonably to the system, also represent a step backward in the District's movement towards energy system modernization. This proposal would override the use of hosting capacity analysis, except in instances where only a small amount of hosting capacity remains on a circuit. This change will reduce the size of projects able to connect in the District of Columbia, which could increase the overall costs of interconnection and delay implementation of projects that could contribute to the RPS carve-out. DOEE is concerned that this proposal will place an undue delay and penalize larger and more cost-efficient solar systems, thereby undermining the District's solar policy. Therefore, DOEE asks the Commission to reject this proposed change.

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[63] Pg. 20

2. DOEE is unaware of issues facing small systems in the District of Columbia.

Pepco's reduction in system size eligibility is proposed as a solution to issues faced by small projects: "Pepco proposes to modify the chart, as shown below, because the regulations, as shown in the 2020 NOPR, disadvantage small customers."[64] However, DOEE is unaware of any issue in the District of Columbia regarding the interconnection of small systems at this point in time and requests clarification of Pepco regarding how many Level 1 projects have been rejected in the past 24 months due to insufficient hosting capacity. DOEE has been made aware, by its own work with solar and interactions with several developers, that there are significant interconnection issues in the District of Columbia, but that these issues tend to face projects that are larger than a typical Level 1 residential rooftop system. These issues were catalogued in DOEE's Initial Comments in this proceeding.

DOEE also notes that Pepco, in this proposal to purportedly protects small systems, is referencing its "experience in the PHI system"[65] as justification for this proposal. The PHI territory is not specific to the District of Columbia, and the characteristics of the Atlantic City distribution network, for example, are very different from the distribution network for the District of Columbia. DOEE believes that experience in the PHI system does not provide significant justification for amending the interconnection rules in a way that would reduce the maximum system size for eligibility to apply for a Level 2 interconnection.

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[64] Pepco Initial Comments, pg. 20.
[65] Pepco Initial Comments, pg. 20

3. DOEE requests clarification regarding Pepco's hosting capacity map webpage which contains this unapproved proposal for size limits.

DOEE requests clarification from the Commission and Pepco regarding the status of this proposal. Pepco has provided this proposed change to the SGIR in this NOPR, which has not been approved by the Commission and is still in the rulemaking process. However, Pepco's hosting capacity website contains the following language, as if this proposal has already been accepted by the Commission as part of the SGIR:[66]

> **Radial Distribution Feeders**
>
> Please note that the aggregate limit of large distributed energy resources is 3 MW on 12/13 kV, 6 MW on 25 kV, and 10 MW on 34 kV. Any system over 250 kW is considered to be "large." After the aggregate large limit is reached, 250 kW or smaller systems can continue to be added until another circuit or substation violation would be reached.
>
> Click here to access a searchable version of the Hosting Capacity map for radial distribution feeders. Type an address into the search box to locate a specific location.

DOEE asks that the Commission request additional information from Pepco regarding this discrepancy.

VIII. CONCLUSION

DOEE appreciates all of the efforts made by the parties, including Pepco, to improve the interconnection process in the District of Columbia. However, much work remains to be done, and some of the proposed changes by Pepco may hurt the development of solar in the District of Columbia. Therefore, DOEE respectfully recommends that the Commission adopt DOEE's proposed changes to 15 DCMR Chapter 40 presented in DOEE's Initial and Reply Comments. DOEE asks that the Commission maintain (with DOEE's requested changes) the

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[66] Pepco Hosting Capacity website, accessed 13 August 2020, https://www.pepco.com/SmartEnergy/MyGreenPowerConnection/Pages/HostingCapacityMap.aspx

proposed text that introduces additional transparency and predictability, streamlined processes, and implements grid modernization, while rejecting proposals that would slow down or otherwise harm DER interconnection. DOEE commends the Commission for this NOPR, which takes additional steps in the direction of a modern and non-discriminatory EDS. DOEE requests that the Commission move quickly to convene the AIWG, and reconvene the RM-9 Stakeholder Working Group where necessary to address outstanding issues.

ATTACHMENT A

Chapter 40, DISTRICT OF COLUMBIA SMALL GENERATOR INTERCONNECTION RULES of Title 15 DCMR, PUBLIC UTILITIES AND CABLE TELEVISION, is amended in its entirety to read as follows:

CHAPTER 40 DISTRICT OF COLUMBIA SMALL GENERATOR INTERCONNECTION RULES

Section

4000 PURPOSE AND APPLICABILITY

4000.1 This chapter establishes the District of Columbia Small Generator Interconnection Rules ("DCSGIR") which apply to facilities satisfying the following criteria:

(a) The total Nameplate Capacity of the Small Generator Facility is equal to or less than twenty (20) megawatts ("MW").

(b) The Small Generator Facility is not subject to the interconnection requirements of PJM Interconnection.

(c) The Small Generator Facility is designed to operate in parallel with the Electric Distribution System.

4001 INTERCONNECTION REQUESTS, FEES, AND FORMS

4001.1 Interconnection customers seeking to interconnect a Small Generator Facility shall submit an Interconnection Request using a standard form approved by the Commission to the Electric Distribution Company ("EDC") that owns the Electric Distribution System ("EDS") to which interconnection is sought. The EDC shall establish processes for accepting Interconnection Requests electronically.

4001.2 The Commission shall determine the appropriate interconnection fees, and the fees shall be posted on the EDC's website and listed in the EDC's tariffs. There shall be no application fee for submitting a Level 1 Interconnection Request.

4001.3 In circumstances where standard forms and agreements are used as part of the interconnection process defined in this document, electronic versions of those forms shall be approved by the Commission and posted on the EDC's website. The EDC's Interconnection Request forms shall be provided in a format that allows for electronic entry of data.

4001.4 The EDC shall allow an Interconnection Request to be submitted through the EDC's website. The EDC shall allow electronic signatures to be used for Interconnection Request.

4001.5 In accordance with Subsection 4003.2 herein, Interconnection Customers may request an optional Pre-Application Report from the EDC to get information about the Electric Distribution System conditions at their proposed Point of Common Coupling without submitting a completed Interconnection Request form.

4001.6 The EDC shall assign each completed Application a queue position based on when it is deemed complete. The EDC shall maintain a single queue, which ~~may~~ shall be sortable by feeder. The queue shall be publicly available and updated at least monthly. Projects will remain in the queue for a period of three (3) years. Information to be included in the queue is available in Attachment 1.

4001.7 The EDC shall maintain on its website an Interconnection Facilities Cost Matrix as defined in Section 4099. The Matrix will be updated annually by April 1st of each year. The EDC shall file a Notice with the Commission of the Matrix it intends to post not less than fourteen (14) days prior to posting the Matrix on its website. The Notice shall specify the intended effective date of the Matrix. In the event of any dispute, the filed copy of the Matrix is controlling.

4002 APPLICABLE STANDARDS

4002.1 Unless waived by the EDC, a Small Generator Facility must comply with the following standards, as applicable:

Commented [AF1]: Request for Commission to provide clarity

(a) Institute of Electrical and Electronics Engineers ("IEEE") Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems for Generating Facilities up to 20 MW in size;

(b) IEEE 1547.1 Standard for Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems;

(c) Underwriters Laboratories ("UL") 6142 Standard for Small Wind Turbine Systems; and

(d) UL 1741 Standard for Inverters, Converters and Controllers for Use in Independent Power Systems. UL 1741 compliance must be recognized or Certified by a Nationally Recognized Testing Laboratory as designated by the U.S. Occupational Safety and Health Administration. Certification of a particular model or a specific piece of equipment is sufficient. It is also sufficient for an inverter built into a Generating Facility to be recognized as being UL 1741 compliant by a Nationally Recognized Testing Laboratory.

4002.2-4002.4 [RESERVED]

4002.5 The Interconnection Equipment shall meet the requirements of the most current approved version of each document listed in Subsection 4002.1, as amended and supplemented at the time the Interconnection Request is submitted.

4002.6 Nothing herein shall preclude the need for an on-site Witness Test or operational test by the Interconnection Customer.

4002.7 Advanced Inverters

To comply with IEEE 1547-2018:

(a) After January 1, 2022, any Small Generator Facility requiring an inverter that submits an interconnection request shall use an Advanced Inverter with either a default or a site-specific EDC required inverter settings profile, as determined by the EDC.

(b) Any Small Generator Facility may replace an existing inverter with a similar spare inverter that was purchased prior to January 1, 2022, for use at the Small Generator Facility.

(c) Prior to January 1, 2022, the Commission will develop stakeholder-informed District-wide ~~EDC will establish~~ default EDC required inverter settings profiles for Advanced Inverters on both radial and network (including spot network) distribution circuits pursuant to Subsection 4002.7(e). The District-wide required inverter settings profiles will optimize the safe and reliable operation of the electric distribution system, and shall serve the following objectives:

(1) The primary objective is to incur no involuntary real power inverter curtailments incurred during normal operating conditions and minimal real power curtailments during abnormal operating conditions.

(2) The secondary objective is to enhance electric distribution system hosting capacity and to optimize the provision of grid support services.

~~(c)~~

(d) To the extent reasonable, pursuant to any modifications required by Subsection 4002.7(e), all EDC required inverter settings profiles shall be consistent with applicable Advanced Inverter recommendations from PJM Interconnection, LLC that are applicable.

(e) ~~A~~ The default EDC required inverter settings profiles for radial and network (including spot network) distribution circuits shall be established by an EDC based on the District-wide default settings in collaboration with the Advanced Inverter Working Group and approved by the Commission. ~~to optimize the safe and reliable operation of the electric distribution system, and shall serve the following objectives~~:

~~(1) The primary objective is to incur no involuntary real power inverter curtailments incurred during normal operating conditions and minimal real power curtailments during abnormal operating conditions.~~

~~(2) The secondary objective is to enhance electric distribution system hosting capacity and to optimize the provision of grid support services.~~

(f) A site-specific EDC required inverter settings profile may be established by an EDC as necessary to optimally meet objectives established in Subsection 4002.7(e), provided a technical justification for the settings profile is provided to the interconnection customer.

(g) ~~All~~ The default ~~EDC required~~ inverter settings profiles will be documented in the interconnection agreements.

(h) A default EDC required inverter settings profile will be published on the EDC's website.

(i) A list of acceptable Advanced Inverters shall be published on the EDC's website.

4003 INTERCONNECTION REVIEW LEVELS

4003.1 The EDC shall review Interconnection Requests using one (1) or more of the four (4) levels of review procedures established by this chapter. The EDC shall first use the level of agreement specified by the Interconnection Customer in the Interconnection Request form. If a Small Generator Facility fails a screen at any level, the EDC may elect to complete the evaluation at the current level, if safety and reliability are not adversely impacted, or at the next appropriate level. The EDC may not impose additional requirements not specifically authorized unless the EDC and the Interconnection Customer mutually agree to do so in writing.

4003.2 If an Interconnection Customer requests a Pre-Application Report from the EDC, the request shall include:

(a) Contact information (name, address, phone and email).

(b) A proposed Point of Common Coupling, including latitude and longitude, site map, street address, utility equipment number (*e.g.*, pole number), meter number, account number or some combination of the above sufficient to clearly identify the location of the Point of Common Coupling.

(c) Generation technology and fuel source (if applicable).

(d) A three hundred dollar ($300) non-refundable processing fee.

4003.3 For each Pre-Application Report requested, which includes the requisite information and fee, the EDC shall furnish a report, within ten (10) business days of receipt of the completed Pre-Application Report request, which:

(a) Advises the Interconnection Customer that the existence of "Available Capacity" in no way implies that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review procedures.

(b) Informs the Interconnection Customer that the Electric Distribution System is dynamic and subject to change.

(c) Informs the Interconnection Customer that data provided in the Pre-Application Report may become outdated and not useful at the time of submission of the complete Interconnection Request.

(d) Includes the following information, if available:

(1) Total Capacity (MW) of substation/area bus or bank and distribution circuit likely to serve proposed Point of Common Coupling.

(2) Allocated Capacity (MW) of substation/area bus or bank and distribution circuit likely to serve proposed Point of Common Coupling.

(3) Queued Capacity (MW) of substation/area bus or bank and distribution circuit likely to serve proposed Point of Common Coupling.

(4) Available Capacity (MW) of substation/area bus or bank and distribution circuit most likely to serve proposed Point of Common Coupling.

(5) Whether the proposed Small Generator Facility is located on an area, spot or radial network.

(6) Substation nominal distribution voltage or transmission nominal voltage if applicable.

(7) Nominal distribution circuit voltage at the proposed Point of Common Coupling.

(8) Approximate distribution circuit distance between the proposed Point of Common Coupling and the substation.

(9) Relevant Line Section(s) peak load estimate, and minimum load data, when available.

(10) Number of protective devices and number of voltage regulating devices between the proposed Point of Common Coupling and the substation/area.

(11) Whether or not three-phase power is available at the proposed Point of Common Coupling and/or distance from three-phase service.

(12) Limiting conductor rating from proposed Point of Common Coupling to the electrical distribution substation.

(13) Based on proposed Point of Common Coupling, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

(14) The Pre-Application Report need only include pre-existing data. The EDC is not obligated in its preparation of a Pre-Application Report to conduct a study or other analysis of the proposed project in the event that data is not available. If the EDC cannot complete

all or some of a Pre-Application Report due to lack of available data, the EDC will provide the potential Applicant with a Pre-Application Report that includes the information that is available and identify the information that is unavailable. Notwithstanding any of the provisions of this Section, the EDC shall, in good faith, provide Pre-Application Report data that represents the best available information at the time of reporting.

(e) As an alternative to information required pursuant to § 4003.3(d), the EDC may elect to perform a power flow-based study providing the Interconnection Customer with the maximum size distributed energy resource (DER) that can be installed at a specified location without Distribution System Upgrades and the constraint encountered precluding installation of a larger system without upgrades. EDC shall make available, upon request, a copy of its power flow-based study for each Interconnection Customer to the Commission.

4004 LEVEL 1 INTERCONNECTION REVIEWS

4004.1 For Level 1 Interconnection Review, the EDC shall use Level 1 procedures for evaluation of all Interconnection Requests to connect inverter-based small generation facilities.

4004.2 For Level 1 Adverse System Impact screens, the EDC shall evaluate the potential for Adverse System Impacts using the following screens, which must be satisfied:

(a) The Small Generator Facility has a Nameplate Capacity of twenty (20) kW or less.

(b) For interconnection of a proposed Small Generator Facility to a Line Section on a Radial Distribution Circuit, the aggregated generation on the Line Section, including the proposed Small Generator Facility and all other generator facilities capable of coincidental export of energy on the Line Section, shall not exceed the anticipated minimum load on the Line Section, as determined by the results of a power flow-based study performed by the EDC to evaluate the impact of the proposed Small Generator Facility. If such results are unavailable, the aforementioned aggregate generating capacity shall not exceed fifteen percent (15%) of the Line Section's annual peak load as most recently measured at the substation or calculated for the Line Section. Should the EDC have previously identified the aforementioned Line Section as exceeding fifteen percent (15%) of the Line Section's annual peak load, the EDC shall use its best efforts to complete a power-flow based study to evaluate the impact of the proposed Small Generator Facility as described herein. The EDC shall not fail the Small Generator Facility based solely on the application of the fifteen percent (15%) peak load limitation if the EDC has valid power flow-based study results that can be used to evaluate the impact of the proposed Small Generator Facility.

(c) When a proposed Small Generator Facility is to be interconnected on a single-phase shared Secondary Line, the aggregate generation capacity on the shared Secondary Line, including the proposed Small Generator Facility, may not exceed twenty (20) kW.

(d) When a proposed Small Generator Facility is single-phase and is to be interconnected on a transformer center tap neutral of a two hundred forty (240) volt service, its addition may not create an imbalance between the two (2) sides of the two hundred forty (240) volt service of more than twenty percent (20%) of the nameplate rating of the service transformer.

(e) For interconnection of a Small Generator Facility within a Spot Network or Area Network, the aggregate generating capacity including the Small Generator Facility may exceed fifty percent (50%) of the network's anticipated minimum load if the EDC determines that safety and reliability are not adversely impacted. If solar energy small generator facilities are used, only the anticipated daytime minimum load shall be considered. The EDC may select any of the following methods to determine anticipated minimum load:

(1) The network's measured minimum load in the previous year, if available;

(2) Five percent (5%) of the network's maximum load in the previous year;

(3) The Interconnection Customer's good faith estimate, if provided; or

(4) The EDC's good faith estimate, if provided in writing to the Interconnection Customer, along with the reasons why the EDC considered the other methods to estimate minimum load inadequate.

(f) Construction of facilities by the EDC on its own system is not required in order to accommodate the Small Generator Facility.

(g) The EDC may use results from a valid power flow-based study performed to evaluate the impact of the proposed Small Generator Facility, provided such results are not used to fail any of the Subsections 4004.2 (c), (d), or (e) screens. EDC shall make available upon request a copy of its power flow-based study for each applicant to the Commission.

(h) If a Small Generator Facility fails a Level 1 Adverse System Impact screen, the EDC may elect to complete the evaluation at Level 1, if safety and reliability are not adversely impacted, or at the next appropriate level.

4004.3 The Level 1 Interconnection Review shall be conducted in accordance with the following procedures:

(a) The EDC shall, within five (5) business days after receipt of Part 1 of the Interconnection Request, notify the Interconnection Customer in writing or by electronic mail of the review results, which shall indicate that the Interconnection Request is complete or incomplete, and what materials, if any, are missing.

(1) If the EDC identifies a need to construct EDS Upgrades and/or Interconnection Facilities during the Interconnection Request process, the EDC shall provide a technical explanation that justifies the need for the additional facilities and/or upgrades. The EDC shall demonstrate that required functionalities are not satisfied by employing IEEE STD 1547 certified and UL 1741 SA listed equipment. The Interconnection Customer shall, within ten (10) business days after receipt of the EDC technical explanation, notify the EDC of any technical challenges to the identified requirements. The EDC will address the challenge and seek a collaborative resolution with the Interconnection Customer within twenty (20) business days after receiving the technical challenge. If the EDC and Interconnection Customer are unable to reach agreement, the parties shall seek remedy with the Commission.

~~(1)~~

(2) If the Interconnection Request requires the unchallenged construction of Interconnection Facilities or Distribution System Upgrades, the following additional information will be required to be submitted with the application:~~. Provision of the additional information does not preclude challenging the findings in accordance with Subsection 4004.3(a)(1)~~:

(A) Electrical room drawings;

(B) Meter locations;

(C) Initial proposed interconnection drawings.

~~(3) If the EDC requires the construction of EDS Upgrades during the Interconnection Request process, the EDC shall provide a technical explanation that justifies the need for the identified facilities and/or upgrades. The EDC shall demonstrate that required functionalities~~

~~are not satisfied by employing IEEE STD 1547 certified and UL 1741 SA listed equipment.~~

(b) When an Interconnection Request is complete, the EDC shall assign the request a Queue Position.

(c) Unless Subsection 4004.4 applies, within five (5) business days after the EDC acknowledges receipt of a complete Interconnection Request, the EDC shall notify the Interconnection Customer of the Level 1 Adverse System Impact screening results. If the proposed interconnection meets all of the applicable Level 1 Adverse System Impact screens or the EDC determines that the Small Generator Facility can be interconnected safely and reliably to its system, the EDC shall provide the Interconnection Customer with an Approval to Install.

(d) The EDC will provide an EDC-executed Interconnection Agreement within three (3) business days of issuing the Approval to Install.

(e) Unless extended by mutual agreement of the Interconnection Customer and the EDC, within six (6) months of receiving an Approval to Install or six (6) months from the completion of any upgrades, whichever is later, the Interconnection Customer shall provide the EDC a completed Level 1 PART II - Small Generator Facility Interconnection Certificate of Completion Form, including the signed inspection certificate.

(f) The EDC may, within ten (10) business days of receiving a completed Level 1 PART II – Small Generator Facility Interconnection Certificate of Completion Form and the inspection certificate from the Interconnection Customer, conduct a Witness Test at a time mutually agreeable to the parties. If the Witness Test fails to reveal that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes, the EDC shall offer to redo the Witness Test at the Interconnection Customer's expense at a time mutually agreeable to the parties. If the EDC determines that the Small Generator Facility fails the inspection it must provide a written explanation detailing the reasons and any standards violated. If the EDC does not perform the Witness Test within ten (10) business days or other time as is mutually agreed to by the parties, the Witness Test is deemed waived.

(g) The EDC shall provide the Interconnection Customer with the Authorization to Operate within twenty (20) business days of receiving a completed Level 1 PART II - Small Generator Facility Interconnection Certificate of Completion Form, including the signed inspection certificate. An Interconnection Customer may begin interconnected operation of a Small Generator Facility provided that there is an Interconnection Agreement in effect, the EDC has received proof of the electrical code official's approval, the Small Generator Facility has passed any Witness Test by the EDC, and the EDC has issued the Authorization to Operate

(h) The EDC may require photographs of the site, Small Generator Facility components, meters or any other aspect of the Interconnection Facilities as part of the Level 1 Interconnection Review process, provided that failure to provide a photo in a timely manner will not be a reason for the EDC to deem an Interconnection Request incomplete.

4004.4 Modifications to Level 1 Interconnection Review Process:

~~(a)~~ If the Interconnection Request requires the addition of Interconnection Facilities and/or Distribution Upgrades, it shall be processed under Level 2 starting at 4005.6. ~~If the Interconnection Request requires the addition of Interconnection Facilities that fall within the Interconnection Facilities Cost Matrix, the following process shall be followed for the Approval to Install. Subsection 4004.3(c) does not apply.~~

~~(1) The EDC will maintain on its website the Interconnection Facilities Cost Matrix providing the Interconnection Facilities for which the Interconnection Customer is responsible for specific categories of facilities. If the only Interconnection Facilities required in the Interconnection Request are captured in one of the categories in the Matrix.~~

~~(2) The Interconnection Customer will be responsible only for the applicable cost in the matrix~~

~~(3) The costs in the Interconnection Facilities Cost Matrix will be final costs.~~

~~(4) The final cost letter will contain only the applicable cost in the Interconnection Facility Cost Matrix and will be provided concurrently with the Approval to Install.~~

~~The Approval to Install and the final detailed cost letter shall be provided within twenty-five (25) business days after the Interconnection Request is deemed complete.~~

~~(b) If the Interconnection Request requires the addition of Interconnection Facilities and the Interconnection Facilities Cost Matrix is not applicable or requires the addition of Distribution System Upgrades, the following process shall be followed for the Approval to Install. Subsection 4004.3(c) does not apply.~~

~~(1) The Approval to Install and the final non-itemized cost letter shall be provided within twenty-five (25) business days after the Interconnection Request is deemed complete.~~

~~(2) The EDC will provide a cost estimate based on a forty percent (40%) design that is accurate within +/- fifty percent (50%) concurrently with the Approval to Install.~~

~~(3) Unless extended by mutual agreement of the Interconnection Customer and the EDC, the Interconnection Customer must agree to the cost estimate and the operational requirements and execute the Interconnection Agreement within ten (10) business days of receiving the Approval to Install.~~

~~(4) Once the Interconnection Customer has approved the cost letter and operational requirements, the Interconnection Customer is responsible for the costs the EDC incurs designing or constructing Interconnection Facilities or Distribution System Upgrades if the Interconnection Customer decides not to move forward with the interconnection of the Small Generator Facility.~~

~~(5) Within sixty (60) business days after the EDC notifies the Interconnection Customer that it has received a completed Interconnection Request, the EDC will issue a final cost letter based on one hundred percent (100%) design.~~

~~(6) If the Interconnection Customer changes the design of the interconnection of the Small Generator Facility at any point, the final and estimated cost letters, as applicable, will be void and the EDC will restart the Interconnection Review process.~~

~~The EDC will provide an EDC-executed Interconnection Agreement within three (3) business days of issuing the Approval to Install.~~

4004.5 [RESERVED]

4004.6 The EDC, at its sole option, may approve the Interconnection Request provided that such approval is consistent with safety and reliability. If the EDC cannot determine that the Small Generator Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the EDC shall provide the Interconnection Customer with detailed information on the reason(s) for failure in writing. In addition, the EDC shall either:

(a) Notify Interconnection Customer that the EDC is continuing to evaluate the Small Generator Facility under Supplemental Review if the EDC concludes that the Supplemental Review might determine that the Small Generator Facility could continue to qualify for interconnection pursuant to Level 2; or

(b) Offer to continue evaluating the Interconnection Request under Level 4.

4004.7 If, on an annual basis, the EDC fails to issue at least ninety percent (90%) of All Authorizations to Operate in the Level 1 interconnection process within the twenty (20) business days as required in Subsection 4004.3(f), it shall be required to develop a corrective action plan.

4004.8 The corrective action plan shall describe the cause(s) of the EDC's non-compliance with Subsection 4004.7, describe the corrective measure(s) to be taken to ensure that the standard is met or exceeded in the future, and set a target date for completion of the corrective measure(s).

4004.9 Progress on current corrective action plans shall be included in the EDC's Small Generator Interconnection Annual Report.

4004.10 The EDC shall report the actual performance of compliance with Subsection 4004.7 during the reporting period in the Small Generator Interconnection Annual Report of the following year.

4005 LEVEL 2 INTERCONNECTION REVIEWS

4005.1 For a Level 2 Interconnection Review, the EDC shall use the Level 2 procedures for an Interconnection Request.

4005.2 For Level 2 Adverse System Impact screens, the EDC shall evaluate the potential for Adverse System Impacts using the following screens, which must be satisfied:

(a) The Small Generator Facility Nameplate Capacity rating does not exceed the limits identified in the table below, which vary according to the voltage of the line at the proposed Point of Common Coupling. Small Generator Facilities located within two and a half (2.5) miles of a substation and on a main distribution line with minimum six hundred (600)-amp capacity are eligible for Level 2 Interconnection Review under higher thresholds.

Line Capacity	**Level 2 Eligibility**	
	Regardless of location	**On ≥ 600 amp line and ≤ 2.5 miles from substation**
≤ 4 kV	< 1 MW	< 2 MW
4.1 kV – 14 kV	< 2 MW	< 3 MW
15 kV – 30 kV	< 3 MW	< 4 MW
31 kV – 60 kV	≤ 4 MW	≤ 5 MW

(b) For interconnection of a proposed Small Generator Facility to a Radial Distribution Circuit, the Small Generator Facility aggregated with all other generation capable of coincidental exporting energy on the Line Section may not exceed the anticipated minimum load on the Line Section, as determined by the results of a power flow-based study performed by the EDC to evaluate the impact of the proposed Small Generator Facility. If such results are unavailable, the aforementioned aggregate generating capacity shall not exceed fifteen percent (15%) of the Line Section annual peak load, as most recently measured at the substation or calculated for the Line Section. Should the EDC have previously identified the aforementioned Line Section as exceeding fifteen percent (15%) of the Line Section's annual peak load, the EDC shall use its best efforts to complete a power-flow based study to evaluate the impact of the proposed Small Generator Facility as described herein. The EDC shall not fail the Small Generator Facility based solely on the application of the fifteen percent (15%) peak load limitation if the EDC has valid power flow-based study results that can be used to evaluate the impact of the proposed Small Generator Facility.

~~(c)~~ For interconnection of a proposed Small Generator Facility within a Spot or Area Network, the proposed Small Generator Facility shall utilize an inverter-based equipment package, ~~and use~~ a minimum import relay, or other protective scheme that will ensure that power will never be exported. If the EDC requires minimum import, a technical explanation shall accompany the requirement that specifies the reasons for the identified import power levels. The Interconnection Customer shall, within ten (10) business days after receipt of the EDC technical explanation, notify the EDC of any technical challenges to the identified requirements. The EDC will address the challenge and seek a collaborative resolution with the Interconnection Customer within twenty (20) business days after receiving the technical challenge. If the EDC and Interconnection Customer are unable to reach agreement, the EDC shall seek remedy with the Interconnection Ombudsperson. ~~power imported from the EDC to the network will, during normal EDC operations, remain above twenty percent (20%) of the minimum load on the network transformer based on historical data, or will remain above an import point reasonably set by the EDC in good faith. For interconnection of a proposed Small Generator Facility within an Area Network, the proposed Small Generator Facility shall utilize an inverter-based equipment package and adhere to a maximum aggregate export level of eighty percent (80%) of the generation level that would cause reverse flow on a network transformer, or will remain below an export point reasonably set by the EDC in good faith. At the EDC's discretion, the requirement for minimum import relays or other protective schemes may be waived.~~

~~(d)~~(c) The proposed Small Generator Facility, in aggregation with other generation on the distribution circuit, may not contribute more than ten percent (10%) to the distribution circuit's maximum Fault Current at the point on the high voltage (primary) level nearest the Point of Common Coupling.

~~(e)~~(d) The proposed Small Generator Facility, in aggregate with other generation on the distribution circuit, may not cause any distribution protective devices and equipment (including substation breakers, fuse cutouts, and line reclosers), or EDC customer equipment on the Electric Distribution System, to exceed ninety percent (90%) of the short circuit interrupting capability. The Interconnection Request may not receive approval for interconnection on a circuit that already exceeds ninety percent (90%) of the short circuit interrupting capability.

~~(f)~~(e) The proposed Small Generator Facility's Point of Common Coupling may not be on a transmission line.

~~(g)~~(f) The Small Generator Facility complies with the applicable type of interconnection, based on the table below. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the EDC's Electric Distribution System due to a loss of ground during the operating time of any anti-islanding function. This screen does not apply to Small Generator Facilities with a gross rating of 11 kVA or less.

Primary Distribution Line Configuration	**Type of Interconnection to be Made to the Primary Circuit**	**Results/Criteria**
Three-phase, three-wire	Any type	Pass Screen
Three-phase, four-wire	Single-phase, line-to-neutral	Pass Screen
Three-phase, four-wire (For any line that has such a section, or mixed three wire and four wire)	All Others	To pass, aggregate Small Generator Facility Nameplate Capacity must be less than or equal to 10% of Line Section peak load

~~(h)~~(g) When the proposed Small Generator Facility is to be interconnected on single-phase shared Secondary Line, the aggregate generation capacity on the shared Secondary Line, including the proposed Small Generator Facility, shall not exceed sixty-five percent (65%) of the transformer nameplate power rating.

~~(i)~~(h) When a proposed Small Generator Facility is single-phase and is to be interconnected on a transformer center tap neutral of a two hundred forty (240) volt service, its addition may not create an imbalance between the two sides of the 240-volt service of more than twenty percent (20%) of the nameplate rating of the service transformer.

~~(j)~~(i) A Small Generator Facility, in aggregate with other generation interconnected to the distribution low-voltage side of a substation transformer feeding the electric distribution circuit where the Small Generator Facility proposes to interconnect, may not exceed 20MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity (*e.g.* three (3) or four (4) transmission voltage level buses from the Point of Common Coupling), or the proposed Small Generator Facility shall not have interdependencies, known to the EDC, with earlier-queued Interconnection Requests.

~~(k)~~(j) Except as permitted by an additional review in Level 2 procedures, Subsection 4005.7, no construction of facilities by the EDC on its own system shall be required to accommodate the Small Generator Facility.

~~(l)~~(k) The EDC may use results from a valid power flow-based study performed to evaluate the impact of the proposed Small Generator Facility, provided such results are not used to fail any of the Subsections 4005.2 (c), (d), (e), (f), (g), (h), (i), or (j) screens.

~~(m)~~(l) If a power-flow analysis is performed based on Subsections 4005.2 (b) or (l), the EDC shall make available upon request a copy of its power flow-based study for each applicant to the Commission.

4005.3 [RESERVED]

4005.4 The Level 2 Interconnection Review shall be conducted in accordance with the following procedures:

(a) The EDC shall, within five (5) business days after receipt of Part 1 of the Interconnection Request, acknowledge, in writing or by electronic mail, receipt of the Interconnection Request, indicating whether it is complete or incomplete, and the appropriate application fee.

(1) If the EDC identifies a need to construct EDS Upgrades and/or Interconnection Facilities during the Interconnection Request process, the EDC shall provide a technical explanation that justifies the need for the additional facilities and/or upgrades. The EDC shall demonstrate that required functionalities are not satisfied by employing IEEE STD 1547 certified and UL 1741 SA listed equipment. The Interconnection Customer shall, within ten (10) business days after receipt of the EDC technical explanation, notify the EDC of any technical challenges to the identified requirements. The EDC shall address the challenge and seek a collaborative resolution with the Interconnection Customer within twenty (20) business days after receiving the technical challenge. If

the EDC and Interconnection Customer are unable to reach agreement, the parties shall seek remedy with the Commission.

~~(1)~~(2) If the Interconnection Request requires the unchallenged construction of Interconnection Facilities or Distribution System Upgrades, the following additional information will be required to be submitted with the application.

(A) Electrical room drawings

(B) Meter locations

(C) Initial proposed interconnection drawings

~~(2) If the EDC requires the construction of EDS upgrades during the Interconnection Request process, the EDC shall provide a technical explanation that justifies the need for the identified facilities and/or upgrades. The EDC shall demonstrate that required functionalities are not satisfied by employing IEEE STD 1547 certified and UL 1741 SA listed equipment.~~

(b) When the Interconnection Request is deemed incomplete, the EDC shall provide a written list detailing all information that must be provided to complete the request. The Interconnection Customer shall have ten (10) business days after receipt of the list to revise the Interconnection Request to include the requested information and resubmit the Interconnection Request or request an extension of time to provide such information. If the Interconnection Request is not resubmitted with the requested information within ten (10) days, the Interconnection Request shall be deemed withdrawn. The EDC shall notify the Interconnection Customer within three (3) business days of receipt of a revised Interconnection Request whether the request is complete or incomplete. The EDC may deem the request withdrawn if it remains incomplete.

(c) When an Interconnection Request is complete, the EDC shall assign a Queue Position. Unless Section 4005.6(c) applies, the Queue Position of an Interconnection Request shall be used to determine the cost responsibility necessary for the Small Generator Facilities to accommodate the interconnection. The EDC shall notify the Interconnection Customer about other higher-queued Interconnection Customer Requests that have the potential to impact the cost responsibility.

(d) Unless Subsection 4005.6 applies, within fifteen (15) business days after the EDC notifies the Interconnection Customer that it has received a completed Interconnection Request, the EDC shall evaluate the Interconnection Request using the Level 2 screening criteria and notify the Interconnection Customer whether the Small Generator Facility meets all of the applicable Level 2 Adverse System Impact screens. If the proposed interconnection meets all of the applicable Level 2 Adverse System Impact screens and the EDC determines that the Small Generator Facility can be interconnected safely and reliably to the Electric Distribution System, the EDC shall provide the Interconnection Customer an Approval to Install. The EDC shall provide an EDC-executed Interconnection Agreement within three (3) business days after notification of Level 2 issuance of the Approval to Install.

(1) If EDS upgrades are required, the Interconnection Customer will be notified at this time that the modified process in Subsection 4005.6 has been triggered, with an extended timeline of twenty-five (25) business days to Approval to Install.

(e) Unless extended by mutual agreement of the Interconnection Customer and the EDC, within twenty-four (24) months of receiving an Approval to Install or six (6) months of completion of any Distribution System Upgrades, whichever is later, the Interconnection Customer shall provide the EDC with the signed Level 2-4 Part II – Small Generator Interconnection Certificate of Completion, including the signed inspection certificate. An Interconnection Customer shall communicate with the EDC no less frequently than every six (6) months regarding the status of a proposed Small Generator Facility to which an Interconnection Agreement refers.

(f) The EDC may conduct a Witness Test within ten (10) business days of receiving the completed Level 2-4 Part II – Small Generator Facility Interconnection Certificate of Completion and the signed inspection certificate from the Interconnection Customer, conduct a Witness Test at a time mutually agreeable to the parties. If the Witness Test fails to reveal that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes, the EDC shall offer to redo the Witness Test at the Interconnection Customer's expense at a time mutually agreeable to the parties. If the EDC determines that the Small Generator Facility fails the inspection it must provide a written explanation detailing the reasons and any standards violated. If the EDC does not perform the Witness Test within ten (10) business days or other such time as is mutually agreed to by the parties, the Witness Test is deemed waived.

(g) An Interconnection Customer may begin interconnected operation of a Small Generator Facility provided that there is an Interconnection Agreement in effect, the EDC has received proof of the electrical code official's approval, the Small Generator Facility has passed any Witness Test by the EDC, and the EDC has issued the Authorization to Operate. The EDC shall issue the Authorization to Operate within twenty (20) business days of receipt of required documentation in 4005.4(c). Evidence of approval by an electric code official includes a signed inspection certificate.

(h) The EDC may require photographs of the site, Small Generator Facility components, meters or any other aspect of the Interconnection Facilities as part of the Level 2 Interconnection Review process, provided that failure to provide a photo in a timely manner will not be a reason for the EDC to deem an Interconnection Request incomplete.

4005.5 [RESERVED]

4005.6 Modifications to Level 2 Interconnection Review Process:

(a) If the Interconnection Request requires the addition of Interconnection Facilities~~ that fall within the Interconnection Facilities Cost Matrix~~, the following process shall be followed for the Approval to Install. Subsection 4005.4(d) does not apply.

(1) The EDC will provide the itemized breakdown in the final cost letter along with a technical justification as specified in 4005.4(a)(2).

~~(1) The EDC will maintain on its website the Interconnection Facilities Cost Matrix providing the Interconnection Facilities for which the Interconnection Customer is responsible for specific categories of facilities. If the only Interconnection Facilities required in the Interconnection Request are captured in one of the categories in the Cost Matrix:~~

~~(2) The Interconnection Customer will be responsible only for the applicable cost in the matrix~~

~~(3) The costs in the Interconnection Facilities Cost Matrix will be final costs.~~

~~(4) The final cost letter will contain only the applicable cost in the Interconnection Facility Cost Matrix and will be provided concurrently with the Approval to Install.~~

~~(5)~~(2) The Approval to Install and the final cost letter shall be provided within ~~twenty-five (25)~~fifteen (15) business days after the Interconnection Request is deemed complete.

(b) If the Interconnection Request requires the addition of ~~Interconnection Facilities and the Interconnection Facilities Cost Matrix is not applicable or requires the addition of~~ Distribution System Upgrades, the following process shall be followed for the Approval to Install.~~ ~~ Subsection 4005.4(d) does not apply.

(1) The Approval to Install and the final non-itemized cost letter shall be provided within twenty-five (25) business days after the Interconnection Request is deemed complete.

(2) The EDC will provide a cost estimate based on a forty percent (40%) design that is accurate within +/- ~~fifty percent (50%)~~twenty-five percent (25%) concurrently with the Approval to Install.

(3) Unless extended by mutual agreement of the Interconnection Customer and the EDC, the Interconnection Customer must agree to the cost estimate and the operational requirements and execute the Interconnection Agreement within ten (10) business days of receiving the Approval to Install.

(4) The EDC shall provide a technical explanation that justifies the need for the identified facilities and/or upgrades. The EDC shall demonstrate that the required functionalities are not satisfied by employing IEEE STD 1547 certified and UL 1741 listed equipment.

(5) Once the Interconnection Customer has approved the cost letter and operational requirements, the Interconnection Customer is responsible for the costs the EDC incurs designing or constructing Interconnection Facilities or Distribution System Upgrades if the Interconnection Customer decides not to move forward with the interconnection of the Small Generator Facility.

(6) Within ~~sixty (60)~~thirty (30) business days after the EDC notifies the Interconnection Customer that it has received a completed Interconnection Request, the EDC will issue a final cost letter based on one hundred percent (100%) design. The cost letter will include a detailed list of necessary EDS upgrades and an itemized cost estimate, breaking out equipment, labor, operation and maintenance and other costs, including overhead, for completing such upgrades. The final cost letter will also indicate the milestones for completion of the Applicant's installation of its Generating Facility and the EDC's completion of any EDS modifications, and these milestones will be incorporated into the Interconnection Agreement.

(7) If the Interconnection Customer changes the design of the interconnection of the Small Generator Facility in response to the EDC amending site-specific operating or other requirements, the project shall retain its eligibility for interconnection, including its place in the interconnection queue.

(8) If the Interconnection Customer changes the design of the interconnection of the Small Generator Facility at any point, without prompting by the EDC, in a manner that results in a

Material Modification, the final and estimated cost letters, as applicable, will be void and the EDC will restart the Interconnection Review process.

(9) If the proposed modification is determined not to be a Material Modification, then the Area EPS Operator shall notify the Interconnection Customer in writing that the modification has been accepted and that the Interconnection Customer shall retain its eligibility for interconnection, including its place in the interconnection queue.

~~(7)~~(10) The EDC will provide an EDC-executed Interconnection Agreement within three (3) business days of issuing the Approval to Install.

(c) The EDC shall design, procure, construct, install, and own any Distribution System Upgrades for a CREF. The Distribution System Upgrades costs shall be allocated as follows:

(1) Fifty percent (50%) of the costs to and paid for by the CREF Interconnection Customer

(2) Fifty percent (50%) of the costs paid for by the EDC, tracked in a regulatory asset, and recovered in its next base rate case.

The Distribution System Upgrade Costs for the shared allocation above shall be capped at two hundred thousand dollars ($200,000) per calendar year. Any costs above this cap in a calendar year shall be paid by the CREF Interconnection Customer.

4005.7 When a Small Generator Facility is not approved under a Level 2 review, the EDC, at its sole option, may approve the Interconnection Request provided such approval is consistent with safety and reliability and shall provide the Interconnection Customer an Approval to Install after the determination. If the EDC cannot determine that the Small Generator Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the EDC shall provide the Interconnection Customer with detailed information on the reason(s) for failure in writing. In addition, the EDC shall either:

(a) Notify Interconnection Customer that the EDC is continuing to evaluate the Interconnection Request under Supplemental Review if the EDC concludes that the Supplemental Review might determine that the Small Generator Facility could continue to qualify for interconnection pursuant to Level 2; or

(b) Offer to continue evaluating the Interconnection Request under Level 4.

4006 LEVEL 3 INTERCONNECTION REVIEWS

4006.1 The EDC shall use Level 2 Interconnection Review procedures for evaluating Level 3 Interconnection Requests provided the proposed Small Generator Facility has a ~~Nameplate~~ Net System Capacity rating not greater than 20MW and uses reverse power relays, minimum import relays or other protective devices to assure that power may never be exported from the Small Generator Facility to the EDC's electrical distribution system. ~~An Interconnection Customer proposing to interconnect a Small Generator Facility to a spot or Area Network is not permitted under the Level 3 review process.~~

4007 LEVEL 4 INTERCONNECTION REVIEWS

4007.1 The EDC shall use the Level 4 Interconnection Review procedures for evaluating Interconnection Requests when:

(a) The Interconnection Request was not approved under a Level 1, Level 2, or Level 3 Interconnection Review and the Interconnection Customer has submitted a new Interconnection Request for consideration under a Level 4 Interconnection Review or requested that the rejected Interconnection Request be treated as a Level 4 Interconnection Request; and

(b) The Interconnection Request does not meet the criteria for qualifying for a review under Level 1, Level 2 or Level 3 Interconnection Review procedures.

4007.2 The Level 4 Interconnection Review shall be conducted in accordance with the following process:

(a) Within five (5) business days from receipt of Part I of an Interconnection Request or transfer of an existing request to a Level 4 Interconnection Request, the EDC shall notify the Interconnection Customer whether or not the request is complete.

(1) If the EDC identifies a need to construct EDS Upgrades and/or Interconnection Facilities during the Interconnection Request process, the EDC shall provide a technical explanation that justifies the need for the additional facilities and/or upgrades. The EDC shall demonstrate that required functionalities are not satisfied by employing IEEE STD 1547 certified and UL 1741 SA listed equipment. The Interconnection Customer shall, within ten (10) business days after receipt of the EDC technical explanation, notify the EDC of any technical challenges to the identified requirements. The EDC shall address the challenge and seek a collaborative resolution with the Interconnection Customer within twenty (20) business days after receiving the technical challenge. If the EDC and Interconnection Customer are unable to reach agreement, the parties shall seek remedy with the Commission.

~~(1)~~(2) If the Interconnection Request requires the unchallenged construction of Interconnection Facilities or Distribution System Upgrades, the following additional information will be required to be submitted with the application.

(A) Electrical room drawings

(B) Meter locations

(C) Initial proposed interconnection drawings

~~(2) If the EDC requires the construction of EDS upgrades during the Interconnection Request process, the EDC shall provide a technical explanation that justifies the need for the identified facilities and/or upgrades. The EDC shall demonstrate that required functionalities are not satisfied by employing IEEE STD 1547 certified and UL 1741 SA listed equipment.~~

(b) When the Interconnection Request is deemed not complete, the EDC shall provide the Interconnection Customer with a written list detailing information required to complete the Interconnection Request. The Interconnection Customer shall have twenty (20) business days to revise the Interconnection Request to include the requested information and resubmit the Interconnection Request, or the Interconnection Request shall be considered withdrawn. The parties may agree to extend the time for receipt of the revised Interconnection Request. The EDC shall notify the Interconnection Customer within five (5) business days of receipt of the revised Interconnection Request whether or not the Interconnection Request is complete. The EDC may deem the Interconnection Request withdrawn if it remains incomplete.

(1) When an Interconnection Request is complete, the EDC shall assign a Queue Position. . Unless Section 4008.13 applies, the Queue Position of an Interconnection Request shall be used to determine the cost responsibility necessary for the Small Generator Facilities to accommodate the interconnection. The EDC shall notify the Interconnection Customer about other higher-queued Interconnection Customer Requests that have the potential to impact the cost responsibility.

(c) The following procedures shall be followed in performing a Level 4 Interconnection Review:

(1) By mutual agreement of the parties, the Scoping Meeting, interconnection feasibility study, interconnection impact study, or Facilities Study provided for in a Level 4 Interconnection Review and discussed in this paragraph may be waived;

(2) If agreed to by the parties, a Scoping Meeting shall be held within ten (10) business days, or other mutually agreed to time, after the EDC has notified the Interconnection Customer that the Interconnection Request is deemed complete, or the Interconnection Customer has requested that its Interconnection Request proceed after failing the requirements of a Level 2 Interconnection Review or Level 3 Interconnection Review. The Scoping Meeting shall take place in person, by telephone, or electronically by a means mutually agreeable to the parties. The purpose of the Scoping Meeting shall be to review the Interconnection Request; existing studies relevant to the Interconnection Request; the conditions at the proposed location including the available Fault Current at the proposed location, the existing peak loading on the lines in the general vicinity of the proposed Small Generator Facility, and the configuration of the distribution line at the proposed Point of Common Coupling; and the results of the Level 1, Level 2 or Level 3 Adverse System Impact screening criteria;

(3) When the parties agree at a Scoping Meeting that an interconnection feasibility study shall be performed, and if the parties do not waive the interconnection impact study, the EDC shall provide to the Interconnection Customer, no later than five (5) business days after the Scoping Meeting, an Interconnection System Feasibility Study Agreement, including an outline of the scope of the study and a cost estimate (accurate to +/- 25%) ~~nonbinding good faith estimate of the cost~~ and time to perform the study;

(4) When the parties agree at a Scoping Meeting that an interconnection feasibility study is not required, and if the parties agree that an interconnection system impact study shall be performed, the EDC shall provide to the Interconnection Customer, no later than five (5) business days after the Scoping Meeting, an Interconnection System Impact Study Agreement, including an outline of the scope of the study and a cost estimate (accurate to +/- 25%) ~~nonbinding good faith estimate of the cost~~ to perform the study; and

(5) When the parties agree at the Scoping Meeting that an interconnection feasibility study and interconnection system impact study are not required, the EDC shall provide to the Interconnection Customer, no later than five (5) business days after the Scoping Meeting, an Interconnection Facilities Study Agreement including an outline of the scope of the study and a cost estimate (accurate to +/- 25%) ~~nonbinding good faith estimate of the cost~~ to perform the study.

(6) The EDC may elect to perform one or more of these studies concurrently.

(e) Any required Adverse System Impact studies shall be carried out using the following guidelines:

(1) An interconnection feasibility study shall include the following analyses and conditions for the purpose of identifying and addressing potential Adverse System Impact to the EDC's Electric Distribution System that would result from the interconnection:

(A) Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

(B) Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

(C) Initial review of grounding requirements and system protection;

(D) Description and cost estimate (accurate to +/- 25%) ~~nonbinding estimated cost~~ of facilities required to interconnect the Small Generator Facility to the EDC's Electric Distribution System in a safe and reliable manner; and

(E) Additional evaluations, at the expense of the Interconnection Customer, when an Interconnection Customer requests that the interconnection feasibility study evaluate multiple potential Points of Common Coupling.

(2) An interconnection system impact study shall evaluate the impacts of the proposed interconnection on both the safety and reliability of the EDC's Electric Distribution System. The study shall identify and detail the Adverse System Impacts that result when a Small Generator Facility is interconnected without project modifications or Distribution System Upgrades, focusing on the Adverse System Impacts identified in the interconnection feasibility study or potential impacts including those identified in the Scoping Meeting. The interconnection system impact study shall consider all Small Generator Facilities that, on the date the interconnection system impact study is commenced, are directly interconnected with the EDC's Electric Distribution System, have a pending higher Queue Position to interconnect to the system, or have a signed Interconnection Agreement.

(A) A distribution interconnection system impact study shall be performed when a potential Electric Distribution System

Adverse System Impact is identified in the interconnection feasibility study. The EDC shall send the Interconnection Customer an Interconnection System Impact Study Agreement within five (5) business days of transmittal of the interconnection feasibility study report. The agreement shall include an outline of the scope of the study and a cost estimate (accurate to +/- 25%) ~~good faith estimate of the cost~~ to perform the study. The impact study shall include:

(i) A load flow study;

(ii) Identification of Affected Systems;

(iii) An analysis of equipment interrupting ratings;

(iv) A protection coordination study;

(v) Voltage drop and flicker studies;

(vi) Protection and set point coordination studies;

(vii) Grounding reviews; and

(viii) Impact on system operation.

(B) An interconnection system impact study shall consider the following criteria:

(i) A short circuit analysis;

(ii) A stability analysis;

(iii) Alternatives for mitigating Adverse System Impacts on Affected Systems;

(iv) Voltage drop and flicker studies;

(v) Protection and set point coordination studies; and

(vi) Grounding reviews.

(C) The final interconnection system impact study shall provide the following:

(i) The underlying assumptions of the study;

(ii) The results of the analyses;

(iii) A list of any potential impediments to providing the requested interconnection service;

(iv) Required distribution upgrades; and

(v) A cost estimate (accurate to +/- 25%) ~~nonbinding good faith estimate of cost~~ and time to construct any required Distribution System Upgrades.

(D) The parties shall use an Interconnection System Impact Study Agreement approved by the Commission.

(3) The Facilities Study shall be conducted as follows:

(A) Within five (5) business days of completion of the interconnection system impact study, the EDC shall transmit a report to the Interconnection Customer with an Interconnection Facilities Study Agreement, which includes an outline of the scope of the study and a cost estimate (accurate to +/- 25%) ~~nonbinding good faith estimate of the cost~~ and time to perform the study;

(B) The Facilities Study shall estimate the cost of the equipment, engineering, procurement and construction work including overheads needed to implement the conclusions of the interconnection feasibility study and the interconnection system impact study to interconnect the Small Generator Facility. The Facilities Study shall identify:

(i) The electrical switching configuration of the equipment, including transformer, switchgear, meters and other station equipment;

(ii) The nature and cost estimate (accurate to +/- 25%) ~~estimated cost~~ of the EDC's Interconnection Facilities and Distribution System Upgrades necessary to accomplish the interconnection; and

(iii) An estimate of the time required to complete the construction and installation of the facilities;

(C) The parties may agree to permit an Interconnection Customer to separately arrange for a third party to design and construct the required Interconnection Facilities. The EDC may review the design of the facilities under the Interconnection Facilities Study Agreement. When the parties agree to separately arrange for design and construction and to comply with security and confidentiality requirements, the EDC shall make all relevant information and required specifications available to the Interconnection Customer to permit the Interconnection Customer to obtain an independent design and cost estimate for the facilities, which shall be built in accordance with the specifications;

(D) Upon completion of the Facilities Study and with the agreement of the Interconnection Customer to pay for the Interconnection Facilities and Distribution System Upgrades identified in the Facilities Study, the EDC shall issue the Approval to Install; and

(E) The parties shall use an Interconnection Facilities Study Agreement approved by the Commission.

(f) Upon completion or waiver of procedures defined in Subsection 4007.2(c) as mutually agreed by the parties and the EDC determines that the Small Generator Facility can be interconnected safely and reliably to the Electric Distribution System, the EDC shall provide the Interconnection Customer with an Approval to Install. If the Interconnection Request is denied, the EDC shall provide a written explanation;

(g) When Distribution System Upgrades are required, the interconnection of the Small Generator Facility shall proceed according to milestones agreed to by the parties in the Interconnection Agreement. The Authorization to Operate ~~may not be issued until~~will be issued within twenty (20) business days of completion of the following:

(1) The milestones agreed to in the Interconnection Agreement are satisfied;

(2) The Small Generator Facility is approved by electric code officials with jurisdiction over the interconnection;

(3) The Interconnection Customer provides a Certificate of Completion to the EDC. Completion of local inspections may be designated on inspection forms used by local inspecting authorities; and

(4) There is a successful completion of the Witness Test per the terms and conditions found in the Standard Agreement for Interconnection of Small Generator Facilities, unless waived.

(h) The EDC may require photographs of the site, Small Generator Facility components, meters or any other aspect of the Interconnection Facilities as part of the Level 4 Interconnection Review process, provided that failure to provide a photo in a timely manner will not be a reason for the EDC to deem an Interconnection Request incomplete.

4007.3 An interconnection system impact study is not required when the interconnection feasibility study concludes there is no Adverse System Impact, or when the study identifies an Adverse System Impact, but the EDC is able to identify a remedy without the need for an interconnection system impact study.

4007.4 The parties shall use a form of Interconnection Feasibility Study Agreement approved by the Commission.

4008 TECHNICAL REQUIREMENTS

4008.1 Unless waived by the EDC, a Small Generator Facility must comply with the technical standards listed in Section 4002.1, as applicable. IEEE 1547.2 (2008), "Application Guide for IEEE Standard 1547," IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems and the PJM Interconnection Planning Manual 14A Attachment E, which is available at: https://www.pjm.com/~/media/documents/manuals/m14a.ashx, shall be used as a guide (but not a requirement) to detail and illustrate the interconnection protection requirements that are provided in IEEE Standard 1547.

4008.2 When an Interconnection Request is for a Small Generator Facility that includes multiple energy production devices at a site for which the Interconnection Customer seeks a single Point of Common Coupling, the Interconnection Request shall be evaluated on the basis of the ~~aggregate Nameplate~~Net System Capacity of multiple devices.

4008.3 When an Interconnection Request is for an increase in capacity for an existing Small Generator Facility, the Interconnection Request shall be evaluated on the basis of the new total Nameplate Capacity of the Small Generator Facility.

4008.4 The EDC shall maintain records of the following for a minimum of three (3) years:

(a) The total number of and the Nameplate Capacity of the Interconnection Requests received, approved and denied under Level 1, Level 2, Level 3 and Level 4 reviews;

(b) The number of Interconnection Requests that were not processed within the timelines established in this rule;

(c) The number of Scoping Meetings held and the number of feasibility studies, impact studies, and Facility Studies performed, and the fees charged for these studies;

(d) The justifications for the actions taken to deny Interconnection Requests; and

(e) Any special operating requirements required in Interconnection Agreements that are not part of the EDC's written and published operating procedures applicable to Small Generator Facilities.

4008.5 The EDC shall provide a report to the Commission containing the information required in Subsection 4008.4, paragraphs (a)-(c) within ninety (90) calendar days of the close of each year.

(a) The EDC shall include the total amount of solar energy from solar energy systems meeting the requirements of D.C. Official Code § 34-1432(e)(1) for which interconnection requests have been submitted in the previous six (6) months in its Quarterly Interconnection Report filed in accordance with Commission Order No. 18575.

(b) The EDC shall provide a public and confidential list of final interconnection approvals for renewable generators (name, address, interconnection level, capacity (DC and AC), ~~and~~ system type, date of application, date of receipt of Authorization to Operate, total cost of interconnection facilities, and total cost of EDS upgrades) on the fifteenth (15th) of each month, for the previous month interconnections.

(d) The EDC shall provide a report listing out all of the CREFs that are interconnected and generating, the total amount of energy generated for the month, and the total amount of energy allocated to CREF subscribers for the month on the fifteenth (15th) of each month.

4008.6 The EDC shall designate a contact person and contact information on its website and the Commission's website for submission of all Interconnection Requests and from whom information on the Interconnection Request process and the EDC's Electric Distribution System can be obtained regarding a proposed project. The information shall include studies and other materials useful to an understanding of the feasibility of interconnecting a Small Generator Facility at a particular point on the EDC's Electric Distribution System, except to the extent that providing the materials would violate security requirements or confidentiality agreements, or otherwise deemed contrary to District or federal law/regulations. In appropriate circumstances, the EDC may require a confidentiality agreement prior to release of information.

4008.7 When an Interconnection Request is deemed complete, a modification other than a minor equipment modification that is not agreed to in writing by the EDC, shall require submission of a new Interconnection Request.

4008.8 When an Interconnection Customer is not currently a customer of the EDC at the proposed site, the Interconnection Customer, upon request from the EDC, shall provide proof of site control evidenced by a property tax bill, deed, lease agreement, or other legally binding contract.

4008.9 To minimize the cost of interconnecting multiple Small Generator Facilities, the EDC or the Interconnection Customer may propose a single Point of Common Coupling for multiple Small Generator Facilities located at a single site. If the Interconnection Customer rejects the EDC's proposal for a single Point of Common Coupling, the Interconnection Customer shall pay the additional cost, if any, of providing a separate Point of Common Coupling for each Small Generator Facility. If the EDC rejects the customer's proposal for a single Point of Common Coupling without providing a written technical explanation, the EDC shall pay the additional cost, if any, of providing a separate Point of Common Coupling for each Small Generator Facility.

4008.10 Small Generator Facilities shall be capable of being isolated from the EDC. For all Small Generator Facilities interconnecting to a Primary Line, the isolation shall be by means of a lockable, visible-break isolation device accessible by the EDC. For all Small Generator Facilities interconnecting to a Secondary Line, the isolation shall be by means of a lockable isolation device whose status is clearly indicated and is accessible by the EDC. The isolation device shall be installed, owned and maintained by the owner of the Small Generator Facility and located between the Small Generator Facility and the Point of Common Coupling. A Draw-out Type Circuit Breaker with a provision for padlocking at the draw-out position can be considered an isolation device for purposes of this requirement.

4008.11 The Interconnection Customer may elect to provide the EDC access to an isolation device that is contained in a building or area that may be unoccupied and locked or not otherwise readily accessible to the EDC, by installing a lockbox provided by the EDC that shall provide ready access to the isolation device. The Interconnection Customer shall install the lockbox in a location that is readily accessible by the EDC, and the Interconnection Customer shall permit the EDC to affix a placard in a location of its choosing that provides clear instructions to the EDC's operating personnel on access to the isolation device. In the event that the Interconnection Customer fails to comply with the terms of this subsection and the EDC needs to gain access to the isolation device, the EDC shall not be held liable for any damages resulting from any necessary EDC action to isolate the Interconnection Customer.

4008.12 Any metering necessitated by a Small Generator Facility interconnection shall be installed, operated and maintained in accordance with applicable tariffs. Any such metering requirements shall be clearly identified as part of the Interconnection Agreement executed by the Interconnection Customer and the EDC. The EDC is not responsible for installing, operating, or maintaining customer-owned meters.

4008.13 The EDC shall design, procure, construct, install, and own any Distribution System Upgrades for a CREF. The Distribution System Upgrades costs shall be allocated as follows:

(a) Fifty percent (50%) of the costs to and paid for by the CREF Interconnection Customer.

(b) Fifty percent (50%) of the costs paid for by the EDC, tracked in a regulatory asset, and recovered in its next base rate case.

The Distribution System Upgrade Costs for the shared allocation above shall be capped at two hundred thousand dollars ($200,000) per calendar year. Any costs above this cap in a calendar year shall be paid by the CREF Interconnection Customer.

4008.14 [RESERVED]

4008.15 The Interconnection Customer shall design its Small Generator Facility to maintain a composite power delivery at continuous rated power output at the Point of Common Coupling at a power factor within the power factor range required by the EDC's applicable tariff for a comparable load customer. The EDC may also require the Interconnection Customer to follow a voltage or VAR schedule if such schedules are applicable to similarly situated generators in the control area on a comparable basis and have been approved by the Commission. The specific requirements for meeting a voltage or VAR schedule shall be clearly specified in Attachment 3 of the "District of Columbia Small Generator Interconnection Rule Level 2-4 Standard Agreement for Interconnection of Small Generator Facilities". Under no circumstance shall these additional requirements for reactive power or voltage support exceed the normal operating capabilities of the Small Generator Facility.

4008.16 For retail interconnection non-exporting Energy Storage devices, the load aspects of the storage devices will be treated the same as other load from customers, based on incremental net load.

4008.17 Interconnection of Energy Storage facilities should comply with IEEE Standard 1547 technical & test specifications and requirements.

4008.18 The Energy Storage overcurrent protection (charge/discharge) ratings from inverter nameplate shall not exceed EDC capabilities.

4008.19 In front of the meter Energy Storage exporting systems will be subject to Level 4 review requirements.

4008.20 When a Microgrid reconnects to the EDC, the Microgrid must be synchronized to the grid, matching: (1) voltage, (2) frequency, and (3) phase angle. This should require an asynchronous interconnection.

4008.21 At all interconnection levels, the power conversion system performing energy conversion/control at the Point of Common Coupling must be equipped to communicate system characteristics over secured EDC protocol.

4008.22 Inverters shall meet the safety requirements of UL 1741 and 12 months after the publication of UL 1741 SA (Supplement A) utility-interactive inverters shall meet the specifications of UL 1741 SA.

4009 TIMELINE EXTENSIONS AND DISPUTES

The EDC shall make reasonable efforts to meet all timelines set by these Interconnection Procedures. If the EDC cannot meet a timeline, the EDC shall notify the Applicant in writing within one (1) Business Day after the missed deadline. The notification shall explain the reason for the EDC's failure to meet the deadline and provide an estimate of when the step will be completed. The EDC shall keep the Applicant updated of any changes in the expected completion date.

The Applicant may request in writing the extension of one timeline set by these Interconnection Procedures. The requested extension may be for up to one-half of the time originally allotted (e.g., a ten (10) Business Day extension for a twenty (20) Business Day timeframe). The EDC shall not unreasonably refuse this request. If further timeline extensions are necessary, the Applicant may request an extension in writing to the Interconnection Ombudsperson, who shall grant or deny the request, if it is reasonable, within three (3) Business Days."

4009.1 A party shall attempt to resolve all disputes regarding interconnection as provided in the DCSGIR promptly, equitably, and in a good faith manner.

4009.2 In the event of a dispute, the disputing Party shall provide the other Party a written Notice of Dispute containing the relevant known facts pertaining to the dispute, the specific dispute and the relief sought, and express notice by the disputing Party that it is invoking the procedures under this Section. The notice shall be sent to the non-disputing Party's email address and physical address set forth in the Interconnection Agreement or Application, if there is no Interconnection Agreement. A copy of the notice shall also be sent to Interconnection Ombudsperson. The non-disputing Party shall acknowledge the notice within three (3) Business Days of its receipt and identify a representative with the authority to make decisions for the non-disputing Party with respect to the dispute. When a dispute arises, a party may seek immediate resolution through complaint procedures available through the Commission by providing written notice to the Commission and the other party stating the issues in dispute.~~When a dispute arises, a party may seek immediate resolution through complaint procedures available through the Commission by providing written notice to the Commission and the other party stating the issues in dispute.~~

4009.3 If the dispute is principally related to one or both Parties' compliance with timelines specified in these Interconnection Procedures or associated agreements, the Parties shall seek assistance from Interconnection Ombudsperson if the Parties cannot mutually resolve the dispute within eight (8) Business Days.~~When disputes relate to the technical application of the DCSGIR, the Commission may designate a technical consultant to resolve the dispute. Upon Commission designation, the parties shall use the technical consultant to resolve disputes related to~~

~~interconnection. Costs for a dispute resolution conducted by the technical consultant shall be established by the technical consultant and subject to review by the Commission.~~

If the dispute is not principally related to one or both Parties' compliance with a timeline then the non-disputing Party shall provide the disputing Party with all relevant regulatory and/or technical details and analysis regarding any EDC interconnection requirements under dispute within ten (10) Business Days of the date of the notice of dispute. Within twenty (20) Business Days of the date of the notice of dispute, the Parties' authorized representatives shall meet and confer to try to resolve the dispute. Parties shall operate in good faith and use best efforts to resolve the dispute.

If a resolution is not reached in thirty (30) Business Days from the date of the notice of dispute, either (1) a Party may request to continue negotiations for an additional twenty (20) Business Days, or (2) the Parties may by mutual agreement make a written request for mediation to the Interconnection Ombudsperson. Alternatively, both Parties by mutual agreement may request mediation from an outside third-party mediator with costs to be shared equally between the Parties.

If the results of the mediation are not accepted by one or more Parties and there is still disagreement, the dispute shall proceed to the formal complaint process provided by the Commission.

At any time, either Party may file a complaint before the Commission pursuant to its rules.

If neither Party elects to seek assistance from the Commission, or if the attempted dispute resolution fails, then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of these procedures.

4009.4 Pursuit of dispute resolution shall not affect an Interconnection Customer with regard to consideration of an Interconnection Request or an Interconnection Customer's Queue Position.

4010 WAIVER

4010.1 The Commission may, in its discretion, waive any provisions of Chapter 40 upon notice to the affected persons.

4011 SUPPLEMENTAL REVIEW

4011.1 Within twenty (20) business days of determining that Supplemental Review is appropriate, the EDC shall perform Supplemental Review using the screens set forth below, notify the Interconnection Customer of the results, and include with the notification a written report of the analysis and data underlying the EDC's determinations under the screens.

(a) Where twelve (12) months of Line Section minimum load data is available, can be calculated, can be estimated from existing data, or can be determined from a power flow model, the aggregate Small Generator Facility Nameplate Capacity on the Line Section is less than one hundred percent (100%) of the minimum load for all Line Sections bounded by automatic sectionalizing devices upstream of the proposed Small Generator Facility. If the minimum load data is not available, or cannot be calculated or estimated, the aggregate Small Generator Facility Nameplate Capacity on the Line Section is less than thirty percent (30%) of the peak load for all Line Sections bounded by automatic sectionalizing devices upstream of the proposed Small Generator Facility.

(1) The type of generation used by the proposed Small Generator Facility will be taken into account when calculating, estimating, or determining circuit or Line Section minimum load relevant for the application of this screen. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (*e.g.*, 8 a.m. to 6 p.m.), while all other generation uses absolute minimum load.

(2) When this screen is being applied to a Small Generator Facility that serves some onsite electrical load, all generation will be considered as part of the aggregate generation. If a Small Generator Facility uses Energy Storage without energy production equipment, and incorporates controls which limit Energy Storage discharge schedule to periods that are fixed and known to the EDC, the EDC shall consider the Energy Storage discharge schedule when calculating, estimating, or determining circuit or Line Section minimum load relevant for the application of this screen

(b) In aggregate with existing generation on the Line Section:

(1) The voltage regulation on the Line Section can be maintained in compliance with relevant requirements under all system conditions;

(2) The voltage fluctuation is within acceptable limits as defined by IEEE Standard 1453 or Good Utility Practice similar to IEEE Standard 1453; and

(3) The harmonic levels meet IEEE 519 limits at the Point of Common Coupling.

(c) The locations of the proposed Small Generator Facility and the aggregate Small Generator Facility Nameplate Capacity on the Line Section do not create impacts to safety or reliability that cannot be adequately addressed without application of Level 4 Interconnection Review procedures. The

EDC may consider the following factors and others in determining potential impacts to safety and reliability in applying this screen.

(1) Whether the Line Section has significant minimum loading levels dominated by a small number of customers (*i.e.*, several large commercial customers).

(2) If there is an even or uneven distribution of loading along the feeder.

(3) If the proposed Small Generator Facility is located in close proximity to the substation (*i.e.*, < 2.5 electrical line miles), and if the distribution line from the substation to the Small Generator Facility is composed of large conductor/feeder section (*i.e.*, 600A class cable).

(4) If the proposed Small Generator Facility incorporates a time delay function to prevent reconnection of the generator to the Electric Distribution System until system voltage and frequency are within normal limits for a prescribed time.

(5) If operational flexibility is reduced by the proposed Small Generator Facility, such that transfer of the Line Section(s) of the Small Generator Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

(6) If the proposed Small Generator Facility utilizes certified anti-islanding functions and equipment.

(d) Modifications to the Electric Distribution System required by interconnections based on the Supplemental Review shall be treated in the following manner:

(1) If the Interconnection Request requires only Interconnection Facilities to the Electric Distribution System, a non-binding good faith cost estimate and construction schedule for the Interconnection Facilities to the Electric Distribution System, along with an Approval to Install, shall be provided within fifteen (15) business days after notification of the Supplemental Review results.

(2) If the Interconnection Request requires more than the addition of Interconnection Facilities, the EDC may elect to provide a non-binding good faith cost estimate and construction schedule for such Distribution System Upgrades within thirty (30) business days after notification of the Supplemental Review results, or the EDC may notify the Interconnection Customer that the EDC will need to complete a Facilities Study under Level 4 Interconnection Review

to determine the cost estimate and construction schedule for necessary Distribution System Upgrades.

(e) If the proposed interconnection meets all of the applicable Adverse System Impact screens and the EDC determines that the Small Generator Facility can be interconnected safely and reliably to the Electric Distribution System, the EDC shall provide the Interconnection Customer an Approval to Install

(f) An Interconnection Customer that receives an Approval to Install shall provide the Small Generator Interconnection Part II – Certificate of Completion and signed inspection certificate in the following timeframes:

(1) For Level 1 Interconnection Requests: Unless extended by mutual agreement of the parties, within six (6) months of receipt of the Approval to Install or six (6) months from the completion of any Distribution System Upgrades, whichever is later, the Interconnection Customer shall provide to the EDC the Level 1 Small Generator Interconnection Part II – Certificate of Completion, including the signed inspection certificate.

(2) For Level 2 and 3 Interconnection Requests: Unless extended by mutual agreement of the parties, within twenty-four (24) months from an Interconnection Customer's receipt of the Approval to Install or six (6) months of completion of any Distribution System Upgrades, whichever is later, the Interconnection Customer shall provide to the EDC the Level 2-4 Small Generator Interconnection Part II – Certificate of Completion, including the signed certificate of inspection. An interconnection customer shall communicate with the EDC no less frequently than every six (6) months regarding the status of a proposed small generator facility to which an Interconnection Agreement refers.

(g) The EDC may conduct a Witness Test within ten (10) business days' of issuing the Authorization to Operate at a time mutually agreeable to the parties. If a Small Generator Facility initially fails the test, the EDC shall offer to redo the Witness Test at the Interconnection Customer's expense at a time mutually agreeable to the parties. If the EDC determines that the Small Generator Facility fails the Witness Test it must provide a written explanation detailing the reasons and any standards violated.

(h) Upon EDC's issuance of the Authorization to Operate, an Interconnection Customer may begin interconnected operation of a Small Generator Facility, provided that there is an Interconnection Agreement in effect, the Small Generator Facility has passed any Witness Test required by the EDC, and that the Small Generator Facility has passed any inspection required by the EDC. Evidence of approval by an electric code official includes a signed inspection certificate.

(i) As an alternative to the Supplemental Review procedures prescribed in this section, the EDC may elect to perform a power flow-based study, providing the Interconnection Customer with the results and the required mitigation, if necessary. The EDC shall make available, upon request, a copy of its power flow-based study for each applicant to the Commission within thirty (30) days after analysis completion.

(j) The EDC may require photographs of the site, Small Generator Facility components, meters or any other aspect of the Interconnection Facilities as part of the Supplemental Review process.

4012 APPLICANT OPTIONS MEETING

4012.1 If the EDC determines the Interconnection Request cannot be approved without evaluation under Level 4 Interconnection Review, at the time the EDC notifies the Interconnection Customer of either the Level 1, 2 or 3 Interconnection Review, or Supplemental Review, results, it shall provide the Interconnection Customer the option of proceeding to a Level 4 Interconnection Review or of participating in an applicant options meeting with the EDC to review possible Small Generator Facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Small Generator Facility to be connected safely and reliably. The Interconnection Customer shall notify the EDC that it requests an applicant options meeting or that it would like to proceed to Level 4 Interconnection Review in writing within fifteen (15) business days of the EDC's notification or the Interconnection Request shall be deemed withdrawn. If the Interconnection Customer requests an applicant options meeting, the EDC shall offer to convene a meeting at a mutually agreeable time within the next fifteen (15) business days.

4013-4098 [RESERVED]

4099 DEFINITIONS

4099.1 When used in this chapter, the following terms and phrases shall have the following meaning:

"Adverse System Impact" means a negative effect, due to technical or operational limits on conductors or equipment being exceeded, that compromises the safety and reliability of the Electric Distribution System.

"Advanced Inverters" means inverters with a digital architecture, bidirectional communications, and software that enables functionalities providing autonomous grid support and enhance system reliability, along with the capability to adjust their operational set points in response to the changing characteristics of the grid through dedicated communications protocols and standards. Advanced inverters must enable, at the minimum, the following functionalities, as defined in IEEE Standard 1547-2018: dynamic and real power support, voltage ride-through, frequency ride-through, voltage support, frequency support, and ramp rates.

"Affected System" means an electric system not owned or operated by the Electric Distribution Company reviewing the Interconnection Request that may suffer an Adverse System Impact from the proposed interconnection.

"Area Network" means a type of Electric Distribution System served by multiple transformers interconnected in an electrical network circuit, which is generally used in large metropolitan areas that are densely populated. Area networks are also known as grid networks. Area network has the same meaning as the term distribution secondary grid networks in Section 9.2 of IEEE Standard 1547.

"Approval to Install" means written notification that the Small Generator Facility is conditionally approved for installation contingent upon the terms and conditions of the Interconnection Request, and the EDC shall provide such conditional approval by furnishing to Interconnection Customer an EDC-executed copy of the Interconnection Agreement.

"Authorization to Operate" means written notification that the Small Generator Facility is approved for operation under the terms and conditions of the District of Columbia Small Generator Interconnection Rules.

"Certificate of Completion" means a certificate in a completed form approved by the Commission containing information about the Interconnection Equipment to be used, its installation and local inspections.

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

"Commissioning Test" means the tests applied to a Small Generator Facility by the Interconnection Customer after construction is completed to verify that the facility does not create Adverse System Impacts. The scope of the Commissioning Tests performed shall include the Commissioning Test specified IEEE Standard 1547 Section 11.2.5 "Commissioning tests".

"Community Renewable Energy Facility" or **"CREF"** – means an energy facility with a capacity no greater than five (5) megawatts that: (a) uses renewable resources defined as a Tier One Renewable Source in accordance with Section 3(15) of the Renewable Energy Portfolio Standard Act of 2004, effective April 12, 2005 (D.C. Law 15-340; D.C. Official Code § 34-1431(15), as amended); (b) is located within the District of Columbia; (c) has at least two (2) Subscribers; and (d) has executed an Interconnection Agreement and a CREF Rider with the Electric Company.

"Customer Generation Meter" means the meter used to capture the level of customer-generated electricity at an Interconnection Customer's premise.

"Customer Usage Meter" means the meter furnished by the EDC used to capture the level of electricity consumption at an Interconnection Customer's premise.

"Default EDC Required Inverter Settings Profile" is a utility set of default smart inverter settings optimized for use across a utility's service territory, based on the District-wide settings

"Distribution System Upgrade" means a required addition or modification to the EDC's Electric Distribution System at or beyond the Point of Common Coupling to accommodate the interconnection of a Small Generator Facility. Distribution upgrades do not include interconnection facilities.

"District of Columbia Small Generator Interconnection Rule (DCSGIR)" means the most current version of the procedures for interconnecting Small Generator Facilities adopted by the Public Service Commission of the District of Columbia.

"District-Wide Required Inverter Settings Profile" is a set of smart inverter settings optimized for use by utilities and manufacturers in establishing defaults District-wide, maintained by the Commission

"Draw-out Type Circuit Breaker" means a switching device capable of making, carrying and breaking currents under normal and abnormal circuit conditions such as those of a short circuit. A draw-out circuit breaker can be physically removed from its enclosure, creating a visible break in the circuit. For the purposes of these regulations, the draw-out circuit breaker shall be capable of being locked in the open, draw-out position.

"Electric Distribution Company" or "EDC" means an electric utility entity that distributes electricity to customers and is subject to the jurisdiction of the Commission.

"Electric Distribution System" or "EDS" means the facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries from interchanges with higher voltage transmission networks that transport bulk power over longer distances. The voltage levels at which Electric Distribution Systems operate differ among areas but generally carry less than sixty-nine (69) kilovolts of electricity. Electric distribution system has the same meaning as the term Area EPS, as defined in IEEE Standard 1547.

"Energy Storage" means a resource capable of absorbing electric energy from the grid, from a behind-the-meter generator, or other DER, storing it for a period of time and thereafter dispatching the energy for use on-site or back to the grid, regardless of where the resource is located on the electric distribution system. These resources include all types of energy storage technologies, regardless of their size, storage medium (*e.g.*, batteries, flywheels, electric vehicles, compressed air), or operational purpose.

"Facilities Study" means an engineering study conducted by the EDC to determine the required modifications to the EDC's Electric Distribution System, including the cost and the time required to build and install such modifications as necessary to accommodate an Interconnection Request.

"Fault Current" means the electrical current that flows through a circuit during an electrical fault condition. A fault condition occurs when one or more electrical conductors contact ground or each other. Types of faults include phase to ground, double-phase to ground, three-phase to ground, phase-to-phase, and three-phase. Fault current is several times larger in magnitude than the current that normally flows through a circuit.

"Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result of the lowest reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

"Governmental Authority" means any federal, State, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other Governmental Authority having jurisdiction over the Parties, respective facilities, or services provided, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, EDC or any affiliate thereof.

"IEEE Standard 1547" refers to the Institute of Electrical and Electronics Engineers, Inc. (IEEE) Standard 1547 (2018) "Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," as amended and supplemented at the time the Interconnection Request is submitted.

"IEEE Standard 1547.1" refers to the IEEE Standard 1547.1 (2015) "Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems," as amended and supplemented at the time the Interconnection Request is submitted.

"Interconnection Customer" means an entity that has submitted either an Interconnection Request to interconnect a Small Generator Facility to the EDC's Electric Distribution System or a pre-application report to get information about EDC's electrical distribution system at a proposed Point of Common Coupling.

"Interconnection Equipment" means a group of equipment, components, or an integrated system connecting an electric generator with a Local Electric Power System or an Electric Distribution System that includes all interface equipment including switchgear, protective devices, inverters or other interface devices. Interconnection equipment may be installed as part of an integrated equipment package that includes a generator or other electric source.

"Interconnection Facilities" means facilities and equipment required by the EDC to accommodate the interconnection of a Small Generator Facility. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generator Facility and the Point of Common Coupling, including modification, additions, or upgrades that are necessary to physically and electrically interconnect the Small Generator Facility to the Electric Distribution System. ~~Interconnection Facilities also includes Customer Generation Meters.~~ Interconnection Facilities are sole use facilities and do not include Distribution System Upgrades, ~~or~~ Customer Usage Meters, or Customer Generation Meters.

"Interconnection Facilities Cost Matrix" means the matrix maintained on the EDC's website that contains fixed-cost Interconnection Facilities projects associated with the installation of Small Generator Interconnection Facilities. The Interconnection Facilities Cost Matrix is not an exhaustive list of Small Generator Interconnection Facilities.

"Interconnection Request" means an Interconnection Customer's application and interconnection agreement, in a form approved by the Commission, requesting to interconnect a new Small Generator Facility, or to increase the capacity or modify operating characteristics of an existing approved Small Generator Facility that is interconnected with the EDC's Electric Distribution System.

"Line Section" means that portion of the EDC's Electric Distribution System connected to an Interconnection Customer, bounded by automatic sectionalizing devices or the end of the distribution line.

"Local Electric Power System" or "Local EPS" means facilities that deliver electric power to a load that are contained entirely within a single premises or group of premises. Local electric power system has the same meaning as the term Local Electric Power System defined in IEEE Standard 1547.

"Microgrid" means a collection of interconnected loads, generation assets, and advanced control equipment, installed across a limited geographic area and within a defined electrical boundary that is capable of disconnecting from the larger Electric Distribution System. A Microgrid may serve a single customer with several structures or serve multiple customers. A Microgrid can connect and disconnect from the distribution system to enable it to operate in both interconnected or island mode.

"Nameplate Capacity" means the maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer and is usually indicated on a nameplate physically attached to the power production equipment.

"Nationally Recognized Testing Laboratory" or "NRTL" means a qualified private organization that meets the requirements of the Occupational Safety and Health Administration's (OSHA) regulations. NRTLs perform independent safety testing and product certification. Each NRTL shall meet the requirements as set forth by OSHA in the NRTL program.

"Parallel Operation" or "Parallel" means the sustained state of operation over one hundred (100) milliseconds, which occurs when a Small Generator Facility is connected electrically to the Electric Distribution System and thus has the ability for electricity to flow from the Small Generator Facility to the Electric Distribution System.

"PJM Interconnection" means the regional transmission organization that is regulated by the Federal Energy Regulatory Commission and functionally controls the transmission system for the region that includes the District of Columbia.

"Point of Common Coupling" means the point where the Small Generator Facility is electrically connected to the Electric Distribution System. Point of common coupling has the same meaning as defined in IEEE Standard 1547.

"Primary Line" means a distribution line rated at greater than six hundred (600) volts.

"Production Test" is defined in IEEE Standard 1547.

"Queue Position" means the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the EDC.

"Radial Distribution Circuit" means a circuit configuration where independent feeders branch out radially from a common source of supply. From the standpoint of a utility system, the area described is between the generating source or intervening substations and the customer's entrance equipment. A radial distribution system is the most common type of connection between a utility and load in which power flows in one direction from the utility to the load.

"Scoping Meeting" means a meeting between representatives of the Interconnection Customer and EDC conducted for the purpose of discussing alternative interconnection options, exchanging information including any Electric Distribution System data and earlier study evaluations that would be reasonably expected to impact interconnection options, analyzing information, and determining the potential feasible points of interconnection.

"Secondary Line" means a service line subsequent to the Primary Line that is rated for six hundred (600) volts or less, also referred to as the customer's service line.

"Shared Transformer" means a transformer that supplies secondary source voltage to more than one customer.

"Site-Specific Utility Required Inverter Settings Profile" is a set of smart inverter settings optimized for use at a specific site on a utility's electric system."

"Small Generator Facility" means the equipment used by an Interconnection Customer to generate or store electricity that operates in parallel with the Electric Distribution System and, for the purposes of this standard, is rated at twenty (20) MW or less. A Small Generator Facility typically includes an electric generator, Energy Storage, prime mover, and the Interconnection Equipment required to safely interconnect with the Electric Distribution System or Local Electric Power System as mutually agreed between the parties of the Interconnection Request.

"Spot Network" means a type of Electric Distribution System that uses two or more inter-tied transformers to supply an electrical network circuit. A Spot Network is generally used to supply power to a single customer or a small group of customers. Spot network has the same meaning as the term distribution secondary Spot Networks defined in Section 9.3 of IEEE Standard 1547.

"Standard Agreement for Interconnection of Small Generator Facilities, Interconnection Agreement, or Agreement" means a set of standard forms of Interconnection Agreements approved by the Commission which are applicable to Interconnection Requests pertaining to small generating facilities. The agreement between the Interconnection Customer and the EDC, which governs the connection of the Small Generator Facility to the EDC's Electric Distribution System, as well as the ongoing operation of the Small Generator Facility after it is connected to the EDC's Electric Distribution System.

"UL Standard 1741" means Underwriters Laboratories' standard titled "Inverters Converters, and Controllers for Use in Independent Power Systems," as amended and supplemented at the time the Interconnection Request is submitted.

"Witness Test" means verification (either by an on-site observation or review of documents) by the EDC that the installation evaluation required by IEEE Standard 1547 Section 11.2.4 and the Commissioning Test required by IEEE Standard 1547 Section 11.2.5 have been adequately performed. For Interconnection Equipment that has not been certified, the Witness Test shall also include the verification by the EDC of the on-site design tests as required by IEEE Standard 1547 Section 11.2.4 and verification by the EDC of Production Tests required by IEEE Standard 1547 Section 11.2.3. All tests verified by the EDC are to be performed in accordance with the applicable test procedures specified by IEEE Standard 1547.1.

1. Any person interested may submit written comments on this NOPR not later than thirty (30) days after publication of this Notice in the *D.C. Register* with Brinda Westbrook-Sedgwick, Commission Secretary, Public Service Commission of the District of Columbia, 1325 G Street, N.W., Suite 800, Washington, D.C. 20005, or electronically on the Commission's website at https://edocket.dcpsc.org/public/public_comments. Copies of the proposed rules may be obtained by visiting the Commission's website at www.dcpsc.org or at cost, by contacting the Commission Secretary at the address provided above. Persons with questions concerning this NOPR should call (202) 626-5150 or send an email to psc-commissionsecretary@dc.gov.

ATTACHMENT 1 ~~–~~ PUBLIC QUEUE REQUIREMENTS

The EDC shall maintain an interconnection queue, available in a sortable spreadsheet format, which it shall update on at least a monthly basis. The date of the most recent update shall be clearly indicated.

The queue ~~should~~ shall include, at a minimum, the following information about each interconnection application.

1. Queue number
2. Facility nameplate capacity (kW_{AC})
~~2.~~3. Facility net system capacity (kW_{AC})
~~3.~~4. Primary fuel type (*e.g.*, solar, wind, bio-gas, etc.)
~~4.~~5. Secondary fuel type (if applicable)
~~5.~~6. Exporting or non-exporting
~~6.~~7. Zip code
~~7.~~8. Substation
~~8.~~9. Feeder
~~9.~~10. Status (active, withdrawn, interconnected, etc.)
~~10.~~11. Date application deemed complete
~~11.~~12. Date of notification of screen results (Levels 1-3)
~~12.~~13. Screen results for Levels 1-3 (pass or fail, and if fail, identify the screens failed)
~~13.~~14. Date of notification of Supplemental Review results (if applicable)
~~14.~~15. Supplemental Review results (pass or fail, and if fail, identify the screens failed)
~~15.~~16. Date of notification of System Impact Study results (if applicable)
~~16.~~17. Date of notification of Facilities Study results and/or construction estimates (if applicable)
~~17.~~18. Date final Interconnection Agreement is provided to Customer
~~18.~~19. Date Interconnection Agreement is signed by both parties
~~19.~~20. Date of grant of ~~approval~~ authorization to operate
~~20.~~21. Final interconnection cost paid to EDC~~utility~~

ATTACHMENT B

Queue Postiion	Capacity (kWAC)	Primary Fuel Type	Secondary Fuel Type	Exporting	Zip Code	Substation	Feeder ID	Status	Date of Complete Application	Date Screen Results (Lvl 1-3)	Screen Results (Lvl 1-3)	Date Supplemental Review Results (Lvl 4)	Supplemental Review Results (Lvl 4)	Date System Impact Study Results (Lvl 4)	Date Notification Facilities Study Results (Lvl 4)	Date Final Interconnection Agreement Issued	Date Interconnection Agreement Signed	Date of Approval to Operate	Final Interconnection Costs Paid
1	20	Solar	n/a	Y	20002	X	ABCD	Active	8/3/2020	8/10/2020	Pass	n/a	n/a	n/a	n/a	8/13/2020	8/16/2020		
2	35	Solar	BESS	N	20020	Y	EFGH	Active	8/4/2020	8/25/2020	Pass	n/a	n/a	n/a	n/a	8/28/2020	8/31/2020		
3	10	Solar	n/a	Y	20008	Z	1234	Active	8/5/2020	8/12/2020	Pass	n/a	n/a	n/a	n/a	8/15/2020	8/18/2020		
4	15	Solar	n/a	Y	20016	AA	5678	Active	8/6/2020	8/13/2020	Pass	n/a	n/a	n/a	n/a	8/16/2020	8/19/2020		
5	50	Solar	n/a	Y	20032	BB	LMNO	Active	8/7/2020	8/28/2020	Pass	n/a	n/a	n/a	n/a	8/31/2020	9/3/2020		
6	200	Solar	n/a	Y	20019	CC	PQRS	Active	8/8/2020	8/29/2020	Pass	n/a	n/a	n/a	n/a	9/1/2020	9/4/2020		
7	300	Solar	n/a	Y	20017	DD	TUVW	Active	8/9/2020	8/30/2020	Pass	n/a	n/a	n/a	n/a	9/2/2020			
8	450	Solar	BESS	Y	20001	EE	9876	Active	8/10/2020	8/31/2020	Pass	n/a	n/a	n/a	n/a	9/3/2020			
9	155	Solar	n/a	N	20011	FF	5432	Active	8/11/2020	9/1/2020	Pass	n/a	n/a	n/a	n/a	9/4/2020			
10	25	Solar Thermal	n/a	N	20001	GG	7056	Active	8/12/2020	9/2/2020	Pass	n/a	n/a	n/a	n/a	9/5/2020			
11	15	Solar	n/a	Y	20002	HH	3425	Active	8/13/2020	8/20/2020	Pass	n/a	n/a	n/a	n/a	8/23/2020			
12	950	Solar	n/a	Y	20020	II	2983	Active	8/14/2020	9/4/2020	Pass	n/a	n/a	n/a	n/a				
13	60	Solar	n/a	Y	20019	JJ	WALS	Active	8/15/2020	9/5/2020	Fail	n/a	n/a	n/a	n/a				
14	100	Solar	n/a	Y	20016	XX	CO34	Active	8/16/2020	9/6/2020	Pass	n/a	n/a	n/a	n/a				
15	2500	Solar	n/a	Y	20017	YY	3492	Active	8/17/2020	n/a	n/a								

ATTACHMENT C

Southern California Edison Unit Cost Guide dated March 30, 2019
In accordance with Attachment A to Decision D16-06-052, the Unit Cost Guide represents facilities generally required for interconnection. Unit Cost Guide is not binding for actual facility costs and is provided only for additional cost transparency and developer reference. For reference, Ft = Per Foot

Category 1 - 12/16kV 480 volt transformer - includes 100' Sec. cable length

Item #	Equipment	Unit Cost	Notes
1			
2	300kva & Sec. Cable	$36,000	
3	500kva & Sec. Cable	$46,000	
4	750kva & Sec. Cable	$53,000	
5	1000kva & Sec. Cable	$68,000	
6	1500kva, Sec. Cable & fuse cabinet	$94,000	
7	2500kva, Sec. Cable & fuse cabinet (Fuseing); Used with an External Fuse Cabinet	$178,000	

Category 2 - Overhead to Underground (UG)- Set Pole and make up Cable

#	Equipment	Unit Cost	Notes
1	Pri 1/0 Cable from New Pole 200'	$31,000	
2	Pri 350 Cable from New Pole 200'	$35,000	
3	Pri 1000 Cable from New Pole 200'	$41,000	

Category 3 - Overhead (OH) Service

#	Equipment	Unit Cost	Notes
1	OH Primary Service	$16,000	
2	New Conductor Extension from POI to PCC	$120/ft	

Category 4 - Underground to Underground - Cable with Terminators

#	Equipment	Unit Cost	Notes
1	Pri Low Ampacity Cable undg feed 400'	$16,000	1/O XLP
2	Pri High Ampacity Cable undg feed 400'	$35,000	350XLP
3	Pri High Ampacity Cable undg feed 400'	$37,000	1000XLP
4			
5			
6			
7	New underground cable and connections (ft)	$25/ft	1/O XLP
8	New underground cable and connections (ft)	$50/ft	350XLP - 1000XLP

Category 5 - Metering

#	Equipment	Unit Cost	Notes
1	Secondary Metering	$5,300	
2	12KV/16KV - 50/400 Amp Demand	$15,000	
3	33kV Pole Top Mtrg - Transformer rack configuration	$110,000	
4	Single Phase, self-contained meter (600 V)	$1,100	

#	Equipment	Unit Cost	Notes
	Southern California Edison Unit Cost Guide dated March 30, 2019 In accordance with Attachment A to Decision D16-06-052, the Unit Cost Guide represents facilities generally required for interconnection. Unit Cost Guide is not binding for actual facility costs and is provided only for additional cost transparency and developer reference. For reference, Ft = Per Foot		
5	Transformer-rated meter (600 V)	$6,000	3000/5 CT
6	Primary Transformer-rated meter (5 kV)	$12,000	4 kV Meter
7	Primary Transformer-rated meter (15 kV)	$13,000	Indoor type
8	Primary Transformer-rated meter (25 kV) - Existing single pole	$48,000	33 kV pole mounted

Category 6 - Telemetry

#	Equipment	Unit Cost	Notes
1	33kV Automatic Recloser	$135,000	Used for Interconnection switch and not used for telemetry
2	12/16kV-Gas switch with Automation	$57,000	Used for Interconnection switch and not used for telemetry
3	Centralized Remote Terminal Unit	$6,100	0.99 MVA-9.99 MVA
4	Dedicated Remote Terminal Unit	$144,000	Greater than 9.9 MVA
5	Bi-directional watt transducer	$50,000	
6	Data Point addition and existing HMI	$9,500	
7			

Category 7 - System Equipment

#	Equipment	Unit Cost	Notes
1	12 & 16kv Omni Pole Switch (switch itself and handle)	$13,500	
2	Padmounted Gas Switch (without SCADA)	$50,000	
3	12/16kV 1200 KVAR Capacitor Bank & Pole	$33,000	
4	12/16KV 1200 KVAR Capacitor Bank on Pad	$56,000	
5	12/16kV regulator 3-228s	$185,000	
6	33kV Regulator 3-690/722	$282,000	
7			
8	Pole Mounted 12kV Grd detector	$31,000	Average of Padmount and Overhead
9	Ground Bank	$61,000	Average of small and large
10	Reconductor (Per ft) - OH - Urban	$180/ft	
11	Reconductor (Per ft) - OH - Rural	$130/ft	
12	Reconductor (Per ft) - UG	$80/ft	

	Southern California Edison Unit Cost Guide dated March 30, 2019 In accordance with Attachment A to Decision D16-06-052, the Unit Cost Guide represents facilities generally required for interconnection. Unit Cost Guide is not binding for actual facility costs and is provided only for additional cost transparency and developer reference. For reference, Ft = Per Foot		
13			
14			
15	Overhead Fuse Replacement	$3,500	
16			
17	Relocate Capacitor Bank	$19,000	
18			
19	Relocate Voltage Regulator	$44,000	
20			
21			
22			
23			
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30			

Note: For overall IOU line consistency, facilities not commonly used for SCE interconnection have been placed in gray.

Southern California Edison Unit Cost Table - September 21, 2019 - Acronym Table

Acronym	Description	IOU (if used)
ITCC	Income Tax Component of Construction	All
CICA	Contributions is Aid of Construction	All
IF	Interconnection Facilities	All
PCC	Point of Common Coupling	All
POI	Point of Interconnection	All
ESR	Electrical Service Requirements	SCE
UG	Under Ground	All
OH, OVH	Over Head	All
DER	Distributed Energy Resource	All
DG	Distributed Generation	All
IC	Interconnection Customer	All
SLD	Single Line Diagram	All
ROW	Right of Way	All
BLM	Bureau of Land Management	All
AFUCD	Allowance of Funds Used During Construction	SDGE
CNF	Cleveland National Forest	SDGE
SCADA	Supervisory Control and Data Acquisition	All
RTU	Remote Terminal Unit	All
GS	Gas Switch	All
PME	Pad Mount Equipment	All
COO	Cost of Ownership	PGE

Southern California Edison Cost Table Assumptions

General labor overtime: based on 6-10 work schedule.
General contingency factor: 35% - SCE Standard Contingency Policy used for preliminary project estimating based on AACE guidelines.
Unit cost guide assumes facilities are constructed under an Engineer, Procurement and Construction (EPC) agreement. All facilities are owned by SCE.
Unit costs exclude generator's responsibility for Income Tax Component of Contribution (ITCC), (these will be added to total cost estimates, if required) along with O&M Replacement (both discussed under example assumptions)
Unit costs exclude environmental monitoring, licensing and mitigations.
Unit cost are given w/out the benefit of any preliminary & final engineering. Unforeseen conflicts and/or scope will increase costs. These unit costs do not include: right-of-way & easements requirements, environmental engineering/mitigation, GO 131-D engineering /permitting, other permitting, associated SCE/3rd Party under-build work, etc. A signed Interconnection Agreement is required before final design/engineering can start. Construction will not commence until all of the above conditions have been addressed.
Unit costs do not include the construction of UG ducts and structures (civil construction).

4
5
6
7
8

Southern California Edison Unit Cost Guide Variability Illustrative Discussion

The impacts identified below are only examples of items based upon historic experience. While effort has been made to include numerous examples, this list is not meant to be viewed as all inclusive and is for illustrative purposes only. Impacts are not always know in advance and final estimates are driven by project specific conditions as reviewed during the system review process.

Examples of Potential Factors Effecting Rule 21 Estimated or Actual Costs

1	**3rd Party or Multi-Party Easements** Example: Roof top solar project on leased building. Significant added coordination to obtain easements. Leasing tenant and/or developer failed to engage building owner of need for interconnection facilities in advance of proceeding with project. This issue is compounded when the site plans and drawings provided do not include surveyed property lines. Even with approval, 3rd party easements require additional document preparation, review and processing.
2	**City Restrictions** Example: Traffic control in a school area limited work to 9:00 AM to 2:00, doubled project duration (days) of project, impacted efficiency and doubled traffic control and number of resource mobilizations (Road moratorium, customer research)
3	**Local Jurisdiction Improvements** Example: Long term city plan for road widening. Required existing pole to be set back to get jurisdictional permits. Critical that customer communicate plans with city well in advance to determine required upgrades or improvements.
4	**Outage Coordination** Utilities make best efforts to balance impacts to all customer when taking outages. Multiple customer needs must be considered. While there is obligation to get service connected impact to existing customer(s) must be considered.
5	**Pole Height Restrictions** Deteriorated pole condition requires a replacement. Under build requires pole change and taller pole is restricted by view or other issues. Local airport restrictions on pole height.
6	**Underground Impairments & Structure Limits** Errors in customer base map for underground. Mapping can not forecast underground structure volume available for new facilities. Overcrowded structures can be an issue.
7	**Undisturbed Grounds** Customer environmental survey work does not take into account potential utility work.
8	**Customer Base Map Quality** Low quality customer base maps requiring field visits, surveying and multiple back and forth communication to get correct details. Often causes months of delay to project construction.
9	**Neighboring Customer Impacts** Customer on circuit with seasonal operation would be excessively impacted by outage. Circuit with high level of critical care customers. Generator required to support outage. Construction anticipated in winter months or during storm season.
10	**Topology** What appeared to be "drainage channel" was classified as waterway and required long span crossing
11	**Customer Civil Work** A high number or projects see delays in start and completion of customer civil work that extends project duration and can result in added crew trips to site for re-starts. Heavily impacts crew scheduling.
12	**Requested Project Timing** Construction anticipated in winter months or during storm season.

Project Examples - Southern California Edison Unit Cost Table; examples provided below are for illustrative purposes only and are not binding for actual facility costs

Scenarios < 1MW:

Scenario 1

Interconnection Facilities	Unit	Quantity	Cost ($)	Category
500 kVA trans /cable	EA	1	$44,000	(1)
480V metering	EA	1	$5,000	(5)
Riser w/cable	EA	1	$30,000	(2)
		Project Total:	$79,000	
Tax Component (if applied/see assumption 1)			$27,650	
Monthly Interconnection Facilities Charge (see assumption 2/Replacement with Additional Cost)			$300	

Supporting Comments

This is a 0.380 MW, 480V solar generator interconnecting to an OH service located on a low DG penetration 12 kV circuit. Based on the size of the project, standard Interconnection Facilities are required: new riser pole, primary cable, new padmount transformer secondary metering cable. The main feeder did not require any Distribution Upgrades.

Scenario 2

Interconnection Facilities	Unit	Quantity	Cost ($)	Category
750 kVA w/cable	EA	1	$51,000	(1)
Ground Detector	EA	1	$30,000	(7)
1/0 Primary cable	FT	400	$34,000	(4)
480V meter	EA	1	$5,000	(5)
		Total	$120,000	
Tax Component (if applied/see assumption 1)			$42,000	
Monthly Interconnection Facilities Charge (see assumption 2/20 Year Replacement and No Additional Cost)			$480	

This is a 0.675 MW, 480V induction generator interconnecting to an existing underground service located on a low DG penetration 12 kV circuit. Based on the size of the project, standard Interconnection Facilities are required: primary cable, new padmount transformer, padmount ground detector and secondary metering and cable. The main feeder did not require any Distribution Upgrades.

Scenarios ≥ 1MW:

Scenario 3

Interconnection Facilities	Unit	Quantity	Cost ($)	Category
Pad G.S. w/automation	EA	1	$56,000	(6)
1500 kVA w/cable	EA	1	$92,000	(1)
PME-5 w/cable	EA	1	$26,000	(7)
480V meter	EA	1	$5,000	(5)
Riser w/cable	EA	1	$30,000	(2)
Centralized RTU	EA	1	$6,100	(6)
		Total	$215,100	
Distribution Upgrades				
Voltage Regulator	EA	1	$180,000	(7)
		Total	$180,000	

This is a 1.5 MW, 480V solar generator interconnecting downstream of an existing Automatic Recloser on a 12 kV circuit. Based on the size of the project, standard Interconnection Facilities are required: riser pole, primary cable, padmount gas switch, padmount PME switch, padmount transformer, secondary metering and cable. Since this project is ≥ 1 MW but <10MW telemetry is required. In addition, the solar project triggers a high voltage condition on the circuit. As a result, a Voltage Regulator is install to mitigate the high voltage condition.

Scenario 4

Interconnection Facilities	Unit	Quantity	Cost ($)	Category
Pad G.S. w/auto	EA	1	$56,000	(6)
350 Cable	EA	1	$34,000	(2)
12 kV meter	EA	1	$14,000	(5)
Centralized RTU	EA	1	$6,100	(6)
		Total	$110,100	
Distribution Upgrades				
Reconductor 1500 of OH to 336 ACSR	EA	1	$195,000	(7)
		Total	$195,000	

This is a 2.0 MW, 12 kV solar project interconnecting to an existing underground service located on a high penetration DG, 12 kV circuit. Based on the size of the project, standard Interconnection Facilities are required. Primary cable, padmount gas switch, Remote Control Switch for automation, an primary metering. The addition of the generator triggered a thermal overload on the feeder. Thus, a line reconductoring is necessary to alleviate the thermal overload.

Scenario 5

Interconnection Facilities	Unit	Quantity	Cost ($)	Category
Pad G.S. w/auto	EA	1	$56,000	(6)
1/0 Primary cable	EA	1	$15,000	(4)
16 kV meter	EA	1	$14,000	(5)
Centralized RTU	EA	1	$6,100	(6)
		Total	$91,100	
Distribution Upgrades				
Remote Automatic Recloser	EA	1	$96,000	(6)
Bi-directional Watt transducer	EA	1	$49,300	(6)
Data point addition to HMI	EA	1	$9,500	
		Total	$154,800	

This is a 3.0 MW, 16 kV solar generator interconnecting at the end of the line on an existing overhead service. Base on the size of the project new Interconnection Facilities are triggered: riser pole, primary cable, padmount gas switch, Remote Control Switch for automation, primary metering and associated wiring and telemetry. The addition of the generator triggers the installation of an Automatic Recloser to detect end of line faults. It also triggers reverse power flow back (MW/MVAR) at the SCE substation. As a result, a transducer and data point addition to an existing RTU is required to monitor watts and reactive power.

Project Examples - Southern California Edison Unit Cost Table; examples provided below are for illustrative purposes only and are not binding for actual facility costs

Scenario 6

Interconnection Facilities				
Pad G.S. w/auto	EA	1	$56,000	(6)
Ground Bank	EA	1	$63,000	(7)
Riser w/cable	EA	1	$40,000	(2)
16 kV meter	EA	1	$14,000	(5)
Centralized RTU	EA	1	$6,100	(6)
		Total	$179,100	

This is a >1 MW, 16 kV synchronous generator interconnecting to an existing overhead service. Based on the size of the project, standard Interconnection Facilities are required: riser pole, padmount gas switch, Remote Control Switch for automation, ground detector and primary metering. The ground bank would be dependent on the grounding configuration of the Generating Facility. If the step transformer is connected Delta/Y-grounded (Delta on the gen side), then the ground bank would not be required.

Scenario 7

Interconnection Facilities				
33 kV RAR	EA	1	$131,000	(6)
9000' 336 ACSR	EA	1	$1,170,000	(7)
33 kV OH meter	EA	1	$108,000	(5)
Dedicated RTU	EA	1	$140,000	(6)
		Total	$1,549,000	
Distribution Upgrades				
1000' of 4/0 to 750 cable upgrade	EA	1	$30,000	(7)
		Total	$30,000	

This is >10 MW, 33 kV solar generator interconnecting to an existing overhead service. Based on the size of the project, new Interconnection Facilities are required: pole line extension, Automatic Recloser and 33 kV poletop metering and a Dedicated Remote Terminal Unit. The main feeder experience a high voltage condition and a line recoductor is required to mitigate the voltage.

EXAMPLE DEVELOPMENT ASSUMPTIONS:

1. ITCC (Income Tax Component of the Contribution): For purposes of the example assumptions, the ITCC rate is assumed to be at 35% (based upon standard depreciation)
2. The Interconnection Facilities Charge (O&M) is determined in accordance with GRC Authorization Provided in Rule 2.H (2015 Southern California Edison General Rate Case, 15-11-021 authorized rate from January 1, 2016). Please note that the rate is subject to change based on future filings. For the Interconnection Facilities Charge Replacement Options, Interconnection Applicant would pay the following as provided in Examples 1 and 2: Customer Financed with Replacement at Additional Cost = 0.38%, With Replacement for 20 yrs at No Additional Cost = 0.40%
3. Removal Costs are case dependent and determined based upon actual costs and are not prepared utilizing a proxy percentage.
4. ITCC and Interconnection Facilities Charge are reflected in examples 1 and 2; same methodology can be utilized in other shown examples.

SCE Escalation Factor - Unit Cost Guide

ESCALATION OVERVIEW :

Current SCE Unit Cost Guide Escalation Factors (consistent with CAISO) is in 2019 Constant Dollars.

SCE's cost estimating is done in 2019 constant dollars and then escalated over the years during which the project will be constructed, arriving at project costs in 2016 Constant Dollars Escalated to OD Year.

Current escalation rates used to arrive at escalated dollars are derived as follows:

► 2015-2025 - Q3 2015 IHS Global Insight Forecast of Transmission Capital escalation for the Pacific region (JUEPT@PCF)

DEFINITIONS :

Project Cost in 2019 Constant Dollars represents the cost of the Project if all costs were paid for in 2019.

Project Cost Escalated to OD Year represents the cost of the Project if all costs were paid for in the OD Year.

Mathematical formula: Constant Dollars Escalated to OD Year = Cost in Constant Dollars x Escalation Factor to OD year

CURRENT SCE ESCALATION RATES :

	2019	2020	2021	2022	2023	2024
Escalation Rate	**2.72%**	**2.44%**	**2.35%**	**2.08%**	**2.21%**	**2.19%**
Escalation Factors	**1.0000**	**1.0244**	**1.0485**	**1.0703**	**1.0940**	**1.1179**

Factors listed above consistent with CAISO unit cost guide.

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ATTACHMENT D

COVER PAGE FOR THE PEPCO – MARYLAND ELECTRIC TARIFF

CURRENT UPDATE

Internet updated on: July 16, 2020

Tariff changes effective: Riders SOS Type II effective September 1, 2020.

Total Pages 114

Reason for the Tariff Changes: Rider SOS Type II effective September 1, 2020.

Case/Order Reference(s): Case No. 9056/9064 Approved at July 15, 2020 Admin Mtg.

Tariff pages changed in this update: Cover Page, Page Nos. 1-2.2, 43 - 43.6.

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PRIOR UPDATE

Internet updated on: May 28, 2020

Tariff changes effective: Riders R-PIV, PIV and SOS effective June 1, 2020.

Total Pages 114

Reason for the Tariff Changes: Riders R-PIV, PIV and SOS effective June 1, 2020.

Case/Order Reference(s): Case No. 9478 Approved at May 20, 2020 Admin Mtg. and Case Nos. 9056/9064 approved at May 27, 2020 Admin. Mtg.

Tariff pages changed in this update: Cover Page, Page Nos. 1-2.2, 21-22.1, 43 - 43.6.

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RATE SCHEDULES

FOR

ELECTRIC SERVICE

IN

MARYLAND

POTOMAC ELECTRIC POWER COMPANY

An Exelon Company

RATES AND REGULATORY PRACTICES GROUP

TABLE OF CONTENTS
RATE SCHEDULES

RIDERS

RESIDENTIAL SERVICE

SCHEDULE "R"

AVAILABILITY
Available for Distribution Service and Standard Offer Service when modified by Rider "SOS" in the Maryland portion of the Company's service area for low voltage electric service where the use is primarily for residential purposes and for farm operations where the electricity for both farm and residential purposes is delivered through the same meter.

Not available for residential premises in which five (5) or more rooms are for hire.

Not available for seasonal loads metered separately from lighting and other usage in the same occupancy.

Not available for temporary, auxiliary or emergency service.

CHARACTER OF SERVICE
The service supplied under this schedule normally will be alternating current, sixty hertz, single phase, three wire, 120/240 volts, or three wire, 120/208 volts.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 8.01 per month	$ 8.01 per month
Kilowatt-hour Charge	$ 0.06595 per kwhr	$ 0.03259 per kwhr

Opt-Out Fee *

One-time, Up-front Fee	$	75.00 (payable in three monthly installments)
Monthly Fee	$	14.00 per month

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.61 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

*** Opt-Out Fees** – Customers who choose to decline the installation of an AMI meter are considered to be Opting-Out and will incur a One Time Enrollment Fee payable in three monthly installments as well as an Ongoing Monthly Fee. A customer who requests to Opt-Out of receiving a smart meter shall be moved to a non-time-of-use schedule and shall receive a non-time-of-use ERT (encoder receiver transmitter) or AMR (automatic meter reading) meter for no additional costs beyond the specified Opt-Out Fees. Opt-Out Customers will receive an initial bill that includes the first installment of One-Time Upfront Fee and Ongoing Monthly Fee. An Opt-Out Customer can elect to discontinue the application of Opt-Out Fees at any time by electing to have a smart meter installed. The Fees shall be waived and removed from the Customer's bill where the Opt-Out Fees first appear if the customer agrees, before the end of the subsequent billing cycle, to have a smart meter installed, provided the customer allows reasonable access for installation of the smart meter. For customers who elect to have a smart meter installed after the initial billing cycle in which Opt-Out Fees are billed, the charges shall continue to be billed and shall cease upon the earlier of the installation of a smart meter or within 30 days of receiving customer notification, provided the customer allows reasonable access for installation of the smart meter. Charges begin the later of the first full billing cycle following July 1, 2014 or following the first full billing cycle after the AMI installation date in that customer's community.

A Customer who is non-responsive to Pepco's attempts to install a smart meter, as detailed in Order No. 86727, shall also be responsible for these Fees. However, in the instance where a customer is non-responsive to Pepco's attempts to install a smart meter, as detailed in Order No. 86727, opt-out charges for those customers will be waived if the customer contacts Pepco to schedule a smart meter installation within 30 days after the charges first appear on the bill.

The applicable fees for enrolling in smart meter Opt-Out will be shown as separate line items on the customer's bill.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GROSS RECEIPTS TAX

A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Residential
Administrative Credit
Universal Service Charge Recovery
Net Energy Metering
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Experimental Residential Electric Vehicle Service
Optional Meter Equipment Related Services
Bill Stabilization Adjustment
Empower MD Charge
Residential Direct Load Control
RGGI Rate Credit
Aggregate Net Energy Metering
Demand Resource Surcharge
Dynamic Pricing – Peak Energy Savings Credit
Grid Resiliency Charge

TIME METERED RESIDENTIAL SERVICE

SCHEDULE "R-TM"

AVAILABILITY
Available for Distribution Service and Standard Offer Service when modified by Rider “SOS” to customers served under this Schedule prior to July 1, 2000. Existing Schedule "R-TM" customers may, at their own option, make a one-time non-revocable election to be placed on Residential Service Schedule "R" after sufficient notice to the Company. Rate schedule changes will be made annually and become effective with the billing month of June.

CHARACTER OF SERVICE
The service supplied under this schedule normally will be alternating current, sixty hertz, single phase, three wire 120/240 volts, or three wire, 120/208 volts.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$17.25 per month	$ 17.25 per month
Kilowatt-hour Charge	$ 0.03903 per kwhr	$ 0.03311 per kwhr

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company’s General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider “SOS” – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.61 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS
Summer – Billing months of June through October.
Winter – Billing months of November through May.

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GROSS RECEIPTS TAX
A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Residential
Administrative Credit
Universal Service Charge Recovery
Net Energy Metering
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Experimental Residential Time-of-Use Electric Vehicle Service
Optional Meter Equipment Related Services
Bill Stabilization Adjustment
Empower MD Charge
Residential Direct Load Control
RGGI Rate Credit
Aggregate Net Energy Metering
Demand Resource Surcharge
Dynamic Pricing – Peak Energy Savings Credit
Grid Resiliency Charge

GENERAL SERVICE
SCHEDULE "GS"

AVAILABILITY
Available for Distribution Service and Standard Offer Service when modified by Rider “SOS” in the Maryland portion of the Company's service area, except for customers whose maximum thirty (30) minute demand equals or exceeds 25 kW during one (1) or more months within twelve (12) billing months or whose monthly energy consumption exceeds 6,000 kilowatt-hours in two (2) consecutive winter billing months (November through May, inclusive), or whose monthly energy consumption exceeds 7,500 kilowatt-hours for a single summer billing month. Customers who exceed the above limits will be transferred to Schedule "MGT LV II", "MGT 3A II ", “MGT LV III", "MGT 3A III", "GT LV", "GT 3A", or "GT 3B" in accordance with the availability provisions therein. Rate schedule changes will occur annually and become effective with the billing month of June.

Available for low voltage electric service at sixty hertz.

Not available for railway propulsion service.

Not available for secondary temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

CHARACTER OF SERVICE
The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 11.97 per month	$ 11.97 per month
Kilowatt-hour Charge	$ 0.06034 per kwhr	$ 0.03170 per kwhr

Opt-Out Fee *	
One-time, Up-front Fee	$ 75.00 (payable in three monthly installments)
Monthly Fee	$ 14.00 per month

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company’s General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider “SOS” – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.74 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

*** Opt-Out Fees** – Customers who choose to decline the installation of an AMI meter are considered to be Opting-Out and will incur a One Time Enrollment Fee payable in three monthly installments as well as an Ongoing Monthly Fee. A customer who requests to Opt-Out of receiving a smart meter shall be moved to a non-time-of-use schedule and shall receive a non-time-of-use ERT (encoder receiver transmitter) or AMR (automatic meter reading) meter for no additional costs beyond the specified Opt-Out Fees. Opt-Out Customers will receive an initial bill that includes the first installment of One-Time Upfront Fee and Ongoing Monthly Fee. An Opt-Out Customer can elect to discontinue the application of Opt-Out Fees at any time by electing to have a smart meter installed. The Fees shall be waived and removed from the Customer's bill where the Opt-Out Fees first appear if the customer agrees, before the end of the subsequent billing cycle, to have a smart meter installed, provided the customer allows reasonable access for installation of the smart meter. For customers who elect to have a smart meter installed after the initial billing cycle in which Opt-Out Fees are billed, the charges shall continue to be billed and shall cease upon the earlier of the installation of a smart meter or within 30 days of receiving customer notification, provided the customer allows reasonable access for installation of the smart meter. Charges begin the later of the first full billing cycle following July 1, 2014 or following the first full billing cycle after the AMI installation date in that customer's community.

A Customer who is non-responsive to Pepco's attempts to install a smart meter, as detailed in Order No. 86727, shall also be responsible for these Fees. However, in the instance where a customer is non-responsive to Pepco's attempts to install a smart meter, as detailed in Order No. 86727, opt-out charges for those customers will be waived if the customer contacts Pepco to schedule a smart meter installation within 30 days after the charges first appear on the bill.

The applicable fees for enrolling in smart meter Opt-Out will be shown as separate line items on the customer's bill.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GROSS RECEIPTS TAX

A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Type I Non-Residential
Administrative Credit
Universal Service Charge Recovery
Net Energy Metering
Power Factor
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Optional Meter Equipment Related Services
Bill Stabilization Adjustment
Empower MD Charge
Aggregate Net Energy Metering
Non-Residential Direct Load Control
Demand Resource Surcharge
Grid Resiliency Charge

TEMPORARY OR SUPPLEMENTARY SERVICE

SCHEDULE "T"

AVAILABILITY

Available for Distribution Service and Standard Offer Service when modified by Rider “SOS” in the Maryland portion of the Company's service area for low voltage electric service for construction or other commercial purposes furnished through service connection facilities of a temporary rather than a permanent nature, or for temporary electric service supplied for a limited time, such as for carnivals, festivals, etc.

Customers receiving Temporary Service on a continuous basis for five (5) years will normally be transferred to the otherwise applicable rate schedule in accordance with the availability provisions therein.

Available for high voltage electric service of a temporary rather than a permanent nature, such as for customer testing of facility equipment, provided that the customer obtains prior authorization from the Company's power system dispatcher to commence testing of equipment with expected demands greater than 1,000 kW.

CHARACTER OF SERVICE

The service supplied under this schedule will be alternating current, sixty hertz, at any of the approved classes of service.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 12.16 per month	$ 12.16 per month
Kilowatt-hour Charge	$ 0.07125 per kwhr	$ 0.02230 per kwhr

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company’s General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider “SOS” – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.74 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GROSS RECEIPTS TAX

A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Type I Non-Residential
Administrative Credit
Universal Service Charge Recovery
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Bill Stabilization Adjustment
Empower MD Charge
Non-Residential Direct Load Control
Demand Resource Surcharge
Grid Resiliency Charge

TIME METERED MEDIUM GENERAL SERVICE –
LOW VOLTAGE – TYPE II
SCHEDULE "MGT LV II"

AVAILABILITY
Available for Distribution Service and Standard Offer Service when modified by Rider “SOS” in the Maryland portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds 25 kW and is less than 1,000 kW during one (1) or more months within twelve (12) billing months or whose monthly energy consumption exceeds 6,000 kilowatt-hours in two (2) consecutive winter billing months (November through May, inclusive), or whose monthly energy consumption exceeds 7,500 kilowatt-hours for a single summer billing month (June through October, inclusive). Once an account is established it will remain in Schedule "MGT LV II " even if the party responsible for the account should change. Removal from Schedule "MGT LV II ” is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "MGT LV II" will continue to be served under this schedule until either they qualify for Schedule "GT LV", or Schedule “MGT LV III”, or qualify for the option of moving to Schedule "GS" by having consumption for each of the previous twelve months below 6,000 kilowatt-hours. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for low voltage electric service at sixty hertz.

Available for standby service when modified by Schedule "S".

Not available for temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

Not available for railway propulsion service.

CHARACTER OF SERVICE
The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts.

MD – MGT LV II

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 44.96 per month	$ 44.96 per month
Kilowatt-hour Charge	$ 0.01682 per kwhr	$ 0.01682 per kwhr
Kilowatt Charge		
Maximum	$ 3.1663 per kW	$ 3.1663 per kw

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.74 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

FACILITIES CHARGE

The customer may elect to pay the fee for the facilities provided pursuant to Section 10--SERVICE CONNECTIONS of the Company's "General Terms and Conditions" through the application of a monthly charge of 2% of the amount which would otherwise be payable as a contribution-in-aid-of-construction under Subsection 10.e.3--Charges for Service Connections, Commercial - Industrial. The monthly charge will be recalculated each time additions or retirements to the facilities occur as the result of modifications, relocations, or alterations.

In the event that the facilities are removed before they have been in place for five (5) years, the customer shall agree to pay the cost of removal plus the original cost to which the facilities charge was applied, less depreciation and estimated salvage value. The customer initially making the monthly payment election, and all subsequent customers at the same location, shall pay this monthly charge until such time as the facilities are removed, or the current customer elects to terminate the charge, by the payment of an amount equal to the contribution-in-aid-of-construction which would be paid on the depreciated original cost of the installed facilities. In the event that the property is sold by the customer, the customer shall pay an amount equal to the contribution-in-aid-of-construction which would be paid on the depreciated original cost of the installed facilities or shall secure the written election of the new owner of the property to pay the fees provided for above.

MD – MGT LV II

RATING PERIODS

Weekdays - (Excluding Holidays)

On-Peak Period	12:00 noon	to	8:00 p.m.
Intermediate Period	8:00 a.m.	to	12:00 noon
		and	
	8:00 p.m.	to	12:00 midnight
Off-Peak Period	12:00 midnight	to	8:00 a.m.

Saturdays, Sundays and Holidays

Off-Peak Period All Hours

Holidays

For the purpose of this tariff, holidays will be New Year's Day, Rev. Martin Luther King's Birthday, Presidents' Day, Memorial Day, Independence Day, Labor Day, Columbus Day, Veterans' Day, Thanksgiving Day and Christmas Day, as designated by the Federal Government.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GROSS RECEIPTS TAX

A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Type II Non-Residential
Administrative Credit
Universal Service Charge Recovery
Net Energy Metering
Power Factor
Thermal Energy Storage Service
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Optional Meter Equipment Related Services
Excess Facilities
Reserved Delivery Capacity Service
Bill Stabilization Adjustment
Empower MD Charge
MM-Direct Load Control
Aggregate Net Energy Metering
Non-Residential Direct Load Control
Demand Resource Surcharge
Grid Resiliency Charge
Electric Vehicle Charging Distribution Demand Charge Credit

TIME METERED MEDIUM GENERAL SERVICE –
LOW VOLTAGE – TYPE III
SCHEDULE "MGT LV III"

AVAILABILITY
Available for Distribution Service and Standard Offer Service when modified by Rider “SOS” in the Maryland portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds 25 kW and is less than 1,000 kW during one (1) or more months within twelve (12) billing months or whose monthly energy consumption exceeds 6,000 kilowatt-hours in two (2) consecutive winter billing months (November through May, inclusive), or whose monthly energy consumption exceeds 7,500 kilowatt-hours for a single summer billing month (June through October, inclusive). In addition, accounts classified as Rate Schedule “MGT LV III” have PJM capacity Peak Load Contributions of greater than or equal to 600 kW. Once an account is established it will remain in Schedule "MGT LV III" even if the party responsible for the account should change. Removal from Schedule "MGT LV III” is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "MGT LV III" will continue to be served under this schedule until either they qualify for Schedule "GT LV" or Schedule “MGT LV II B” or “MGT LV II A”, or qualify for the option of moving to Schedule "GS" by having consumption for each of the previous twelve months below 6,000 kilowatt-hours. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for low voltage electric service at sixty hertz.

Available for standby service when modified by Schedule "S".

Not available for temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

Not available for railway propulsion service.

CHARACTER OF SERVICE
The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts.

MD – MGT LV III

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 44.96 per month	$ 44.96 per month
Kilowatt-hour Charge	$ 0.01682 per kwhr	$ 0.01682 per kwhr
Kilowatt Charge		
Maximum	$3.1663 per kW	$3.1663 per kW

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.74 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

FACILITIES CHARGE

The customer may elect to pay the fee for the facilities provided pursuant to Section 10--SERVICE CONNECTIONS of the Company's "General Terms and Conditions" through the application of a monthly charge of 2% of the amount which would otherwise be payable as a contribution-in-aid-of-construction under Subsection 10.e.3--Charges for Service Connections, Commercial - Industrial. The monthly charge will be recalculated each time additions or retirements to the facilities occur as the result of modifications, relocations, or alterations.

In the event that the facilities are removed before they have been in place for five (5) years, the customer shall agree to pay the cost of removal plus the original cost to which the facilities charge was applied, less depreciation and estimated salvage value. The customer initially making the monthly payment election, and all subsequent customers at the same location, shall pay this monthly charge until such time as the facilities are removed, or the current customer elects to terminate the charge, by the payment of an amount equal to the contribution-in-aid-of-construction which would be paid on the depreciated original cost of the installed facilities. In the event that the property is sold by the customer, the customer shall pay an amount equal to the contribution-in-aid-of-construction which would be paid on the depreciated original cost of the installed facilities or shall secure the written election of the new owner of the property to pay the fees provided for above.

RATING PERIODS

Weekdays - (Excluding Holidays)

On-Peak Period	12:00 noon	to	8:00 p.m.
Intermediate Period	8:00 a.m.	to	12:00 noon
		and	
	8:00 p.m.	to	12:00 midnight
Off-Peak Period	12:00 midnight	to	8:00 a.m.

Saturdays, Sundays and Holidays

Off-Peak Period All Hours

Holidays

For the purpose of this tariff, holidays will be New Year's Day, Rev. Martin Luther King's Birthday, Presidents' Day, Memorial Day, Independence Day, Labor Day, Columbus Day, Veterans' Day, Thanksgiving Day and Christmas Day, as designated by the Federal Government.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GROSS RECEIPTS TAX

A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Hourly-Priced Service
Administrative Credit
Universal Service Charge Recovery
Net Energy Metering
Power Factor
Thermal Energy Storage Service
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Optional Meter Equipment Related Services
Excess Facilities
Reserved Delivery Capacity Service
Bill Stabilization Adjustment
Empower MD Charge
MM-Direct Load Control
Aggregate Net Energy Metering
Non-Residential Direct Load Control
Demand Resource Surcharge
Grid Resiliency Charge
Electric Vehicle Charging Distribution Demand Charge Credit

TIME METERED MEDIUM GENERAL SERVICE -

PRIMARY SERVICE – TYPE II

SCHEDULE "MGT 3A II"

AVAILABILITY

Available for Distribution Service and Standard Offer Service when modified by Rider “SOS” in the Maryland portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds 25 kW and is less than 1,000 kW during one (1) or more months within twelve (12) billing months or whose monthly energy consumption exceeds 6,000 kilowatt-hours in two (2) consecutive winter billing months (November through May, inclusive), or whose monthly energy consumption exceeds 7,500 kilowatt-hours for a single summer billing month (June through October, inclusive). Once an account is established it will remain in Schedule "MGT 3A II" even if the party responsible for the account should change. Removal from Schedule "MGT 3A II" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "MGT 3A II" will continue to be served under this schedule until either they qualify for Schedule "GT 3A", or Schedule “MGT 3A III”, or qualify for the option of moving to Schedule "GS" by having consumption for each of the previous twelve months below 6,000 kilowatt-hours. Rate schedule will be made annually and become effective with the billing month of June.

Available for standby service when modified by Schedule "S".

Available for primary service furnished by the Company directly from its electric system at voltages of 4.16 kV, 13.2 kV or 33 kV, while the customer provides at the customer’s own expense, all necessary transformers, converted apparatus, switches, disconnectors, regulators and protective equipment.

Not available for temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

Not available for railway propulsion service.

CHARACTER OF SERVICE -

The service supplied under this schedule will be alternating current, sixty hertz, three phase, three wire, at 4.16 kV, 13.2 kV or 33 kV. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MD – MGT 3A II

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 42.70 per month	$ 42.70 per month
Kilowatt-hour Charge	$ 0.00965 per kwhr	$ 0.00965 per kwhr
Kilowatt Charge		
Maximum	$ 1.7232 per kW	$ 1.7232 per kW

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.74 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

FACILITIES CHARGE

The customer may elect to pay the fee for the facilities provided pursuant to Section 10--SERVICE CONNECTIONS of the Company's "General Terms and Conditions" through the application of a monthly charge of 2% of the amount which would otherwise be payable as a contribution-in-aid-of-construction under Subsection 10.e.3--Charges for Service Connections, Commercial - Industrial. The monthly charge will be recalculated each time additions or retirements to the facilities occur as the result of modifications, relocations, or alterations.

In the event that the facilities are removed before they have been in place for five (5) years, the customer shall agree to pay the cost of removal plus the original cost to which the facilities charge was applied, less depreciation and estimated salvage value. The customer initially making the monthly payment election, and all subsequent customers at the same location, shall pay this monthly charge until such time as the facilities are removed, or the current customer elects to terminate the charge, by the payment of an amount equal to the contribution-in-aid-of-construction which would be paid on the depreciated original cost of the installed facilities. In the event that the property is sold by the customer, the customer shall pay an amount equal to the contribution-in-aid-of-construction which would be paid on the depreciated original cost of the installed facilities or shall secure the written election of the new owner of the property to pay the fees provided for above.

RATING PERIODS

Weekdays - (Excluding Holidays)

On-Peak Period	12:00 noon	to	8:00 p.m.
Intermediate Period	8:00 a.m.	to	12:00 noon
		and	
	8:00 p.m.	to	12:00 midnight
Off-Peak Period	12:00 midnight	to	8:00 a.m.

Saturdays, Sundays and Holidays

Off-Peak Period All Hours

Holidays

For the purpose of this tariff, holidays will be New Year's Day, Rev. Martin Luther King's Birthday, Presidents' Day, Memorial Day, Independence Day, Labor Day, Columbus Day, Veterans' Day, Thanksgiving Day and Christmas Day, as designated by the Federal Government.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GROSS RECEIPTS TAX

A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Type II Non-Residential
Administrative Credit
Universal Service Charge Recovery
Net Energy Metering
Power Factor
Thermal Energy Storage Service
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Optional Meter Equipment Related Services
Excess Facilities
Reserved Delivery Capacity Service
Bill Stabilization Adjustment
Empower MD Charge
MM-Direct Load Control
Aggregate Net Energy Metering
Non-Residential Direct Load Control
Demand Resource Surcharge
Grid Resiliency Charge
Electric Vehicle Charging Distribution Demand Charge Credit

TIME METERED MEDIUM GENERAL SERVICE -

PRIMARY SERVICE – TYPE III

SCHEDULE "MGT 3A III"

AVAILABILITY

Available for Distribution Service and Standard Offer Service when modified by Rider “SOS” in the Maryland portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds 25 kW and is less than 1,000 kW during one (1) or more months within twelve (12) billing months or whose monthly energy consumption exceeds 6,000 kilowatt-hours in two (2) consecutive winter billing months (November through May, inclusive), or whose monthly energy consumption exceeds 7,500 kilowatt-hours for a single summer billing month (June through October, inclusive). In addition, accounts classified as Rate Schedule “MGT 3A III” have PJM capacity Peak Load Contributions of greater than or equal to 600 kW. Once an account is established it will remain in Schedule "MGT 3A III" even if the party responsible for the account should change. Removal from Schedule "MGT 3A III" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "MGT 3A III" will continue to be served under this schedule until either they qualify for Schedule "GT 3A", Schedule “MGT 3A II A” or Schedule “MGT 3A II B”, or qualify for the option of moving to Schedule "GS" by having consumption for each of the previous twelve months below 6,000 kilowatt-hours. Rate schedule changes will occur annually and become effective with the billing month of June.

Available for standby service when modified by Schedule "S".

Available for primary service furnished by the Company directly from its electric system at voltages of 4.16 kV, 13.2 kV or 33 kV, while the customer provides at the customer’s own expense, all necessary transformers, converted apparatus, switches, disconnectors, regulators and protective equipment.

Not available for temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

Not available for railway propulsion service.

CHARACTER OF SERVICE -

The service supplied under this schedule will be alternating current, sixty hertz, three phase, three wire, at 4.16 kV, 13.2 kV or 33 kV. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 42.70 per month	$ 42.70 per month
Kilowatt-hour Charge	$0.00965 per kwhr	$0.00965 per kwhr
Kilowatt Charge		
Maximum	$ 1.7232 per kW	$ 1.7232 per kW

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.74 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

FACILITIES CHARGE

The customer may elect to pay the fee for the facilities provided pursuant to Section 10--SERVICE CONNECTIONS of the Company's "General Terms and Conditions" through the application of a monthly charge of 2% of the amount which would otherwise be payable as a contribution-in-aid-of-construction under Subsection 10.e.3--Charges for Service Connections, Commercial - Industrial. The monthly charge will be recalculated each time additions or retirements to the facilities occur as the result of modifications, relocations, or alterations.

In the event that the facilities are removed before they have been in place for five (5) years, the customer shall agree to pay the cost of removal plus the original cost to which the facilities charge was applied, less depreciation and estimated salvage value. The customer initially making the monthly payment election, and all subsequent customers at the same location, shall pay this monthly charge until such time as the facilities are removed, or the current customer elects to terminate the charge, by the payment of an amount equal to the contribution-in-aid-of-construction which would be paid on the depreciated original cost of the installed facilities. In the event that the property is sold by the customer, the customer shall pay an amount equal to the contribution-in-aid-of-construction which would be paid on the depreciated original cost of the installed facilities or shall secure the written election of the new owner of the property to pay the fees provided for above.

RATING PERIODS

Weekdays - (Excluding Holidays)

On-Peak Period	12:00 noon	to	8:00 p.m.
Intermediate Period	8:00 a.m.	to	12:00 noon
		and	
	8:00 p.m.	to	12:00 midnight
Off-Peak Period	12:00 midnight	to	8:00 a.m.

Saturdays, Sundays and Holidays

Off-Peak Period All Hours

Holidays

For the purpose of this tariff, holidays will be New Year's Day, Rev. Martin Luther King's Birthday, Presidents' Day, Memorial Day, Independence Day, Labor Day, Columbus Day, Veterans' Day, Thanksgiving Day and Christmas Day, as designated by the Federal Government.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GROSS RECEIPTS TAX

A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Hourly-Priced Service
Administrative Credit
Universal Service Charge Recovery
Net Energy Metering
Power Factor
Thermal Energy Storage Service
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Optional Meter Equipment Related Services
Excess Facilities
Reserved Delivery Capacity Service
Bill Stabilization Adjustment
Empower MD Charge
MM-Direct Load Control
Aggregate Net Energy Metering
Non-Residential Direct Load Control
Demand Resource Surcharge
Grid Resiliency Charge
Electric Vehicle Charging Distribution Demand Charge Credit

TIME METERED GENERAL SERVICE - LOW VOLTAGE

SCHEDULE "GT LV"

AVAILABILITY
Available for Distribution Service and Standard Offer Service when modified by Rider "SOS" in the Maryland portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds 1,000 kW during two (2) or more months within twelve (12) billing months. Once an account is established it will remain on Schedule "GT LV" even if the party responsible for the account should change. Removal from Schedule "GT LV" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "GT LV" whose maximum thirty (30) minute demand is less than 900 kW for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for low voltage electric service at sixty hertz.

Available for standby service when modified by Schedule "S".

Not available for temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

Not available for railway propulsion service.

CHARACTER OF SERVICE
The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 365.32 per month	$ 365.32 per month
Kilowatt-hour Charge	$0.01746 per kwhr	$0.01746 per kwhr
Kilowatt Charge		
Maximum	$ 3.5951 per kW	$ 3.5951 per kW

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.74 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

FACILITIES CHARGE

The customer may elect to pay the fee for the facilities provided pursuant to Section 10--SERVICE CONNECTIONS of the Company's "General Terms and Conditions" through the application of a monthly charge of 2% of the amount which would otherwise be payable as a contribution-in-aid-of-construction under Subsection 10.e.3--Charges for Service Connections, Commercial - Industrial. The monthly charge will be recalculated each time additions or retirements to the facilities occur as the result of modifications, relocations, or alterations.

In the event that the facilities are removed before they have been in place for five (5) years, the customer shall agree to pay the cost of removal plus the original cost to which the facilities charge was applied, less depreciation and estimated salvage value. The customer initially making the monthly payment election, and all subsequent customers at the same location, shall pay this monthly charge until such time as the facilities are removed, or the current customer elects to terminate the charge, by the payment of an amount equal to the contribution-in-aid-of-construction which would be paid on the depreciated original cost of the installed facilities. In the event that the property is sold by the customer, the customer shall pay an amount equal to the contribution-in-aid-of-construction which would be paid on the depreciated original cost of the installed facilities or shall secure the written election of the new owner of the property to pay the fees provided for above.

RATING PERIODS

Weekdays - (Excluding Holidays)

On-Peak Period	12:00 noon	to	8:00 p.m.
Intermediate Period	8:00 a.m.	to	12:00 noon
		and	
	8:00 p.m.	to	12:00 midnight
Off-Peak Period	12:00 midnight	to	8:00 a.m.

Saturdays, Sundays and Holidays

Off-Peak Period	All Hours

Holidays

For the purpose of this tariff, holidays will be New Year's Day, Rev. Martin Luther King's Birthday, Presidents' Day, Memorial Day, Independence Day, Labor Day, Columbus Day, Veterans' Day, Thanksgiving Day and Christmas Day, as designated by the Federal Government.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GROSS RECEIPTS TAX
A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS
Standard Offer Service – Hourly-Priced Service
Administrative Credit
Universal Service Charge Recovery
Net Energy Metering
Power Factor
Thermal Energy Storage Service
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Optional Meter Equipment Related Services
Excess Facilities
Reserved Delivery Capacity Service
Bill Stabilization Adjustment
Empower MD Charge
MM-Direct Load Control
Aggregate Net Energy Metering
Non-Residential Direct Load Control
Demand Resource Surcharge
Grid Resiliency Charge
Electric Vehicle Charging Distribution Demand Charge Credit

TIME METERED GENERAL SERVICE - PRIMARY SERVICE

SCHEDULE "GT 3A"

AVAILABILITY
Available for Distribution Service and Standard Offer Service when modified by Rider "SOS" in the Maryland portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds 1,000 kW during two (2) or more months within twelve (12) billing months. Once an account is established it will remain on Schedule "GT 3A" even if the party responsible for the account should change. Removal from Schedule "GT 3A" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "GT 3A" whose maximum thirty (30) minute demand is less than 900 kW for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. Rate schedule transfers will be annually and become effective with the billing month of June.

Available for primary service furnished directly from the Company's electric system at voltages of 4.16 kV, 13.2 kV or 33 kV, when the customer provides at the customer's own expense all necessary transformers, converting apparatus, switches, disconnectors, regulators and protective equipment.

Available for standby service when modified by Schedule "S".

Not available for temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

Not available for railway propulsion service.

CHARACTER OF SERVICE
The service supplied under this schedule normally will be alternating current, sixty hertz, three phases, three wire at 4.16 kV, 13.2 kV or 33 kV. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE

	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 343.01 per month	$ 343.01 per month
Kilowatt-hour Charge	$ 0.00997 per kwhr	$ 0.00997 per kwhr
Kilowatt Charge		
Maximum	$ 2.3391 per kW	$ 2.3391 per kW

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.74 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

FACILITIES CHARGE

The customer may elect to pay the fee for the facilities provided pursuant to Section 10--SERVICE CONNECTIONS of the Company's "General Terms and Conditions" through the application of a monthly charge of 2% of the amount which would otherwise be payable as a contribution-in-aid-of-construction under Subsection 10.e.3--Charges for Service Connections, Commercial - Industrial. The monthly charge will be recalculated each time additions or retirements to the facilities occur as the result of modifications, relocations, or alterations.

In the event that the facilities are removed before they have been in place for five (5) years, the customer shall agree to pay the cost of removal plus the original cost to which the facilities charge was applied, less depreciation and estimated salvage value. The customer initially making the monthly payment election, and all subsequent customers at the same location, shall pay this monthly charge until such time as the facilities are removed, or the current customer elects to terminate the charge, by the payment of an amount equal to the contribution-in-aid-of-construction which would be paid on the depreciated original cost of the installed facilities. In the event that the property is sold by the customer, the customer shall pay an amount equal to the contribution-in-aid-of-construction which would be paid on the depreciated original cost of the installed facilities or shall secure the written election of the new owner of the property to pay the fees provided for above.

RATING PERIODS

Weekdays - (Excluding Holidays)

On-Peak Period	12:00 noon	to	8:00 p.m.
Intermediate Period	8:00 a.m.	to	12:00 noon
		and	
	8:00 p.m.	to	12:00 midnight
Off-Peak Period	12:00 midnight	to	8:00 a.m.

Saturdays, Sundays and Holidays

Off-Peak Period All Hours

Holidays

For the purpose of this tariff, holidays will be New Year's Day, Rev. Martin Luther King's Birthday, Presidents' Day, Memorial Day, Independence Day, Labor Day, Columbus Day, Veterans' Day, Thanksgiving Day and Christmas Day, as designated by the Federal Government.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GROSS RECEIPTS TAX

A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Hourly-Priced Service
Administrative Credit
Universal Service Charge Recovery
Net Energy Metering
Power Factor
Thermal Energy Storage Service
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Optional Meter Equipment Related Services
Excess Facilities
Reserved Delivery Capacity Service
Bill Stabilization Adjustment
Empower MD Charge
MM-Direct Load Control
Aggregate Net Energy Metering
Non-Residential Direct Load Control
Demand Resource Surcharge
Grid Resiliency Charge
Electric Vehicle Charging Distribution Demand Charge Credit

TIME METERED GENERAL SERVICE - HIGH VOLTAGE

SCHEDULE "GT 3B”

AVAILABILITY
Available for Distribution Service and Standard Offer Service when modified by Rider “SOS” in the Maryland portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds 1,000 kW during two (2) or more months within twelve (12) billing months. Once an account is established it will remain on Schedule "GT 3B" even if the party responsible for the account should change. Removal from Schedule "GT 3B" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "GT 3B" whose maximum thirty (30) minute demand is less than 900 kW for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for high voltage service furnished directly from the Company’s electric system at voltages of 66 kV or above, when the customer provides at the customer’s own expense all necessary transformers, converting apparatus, switches, disconnectors, regulators and protective equipment.

Available for standby service when modified by Schedule "S".

Not available for temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

Not available for railway propulsion service.

CHARACTER OF SERVICE
The service supplied under this schedule normally will be 66 kV or above.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 321.97 per month	$ 321.97 per month
Kilowatt-hour Charge	$ 0.00483 per kwhr	$ 0.00483 per kwhr
Kilowatt Charge		
Maximum	$ 1.1014 per kW	$ 1.1014 per kW

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company’s General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider “SOS” – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.74 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

FACILITIES CHARGE

The customer may elect to pay the fee for the facilities provided pursuant to Section 10--SERVICE CONNECTIONS of the Company's "General Terms and Conditions" through the application of a monthly charge of 2% of the amount which would otherwise be payable as a contribution-in-aid-of-construction under Subsection 10.e.3--Charges for Service Connections, Commercial - Industrial. The monthly charge will be recalculated each time additions or retirements to the facilities occur as the result of modifications, relocations, or alterations.

In the event that the facilities are removed before they have been in place for five (5) years, the customer shall agree to pay the cost of removal plus the original cost to which the facilities charge was applied, less depreciation and estimated salvage value. The customer initially making the monthly payment election, and all subsequent customers at the same location, shall pay this monthly charge until such time as the facilities are removed, or the current customer elects to terminate the charge, by the payment of an amount equal to the contribution-in-aid-of-construction which would be paid on the depreciated original cost of the installed facilities. In the event that the property is sold by the customer, the customer shall pay an amount equal to the contribution-in-aid-of-construction which would be paid on the depreciated original cost of the installed facilities or shall secure the written election of the new owner of the property to pay the fees provided for above.

RATING PERIODS

Weekdays - (Excluding Holidays)

On-Peak Period	12:00 noon	to	8:00 p.m.
Intermediate Period	8:00 a.m.	to	12:00 noon
		and	
	8:00 p.m.	to	12:00 midnight
Off-Peak Period	12:00 midnight	to	8:00 a.m.

Saturdays, Sundays and Holidays

Off-Peak Period All Hours

Holidays

For the purpose of this tariff, holidays will be New Year's Day, Rev. Martin Luther King's Birthday, Presidents' Day, Memorial Day, Independence Day, Labor Day, Columbus Day, Veterans' Day, Thanksgiving Day and Christmas Day, as designated by the Federal Government.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

GROSS RECEIPTS TAX

A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Hourly-Priced Service
Administrative Credit
Universal Service Charge Recovery
Net Energy Metering
Power Factor
Thermal Energy Storage Service
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Optional Meter Equipment Related Services
Excess Facilities
Reserved Delivery Capacity Service
Bill Stabilization Adjustment
Empower MD Charge
MM-Direct Load Control
Aggregate Net Energy Metering
Non-Residential Direct Load Control
Demand Resource Surcharge
Grid Resiliency Charge
Electric Vehicle Charging Distribution Demand Charge Credit

TIME METERED RAPID TRANSIT SERVICE

SCHEDULE "TM-RT"

AVAILABILITY

Available for Distribution Service and Standard Offer Service when modified by Rider "SOS" in the Maryland portion of the Company's service area for rapid transit electric service furnished directly from the Company's distribution, subtransmission or transmission systems at available voltages of 13.2 kV and higher where the customer provides, at the customer's own expense, all necessary transformers or converting apparatus, switches, disconnectors, regulators, and protective equipment.

Available only at points of delivery on contiguous authority right- of-way.

Also available for low voltage service for purposes of operating electric chiller plants used for the purpose of providing chilled water to passenger stations associated with the rapid transit service.

Not available for partial or auxiliary service.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, three phase, three wire, high tension at 13.2 kV or such higher voltage as is specified by the Company on the basis of its available facilities and the magnitude of load to be served.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$3,764.64 per month	$3,764.64 per month

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.74 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

RATING PERIODS

Weekdays - (Excluding Holidays)

On-Peak Period	12:00 noon	to	8:00 p.m.
Intermediate Period	8:00 a.m.	to	12:00 noon
		and	
	8:00 p.m.	to	12:00 midnight
Off-Peak Period	12:00 midnight	to	8:00 a.m.

Saturdays, Sundays and Holidays

Off-Peak Period All Hours

Holidays

For the purpose of this tariff, holidays will be New Year's Day, Rev. Martin Luther King's Birthday, Presidents' Day, Memorial Day, Independence Day, Labor Day, Columbus Day, Veterans' Day, Thanksgiving Day and Christmas Day, as designated by the Federal Government.

BILLING DEMANDS

On-Peak (Summer Months Only) - The billing demand shall be the maximum thirty (30) minute integrated coincident demand of all delivery points served, recorded during the on-peak period of the billing month.
Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute integrated coincident demand of all delivery points recorded during the billing month.

BILLING ENERGY

The monthly billing energy will be the sum of the registrations of kilowatt-hours of all delivery points.

BILLING REACTIVE

The monthly billing reactive demand will be the maximum 30 minute integrated coincident KVAR demand of each delivery point served less the KVAR that would be supplied for an 85% power factor. A charge of $0.15 per KVAR will be assessed for each KVAR in excess of requirement for 85% Power Factor. The need for reactive metering will be determined by the Company.

GROSS RECEIPTS TAX

A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Hourly-Priced Service
Administrative Credit
Universal Service Charge Recovery
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Optional Meter Equipment Related Services
Reserved Delivery Capacity Service
Empower MD Charge
MM-Direct Load Control
Non-Residential Direct Load Control
Demand Resource Surcharge
Grid Resiliency Charge

ELECTRIC VEHICLE SERVICE

SCHEDULE "EV"

AVAILABILITY - Available for Distribution Service and Standard Offer Service when modified by Rider “SOS” in the Maryland portion of the Company's service area for low voltage electric service used for electric vehicle battery charging purposes in premises where other electric requirements are furnished under Schedules "R", "RTM", "GT LV", "MGT LV II B", "MGT LV II A”, “MGT LV III”, or "GS". Effective August 15, 2012, this schedule is closed to new customers.

CHARACTER OF SERVICE
The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts.

Service will be supplied from the regular service connection facilities but separately metered at the point of service entrance to the building.

An automatic disconnecting device will be installed by the Company so that service will be available only during the hours of 8 p.m. to 8 a.m.

MONTHLY RATE

	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 4.50 per month	$ 4.50 per month
Kilowatt-hour Charge	$ 0.01725 per kwhr	$ 0.01405 per kwhr

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company’s General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider “SOS” – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.61 per residential customer or $0.74 per non-residential customer will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

SUPPLY CAPACITY REQUIREMENT
Should additional service capacity be required for the "off-peak" service, in excess of that provided for regular service, the customer will pay to the Company an amount equal to the estimated cost of the additional facilities. Such payment must be made prior to the commencement of service under this schedule.

GROSS RECEIPTS TAX
A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Type I Non-Residential
Administrative Credit
Universal Service Charge Recovery
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Bill Stabilization Adjustment
Empower MD Charge
Non-Residential Direct Load Control
Demand Resource Surcharge
Grid Resiliency Charge

OUTDOOR LIGHTING SERVICE

SCHEDULE "OL"

AVAILABILITY
Available for Distribution Service and Standard Offer Service when modified by Rider “SOS” in the Maryland portion of the Company's overhead service area for outdoor lighting purposes on customers' premises subject to local ordinance or other appropriate approval.

Not available for street lighting purposes.

CHARACTER OF SERVICE
A photoelectrically controlled outdoor suburban type lighting fixture with high pressure sodium lamp (mercury vapor no longer available as of January 1, 2008) to be owned by the Company will be installed on either an existing Company pole or an approved customer-owned pole installed and maintained at the customers' expense.

Electricity will be supplied from existing overhead secondary distribution system facilities on an unmetered basis. This service will be controlled for daily operation from dusk to dawn for an aggregate of approximately 4,200 burning-hours per year.

MONTHLY RATE
Charge for installation and maintenance of Company-owned equipment and the supply of electricity for operation:

Distribution Service Charge

Mercury Vapor			**High Pressure Sodium**		
175 Watt	$ 11.08	per lamp	100 Watt	$11.08	per lamp
250 Watt	$ 12.94	per lamp	150 Watt	$12.94	per lamp
400 Watt	$ 16.65	per lamp	250 Watt	$16.65	per lamp
Overhead wire	$ 1.54	per span			

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company’s General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider “SOS” – Standard Offer Service.

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GROSS RECEIPTS TAX
A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations" and it is further understood that:

1. Lamp renewal and other necessary maintenance work will be performed by the Company as soon as reasonably practical after notification by the customer of the necessity therefore, but such work will only be done during regular day-time working hours.

GENERAL TERMS AND CONDITIONS (continued)

2. Normally, lighting fixtures will not be installed on poles carrying 34.5 kV or higher voltages, or on poles supporting voltage regulators, two or more transformers or other similar equipment.

3. The Company reserves the right to discontinue the service at any time when the lighting fixture involved has been frequently damaged, apparently as a result of vandalism.

APPLICABLE RIDERS

Standard Offer Service – Type I Non-Residential
Administrative Credit
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Empower MD Charge
Non-Residential Direct Load Control
Demand Resource Surcharge
Grid Resiliency Charge

STREET LIGHTING SERVICE

SCHEDULE "SL"

AVAILABILITY

Available for Distribution Service and Standard Offer Service when modified by Rider “SOS” for street, highway and park lighting purposes in the Maryland portion of the Company's service area when owned by agencies of Federal, State and Municipal governments.

Also available for holiday lighting and seasonal street decoration lighting where the lights are in public space and where the only load supplied is lighting load. Schedule "SL" is not available for services that supply any load other than lighting and telecommunications network devices supplied under Rider "SL-TN".

CHARACTER OF SERVICE

Electricity supplied to multiple lights normally will be sixty hertz, single phase, 120 volts.

MONTHLY RATE

Distribution Service Charge

Standard Night Burning	$0.02304 per kwhr
24-Hour Burning	$0.02306 per kwhr

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company’s General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider “SOS” – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.74 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

The above charges do not include furnishing and/or maintaining street lighting equipment.

MEASUREMENTS OF ELECTRICITY

If electricity delivered for street lighting is unmetered, monthly kilowatt-hour consumption will be computed on the basis of manufacturers' wattage ratings of installed lamps, auxiliary devices where required, and scheduled 4,200 hours of burning time. If metered, watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

Lights controlled for night burning only will be billed at the monthly rate for Standard Night Burning street lights. Lights not controlled for night burning only will be billed at the monthly rate for 24-Hour Burning street lights.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GROSS RECEIPTS TAX
A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS
Standard Offer Service – Type I Non-Residential
Administrative Credit
Telecommunications Network Charge
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Empower MD Charge
Non-Residential Direct Load Control
Demand Resource Surcharge
Grid Resiliency Charge

CHARGES FOR SERVICING

STREET LIGHTS SERVED FROM OVERHEAD LINES

SCHEDULE "SSL-OH"

AVAILABILITY

Available in the Maryland portion of the Company's service area to Municipal, County, Federal and State Governmental Agencies for servicing street, highway and park lighting equipment mounted on Company-owned wooden poles or on poles of another utility with whom the Company has an attachment agreement, when the electricity supplied to such equipment is furnished by the Company from overhead lines.

Available only for lights having a manufacturer's nominal rating of:

Incandescent*	10,000 lumens or less
Mercury Vapor*	175, 250 and 400 Watts
High Pressure Sodium	70, 100, 150, 250 and 400 Watts
Induction QL	55 and 85 Watts

*Not available for new installation or replacement of defective fixtures.

CHARACTER OF SERVICE

Service rendered under this schedule will consist of (1) furnishing, installing and maintaining street lighting luminaries and mounting arms or brackets, (2) furnishing, installing, connecting, operating and maintaining electric service circuits connecting the street lighting equipment to the Company's overhead distribution system, (3) group relamping, (4) washing of globes, (5) furnishing and installing replacement globes, lamps, ballasts and light sensitive switches as needed to maintain the system in an operating mode; all normally limited to standard items of equipment meeting ANSI Standards for street lighting equipment and accepted by the Company for maintenance.

If the Customer agrees in writing with the Company, the Customer may own their street lighting equipment at all locations to include the bracket, fixture, ballast, light sensitive switch unit, and lamp. The maintenance for which can be supplied by the customer or the Company. The supply circuits terminating at the luminare would still be owned and maintained by the Company.

Street lights will be installed on existing Company-owned distribution poles or on existing poles owned by another utility where practicable.

MD - SSL - OH

MONTHLY RATE

	FIXED CHARGES	**O&M CHARGES COMPANY MAINTAINED**	**O&M CHARGES CUSTOMER-SUPPLIED MAINTENANCE**
Incandescent Lights* - Night Burning			
Without Globes - all sizes	$ 0.56	$5.65	$0.89
With Globes - all sizes	$ 6.48	$5.65	$0.89
Fire Alarm Designation	$ 3.01	$5.62	$0.89
Other:			
Attachments to Poles Owned By Another Utility	$ 0.17 each		
Mercury Vapor Lights* - Night Burning			
100 Watt	$2.74	$ 1.96	$0.89
175 Watt	$2.75	$ 1.96	$0.89
250 Watt	$3.38	$ 1.96	$0.89
400 Watt	$4.19	$ 1.96	$0.89
High Pressure Sodium Lights - Night Burning			
70 Watt	$ 4.34	$ 1.98	$0.89
100 Watt	$ 4.85	$ 1.96	$0.89
150 Watt	$ 5.04	$ 1.96	$0.89
250 Watt	$ 6.95	$ 1.96	$0.89
400 Watt	$ 7.93	$ 1.96	$0.89
Induction QL – Night Burning			
55 Watt	$ 0.06	$ 4.66	$0.89
85 Watt	$ 0.06	$ 4.66	$0.89

*Not available for new installation or replacement of defective fixtures.

The above charges will be separate from and in addition to charges for electricity supplied under the provisions of Schedule "SL".

CONTRIBUTION-IN-AID-OF-CONSTRUCTION

The Company will install, remove, or convert each street light upon payment by the customer of a one-time contribution in aid of construction equal to the average estimated cost per street light during the most recent three year period available. This fee shall be updated annually.

For a new overhead street light, this cost shall normally include the following:

1. The luminaire including the lamp, ballast, globe, light-sensitive switch, and mounting arm or bracket; plus,
2. Connection of the street light to the Company owned low voltage (120 volts) overhead distribution system; plus,
3. Installation of replacement poles if required by either the Company or another utility; plus,
4. Tree trimming and adjusting Company owned facilities or the facilities of another utility, in order to provide adequate clearances for the street light.

As discussed under Character of Service, if the Customer agrees in writing with the Company, the Customer may install their own street light and mount. The contribution-in-aid-of-construction shall include only the estimated cost of connecting the new supply (items 2-4 above).

For removing a street light, the contribution-in-aid-of-construction shall normally include the estimated reasonable cost of removing the existing luminaire (and/or bracket, if also removed). This removal charge shall not apply where the light is removed temporarily for repairs to the light or pole, or relocated in the immediate vicinity at the convenience of the Company (or other utility owning the pole on which the light is mounted).

For conversions from one size or wattage of light to another or one type of light to another, the contribution-in-aid-of-construction shall be the estimated reasonable cost of removing the existing equipment and the installation of the new equipment. This charge does not apply if the street light is converted at the convenience of the Company or if the street light is owned by the customer. The Customer is required to inform the Company of the date and characteristic of such conversions as soon as possible.

Beginning on the effective date of this schedule, the rates are as follows:

	Luminare & Mount	New Supply Connection	Type Conversion	Wattage Conversion
High Pressure Sodium				
All Standard Wattages	$ 942.00	$ 1,445.00	$ 482.00	$ 549.00
Induction QL				
All Standard Wattages	$ 2,910.00	$ 1,445.00	$ 2,994.00	$ 2,921.00

The cost of removal only for all light types is $ 211.00.

If the Customer requests that the Company provide facilities or an installation of excess of, or different than, those normally installed or if such excess installation is required by local, state, or federal ordinance, the total estimated additional cost shall be contributed by the Customer.

This contribution shall be in addition to any other service connection fee or contribution required under the "General Terms and Conditions." The contribution-in-aid-of-construction shall not be less than zero.

NON-STANDARD EQUIPMENT
Non-standard equipment, including all equipment not meeting ANSI Standards, if accepted by the Company for maintenance, will be subject to special contract charges and arrangements.

GROSS RECEIPTS TAX
A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

CHARGES FOR SERVICING STREET LIGHTS

SERVED FROM UNDERGROUND LINES

SCHEDULE "SSL-UG"

AVAILABILITY

Available throughout the Company's Maryland service area to Municipal, County, and Federal and State Governmental Agencies for servicing street, highway and park lighting equipment consisting of Customer-owned foundations, posts, brackets and luminaires when the electricity supplied to such equipment is furnished by the Company from underground lines.

Available only for lights having a manufacturer's nominal rating of:

Incandescent*	10,000 lumens or less
Mercury Vapor*	175, 250, and 400 Watts
Metal Halide*	70, 100, 175, and 250 Watts
High Pressure Sodium	70, 100, 150, 250, and 400 Watts
Induction QL	55 and 85 Watts

*Not available for new installation or replacement of defective fixtures

CHARACTER OF SERVICE

Service rendered under this schedule will consist of (1) furnishing, installing, connecting and maintaining electric service circuits connecting the street lighting equipment to the Company's underground distribution system, (2) group relamping, (3) washing of globes, (4) furnishing of labor required to replace ballasts and broken or damaged globes, and (5) furnishing and installing of replacement lamps and light sensitive switch units as needed to maintain the system in an operating mode; all normally limited to standard items of equipment meeting ANSI Standards for street lighting equipment and accepted by the Company for maintenance.

The Customer may provide their own maintenance at all light locations (including street lighting posts, foundations, brackets, fixtures, ballasts, light sensitive switch units and lamps). The supply circuits terminating at the luminare would still be owned and maintained by the Company.

MONTHLY RATE

	FIXED CHARGES	O&M CHARGES COMPANY MAINTAINED	O&M CHARGES CUSTOMER-SUPPLIED MAINTENANCE
Incandescent Lights* - Night Burning			
All Sizes/Wattages	$ 6.49	$ 7.46	$ 1.95
Mercury Vapor Lights* - Night Burning			
100 Watt	$ 2.91	$ 5.06	$ 1.95
175 Watt	$ 3.76	$ 5.06	$ 1.95
250 Watt	$ 6.08	$ 5.06	$ 1.95
400 Watt	$ 10.28	$ 5.06	$ 1.95
Metal Halide* - Night Burning			
All Sizes/Wattages	$ 3.16		$ 1.95

MONTHLY RATE (continued)

	FIXED CHARGES	O&M CHARGES COMPANY MAINTAINED	O&M CHARGES CUSTOMER-SUPPLIED MAINTENANCE
High Pressure Sodium Lights - Night Burning			
70 Watt	$ 2.13	$ 5.06	$ 1.95
100 Watt	$ 2.20	$ 5.06	$ 1.95
150 Watt	$ 3.98	$ 5.06	$ 1.95
250 Watt	$ 7.09	$ 5.06	$ 1.95
400 Watt	$ 11.71	$ 5.06	$ 1.95

*Not available for new installation or replacement of defective fixtures.

The above charges will be separate from and in addition to charges for electricity supplied under the provisions of Schedule "SL".

RESPONSIBILITY AS TO FURNISHING, INSTALLING AND MAINTAINING EQUIPMENT

The street lighting posts, foundations, brackets (if required), and luminaires complete with ballasts, light sensitive switch units and lamps shall be furnished, installed and removed by the Customer or at the Customers expense. Conversion to another light size or type shall be at customer's expense. All maintenance of the equipment installed at the customer's expense, including painting, shall be the responsibility of the customer, except as set forth under "Character of Service" above.

All equipment installed or furnished by the customer and the manner of installation shall be of a type approved by and coordinated with the Company prior to installation.

CONTRIBUTION-IN-AID-OF-CONSTRUCTION

The Company will connect or disconnect each street light from the Company's low voltage (120 volt) distribution system upon payment by the customer of a one-time contribution in aid of construction equal to the average estimated reasonable cost per street light during the most recent three year period available. This fee shall be updated annually. The Customer also has the option, since it owns the lights, to request the Company to install the fixture at the cost shown below.

For removing a street light, the contribution-in-aid-of-construction shall include the cost to disconnect the supply circuit from the street light and the cost to maintain and/or rearrange the supply circuit. This cost shall be based on the average estimated reasonable cost per street light during the most recent three year period available to be updated annually. This charge does not apply if the street light is removed at the convenience of the Company.

For conversions, the Customer owns the street lights and has the option of performing the work itself or requesting the Company to perform the work. If the customer performs this work, the Customer is required to inform the Company of the date and characteristic of such conversions a soon as possible.

Beginning on the effective date of this schedule, the rates are as follows:

	Luminare & Mount	New Supply Connection	Removal Only	Type Conversion	Wattage Conversion
All Standard Types & Wattages	$1,662.00	$2,690.00	$ 140.00	$ 430.00	$ 462.00

If the Customer requests that the Company provide facilities or an installation in excess of, or different than, those normally installed or if such excess installation is required by local, state, or federal ordinance, the total estimated additional cost shall be contributed by the Customer.

This contribution shall be in addition to any other service connection fee or contribution required under the “General Terms and Conditions.” The contribution-in-aid-of-construction shall not be less than zero.

NON-STANDARD EQUIPMENT
Non-standard, special and experimental equipment, including all posts and luminaires which do not meet ANSI Standards for street lighting equipment, if accepted by the Company for maintenance, will be subject to special contract charges and arrangements.

GROSS RECEIPTS TAX
A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

CHARGES FOR SERVICING
STREET LIGHTS SERVED FROM OVERHEAD LINES
SCHEDULE "SSL-OH-LED"

AVAILABILITY
Available in the Maryland portion of the Company's service area to Municipal, County, Federal and State Governmental Agencies for servicing street, highway and park lighting equipment mounted on Company-owned wooden poles or on poles of another utility with whom the Company has an attachment agreement, when the electricity supplied to such equipment is furnished by the Company from overhead lines.

Available only for LED lights having a high pressure sodium (HPS) equivalent manufacturer's nominal rating of: 50, 70, 100, 150 and 250 Watts.

CHARACTER OF SERVICE
Service rendered under this schedule will consist of (1) furnishing, installing, and maintaining street lighting luminaries, mounting arms or brackets and smart ready/smart associated equipment as applicable (2) furnishing, installing, connecting, operating and maintaining electric service circuits connecting the street lighting equipment to the Company's overhead distribution system, (3) furnishing and installing replacement globes, fixtures, and light sensitive switches as needed to maintain the system in an operating mode; all normally limited to standard items of equipment meeting ANSI Standards for street lighting equipment and accepted by the Company for maintenance.

If the Customer agrees in writing with the Company, the Customer may own its street lighting equipment at all locations to include the bracket, fixture and light sensitive switch unit. The maintenance for which can be supplied by the Customer or the Company. The supply circuits terminating at the luminaire would still be owned and maintained by the Company.

Street lights will be installed on existing Company-owned distribution poles or on existing poles owned by another utility where practicable.

MONTHLY RATE

	FIXED CHARGE	O&M CHARGE	OPTIONAL REPLACEMENT CHARGE
Utility Grade			
50 Watt	$ 0.56	$ 0.89	$ 4.27
70 Watt	$ 0.56	$ 0.89	$ 5.94
100 Watt	$ 0.56	$ 0.89	$ 6.42
150 Watt	$ 0.56	$ 0.89	$ 7.09
250 Watt	$ 0.56	$ 0.89	$ 7.12

MONTHLY RATE (continued)

	FIXED CHARGE	O&M CHARGE	OPTIONAL REPLACEMENT CHARGE
Decorative Grade			
70 Watt	$ 0.56	$ 0.89	$ 8.96
100 Watt	$ 0.56	$ 0.89	$ 9.05
150 Watt	$ 0.56	$ 0.89	$ 9.90
250 Watt	$ 0.56	$ 0.89	$ 10.82

The above charges will be separate from and in addition to charges for electricity supplied under the provisions of Schedule “SL”.

CONTRIBUTION–IN-AID-OF-CONSTRUCTION

The Company will supply for the Customer a luminaire (including lamp, globe and light-sensitive switch) mounting arm and/or bracket required, and smart ready/smart associated equipment (includes, but is not limited to, network – integrated LED hardware such as LED street light fixtures with smart nodes (photocells with network interface controller) as applicable upon payment by the Customer of a one-time contribution-in-aid-of-construction equal to the estimated reasonable installed cost of such equipment agreed to by the Company and the Customer at the time of the installation.

For a new overhead street light, this cost shall normally include the following:

1. The luminaire including the lamp, globe, light-sensitive switch, and mounting arm or bracket; and smart ready/smart associated equipment as applicable; plus,
2. Connection of the street light to the Company owned low voltage (120 volts) overhead distribution system; plus,
3. Installation of replacement poles if required by either the Company or another utility; plus,
4. Tree trimming and adjusting Company owned facilities or the facilities of another utility, in order to provide adequate clearances for the street light.

As discussed under Character of Service, if the Customer agrees in writing with the Company, the Customer may install their own street light and mount. The contribution-in-aid-of-construction shall include only the estimated cost of connecting the new supply (items 2-4 above).

For removing a street light, the contribution-in-aid-of-construction shall normally include the estimated reasonable cost of removing the existing luminaire (and/or bracket, if also removed). This removal charge shall not apply where the light is removed temporarily for repairs to the light or pole, or relocated in the immediate vicinity at the convenience of the Company (or other utility owning the pole on which the light is mounted).

For conversions from one size or wattage of light to another or one type of light to another, the contribution-in-aid-of-construction shall be the estimated reasonable cost of removing the existing equipment and the installation of the new equipment. This charge does not apply if the street light is converted at the convenience of the Company or if the street light is owned by the Customer. The Customer is required to inform the Company of the date and characteristic of such conversions as soon as possible.

If the Customer requests that the Company provide facilities or an installation in excess of, or different than, those normally installed or if such excess installation is required by local, state, or federal ordinance, the total estimated additional cost shall be contributed by the Customer.

This contribution shall be in addition to any other service connection fee or contribution required under the “General Terms and Conditions.” The contribution-in-aid-of-construction shall not be less than zero.

In lieu of a one-time payment at the time of installation, the Customer may elect one of the following alternative payment options:

1. Finance the contribution-in-aid-of-construction through the Company, amortized over the number of years to be agreed upon by Pepco and the street light Customer at the applicable Commission-approved overall rate of return at the time of the installation, subject to update as approved in subsequent rate proceedings, if any.

2. A monthly service charge that amortizes the total cost of the installation or conversion, which will be based on the estimated reasonable cost of the LED installation or conversion at that time, over the depreciable life of the installed LED street lights at the applicable Commission-approved overall rate of return at the time of the installation, subject to update as approved in subsequent rate proceedings, if any.

The Customer may only choose a single payment option for all LED lights installed, unless otherwise agreed to by the Company.

REPLACEMENT OF EQUIPMENT
When replacement of installed equipment is necessary, the Company will replace such installed equipment upon payment by the Customer of a contribution equal to the Company's reasonable cost to replace the equipment. If the Customer has chosen either of the alternative payment options for the initial installation of the equipment subject to replacement, the replacement contribution will be added to the unrecovered balance, if any, of the initial installation contribution and recovered consistent with the elected option.

In lieu of the contribution at the time of replacement, the Customer may elect to pay a monthly charge to cover the cost of future replacements (Optional Replacement Charge). The Optional Replacement Charge will be effective at the time of the initial installation of the equipment and will remain in effect to the time of equipment replacement. The monthly Optional Replacement Charge for future replacement are listed in the table of monthly rates.

The Customer may only choose a single replacement charge option for all lights installed.

NON-STANDARD EQUIPMENT
Non-standard equipment, including all equipment not meeting ANSI Standards. If accepted by the Company for maintenance, will be subject to special contract charges and arrangements.

GROSS RECEIPTS TAX
A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

CHARGES FOR SERVICING STREET LIGHTS

SERVED FROM UNDERGROUND LINES

SCHEDULE "SSL-UG-LED"

AVAILABILITY
Available throughout the Company's Maryland service area to Municipal, County, and Federal and State Governmental Agencies for servicing street, highway and park lighting equipment consisting of Customer-owned foundations, posts, brackets and luminaires when the electricity supplied to such equipment is furnished by the Company from underground lines.

Available only for LED lights having a high pressure sodium (HPS) equivalent manufacturer's nominal rating of: 70, 100, 150, and 250 Watts.

CHARACTER OF SERVICE
Service rendered under this schedule will consist of (1) furnishing, installing, connecting and maintaining electric service circuits connecting the street lighting equipment to the Company's underground distribution system, (2) furnishing of labor required to replace broken or damaged globes, and (3) furnishing and installing of replacement fixtures and light sensitive switch units as needed to maintain the system in an operating mode; all normally limited to standard items of equipment meeting ANSI Standards for street lighting equipment and accepted by the Company for maintenance.

The Customer may provide its own maintenance at all light locations (including street lighting posts, foundations, brackets, fixtures and light sensitive switch units) excluding the supply circuits terminating at the luminaire.

MONTHLY RATE

	FIXED CHARGE	O&M CHARGE	OPTIONAL REPLACEMENT CHARGE
Utility Grade			
50 Watt	$ 2.13	$ 1.95	$ 4.27
70 Watt	$ 2.13	$ 1.95	$ 5.94
100 Watt	$ 2.13	$ 1.95	$ 6.42
150 Watt	$ 2.13	$ 1.95	$ 7.09
250 Watt	$ 2.13	$ 1.95	$ 7.12
Decorative Grade			
70 Watt	$ 2.13	$ 1.95	$ 8.96
100 Watt	$ 2.13	$ 1.95	$ 9.05
150 Watt	$ 2.13	$ 1.95	$ 9.90
250 Watt	$ 2.13	$ 1.95	$ 10.82

The above charges will be separate from and in addition to charges for electricity supplied under the provisions of Schedule "SL".

MD - SSL- UG - LED

RESPONSIBILITY AS TO FURNISHING, INSTALLING AND MAINTAINING EQUIPMENT
The street lighting posts, foundations, brackets (if required), luminaires complete with light sensitive switch units and lamps and smart ready/smart associated equipment as applicable shall be furnished, installed and removed by the Customer or at the Customer's expense. Conversion to another light size or type shall be at the Customer's expense. All maintenance of the equipment installed at the Customer's expense, including painting, shall be the responsibility of the Customer, except as set forth under "Character of Service" above.

All equipment installed or furnished by the Customer and the manner of installation shall be of a type approved by and coordinated with the Company prior to installation.

CONTRIBUTION-IN-AID-OF-CONSTRUCTION
The Company will connect or disconnect each street light from the Company's low voltage (120 volt) underground distribution system upon payment by the Customer of a one-time contribution in aid of construction equal to the estimated reasonable cost per street light agreed to by the Company and the Customer at the time of the connection or disconnection.

If along the street adjacent to the location of the street light or lights to be served, there is not available, as part of the Company's distribution system, a low voltage (120 volt) electric circuit usable for supplying the street lighting, a charge will be made in the amount of the estimated cost to the Company of installing the necessary circuit. When lights are to be supplied from underground lines in an area having existing overhead distribution, a charge will be made in the amount of the estimated cost to the Company of installing the necessary underground circuit. Also, if existing overhead lines must be adjusted to provide adequate clearance for the lights, the estimated cost thereof will be charged to the Customer.

For removing a street light, the contribution-in-aid-of-construction shall include the estimated reasonable cost to disconnect the supply circuit from the street light and to maintain and/or rearrange the supply circuit. This charge does not apply if the street light is removed at the convenience of the Company.

For conversions, there is no contribution-in-aid-of-construction since the Customer owns the street lights supplied from the Company’s underground distribution system. The Customer would perform this work at its expense. The Customer is required to inform the Company of the date and characteristic of such conversions as soon as possible.

If the Customer requests that the Company provide facilities or an installation in excess of, or different than, those normally installed or if such excess installation is required by local, state, or federal ordinance, the total estimated additional cost shall be contributed by the Customer.

This contribution shall be in addition to any other service connection fee or contribution required under these "General Terms and Conditions." The contribution-in-aid-of-construction shall not be less than zero.

In lieu of a one-time payment at the time of installation, the Customer may elect one of the following alternative payment options:

1. Finance the contribution-in-aid-of-construction through the Company, amortized over the number of years to be agreed upon by Pepco and the street light Customer at the applicable Commission-approved overall rate of return at the time of the installation, subject to update as approved in subsequent rate proceedings, if any.

2. A monthly service charge that amortizes the total cost of the connection or disconnection, which will be based on the estimated reasonable cost of the connection or disconnection at that time, over the depreciable life of the installed LED street lights at the applicable Commission-approved overall rate of return at the time of the installation, subject to update as approved in subsequent rate proceedings, if any.

The Customer may only choose a single payment option for all LED lights installed, unless otherwise agreed to by the Company.

REPLACEMENT OF EQUIPMENT
When replacement of installed equipment is necessary, the Company will replace such installed equipment upon payment by the customer of a contribution equal to the Company's reasonable cost to replace the equipment. If the Customer has chosen either of the alternative payment options for the initial installation of the equipment subject to replacement, the replacement contribution will be added to the unrecovered balance, if any, of the initial installation contribution and recovered consistent with the elected option.

In lieu of the contribution at the time of replacement, the Customer may elect to pay a monthly charge to cover the cost of future replacements (Optional Replacement Charge). The Optional Replacement Charge will be effective at the time of the initial installation of the equipment and will remain in effect to the time of equipment replacement. The monthly Optional Replacement Charges for future replacement are listed in the table of monthly rates.

The Customer may only choose a single replacement charge option for all lights installed.

NON-STANDARD EQUIPMENT
Non-standard, special and experimental equipment, including all posts and luminaires which do not meet ANSI Standards for street lighting equipment, if accepted by the Company for maintenance, will be subject to special contract charges and arrangements.

GROSS RECEIPTS TAX
A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

TELECOMMUNICATIONS NETWORK SERVICE

SCHEDULE "TN"

AVAILABILITY

Available for Distribution Service and Standard Offer Service when modified by Rider “SOS” in the Maryland portion of the Company’s service area for unmetered electric service to multiple telecommunications network devices, cable television power supply devices or other devices used by government or police organizations with similar load characteristics served directly by the Company and not exceeding 1,800 watts per device.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, single phase, 120 volts.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Kilowatt-hour Charge	$ 0.02892 per kwhr	$ 0.01586 per kwhr

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company’s General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider “SOS” – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.74 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

MEASUREMENTS OF ELECTRICITY

At the customer’s option monthly kilowatt-hour consumption will be computed on the basis of either the manufacturer’s average wattage ratings of installed devices, with no allowance for outages, or on the basis of statistically valid sampling techniques. If the customer chooses the option to use statistically valid sampling techniques, the initial measurement of electricity will be based on the manufacturer’s maximum rating. When historical data are available for the customer’s devices, that data will be used for the sample estimate. If historical metered data are not available, sample usage data may be obtained by means of a handheld current probe. The charges under this rider are for electricity only.

GROSS RECEIPTS TAX

A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Type I Non-Residential
Administrative Credit
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Empower MD Charge
Non-Residential Direct Load Control
Demand Resource Surcharge
Grid Resiliency Charge

COGENERATION AND SMALL POWER PRODUCTION

INTERCONNECTION SERVICE

SCHEDULE "CG-SPP"

AVAILABILITY

Available for Interconnection Service, in the Maryland portion of the Company's service area, to the premises on which the customer operates a qualifying cogeneration facility or qualifying small power production facility as defined in the Federal Power Act, pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978 (a QF).

Available for QF sales to the Company – as set forth under Power Marketing Service.

Available for sales to the Company at a standard rate, by QFs having a maximum generating capability of 100 kilowatts or less – as set forth under Standard Rate for Power Marketing Service To Small QFs.

Available for the delivery of QF-generated electric power to the wholesale marketplace – as set forth under Market Access.

Available for the following services to support the QF's participation in the wholesale marketplace:

1. For metering of the QF's output – as set forth under Metering Service.

2. For dispatch, data entry and billing services – as set forth under PJM Interface Services.

3. For assistance in the sale of QF-generated electric power to third parties – as set forth under Brokering Service.

CHARACTER OF SERVICE

The Interconnection Service supplied under this schedule is interconnected operation of the QF in parallel with the Company's electric system (in accordance with Interconnected Operation, below). The Company, in coordination with PJM, will specify the physical Interconnection Point with the QF and nominal interconnection voltage level on the basis of available Company facilities and the magnitude of the generation and load to be served.

MARKET ACCESS

The Company's electric system is operated as part of the integrated electric system of the PJM Control Area, under the direction of the control area operator, regional transmission provider, and regional market administrator, PJM. Interconnection with the Company's electric system provides access to wholesale markets as follows:

A. **CHOICE OF MARKETS** – Pursuant to 18 CFR §292.303(d) of the regulations, QF energy and capacity will be transmitted as directed by the customer either (1) to the energy, capacity and ancillary services markets administered by PJM, for sale at such prices as may be available in those markets from time to time, or (2) to any bilateral purchaser (including the Company) or other market selected by the customer, for sale as negotiated between the customer and the purchaser.

B. **POINT OF DELIVERY** – Delivery to the PJM marketplace shall occur at the Interconnection Point under this schedule, *provided*, for market administration purposes, if the Interconnection Point is not located on a "generation bus" for which a fixed nodal weighted aggregate locational marginal price is calculated by PJM, the nominal point of delivery to the PJM marketplace will be the PJM-recognized "generation bus" electrically most directly connected to the Interconnection Point. Delivery to a bilateral purchaser shall occur as arranged with PJM and other transmission providers; such arrangements are the responsibility of the customer.

C. **DELIVERY ARRANGEMENTS -** Power generated and delivered by the QF will be metered for sale in the wholesale marketplace. The QF will provide and maintain its own output metering and telemetering equipment in accordance with PJM requirements and the Company's specifications for interconnection and parallel operation. There is no Distribution Service charge for the Company's delivery of the QF's electrical output to the integrated system of the PJM Control Area. Power delivered by the Company will be metered by the Company under the applicable retail rate schedule (for Standard Offer Service or for Distribution Service only, as defined in the Company's General Terms and Conditions). At the election of the customer, deliveries shall be separate or aggregated as follows:

1. **SIMULTANEOUS PURCHASE AND SALE**

(A) All electricity consumed by the customer at the QF's service location (consisting of the generating station electrical consumption of the QF and other electrical consumption of the customer) will be considered delivered by the Company.

(B) All electrical output of the QF will be considered delivered by the QF for wholesale sale in accordance with this schedule.

2. **NET METERING**

At the election of the customer, to the extent consistent with the PJM Tariff, simultaneous deliveries by the QF and the Company may be aggregated or "net metered." Distribution standby charges will apply to the Company's deliveries in accordance with the Company's retail tariff. The customer may elect to exclude from this aggregation, for separate metering and billing by the Company without standby charges, all consumption of electricity on the premises for purposes other than QF generating facility consumption. The QF's elections under this paragraph may be changed no more frequently than once in three years and any resulting costs to the Company of altering the interconnection facilities or metering shall be borne by the QF.

POWER MARKETING SERVICE

Upon request, the Company will purchase the output of the QF for resale by the Company, at a price and for a duration negotiated from time to time, pursuant to the Company's license from the FERC to engage in power marketing purchases and sales. Power marketing service is available from other vendors. Power marketing service is available from the Company only to the extent that the Company is licensed to buy and sell wholesale power at market-based rates, and has the personnel and facilities available to perform the service.

STANDARD RATE FOR POWER MARKETING SERVICE TO SMALL QFS

Upon request, a QF interconnected with the Company under this schedule and having a maximum generating capability of 100 kW or less may sell its output to the Company for resale in the PJM markets in the following manner:

A. The Company will sell the QF's energy in the PJM as-available (real-time) energy market. The Company will pay the QF the energy price received from PJM, less any associated PJM ancillary charges, and less a fixed Company administrative charge of $17 per month where the interconnection is at secondary voltage (600 volts or below), or $65 per month where the interconnection is at primary voltage (4kV to 33kV).

B. If the QF has been certified by PJM as a PJM Capacity Resource, the Company will offer the QF's capacity in the PJM multi-month capacity market, and in the short-term PJM capacity markets if any remains unsold in the seasonal market. The Company will pay the QF the capacity price received from PJM, less any associated PJM charges and less the out-of-pocket cost to the Company of compliance with PJM unit commitment and dispatch requirements with respect to the QF's capacity.

C. At no additional charge, the Company will test and maintain the QF's output meter in accordance with PJM requirements.

SUPPORTING SERVICES AVAILABLE FROM THE COMPANY

The following services may be self-supplied by the QF or purchased from other vendors, or may be purchased from the Company at a negotiated and agreed price and terms. Such services are available from the Company only to the extent that the Company is appropriately licensed and has the personnel and facilities available to perform the service.

1. **METERING SERVICE**
   The Company will provide and maintain output metering and telemetering equipment as requested by the QF.

2. **PJM INTERFACE SERVICES**
   In support of QF sales to the PJM marketplace or bilateral sales to third parties, the Company will arrange for PJM market interface services requested by the QF, such as PJM OASIS input, electronic data entry, unit commitment, energy bid, generation dispatch, 24-hour-call-desk service, and PJM bill processing.

3. **BROKERING SERVICE**
   The Company will broker bilateral arrangements and perform associated billing and administrative services in conjunction with the QF's sales of energy, capacity or ancillary services directly to third parties.

CONTRACTUAL ARRANGEMENTS
The Company will interconnect with the QF pursuant to a detailed interconnection service agreement, and interconnection facilities agreements consistent therewith. Where applicable, these agreements shall be entered into as prescribed in the PJM Open Access Transmission Tariff on file with the FERC as revised and made effective from time to time (PJM Tariff). These agreements will incorporate by reference the generator interconnection requirements of PJM pursuant to the PJM Tariff, and applicable portions of this schedule (including the General Terms and Conditions of the Company's retail electric tariff and the specifications for interconnection and parallel operation furnished by the Company).

In accordance with those requirements, these agreements will require the installation of appropriate Interconnection Facilities for reliability and safety, and will require the customer to keep the Company and PJM system control centers informed of Interconnected Operation as set forth below. Disputes arising under these agreements shall be resolved pursuant to the dispute resolution process under the PJM Tariff as applicable, *provided*, any dispute which cannot be resolved by the parties may be taken by either party to this Commission, *provided further*, a dispute arising from or in connection with services regulated by the FERC shall be taken to the FERC as provided by federal law or regulation.

Applicants for service under this schedule should consult the Company (attention: General Manager, Transmission Interconnections Department) for further information about Company and PJM application and interconnection requirements.

INTERCONNECTION FACILITIES
Pursuant to PJM and Company reliability criteria for the operation of generation equipment in parallel with the PJM transmission system, protective equipment, operational metering (including kilovolt-ampere-reactive meters if required) and communications equipment. Interconnection facilities shall be installed and maintained by or at the expense of the QF in accordance with PJM and Company requirements including all required transmission and distribution facilities. All Interconnection Facilities must be operational and inspected by and tested to the satisfaction of the Company and PJM prior to any Interconnected Operation of the QF.

Normally, the QF and the Company will own and maintain the Interconnection Facilities on their respective sides of the Interconnection Point. Upon request, in accordance with PJM procedures, the Company will contract to install, own and maintain Interconnection Facilities which (1) are Attachment Facilities and Local Upgrade Facilities as defined in the PJM Tariff, and (2) any other facilities on the Company's side of the Interconnection Point the cost of which is reasonably directly assigned to the QF. Any extension or modification of the Company's distribution system to accommodate Interconnected Operation with the QF shall be performed by the Company at the expense of the QF.

Except as otherwise required by the FERC or the PJM Tariff, the QF will make a contribution in aid of construction for the installed cost (including applicable gross receipts taxes) of all Interconnection Facilities furnished by the Company, which shall be due as invoiced and prior to any operation of the QF's facility in parallel with the Company's system. Ongoing operation and maintenance of Company-owned Interconnection Facilities will be at the ongoing expense of the QF, unless prepaid as agreed at the time of installation or thereafter.

INTERCONNECTED OPERATION

As a condition of interconnection, the QF must operate its interconnected facilities pursuant to PJM operating requirements, the specifications for interconnection and parallel operation furnished by the Company, and good utility practice, and must cease interconnected operations immediately as instructed by PJM, or upon notification by the Company that the QF's operation is degrading the quality and reliability of service being provided to the Company's other customers. The Company is not responsible for monitoring the QF's operation and is not liable for any loss, cost, damage or other expense to any party resulting from the use or presence of electric current or potential which originates from the QF's generation facilities. The QF shall indemnify and hold the Company, its officers, directors, affiliates, agents, employees, contractors and subcontractors, harmless from and against any and all claims, demands, actions, losses, liabilities, expenses (including reasonable attorneys' fees), suits and proceedings of any nature whatsoever for personal injury, death, or property damage to third parties, except workers compensation claims, caused by any act or omission of the QF's own officers, directors, affiliates, agents, employees, contractors or subcontractors that arise out of or are in any manner connected with the QF's performance under this Schedule or under any agreement between the QF and the Company, or both, except to the extent such injury or damage is attributable to the negligence or willful misconduct of the Company.

TRANSITION FROM STANDARD RATE UNDER PRIOR SCHEDULE

Any customer already selling QF power to the Company at the “Standard Rate For Purchases From QFs” set forth in the version of Schedule CG-SPP in effect immediately prior to this schedule, will be informed of this superseding schedule when it is accepted by the Commission. Until the first to occur of (1) twelve months from the effective date of this schedule, or (2) the customer implements Market Access pursuant to this schedule, the Company will continue to purchase the QF’s power at the former standard rate without interruption.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company’s “General Terms and Conditions for Furnishing Electric Service” and the Company’s “Electric Service Rules and Regulations”.

STANDBY SERVICE

SCHEDULE "S"

AVAILABILITY

Available in the Maryland portion of the Company's service area when part or all of the customer's electric or other power requirements normally are supplied by his own power producing equipment and auxiliary service is desired for emergency or abnormal conditions. Available in conjunction with Schedule "CG-SPP", when the qualifying cogenerator or small power producer elects to sell electricity to the Company under the designated excess power provision of the tariff. Not available for cogenerators or small power producers served under Schedule "CG-SPP", whose own needs would otherwise be provided under a residential or general service non-demand schedule and whose self-generated power does not exceed 25 kW.

CHARACTER OF SERVICE

The electricity supplied under this schedule will be of a type normally supplied under the Company's standard retail rates.

MONTHLY RATE

FACILITIES CHARGE

When the company has installed facilities specifically to provide standby service under this schedule, a monthly charge of 2% of the total installed cost of such facilities will be made in addition to any other charges described below. This total installed cost shall not include the cost of any protective or metering equipment otherwise recoverable under the terms of Schedule "CG-SPP". If any facilities installed to provide service under this schedule are used in common to provide retail service under any other schedule, except for Schedule "CG-SPP", the facilities charge percentage will be applied to the actual total installed cost of the facilities less the estimated installed cost of the common facilities required to provide such other retail service. In the event that the facilities are removed before they have been in place for five (5) years, the customer shall agree to pay the cost of removal plus the original cost to which the facilities charge was applied, less depreciation and estimated salvage value.

USAGE CHARGES

When the company is called upon to provide standby service, the demand and energy usage shall be billed under the schedule which would be normally applicable for the customer, including any fuel rate. The distribution demand charges for Schedules "GT LV", "GT 3A", and "GT 3B" will be credited by an amount equal to the facilities charge paid under this schedule, but not to exceed the amount of the respective demand charge.

DETERMINATION OF STANDBY CAPACITY AND SERVICE

The customer shall contract in advance for the maximum number of kW which the Company is to stand ready to supply under both this schedule and the applicable non-standby schedule. Whenever the measured demand for any billing month exceeds the maximum provided for under the non-standby schedule, the Company will be considered to have provided standby service under this schedule.

STANDBY IN EXCESS OF CONTRACT

In the event that the Company determines that the customer is drawing on greater standby capacity than that originally contracted for, the Company shall bill the customer retroactively for appropriately recomputed Facilities and Usage Charges for the entire period since the excess standby is determined to have first occurred.

PARALLEL OPERATION

The Company is not liable for any loss, cost, damage or other expense to any party resulting from the use or presence of electric current or potential which originates from a customer's generation facilities. Protective equipment shall be installed and maintained at the expense of the customer, in accordance with specifications furnished by the Company. Such protective equipment will be required in any interconnected operation with a customer.

PERIOD OF CONTRACT

All contracts for service under this schedule shall be effective for one calendar year.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

PLUG-IN VEHICLE CHARGING - SCHEDULE "PIV"

AVAILABILITY – Available for Distribution and Standard Offer Service for low voltage electric service used for Plug-in Vehicle (“PIV”) battery charging purposes in premises where other electric requirements are furnished under Schedule “R” and “RTM”.

The customer agrees to allow the Company to install and maintain necessary equipment (if applicable) to monitor and/or manage the PIV load.

Customers taking service under Rider “NEM” (Net Energy Metering) are eligible for this Schedule “PIV”.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts.

Service will be supplied from the regular service connection facilities.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Kilowatt-hour Charge	$ 0.06595 per kwhr	$ 0.03259 per kwhr
Generation Service Charge		
Kilowatt-hour Charge		
On Peak	$ 0.08637 per kwhr	$ 0.10303 per kwhr
Off Peak	$ 0.04018 per kwhr	$ 0.05493 per kwhr
Transmission Service Charge	$ 0.01794 per kwhr	$ 0.01794 per kwhr

Procurement Cost Adjustment **See www.pepco.com for currently effective rate**

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company’s General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Schedule “PIV”. Supply Service Charges for Schedule “PIV” will be updated to reflect changes to Rider “SOS” rates.

Billing Credit – A monthly billing credit in the amount of $0.61 per residential customer will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

RATING PERIODS

On-peak hours are from 12:00 p.m. to 8 p.m. Monday through Friday excluding holidays falling on weekdays. All other hours are off-peak.

SUPPLY CAPACITY REQUIREMENT

Should additional service capacity be required for the “off-peak” service, in excess of that provided for regular service, the customer will pay to the Company an amount equal to the estimated cost of the additional facilities. Such payment must be made prior to the commencement of service under this schedule.

GROSS RECEIPTS TAX

A surcharge of 2.0408% is applied to the transmission and distribution components of the customer’s bill to recover the amount attributable to the Gross Receipt’s Tax.

GENERAL TERMS AND CONDITION

This schedule is subject in all respects to the Company’s “General Terms and Conditions for Furnishing Electric Service” and the Company’s “Electric Service Rules and Regulations.”

APPLICABLE RIDERS

Administrative Credit
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Bill Stabilization Adjustment
Empower MD Charge
Demand Resource Surcharge
Dynamic Pricing – Peak Energy Savings Credit
Green Rider

RESIDENTIAL SERVICE - WITH PLUG-IN VEHICLE CHARGING SCHEDULE "R-PIV"

AVAILABILITY – Available for Distribution Service and Standard Offer Service when modified by Rider "SOS" in the Maryland portion of the Company's service area for low voltage electric service where the use is primarily for residential purposes and for farm operations where the electricity for both farm and residential purposes is delivered through the same meter.

The service supplied under this Schedule is for Plug-in Vehicle ("PIV") battery charging purposes in addition to the electric requirements for residential purposes and for farm operations as described above. The electricity for PIV battery charging purposes is delivered through the same meter as for both farm and residential purposes.

Not available for residential premises in which five (5) or more rooms are furnished under Schedules "R" and "RTM" for hire.

Not available for seasonal loads metered separately from lighting and other usage in the same occupancy.

Not available for temporary, auxiliary or emergency service.

Customers taking service under Rider "NEM" (Net Energy Metering) are not eligible for Schedule "R-PIV".

CHARACTER OF SERVICE
The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts.

Service will be supplied from the regular service connection facilities.

MONTHLY RATE

Distribution Service Charge		
Customer Charge	$ 8.01 per month	$ 8.01 per month
Kilowatt-hour Charge	$ 0.06595 per kwhr	$ 0.03259 per kwhr
Generation Service Charge		
Kilowatt-hour Charge		
On Peak	$ 0.09188 per kwhr	$ 0.14154 per kwhr
Off Peak	$ 0.03730 per kwhr	$ 0.04596 per kwhr
Transmission Service Charge	$ 0.01794 per kwhr	$ 0.01794 per kwhr

Procurement Cost Adjustment See www.pepco.com for currently effective rate

Generation and Transmission Service Charges – Customers must receive Generation and Transmission Services from the Company under the provisions of Schedule "R-PIV". Supply Service Charges for Schedule "R-PIV" will be updated to reflect changes to Rider "SOS" rates.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

RATING PERIODS

On-peak hours are from 12:00 p.m. to 8 p.m. Monday through Friday excluding holidays falling on weekdays. All other hours are off-peak.

SUPPLY CAPACITY REQUIREMENT

Should additional service capacity be required for the “off-peak” service, in excess of that provided for regular service, the customer will pay to the Company an amount equal to the estimated cost of the additional facilities. Such payment must be made prior to the commencement of service under this schedule.

GROSS RECEIPTS TAX

A surcharge of 2.0408% is applied to the transmission and distribution components of the customer’s bill to recover the amount attributable to the Gross Receipt’s Tax.

GENERAL TERMS AND CONDITION

This schedule is subject in all respects to the Company’s “General Terms and Conditions for Furnishing Electric Service” and the Company’s “Electric Service Rules and Regulations.”

APPLICABLE RIDERS

Administrative Credit
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Bill Stabilization Adjustment
Empower MD Charge
Residential Direct Load Control
Demand Resource Surcharge
Dynamic Pricing – Peak Energy Savings Credit
Universal Service Charge Recovery
Green Rider

COMMUNITY SOLAR PILOT PROGRAM
SCHEDULE "CS"

A. AVAILABILITY

This tariff is available to Subscriber Organizations that have been approved by the Maryland Public Service Commission to participate in the Community Solar Pilot Program (the "Pilot Program") as set forth in Maryland Public Utilities Article § 7-306.2 and Subtitle 62 of Title 20 of the Code of Maryland Regulations. Once approved, a Subscriber Organization can apply with the Company to interconnect Community Solar Energy Generating System ("CSGES") with the stated intent to participate in the Pilot Program. The size of the Pilot Program is limited and access to the Pilot Program will be provided on a first-come-first served basis.

The Pilot Program shall begin the earlier of the date of submission of an Interconnection Application for a CSEGS to the Company or January 18, 2017. The Pilot Program will end three (3) years thereafter.

Using the Company's Community Energy Community Net Metering ("CNM") rider, the Company's distribution customers in the State of Maryland, regardless of rate classification or energy supplier, are provided the opportunity to participate in the development of distributed solar generation by purchasing a Subscription to a portion of the electricity produced by a Community Solar Energy Generating Facility from a Subscriber Organization. For each Subscription, the Customer will receive a CNM Credit on their monthly bill from the Company.

B. PILOT PROGRAM

Subject to Program Capacity Limitations, as set-forth below, the Electric Company will accept applications to participate in the Pilot Program and administer the Pilot Program's queue for the duration of the Pilot Program.

The following table sets forth the annual capacity limits under the Pilot Program for the Company. Updates to the status of the Company's Pilot Program's queue and capacity limits can be found at www.pepco.com/greenpowerconnection.

Program MW Capacity	Small/Brownfield/Other	Open	LMI
Year 1	6.0	8.0	6.0
Year 2	6.0	8.0	6.0
Year 3	3.0	4.0	3.0

Acceptance of a CSEGS into the Small/Brownfield/Other, Low and Moderate Income (LMI), or Open categories will be in accordance with definitions and procedures set-forth in COMAR Section 20.62. Participation in the Pilot Program for existing systems will also be limited as set-forth in the COMAR Section 20.62. Existing systems are generators granted permission to operate on or before May 15, 2016.

A CSEGS in the Pilot Program and granted permission to operate by the Company may continue to operate for 25 years after the end of the Pilot Program, subject to requirements of the CSEGS's Interconnection Agreement. For this period the Company will continue to facilitate the creation and transfer of subscriptions and provide CNM Credits to Subscribers in accordance with this Schedule and the CNM Rider.

C. SUBSCRIBER ORGANIZATION ADMINISTRATION / INTERCONNECTION APPLICATION

Prior to applying for an Interconnection Agreement for a CSEGS, a Subscriber Organization must first be granted permission to participate in this Pilot Program from the Maryland Public Service Commission and have received a Subscriber Organization identification number.

Once the Subscriber Organization has permission to participate from the Commission, they must apply to the Company for an Interconnection Agreement for each CSEGS under Code of Maryland Regulations 20.50.09 and indicate their intent to participate in the Pilot Program. Each interconnection application must be made separately in an electronic format as defined by the Company.

Interconnection Applications will be processed in the order in which the completed Interconnection Applications are received. Each subscriber organization and affiliated-ownership subscriber organizations are limited to 2 (two) Interconnection Applications during the initial 20 business days of the Year 2/3 interconnection queue period. A Subscriber Organization is responsible for all interconnection costs. Projects that are not awarded pilot program capacity in Year 1 will have their Interconnection Application canceled and must reapply for interconnection and reapply to the pilot program in a future year and do not maintain their waiting list position for capacity in Year 2. Year 1 (including the waitlist) will end on October 19, 2018 at 5:00:00PM. Year 2/3 Interconnection Applications may be submitted no earlier than 12:00:00.0PM on October 29, 2018.

A Subscriber Organization must maintain all data and information as prescribed in the regulations as stated in Code of Maryland Regulations Section 20.62.

A Subscriber Organization may apply to have more than one CSEGS participate in the Pilot Program.

D. COMMUNITY SOLAR ENERGY GENERATING SYSTEMS

A CSEGS must be a solar photovoltaic generator located in the Company's Maryland service territory that does not exceed 2 MW in rated capacity$_{AC}$ of the system's inverter. A CSEGS must have a partially executed Interconnection Agreement that is currently effective with the Company. A partially executed Interconnection Agreement includes Part II of the Agreement executed by the Customer. Interconnection Agreements for applicants to the first year of the Pilot Program will expire at the end of the program year if not selected into the first year of the program.
A CSEGS of 500 kW or greater may not be located on the same or contiguous parcel of property as another CSEGS of 500 kW or greater owned by the same Subscriber Organization or its affiliate unless constructed on one of the following: a building rooftop or parking structure, over a parking lot or roadway, in a platted industrial park, or 2 or more projects, each of up to 2 MW in size comprising no more than 6 MW constructed on a brownfield site.

A CESGS may not have subscriptions larger than 200 kilowatts constituting more than 60% of the rated capacity$_{AC}$ of the system's inverter.

The number of Subscribers may not exceed 350 accounts per project. A CSEGS must have a minimum of 2 subscribers at all times. The Subscriber Organization shall maintain a minimum average subscription size of 2 kW for each CSEGS.

Under no circumstance shall a Subscriber Organization sell Subscriptions totaling more than one-hundred percent (100%) of the CSEGS's electrical production.

In no event shall the electricity generated by a CSEGS be eligible for net energy metering and billing.

For billing of any net consumption by a CSEGS, the CSEGS will is subject to all tariff provisions applicable under the schedule they are placed. In determining the appropriate Tariff Schedule for a CSEGS, the billing demand will be based on the rated capacity$_{AC}$ of the CSEGS's inverter. The Company reserves the right to require the CSEGS to be placed or moved to a bill cycle that enables PEPCO to facilitate efficient credit calculation.

A Subscriber Organization must provide an executed conditional Interconnection Agreement in conjunction with a Community Solar Pilot Program Application. In the Pilot Application, the Subscriber Organization must provide information on the Generator Facility that will participate as a CSEGS under this Schedule. In addition, the Subscriber Organization must attest to the fact that it has the legal right to sell all of the electricity, which is exported by the CSEGS to the Electric Company's distribution grid to the Company.

E. PILOT PROGRAM APPLICATION PROCESS

Pilot Program Applications shall be processed in the order in which they are received. The Company will notify the Subscriber Organization of receipt of the Pilot Program Application and whether the Pilot Program Application is complete within 5 business days. A Subscriber Organization receiving notice of an incomplete Pilot Program Application shall revise and resubmit within 10 days of receiving the notice. If a Pilot Program Application exceeds the available program capacity, the Applicant will be offered the opportunity to reduce the applicant's facility size to fit within the Pilot Program's capacity limit for the applicable category within 2 business days of the offer. If the applicant does not agree to reduce their facility size or the category is otherwise complete, the Pilot Program Application shall be placed on a waiting list in order of receipt for the year and category for which the Pilot Program Application was made. Wait listing one Pilot Program Application does not preclude the Company from accepting a smaller Pilot Program Application received after the deferred Pilot Program Application. A CSEGS identification number will be assigned and capacity in the Pilot Program queue will be reserved for the Subscriber Organization's specific CSEGS upon a complete and accepted Pilot Program Application. Once the Company has reserved sufficient program category capacity, the category will be closed. Any further applications received prior to the next anniversary date of the Pilot Program will be added to the category waiting list. Applicants on the waiting list for the first year of the pilot program must reapply for Pilot Program capacity in subsequent years. The Company will fill the queue for the third year of the pilot program starting with applicants' waitlisted projects from the second year of the pilot program.

If a CSEGS or Subscriber Organization raises a dispute with the Company or the Commission regarding the processing of its Interconnection Application or its Pilot Program Application, the Company will not set aside capacity for the CSEGS during the pendency of the investigation of the dispute. The Pilot Program Application Form and available pilot program capacity can be found at www.pepco.com/greenpowerconnection.

If a Subscriber Organization fails to maintain its project's position in the Pilot Program queue, the Company will select the next available project from the current category waitlist. The Company will add unused category capacity to the next year's category capacity.

Pilot Program Applications will only be accepted in electronic format as defined by the Company. The Company will maintain an accurate log of Pilot Program Applications for verification of application time, date and order. In order to apply for capacity in an electric company's pilot program queue, a Subscriber Organization shall provide the following to the electric company with Pilot Program Application:

1. A partially executed interconnection agreement
2. Proof of application for all applicable permits consisting of a receipt confirming the filing fee from a local jurisdiction demonstrating application for at least one of the following permits:
    a. Site Plan Review Application;
    b. Zoning Conditional Use Application;
    c. Zoning Variance Application;
    d. Zoning Certificate of Use Application;
    e. Special Exception Application;
    f. Board of Appeals Hearing Application; or
    g. Building Permit Application.

    If one of the preceding is not available due to preliminary action required by the jurisdiction, the Subscriber Organization may provide a receipt confirming completion of the preliminary action in lieu of one of the permits listed above. If a subscriber organization is unable to provide confirmation of the required permit application within 120 days of application, the Company may rescind the award of project capacity.
3. Proof of site control:
    a. Evidence of property ownership;
    b. An executed lease agreement; or
    c. A signed option to purchase or lease.
4. Selection of one of the Following Project types, as defined in COMAR 20.62.02.02A(3):
    a. Small/Brownfield/Other;
    b. Open; or
    c. Low to Moderate Income (LMI).
5. Evidence to brownfield status (if applicable) to include one of the following:
    a. Inclusion of the site on a list of contaminated or polluted sites maintained by a Federal or State agency;
    b. Inclusion of the site on the MDE Land Restoration Program List, Voluntary Cleanup Program Notice of Application List, or Closed Landfills List;
    c. A letter of certification from the MDE indicating that a closed landfill or contaminated/polluted site is under its regulation;
    d. A copy of a state-issued surface mining permit or license;
    e. A USGS map indicating that the site has been mined;
    f. A letter of certification from a geotechnical consulting firm certifying that surface mining operations were performed at the site.

If a CSEGS fails to begin operating within 12 months of being notified by the Company that it has been accepted into the Pilot Program, it shall be removed from the queue unless the Subscriber Organization pays $50 per kW to maintain its spot in the queue for 6 additional months. CSEGSs in LMI category are exempt from queue deposits. A CSEGS may lose its place in the queue if the Subscriber Organization does not complete any item required by the Company. The Company will notify a subscriber organization prior to removal from the queue.

The Subscriber Organization must provide their initial information on Subscribers to the CSEGS using the Subscriber Information Form. The CSEGS Subscriber Information Form can be found at www.pepco.com/greenpowerconnection. Information included on the form includes:

1. CSEGS Identification Number,
2. Subscriber Organization Identification Number,
3. Subscriber Organization Name,
4. Date of Submission,
5. Subscriber's name (per the Company account),
6. Subscriber's Account Number,
7. Subscriber's LMI Eligibility,
8. Subscriber's Percentage of CSEGS Output, and
9. Subscriber's email address.

A Subscriber Organization will certify in the Pilot Program Application that their Subscriber Organization will verify that for each new or modified subscription, the Subscription will not cause the Customer to exceed the statutory 200% Baseline Annual Usage eligibility threshold. This verification is subject to check by the Company.

The Subscriber Organization will certify in the Pilot Program Application each Subscriber's LMI eligibility, if relevant to the CSEGS.

The Subscriber Organization will certify in the Pilot Program Application that each Subscriber authorizes the utility to release that Subscriber's account information to the Subscriber Organization as necessary.

Once operational, Subscriber Organizations must update their Subscriber information for each CSEGS every month unless there is no change from the previous month. A Subscriber Organization must replace LMI subscribers that are removed from the Subscriber List with eligible LMI customers such that 30% of kWh output is provided to LMI customers. Updates to Subscriber information must be submitted via email using the CSEGS Subscriber Information Form. The CSEGS Subscriber Information Form can be found at www.pepco.com/greenpowerconnection. Non-compatible or incorrect information will be provided to the Subscriber Organization. Subscriptions may not take effect retroactively.

Depending on timing of notification from the Subscriber Organization of the Subscriber's subscription amount, it may take up to two billing cycles before a bill credit is applied to the Subscriber's bill. Updates received by the Company on or before the 10th of each month will be effective the following month. Subscriptions may not take effect retroactively.

The Company shall purchase any Unsubscribed Energy produced by the CSEGS at the hourly PJM Residual Metered Load Aggregate Locational Marginal Prices (LMPs) for the Pepco Maryland sub-zone for energy adjusted as necessary to include ancillary service charges. Subscriptions associated with ineligible Subscribers (such as subscribers that are not the Company customers or have finalized their Company accounts) will be treated as Unsubscribed Energy. No retroactive corrections or changes can be made to Subscriber information or allocation percentage.

F. SUBCRIPTIONS

A Subscriber is a Customer of the Company taking service on any electric Tariff Schedule being billed the same charges that would be assigned if the Subscriber were not participating in this pilot program.

A Customer may have Subscriptions to more than one CSEGS, but no more than 4, and may also participate in net-metering.

A Subscriber may not subscribe for greater than 200% of their Baseline Annual Usage, including any net-metered customer-generators, if applicable. The Customer's Baseline Annual Usage is the total of the Customer's previous 12 months of electricity use in kilowatt-hours at the time the Company is notified of the Subscription or of a change in the Customer's Subscription. If the Customer does not have 12 months of electric energy use in kilowatt-hours at this time, then the Baseline Annual Usage may be estimated based on a mutually agreeable method subject to approval by the Maryland Public Service Commission. Subscriber Organizations applying under this rider may be subject to FERC jurisdiction with respect to net sales of excess generation and interconnection requirements.

A Customer may only subscribe to a CSEGS that is located in the same service territory as the Customer.

For each Subscription, a Subscriber will be enrolled in the Company's Community Net Metering rider and receive a monthly CNM Credit as set forth in the rider.

G. RENEWABLE ENERGY CREDITS

The Subscriber Organization shall own any Solar Renewable Energy Credits ("SRECs") associated with the electricity generated by the CSEGS, unless the SRECs are explicitly contracted for through a separate agreement.

H. METERING

Metering for a CSEGS will be divided in to a net input and a net output channel. All usage on the input channel will be billed in accordance with the applicable tariff schedule of the CSEGS. All generation on the output channel will be used in the calculation of the Subscriber Credits and Unsubscribed Energy.

The Company shall furnish, install, maintain, and own all the metering and data acquisition equipment needed for measurement of the service supplied. To participate under this rider, the Company must be able to remotely read the CSEGS's meter.

I. INTERCONNECTION WITH THE COMPANY'S SYSTEM

Interconnection with the Company's system requires the installation of protective equipment which provides safety for personnel, affords adequate protection against damage to the Company's system or to its Customer's property, and prevents any interference with the Company's supply of service to other Customers. The Company shall not be liable for any loss, cost, damage, or expense to any party resulting from the use or presence of electric current or potential which originates from CSEGS, except as the Company would otherwise be liable under the Company's Maryland electric tariff. Such protective equipment shall be installed, owned, and maintained by the Subscriber Organization at their expense. In addition, it may be necessary for the Company to extend or modify portions of its systems to accommodate the delivery of electricity from the

CSEGS. Should such extension or modification be necessary, all work shall be performed by the Company at the Subscriber Organization’s expense.

The CSEGS shall conform to the National Electrical Code and the applicable codes of the local public authorities. Special attention should be given to the National Electrical Code Sections 690 and 705.

J. CESSATION OF PARALLEL OPERATION

The CSEGS must be installed and configured so that parallel operation must cease immediately and automatically during system outages or loss of the Company’s primary source. The CSEGS must also cease parallel operation upon notification by the Company of a system emergency, abnormal condition, or in cases where such operation is determined to be unsafe, interferes with the supply of service to other Customers, or interferes with the Company’s system maintenance or operation. The Company shall not be liable for damage or injury to any person or property caused by failure of the CSEGS to operate in compliance with Company’s requirements.

K. FAILURE TO COMPLY

If the CSEGS fails to comply with any of the requirements set forth in sections H and I above, the Company may disconnect the CSEGS’s service from the Company’s electric system until the requirements are met.

L. DEFINITIONS

Capitalized Terms not defined in the Company’s General Terms and Conditions for Furnishing Electric Service in Maryland are as defined in Maryland Public Utilities Article § 7-306.2 or in Section 20.62 of the Code of Maryland Regulations.

RESIDENTIAL TIME-OF-USE PILOT PROGRAM

SCHEDULE "R-TOU-P"

AVAILABILITY
Available to existing Residential Standard Offer Service customers, who have been selected by the Company and who affirmatively elect to participate in the pilot program, or those who voluntarily decided to opt-in to the rate.

Customers with less than 12 months of interval data at their current premise are prohibited from being enrolled to this rate. In addition, the following customers are excluded from being enrolled to this rate for operational reasons: customers without activated advanced metering infrastructure (AMI) capable of registering interval usage; customers currently engaged in aggregate net energy metering under the Aggregate Net Energy Metering Rider "ANEM;" or participants in the community solar pilot program under Community Solar Pilot Program Schedule "CS" and the Community Net Energy Metering Pilot Program Rider "CNM".

A maximum of 10% of pilot participants can be net metered under the Net Energy Metering Rider "NEM."

The rate will be effective with the customer's first bill cycle falling on or after April 1, 2019 and remain for three years, or until the customer decides to opt-out of the rate, at which time they will be placed on Residential Service Schedule "R." Customers who choose to opt-out of the pilot prior to the completion of the two years shall not be allowed to return to the pilot rate. A customer may sign up for the rate until April 1, 2021, and the tariff will be in effect until April 1, 2022.

CHARACTER OF SERVICE
The service supplied under this schedule normally will be alternating current, sixty hertz, single phase, three wire 120/240 volts, or three wire, 120/208 volts.

MONTHLY RATE

	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 8.01 per month	$ 8.01 per month
Kilowatt-hour Charge		
On-Peak	$0.20634 per kwhr	$0.20634 per kwhr
Off-Peak	$0.02357 per kwhr	$0.02357 per kwhr

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions in this Pilot Service Classification will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

BILLING MONTHS
Summer – Billing months of June through September.
Winter – Billing months of October through May.

RATING PERIODS

Summer - On Peak hours will be between the hours of 2:00 pm and 7:00 pm, excluding weekends and holidays.

Winter - On Peak hours will be between the hours of 6:00 am and 9:00 am, excluding weekends and holidays.

Holidays
For the purpose of this tariff, holidays will be New Year's Day, Rev. Martin Luther King's Birthday, Presidents' Day, Memorial Day, Independence Day, Labor Day, Columbus Day, Veterans' Day, Thanksgiving Day and Christmas Day, as designated by the Federal Government.

METER READING
The hourly readings of the AMI System smart meter will be aggregated in to the On-Peak and Off-Peak periods designated by the Company, to the nearest multiple of the meter constant, and bills rendered accordingly.

GROSS RECEIPTS TAX
A surcharge of 2.0408% is applied to the transmission and distribution components of the customer's bill to recover the amount attributable to the Gross Receipts Tax.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS
Standard Offer Service – Residential
Administrative Credit
Universal Service Charge Recovery
Delivery Tax Surcharge
Montgomery County Surcharge
Maryland Environmental Surcharge
Optional Meter Equipment Related Services
Bill Stabilization Adjustment
Empower MD Charge
Residential Direct Load Control
RGGI Rate Credit
Demand Resource Surcharge
Dynamic Pricing – Peak Energy Savings Credit

**PUBLIC ELECTRIC VEHICLE CHARGING SERVICE
SCHEDULE “PC-PIV”**

AVAILABILITY – Available only for the purpose of Plug-in Vehicle (“PIV”) battery charging from Company-operated Level 2 (L2) and Direct Current Fast Charging (DCFC) public electric vehicle (EV) charging stations. All public EV charging stations will be sited on property either owned by government entities or government-associated organizations or controlled by those entities and organizations (such as through easements, right-of-ways, or similar legal or equitable mechanisms). L2 charging stations shall cover applications with demand loads up to 19.2 kW. DCFC charging stations cover applications with demand loads greater than 19.2 kW.

The service provided under Schedule “PC-PIV” allows EV operators to charge their EV at a Company-owned public charging station. EV operators who reside either within the Company’s service territory or outside the Company’s service territory are eligible to charge their EV at a Company-owned station.

CHARGING RATE FOR EV OPERATOR
Charges under Schedule “PC-PIV” will be administered and billed through the Company’s third-party vendor (Network Provider) on behalf of the Company. Information on opening an account with the Company’s Network Provider is available on the Company’s website. EV operators that charge their vehicle at a Company-owned station are subject to the payment terms of the Company’s Network Provider.

Any EV operator using Company-operated public EV charging stations for the purpose of PIV battery charging shall pay for such service at the rates listed below. Upon Company verification and account registration, a user operating within the Company’s electric distribution territory 5 or more EVs titled and registered with the Maryland Department of Transportation Motor Vehicle Administration is eligible for a DCFC Charging Stations Multi-Vehicle rate equal to 75 percent of the DCFC Charging Stations Standard rate. These rates are subject to change periodically, subject to Commission approval.

L2 Charging Stations:	$0. 18 per kwhr
DCFC Charging Stations Standard Rate:	$0. 34 per kwhr
DCFC Charging Stations Multi-Vehicle Rate:	$0.255 per kwhr

Schedule “PC-PIV” is provided in conjunction with the contract for service under the applicable Rate Schedule (the Controlling Rate Schedule), as determined by the availability of each Rate Schedule. Controlling Schedule provisions apply, unless they are specifically altered herein.

APPLICABLE RIDERS
The applicable Riders for Schedule “PC-PIV” are determined by the Controlling Rate Schedule, unless they are specifically altered herein.

Rider “Green” provides 100% renewable energy on a mandatory basis to the Controlling Rate Schedules associated with Schedule “PC-PIV.”

CONDITIONS

1. Schedule "PC-PIV" is designed for retail charging service to EV operators at Company-owned public charging stations. Customer-owned EV chargers are not eligible for service under Schedule "PC-PIV."
2. The Charging Rate pricing provided in this tariff is part of a pilot program and is subject to change.
3. Additional fees may apply based on siting location.
4. Operation, repair and maintenance of electric vehicle charging stations on this rate schedule will be the responsibility of the Company.
5. The Company may at its discretion install, relocate, modify, or remove electric vehicle charging stations. Potential modifications to Company operated electric vehicle charging stations may include adding, removing, or changing electric vehicle supply equipment available for charging service. The chargers and the charger site must be accessible to the company at all times, including accessibility for installing the chargers, maintaining the chargers, or performing any work on the chargers.
6. The charger must be accessible to the public for charging at all times.

GENERAL TERMS AND CONDITION
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

UNIVERSAL SERVICE CHARGE RECOVERY

RIDER "USC"

UNIVERSAL SERVICE CHARGE RECOVERY RIDER
This rider is applicable to Schedules "R", "R-TM", "GS", "GT LV", "GT 3A", "GT 3B", "MGT LV II", “MGT LV III”, "MGT 3A II", “MGT 3A III”, "T", "TM-RT", "EV", “R-PIV”, and “R-TOU-P”. Amounts billed to customers shall include a surcharge to recover costs of Universal Service Programs required by the Maryland Electric Customer Choice and Competition Act, including bill assistance, low-income weatherization and the retirement of arrearages that were incurred prior to July 1, 2000.

Schedules "R", "R-TM", “R-PIV”, “R-TOU-P” customers will be charged $0.32 per month per account.

Customers on Schedules "GS", "GT LV", "GT 3A", "GT 3B", "MGT LV II", “MGT LV III”, "MGT 3A II", “MGT 3A III”, "T", "TM-RT", and "EV" will be charged based on the Customer's previous annual distribution revenue, updated in the first quarter of each new year, and in accordance with the Commission’s order.

Customer’s Annual Electric Distribution Bills For Previous Year			Customer Charge (Per Month)
Under $175			$0.25
$175	-	$1,299	$1.85
$1,300	-	$2,599	$6.14
$2,600	-	$6,499	$12.28
$6,500	-	$12,999	$24.56
$13,000	-	$25,999	$36.85
$26,000	-	$51,999	$49.13
$52,000	-	$77,999	$92.12
$78,000	-	$103,999	$122.82
$104,000	-	$129,999	$184.22
$130,000	-	$181,999	$276.35
$182,000	-	$233,999	$368.46
$234,000	-	$259,999	$552.69
$260,000	-	$519,999	$736.91
$520,000	-	$779,999	$982.55
$780,000	-	$1,039,999	$1,228.19
$1,040,000	-	$1,299,999	$1,473.83
$1,300,000	-	$1,559,999	$1,719.47
$1,560,000	-	$1,819,999	$1,965.10
$1,820,000	-	$2,079,999	$2,149.33
$2,080,000	-	$2,339,999	$2,333.56
$2,340,000	-	$2,599,999	$2,456.38
$2,600,000	-	$3,249,999	$2,579.20
Over $3,250,000			$2,763.43

EXPERIMENTAL RESIDENTIAL
ELECTRIC VEHICLE SERVICE
RIDER "R-EV"

EXPERIMENTAL RESIDENTIAL ELECTRIC VEHICLE SERVICE
This experimental rider is applied to and is a part of Schedule "R" when a customer volunteers for this experimental service subject to the provisions listed below. Effective June 16, 2007 this rider is closed to new customers.

Available to customers who require electric service to provide electric vehicle battery charging in premises where other electric requirements are furnished under Schedule "R". Electric vehicle, for the purpose of this rider, will be defined as an electric motorized vehicle licensed to operate on public roadways.

Rider "R-EV" will be limited to the first 50 customers who request participation and agree to the provisions of Rider "R-EV" listed herein. Additional customers may be added to Rider "R-EV" only when a customer previously served under Rider "R-EV" has been removed from this rider.

A customer will be removed from this rider when either of the following occurs:

a. Electric vehicle battery charging is no longer required due to removal of vehicle or a change in customer.
b. The customer fails to comply with any of the terms of Rider "R-EV".

While this rider is experimental, the Company agrees to provide a dedicated circuit for the sole purpose of charging electric vehicles and the customer agrees to only charge electric vehicles on this circuit.

While this rider is experimental, the Company agrees to install at its own expense the dedicated circuit required and any special equipment which may be required to monitor usage and power quality as specified in the next paragraph. The Company, at its sole discretion, may elect to not provide the service in this rider if it determines that the associated costs are prohibitively high. In this case the customer will be allowed to charge electric vehicles from any available circuit in his or her home and all of the other provisions of Riders "R-EV" shall apply.

The customer agrees to allow the Company to install and maintain necessary equipment to monitor the usage to charge the electric vehicle and the power quality of the electric vehicle charging equipment used by the customer.

For Distribution Services, the first 400 kilowatt hours used per month will be billed at the "Monthly Rate". The rate is then modified so that the charge for the next 200 kilowatt hours, which are in excess of 400 kilowatt hours per month is billed at the Monthly Rate - Rider "R-EV". The usage in excess of 600 kilowatt hours, if any, shall be billed at the otherwise applicable rate for consumption exceeding 400 kilowatt hours.

MONTHLY RATES

	Summer	Winter
Distribution Service Charge		
Kilowatt-hour Charge	$ 0.00556 per kwhr	$ 0.00556 per kwhr

EXPERIMENTAL RESIDENTIAL
TIME-OF-USE ELECTRIC VEHICLE SERVICE
RIDER "R-TM-EV"

EXPERIMENTAL RESIDENTIAL TIME-OF-USE ELECTRIC VEHICLE SERVICE
This experimental rider is applied to and is a part of Schedule "R-TM" when a customer volunteers for this experimental service subject to the provisions listed below. Effective June 16, 2007 this rider is closed to new customers.

Available to customers who require electric service to provide electric vehicle battery charging in premises where other electric requirements are furnished under Schedule "R-TM". Electric vehicle, for the purpose of this rider, will be defined as an electric motorized vehicle licensed to operate on public roadways.

Rider "R-TM-EV" will be limited to the first 50 customers who request participation and agree to the provisions of Rider "R-TM-EV" listed herein. Additional customers may be added to Rider "R-TM-EV" only when a customer previously served under Rider "R-TM-EV has been removed from this rider.

A customer will be removed from this rider when any of the following occurs:

a. When the customer chooses Schedule "R" the provisions of Rider "R-EV" will apply.
b. Electric vehicle battery charging is no longer required due to removal of vehicle or a change in customer.
c. The customer fails to comply with any of the terms of Rider "R-TM-EV".

While this rider is experimental, the Company agrees to provide a dedicated meter for the sole purpose of metering electric vehicles and the customer agrees to only charge electric vehicles on this meter. A separate bill will be rendered for the service provided under this rider.

While this rider is experimental, the Company agrees to install at its own expense the dedicated meter required and any special equipment which may be required to monitor usage and power quality as specified in the next paragraph. The Company, at its sole discretion, may elect to not provide the service in this rider if it determines that the associated costs are prohibitively high.

The customer agrees to allow the Company to install and maintain necessary equipment to monitor the usage to charge the electric vehicle and the power quality of the electric vehicle charging equipment used by the customer.

For Distribution Services, all consumption except the kilowatt-hours metered for electric vehicle battery charging will be billed at the "Monthly Rate". The rate is then modified so that the charge for the kilowatt hours metered for electric vehicle battery charging is billed at the Monthly Rate - Rider "R-TM-EV".

MONTHLY RATES

	Summer	Winter
Distribution Service Charge		
Kilowatt-hour Charge	$ 0.00465 per kwhr	$ 0.00465 per kwhr

NET ENERGY METERING

RIDER "NEM"

A. AVAILABILITY

This rider is applied to and is a part of Maryland Schedules "R", "RTM", "GS", "GT LV", "GT 3A", "GT 3B", "MGT LV II", "MGT LV III", "MGT 3A II ", and "MGT 3A III". This rider is available to any eligible Customer, regardless of the Customer's Electricity Supplier, that owns and operates, leases and operates, or contracts with a third party that owns and operates a customer-generator that:

1. Uses as its primary source of fuel: biomass, micro combined heat and power (MCHP), solar, qualifying closed conduit hydroelectric, fuel cell or wind consistent with Public Utilities Article §7-306, Annotated Code of Maryland:
2. Has a capacity of not more than 2 MW except for a MCHP customer-generator which must have a capacity of not more than 30 kW;
3. Is located on the Customer's premises or contiguous property;
4. Is interconnected and operated in parallel with an electric company's transmission and distribution facilities; and
5. Is intended primarily to offset all or part of the Customer's own electricity requirements.

Consistent with Code of Maryland Regulations 20.50.10.01 D.(1)(6), a Customer's proposed customer-generator system may not exceed 200% of the Customer's Baseline Annual Usage. The Customer's Baseline Annual Usage is the total of the Customer's previous 12 months of electricity use in kilowatt-hours at the time of the installation or upgrade of the Customer's generating system. If the Customer does not have 12 months of electric energy use in kilowatt-hours at the time of the installation of the Customer's generating system, then the Baseline Annual Usage may be estimated based on a mutually agreeable methodology subject to approval by the Maryland Public Service Commission.

This rider is available on a first-come, first-served basis as long as the total rated electric generating capacity of eligible customer-generators in the State of Maryland does not exceed 1,500 MW.

B. CONNECTION TO THE COMPANY'S SYSTEM

Any Customer who elects this rider must submit a completed interconnection/participation application with the Company, in writing, at least 30 days prior to activating the eligible customer-generator. The eligible customer-generator shall not be connected to the Company's system unless it conforms to the National Electrical Code, the Institute of Electrical and Electronic Engineers, Underwriters Laboratories and the applicable codes of the local public authorities. The Customer must obtain, at their expense, all necessary inspections and approvals required by the local public authorities before the eligible customer-generator is connected to the Company's electric system. The eligible customer-generator shall have adequate protection as described in Section H below.

C. DELIVERY VOLTAGE

The delivery voltage of the eligible customer-generator shall be at the same voltage level and at the same delivery point as if the Customer were purchasing all of their electricity from the Company.

D. CONTRACT TERM

The contract term shall be same as that under the Customer's applicable Service Classification. A completed Interconnection Application, completed by the Customer and accepted by the utility, is required for service provided under this rider.

E. MONTHLY RATES, RATE COMPONENTS AND BILLING UNIT PROVISIONS

The monthly rates, rate components and billing unit provisions shall be those as stated under the Customer's applicable Service Classification. Under this rider, only the per kilowatt-hour charge components of the Customer's bill are affected. All other billing components and charges, such as Customer Charge and Demand Charge are not affected by this rider. The monthly charges shall be based on one the following conditions:

1. When the monthly energy meter reading registers that the Customer has consumed more energy than the Customer delivered to the Company's delivery system by the end of the monthly billing period, the Customer shall be charged for the electricity consumed based on the rates and charges under the Customer's applicable Rate Schedule for either Distribution Service or the Company's combined Standard Offer Service and Distribution Service.

2. When the Customer has delivered more energy to the Company's delivery system than the Customer has consumed by the end of the monthly billing period ("Excess Generation"), the Company shall take ownership of such Excess Generation, regardless of the Customer's Electricity Supplier, and the Customer shall be charged the greater of:
   a. The Customer Charge, and any applicable non-energy charges such as: Demand Charge and Universal Service Charge under the Customer's applicable Rate Schedule, or
   b. The monthly Minimum Charge under the Customer's applicable Rate Schedule.

3. The Company will carry forward negative kilowatt-hours reading until the Customer's consumption of electricity from the grid eliminates the Excess Generation or until the end of the billing cycle that is completed immediately prior to the end of April of each year. For Customers served under Standard Offer Service, the dollar value of Excess Generation shall be equal to the Generation portion of the rate that the Customer would have been charged averaged over the previous 12-month period ending with the billing cycle that is complete immediately prior to the end of April multiplied by the number of kilowatt-hours of Excess Generation. For Customers served by alternate suppliers of electricity supply service, the dollar value of Excess Generation shall be equal to the Generation portion of the rate that the Customer-generator would have been charged by the electricity supplier, if that rate is known by the Company, multiplied by the number of kilowatt-hours of Excess Generation.

4. On or before 30 days after the billing cycle that is complete immediately prior to the end of April of each year, the Company shall pay each Customer for the dollar value of any accrued net excess generation remaining at the end of the previous 12-month period ending with the billing cycle that is complete immediately prior to the end of April of that year. Payments for the value of Excess Generation less than $25 may be in the form of a bill credit.

5. Within 15 days after the date the Customer closes the Customer's account, the Company shall pay the Customer for the dollar value of any accrued Excess Generation remaining at the time the Customer closes the account.

6. The application of this rider to Schedules "RTM", "GT LV", "GT 3A", "GT 3B", "MGT LV II", "MGT LV III", "MGT 3A II", and "MGT 3A III", shall be on the basis of each Time Metered pricing instead of on the basis of the total monthly energy.

F. RENEWABLE ENERGY CREDITS

The Renewable Energy Credits generated by the customer-generator are owned entirely by the Customer or the eligible Customer's assignee. However, if the Customer chooses to sell solar Renewable Energy Credits, the Customer must first offer them for sale to an electric company or an electricity supplier that shall apply them toward compliance with the Maryland Renewable Energy Portfolio Standard.

G. METERING

The Company shall furnish, install, maintain and own all the metering equipment needed for measurement of the service supplied. Under this rider, the Company shall provide, at no direct charge, a watt-hour energy meter with the capability of reverse registration in order to measure the net watt-hours consumed by the Customer or the net watt-hours delivered by the Customer to the Company for the total billing period. The Company's metering investment shall be limited to that required to serve the Customer under the Customer's applicable Rate Schedule without the eligible customer-generator. Where a larger capacity meter is required to serve the Customer that has an eligible customer-generator, or a larger capacity meter is requested by the Customer, the Customer shall pay the Company the difference between the larger capacity meter investment and the metering investment normally provided under the Customer's Rate Schedule.

H. INTERCONNECTION WITH THE COMPANY'S SYSTEM

Interconnection with the Company's system requires the installation of protective equipment which, provides safety for personnel; affords adequate protection against damage to the Company's system or to its customer's property; and prevents any interference with the Company's supply of service to other Customers. The Company shall not be liable for any loss, cost, damage or expense to any party resulting from the use or presence of electric current or potential which originates from the Customer's eligible customer-generator, except as the Company would otherwise be liable under the Company's Maryland electric tariff. Such protective equipment shall be installed, owned and maintained by the Customer at their expense. In addition, it may be necessary for the Company to extend or modify portions of its systems to accommodate the delivery of electricity from the eligible customer-generator. Should such extension or modification be necessary, all work shall be performed by the Company at the Customer's expense. For new services, such expense shall be determined by the difference between total costs and the investment the Company would make to install a normal service without the Customer's eligible customer-generator.

The eligible customer-generator shall conform to the National Electrical Code and the applicable codes of the local public authorities. Special attention should be given to the National Electrical Code Sections 690 and 705.

I. CESSATION OF PARALLEL OPERATION

The Customer's equipment must be installed and configured so that parallel operation must cease immediately and automatically during system outages or loss of the Company's primary source. The Customer must also cease parallel operation upon notification by the Company of a system emergency, abnormal condition, or in cases where such operation is determined to be unsafe, interferes with the supply of service to other Customers, or interferes with the Company's system maintenance or operation. The Company accepts no responsibility whatsoever for damage or injury to any person or property caused by failure of the Customer to operate in compliance with Company's requirements.

J. FAILURE TO COMPLY

If the Customer fails to comply with any of the requirements set forth in sections H and I above, the Company will disconnect the Customer's service from the Company's electric system until the requirements are met, or the eligible customer-generator is disconnected from the Customer's electric system.

K. RULES AND REGULATIONS

Except as herein modified, the Rules and Regulations set forth in this Tariff shall govern the provision of service under this Rider and under the Customer's applicable Service Classification.

TELECOMMUNICATION NETWORK CHARGE

RIDER "SL-TN"

RIDER "SL-TN" - TELECOMMUNICATION NETWORK CHARGE"
This rider is applied to and is part of Schedule "SL" when a customer owns street lights which have attached telecommunications network devices not exceeding 15 watts per device. In such case the monthly rate for Distribution Services is modified such that there will be the following additional charges applied to the consumption of the telecommunications network device.

MONTHLY RATE

	Summer	**Winter**
Distribution Services Charge		
Kilowatt-hour Charge	$ 0.02892 per kwhr	$ 0.01586 per kwhr

POWER FACTOR

RIDER "PF”

POWER FACTOR RIDER

This rider is applied to and is a part of Schedule "GS", "GT LV", "GT 3A", "GT 3B", "MGT LV II", “MGT LV III”, “MGT 3A II”, and "MGT 3A III" if the customer is found to have a leading power factor or a lagging power factor of less than 85%. If power factor corrective equipment satisfactory to the Company has not been installed within ninety (90) days of notification by the Company, the kW charges for "GT LV", "GT 3A", "GT 3B", "MGT LV II ", “MGT LV III”, “MGT 3A II”, and "MGT 3A III" or the kilowatt-hour charges for "GS" will be multiplied by a factor of 1.1111.

THERMAL ENERGY STORAGE SERVICE

RIDER "TS"

THERMAL ENERGY STORAGE SERVICE RIDER
This rider is applied to and is a part of Schedule "GT LV", "GT 3A", "GT 3B", "MGT LV II", “MGT LV III”, “MGT 3A II”, and "MGT 3A III" where the customer's primary cooling energy requirements are supplied by an electrical thermal energy storage system. In this case, the Maximum Demand Rate is modified as follows:

> **Maximum Demand** - The billing demand shall be the maximum thirty (30) minute demand recorded all weekday hours between 8 a.m. and 8 p.m., except those on holidays.

DELIVERY TAX SURCHARGE

RIDER "DT"

DELIVERY TAX SURCHARGE
This rider is applicable to Schedules "R", "R-TM", "GS", "GT LV", "GT 3A", "GT 3B", "MGT LV II", “MGT LV III”, “MGT 3A II”, "MGT 3A III", "T", "OL", "TM-RT", "EV", “PIV”, “R-PIV” and “R-TOU-P”, "SL" and "TN". The purpose of this rider is to recover the Franchise Tax (Delivery).

The current applicable Rider “DT” is available on the Company’s website at www.pepco.com

MONTGOMERY COUNTY SURCHARGE

RIDER "MCS"

MONTGOMERY COUNTY SURCHARGE
This rider is applied to customers located in Montgomery County. The rider collects the revenue required to compensate the Company for the Montgomery County Fuel and Energy Tax imposed by Montgomery County.

The current applicable Rider "MCS" is available on the Company's website at **www.pepco.com/md-rates**.

This surcharge normally will be recomputed and revised on July 1.

MARYLAND ENVIRONMENTAL SURCHARGE

RIDER "MES"

MARYLAND ENVIRONMENTAL SURCHARGE RIDER
This rider is applied to collect the revenue required to compensate the Company for the environmental surcharge imposed by the State of Maryland on all kilowatt-hours generated in Maryland.

The current applicable Rider “MES” is available on the Company’s website at www.pepco.com.

This surcharge normally will be determined by the Maryland Pubic Service Commission as of June 30, each year to be applied the following year.

OPTIONAL METER EQUIPMENT RELATED SERVICES

RIDER “OMRS”

OPTIONAL METER EQUIPMENT RELATED SERVICES
This rider is applied to and is a part of Schedules “R”, “R-TM”, "GS", "MGT LV II", “MGT LV III”, “MGT 3A II”, "MGT 3A III", "GT LV", "GT 3A", "GT 3B", “TM RT” and “R-TOU-P” when a qualifying Customer requests and receives a value added service offered by the Company that involves use of the Company’s metering equipment in providing, in whole or in part, the desired service.

SERVICES OFFERED BY THE COMPANY
GenerLink™ Service - GenerLink™ Service is available to residential customers served under Schedules “R” and “RTM” utilizing GenerLink™ with their on-site generators. GenerLink™ is a device inserted between the residential electric meter and meter socket that provides a convenient means for the Customer to deploy an electricity generator as the source of electrical power for the operation of Customer-selected household loads. GenerLink™ automatically disconnects a house from the Company’s electric service at a point in this supply circuit that will prohibit power flow between the Company distribution system and Customer generator (and vice versa) before permitting the generator’s connection into this circuit for the purpose of supplying the selected household loads. This program is subject to the provisions listed below.

1. This service is available to residential Customers served under Schedules “R” and “R-TM” who have a 120/240 volt, single phase, three wire class of service and a meter socket maximum rating of 200 amperes (or less).
2. The meter socket must be of a design and construction permitting proper insertion of the GenerLink™ device between meter and meter socket without adversely affecting full functionality of meter socket. The Company may charge the Customer to replace the meter socket, if such replacement is necessitated solely by the need to accommodate GenerLink™ and if the customer owns the meter socket.
3. The meter socket must be located outdoors and be mounted in compliance with Company published specifications as to height (above grade), stability of installation and clearance from obstruction. The Customer’s portable generator must have a rating of at least 4,400 watts but not more than 7,200 continuous watts. The maximum rated capacity of the generator load through GenerLink™ may not exceed 7.2 kW continuous. All power generated must be delivered through a single power take-off. The generator’s specified operating voltage must be 120/240 volt, single phase.
4. The maximum recommended length of the Customer’s electrical connection cord (a cord that is connected at one end to the generator and at the other to GenerLink™) is 60 feet, and may not exceed 75 feet in length. It should be a 10/4 “SO” cord with a NEMA L14-30R twist-lock receptacle on one end to connect to GenerLink™ and one of four possible plug ends: NEMA L14-30P or L14-20P locking or NEMA 14-30P or 14-20P straight four-pronged plug for connection to the customer’s generator. The plug selection will be specific to the customer’s generator and can be determined from the NEMA number on the generator.

In accepting participation in this program, the Customer agrees to the following:

1. The Company will be responsible for the procurement and installation of the GenerLink™ device. The Company does not make any representation, warranty or covenant of any kind or nature expressed or implied with respect to the condition, quality, durability, suitability or use of this device. The Company disclaims any implied warranty of merchantability or fitness for any particular purpose. The device shall remain the property of the Company at all times. At no time shall the Company approve any subletting, assignment or removal of the product to any location other than the original meter socket assigned by the Company.
2. The generator connected to the GenerLink™ device will be operated outdoors and will be properly serviced and maintained as directed by the equipment owner's manual at the Customer's expense.
3. This program is available for a minimum two (2) year term. The Customer agrees to pay the Company a monthly service fee of $9.65, or will pay an upfront fee of $225.82 to compensate the Company for providing GenerLink™ service for two years. The upfront fee is based on the present value of the twenty-four (24) monthly payments using the current interest rate on customer deposits, and may vary each year as the interest rate changes. After two years the Customer will continue to make monthly payments of $9.65 until the Customer's desire to terminate GenerLink™ Service is made known to the Company and the Company has removed its GenerLink™ device. Billing will be terminated at the end of the month when request is made.
4. The Customer may terminate participation at any time within sixty days of installation for a $42.00 fee representing the Company's installation cost plus payment for the one or two month's service used. If a Customer has paid the Company an upfront fee, the Company will refund the remaining fee on a pro rata basis. Following expiration of the initial two-year term, there is no removal fee if the Customer requests termination. A Customer desiring to terminate during the initial two-year term after the first sixty days shall remain liable for the remaining payments due under the term.
5. In the event the Customer fails to make any monthly payment within thirty (30) days after its due date, the Customer shall be determined to be in default and the Company may take possession of the GenerLink™ device. The Customer shall remain liable for any missed payments.
6. The Customer shall not remove or attempt to disable a GenerLink™ device. The Customer shall contact the Company in the event of problems with or attributed to the device. If the Company determines, upon responding to a complaint, that the GenerLink™ device is functioning properly, the Company may bill the Customer for its reasonable expense in responding to such a complaint.

Advanced Metering Service - Advanced metering service is metering equipment capable of recording 15 minute interval consumption data and collection of such data via remote reading. Advanced metering equipment may also be connected to premise equipment that provides customers with near real-time usage information for energy management purposes.

Customers with billing demands in excess of 500 kW taking advanced metering service may own the meter subject to the provisions stated in the Company's General Terms and Conditions for Furnishing Electric Service, Section 2.g.4 Advanced Metering.

Advanced Metering Service is available to Customers served under Schedules “MGT LV II”, “MGT LV III”, “MGT 3A II”, “MGT 3A III”, “GT LV”, “GT 3A”, “GT 3B”, and “TM RT” subject to the provisions stated in the Company’s General Terms and Conditions for Furnishing Electric Service, Section 2.g.4 Advanced Metering.

1. Customer Demand Monitoring – At the Customer’s request, the Company will provide on-site pulse outputs to the Customer through an isolation relay or similar equipment that will allow the Customer near real-time access to energy consumption data. If the billing meter must be replaced to accommodate the installation of pulse outputs, the Customer is responsible for the costs associated with the installation of any new equipment required and removal of existing equipment as outlined in the Company’s General Terms and Conditions for Furnishing Electric Service. The Company will assess a fee of $ 90.00 and a monthly fee of $ 7.00 for a period of five (5) years. If the isolation relay requires replacement at anytime, the Customer will pay $ 90.00 at the time of replacement and continue to make monthly payments for an additional five (5) year period following the replacement date of the isolation relay. The amount of the monthly payment is developed using the interest on customer deposits and is subject to change as the interest rate is revised by the Commission. The fees cover the installed cost of the isolation relay and associated hardware. The isolation relay is the property of the Customer once installed.
2. Remote “Read Only” Access to Advanced Meter – The Company will allow the Customer or an authorized agent “Read Only” Access to the meter over Customer provided dedicated telephone line or other Company approved telecommunication device. The Customer is responsible for the costs associated with the installation of any new equipment required and removal of existing equipment as outlined in the Company’s General Terms and Conditions for Furnishing Electric Service. The Customer is responsible for all telecommunication charges. The Customer must agree to provide the Company access to the telephone line to obtain data for billing purposes.

EXCESS FACILITIES

RIDER "EF"

RIDER "EF" - EXCESS FACILITIES
This rider will apply if, at the request of the Customer, the Company has installed facilities that are of larger capacity than necessary in the judgment of the Company. Under this rider, the Company will set a kW demand for the Customer that reflects the difference between the projected demand of the Company Plan and the projected demand of the Customer Plan as referenced in the General Terms and Conditions. This kW demand will be billed as a one-time charge at the Demand Rate stated below. Any amount paid under this Rider will be refundable five years after the date of installation of the facilities as stated in the Company's General Terms and Conditions.

One-Time Demand Charge:

MGT LV II and MGT LV III................................$87.52 per kW

MGT 3A II and MGT 3A III................................$61.03 per kW

GT LV...$81.58 per kW

GT 3A and GT 3B ....$68.61 per kW

STANDARD OFFER SERVICE
RIDER "SOS"

RIDER "SOS" – STANDARD OFFER SERVICE

Available in the Maryland portion of the Company's service area for the provision of Generation and Transmission Services to customers who do not have an alternate supplier for Generation and Transmission Services as defined in the Customer Choice Act, Section 7-510(C)(2).

Standard Offer Service (SOS) is available beginning July 1, 2004 in accordance with the provisions contained in the Maryland Case No. 8908 Settlement Agreements (Phase I and II) approved by the Maryland Public Service Commission in Order Nos. 78400 and 78710 and in the Code of Maryland Regulations (COMAR) 20.52 Electric Standard Offer Service.

DESCRIPTION OF SOS TYPES

Residential

Applicable to customers served on Schedules "R", "R-TM" and "R-TOU-P".
Customers may leave or return to Rider "SOS" without penalty by the Company, subject to the Company's General Terms and Conditions.
A Customer shall not change Type within the SOS year.

Type I Non-Residential

Applicable to customers served on Schedules "GS", "T", "SL", "TN", "EV", and "OL".
Customers may leave or return to Rider "SOS" without penalty by the Company, subject to the Company's General Terms and Conditions.
A Customer shall not change Type within the SOS year.

Type II Non-Residential

Applicable to customers served on Schedules "MGT LV II" and "MGT 3A II".
Customers may leave or return to Rider "SOS" without penalty by the Company, subject to the Company's General Terms and Conditions.
A Customer shall not change Type within the SOS year.

Hourly-Priced Service (HPS)

Applicable to customers served on Schedules "MGT LV III", "MGT 3A III", "GT LV", "GT 3A", "GT 3B" and "TM-RT".
Customers may leave or return to Rider "SOS" without penalty by the Company, subject to the Company's General Terms and Conditions.
When a customer purchasing from an alternate supplier, other than the Company, returns or is returned to the Company on or after June 1, 2005, the customer will receive HPS.
A Customer shall not change Type within the SOS year.

MONTHLY RATE

Customers receiving Standard Offer Service will pay the Distribution Service Charge, Transmission Service Charge and Generation Service Charge including all applicable riders. The Distribution Service Charges are stated in the Monthly Rates for the Customer's applicable Rate Schedule.

The Standard Offer Service Rate for each Rate Schedule within each SOS Type, including any usage incurred under associated Riders, will include the following components:

1. The seasonally-differentiated and, if applicable, time-of-use differentiated load weighted average of all awarded electric supply prices for specific services in each year.
2. Retail charges designed to recover, on an aggregate basis, FERC-approved transmission charges and any other PJM charges and costs incurred by Pepco.
3. An administrative charge (included in Generation rates shown below)

Residential	$0.00400 per kwh
Type I	$0.00550 per kwh
Type II	$0.00600 per kwh

4. Applicable taxes.

SOS – Residential (Generation, Transmission including separately calculated GRT, and Procurement Cost Adjustment)

Schedule R

Generation Service Charge	**10/01/19-05/31/20**	**06/01/20-09/30/20**	**10/01/20-05/31/21**
Kilowatt-hour Charge	$ 0.06714 per kwhr	$ 0.05180 per kwhr	$ 0.06516 per kwhr

Transmission Service Charge	**Summer**	**Winter**
Kilowatt-hour Charge	$ 0.01794 per kwhr	$ 0.01794 per kwhr

Procurement Cost Adjustment ***See www.pepco.com for currently effective rate***

Schedule R-TM

Generation Service Charge	**10/01/19-05/31/20**	**06/01/20-09/30/20**	**10/01/20-05/31/21**
Kilowatt-hour Charge			
On Peak	$ 0.06784 per kwhr	$ 0.06533 per kwhr	$ 0.06621 per kwhr
Intermediate	$ 0.06910 per kwhr	$ 0.05134 per kwhr	$ 0.06708 per kwhr
Off Peak	$ 0.06247 per kwhr	$ 0.05014 per kwhr	$ 0.06305 per kwhr

Transmission Service Charge	**Summer**	**Winter**
Kilowatt-hour Charge	$0.01843 per kwhr	$0.01843 per kwhr

Procurement Cost Adjustment ***See www.pepco.com for currently effective rate***

Schedule R-TOU-P

Generation Service Charge	**06/01/20-09/30/20**	**10/01/20-05/31/21**
Kilowatt-hour Charge		
On Peak	$ 0.16295 per kwhr	$ 0.18728 per kwhr
Off Peak	$ 0.04563 per kwhr	$ 0.05740 per kwhr

Transmission Service Charge
Kilowatt-hour Charge **Included in Generation Service Charge**
Procurement Cost Adjustment **See www.pepco.com for currently effective rate.**

Note: Schedule R-TOU-P billing periods are as follows:
Summer – Billing months are June through September, and On-Peak hours will be between the hours of 2:00 pm and 7:00 pm excluding weekends and holidays. All other hours are off-peak.
Winter - Billing months are October through May, and On-Peak hours will be between the hours of 6:00 am and 9:00 am, excluding weekends and holidays. All other hours are off-peak.

SOS – Type I Non-Residential (Generation, Transmission including separately calculated GRT, and Procurement Cost Adjustment)

Schedules GS and EV

	10/01/19 – 05/31/20	06/01/20-09/30/20	10/01/20-05/31/21
Generation Service Charge			
Kilowatt-hour Charge	$ 0.06124 per kwhr	$ 0.05585 per kwhr	$ 0.06216 per kwhr
Transmission Service Charge	**Summer**	**Winter**	
Kilowatt-hour Charge	$0.01325 per kwhr	$0.01325 per kwhr	
Procurement Cost Adjustment	***See www.pepco.com for currently effective rate***		

Schedule T

	10/01/19 – 05/31/20	06/01/20-09/30/20	10/01/20-05/31/21
Generation Service Charge			
Kilowatt-hour Charge	$ 0.06124 per kwhr	$ 0.05585 per kwhr	$ 0.06216 per kwhr
Transmission Service Charge	**Summer**	**Winter**	
Kilowatt-hour Charge	$0.00981 per kwhr	$0.00981 per kwhr	
Procurement Cost Adjustment	***See www.pepco.com for currently effective rate***		

Schedule SL

	10/01/19 – 05/31/20	06/01/20 – 09/30/20	10/01/20-05/31/21
Generation Service Charge			
Kilowatt-hour Charge	$ 0.05102 per kwhr	$ 0.04437 per kwhr	$ 0.05653 per kwhr
Transmission Service Charge	**Summer**	**Winter**	
Kilowatt-hour Charge	$ 0.00000 per kwhr	$ 0.00000 per kwhr	
Procurement Cost Adjustment	**See www.pepco.com for currently effective rate**		

Schedule OL

	10/01/19 – 05/31/20	06/01/20-09/30/20	10/01/20 - 05/31/21
Generation Service Charge			
Mercury Vapor			
175 Watt	$ 3.75 per lamp	$ 3.26 per lamp	$ 4.15 per lamp
250 Watt	$ 5.18 per lamp	$ 4.50 per lamp	$ 5.74 per lamp
400 Watt	$ 7.95 per lamp	$ 6.91 per lamp	$ 8.80 per lamp
High Pressure Sodium			
100 Watt	$ 2.14 per lamp	$ 1.86 per lamp	$ 2.37 per lamp
150 Watt	$ 3.12 per lamp	$ 2.72 per lamp	$ 3.46 per lamp
250 Watt	$ 5.27 per lamp	$ 4.58 per lamp	$ 5.84 per lamp
Transmission Service Charge	**Summer**	**Winter**	
175 Watt	$ 0.00 per lamp	$ 0.00 per lamp	
250 Watt	$ 0.00 per lamp	$ 0.00 per lamp	
400 Watt	$ 0.00 per lamp	$ 0.00 per lamp	
Procurement Cost Adjustment	***See www.pepco.com for currently effective rate***		

Schedule TN and Rider SL-TN

	10/01/19 – 05/31/20	06/01/20 – 09/30/20	10/01/20-05/31/21
Generation Service Charge			
Kilowatt-hour Charge	$0.05228 per kwhr	$0.04849 per kwhr	$0.05805 per kwhr
Transmission Service Charge	**Summer**	**Winter**	
Kilowatt-hour Charge	$ 0.00756 per kwhr	$ 0.00756 per kwhr	
Procurement Cost Adjustment	***See www.pepco.com for currently effective rate***		

MONTHLY RATE (continued)

SOS – Type II Non-Residential (Generation, Transmission including separately calculated GRT, and Procurement Cost Adjustment)

Schedule MGT LV II	**12/01/19–02/29/20**	**03/01/20-05/31/20**	**06/01/20-08/31/20**	**09/01/20-11/30/20**
Generation Service Charge				
Kilowatt-hour Charge				
On Peak	$0.07466 per kwhr	$0.05581 per kwhr	$0.05397 per kwhr	$0.05323 per kwhr
Intermediate	$0.07458 per kwhr	$0.05581 per kwhr	$0.04908 per kwhr	$0.05219 per kwhr
Off Peak	$0.07110 per kwhr	$0.05581 per kwhr	$0.04831 per kwhr	$0.05133 per kwhr

Transmission Service Charge	**Summer**	**Winter**
Kilowatt-hour Charge	$ 0.00718 per kwhr	$ 0.00718 per kwhr
Kilowatt Charge		
On Peak	$ 1.58790 per kw	
Maximum	$ 1.15600 per kw	$ 1.15600 per kw
Procurement Cost Adjustment	***See www.pepco.com for currently effective rate***	

Schedule MGT 3A II	**12/01/19–02/29/20**	**03/01/20-05/31/20**	**06/01/20-08/31/20**	**09/01/20-11/30/20**
Generation Service Charge				
Kilowatt-hour Charge				
On Peak	$0.07402 per kwhr	$0.05535 per kwhr	$0.05352 per kwhr	$0.05279 per kwhr
Intermediate	$0.07394 per kwhr	$0.05535 per kwhr	$0.04868 per kwhr	$0.05176 per kwhr
Off Peak	$0.07050 per kwhr	$0.05535 per kwhr	$0.04792 per kwhr	$0.05091 per kwhr

Transmission Service Charge	**Summer**	**Winter**
Kilowatt-hour Charge	$ 0.00751 per kwhr	$ 0.00751 per kwhr
Kilowatt Charge		
On Peak	$ 1.63060 per kw	
Maximum	$ 1.19940 per kw	$ 1.19940 per kw
Procurement Cost Adjustment	***See www.pepco.com for currently effective rate***	

SOS – Hourly Priced Service (HPS)
Schedules MGT LV III, MGT 3A III, GT LV, GT 3A, GT 3B, and TM-RT

Generation Service Charge

The Hourly Price Service will include:

1. **Market Hourly Energy Charge –** The Customer's hourly energy usage, adjusted for applicable losses, multiplied by the hourly energy charge.

   The hourly energy charge will consist of the 1) hourly integrated real time fixed nodal weighted aggregate Locational Marginal Price (LMP) values for the Pepco zone, or its successor for the retail load served in Pepco's Maryland service area, as determined and reported by the PJM; 2) An Administrative Charge of between $0.00225 and $0.00300 per kwh, any applicable taxes, and other items as provided for in paragraphs 79 and 82 of the Phase I Settlement in Maryland Case No. 8908; and 3) Generation Ancillary Service Charges based on the previous month's average cents per kwh generation ancillary service cost for HPS customers in the Pepco Zone as determined and reported by PJM.

2. **Monthly Capacity Charge –** Determined by summing over each day during the Customer's billing period the Customer's obligation in MW multiplied by the daily cost per MW of procuring capacity. The daily Capacity procurement cost shall be in dollars per MW-day, based on capacity purchased to cover HPS shortages and any penalties or deficiency charges and broker fees accruing for the day of the calculation.

When a Customer's account does not have interval data, the Customer's historical data will be used to develop the hourly use.

Transmission Service Charge – The transmission service charges stated in this SOS – Hourly Priced Service (HPS) section apply only to Type III customers receiving HPS from Pepco.

MONTHLY RATE (continued)
SOS – Hourly Priced Service (HPS)
Schedules MGT LV III, MGT 3A III, GT LV, GT 3A, GT 3B, and TM-RT (continued)

Transmission Service Charge

		Summer		Winter
Schedule MGT LV III		**Summer**		**Winter**
Kilowatt-hour Charge	$	0.00718 per kwhr	$	0.00718 per kwhr
Kilowatt Charge				
On Peak	$	1.58790 per kw		
Maximum	$	1.15600 per kw	$	1.15600 per kw
Schedule MGT 3A III		**Summer**		**Winter**
Kilowatt-hour Charge	$	0.00751 per kwhr	$	0.00751 per kwhr
Kilowatt Charge				
On Peak	$	1.63060 per kw		
Maximum	$	1.19940 per kw	$	1.19940 per kw
Schedule GT LV		**Summer**		**Winter**
Kilowatt-hour Charge	$	0.00647 per kwhr	$	0.00647 per kwhr
Kilowatt Charge				
On Peak	$	1.71770 per kw		
Maximum	$	1.26870 per kw	$	1.26870 per kw
Schedule GT 3A		**Summer**		**Winter**
Kilowatt-hour Charge	$	0.00615 per kwhr	$	0.00615 per kwhr
Kilowatt Charge				
On Peak	$	1.67000 per kw		
Maximum	$	1.24870 per kw	$	1.24870 per kw
Schedule GT 3B		**Summer**		**Winter**
Kilowatt-hour Charge	$	0.00593 per kwhr	$	0.00593 per kwhr
Kilowatt Charge				
On Peak	$	1.55630 per kw		
Maximum	$	1.14470 per kw	$	1.14470 per kw
Schedule TM-RT		**Summer**		**Winter**
Kilowatt-hour Charge	$	0.00662 per kwhr	$	0.00662 per kwhr
Kilowatt Charge				
On Peak	$	1.15220 per kw		
Maximum	$	0.82880 per kw	$	0.82880 per kw

The monthly HPS charges shall equal the actual cost of providing energy and capacity supply transmission service, ancillary service, and any other cost element directly related to the Company's HPS load obligation, including an Administrative Charge and applicable taxes.

The Company will determine an Hourly Price Service Procurement Cost Adjustment (HPS – PCA) which will reflect the difference between the actual cost of serving Customers under HPS (including any cost adjustments from the PJM Settlement system) and the amount billed to HPS Customers for the same time period. The Company will determine the HPS-PCA rate by dividing the HPS-PCA amount by the total kilowatt-hour sales of the then current HPS customers. The HPS-PCA rate will be applied to each of the then current HPS customers' sales to determine the credit/charge for the billing month.

At the conclusion of Hourly Price Service on June 1, 2006, any HPS PCA will be returned to, or collected from all Type II Customers regardless of their supplier.

BILLING MONTHS

Summer – Billing months of June through October
Winter – Billing months of November through May.

RATING PERIODS

Weekdays - (Excluding Holidays)

On-Peak Period	12:00 noon	to	8:00 p.m.
Intermediate Period	8:00 a.m.	to	12:00 noon
		and	
	8:00 p.m.	to	12:00 midnight
Off-Peak Period	12:00 midnight	to	8:00 a.m.

Saturdays, Sundays and Holidays

Off-Peak Period All Hours

Holidays

For the purpose of this tariff, holidays will be New Year's Day, Rev. Martin Luther King's Birthday, Presidents' Day, Memorial Day, Independence Day, Labor Day, Columbus Day, Veterans' Day, Thanksgiving Day and Christmas Day, as designated by the Federal Government.

BILLING DEMANDS

On-Peak (Summer Billing Months Only) - The billing demand shall be the maximum thirty (30) minute demand recorded during the on-peak period of the billing month.

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

PROCUREMENT COST ADJUSTMENT

In addition to the Standard Offer Service rates shown above, for Residential, Type I, and Type II customers (excludes HPS customers) there will be a monthly Procurement Cost Adjustment (PCA) shown as a separate line item on the Customer's bill. Refer to HPS for the Hourly Priced Service Procurement Cost Adjustment (HPS-PCA).

The PCA is a $ per kilowatt-hour rate applied to the Customer's billed kilowatt-hours.

The PCA is an adjustment made in order to true-up the rates customers are billed to reflect the Company's actual costs of providing Standard Offer Service.

A true-up adjustment will be made to the PCA at least three (3) times per year- effective with the June, November and February billing months. These true-ups will revise the PCA based on actual and forecasted collections of SOS revenues by SOS Type and the actual and forecasted cost of providing Standard Offer Service.

The current applicable PCA rate by SOS Type is available on the Company's website at www.pepco.com.

PUBLICATION OF PRICES

The Standard Offer Service Rates shown in this Rider are posted on the Company's website at www.pepco.com.

The market hourly Locational Marginal Prices used for HPS are available on the PJM website at www.pjm.com.

ADMINISTRATIVE CREDIT

RIDER “AC”

RIDER “AC” – ADMINISTRATIVE CREDIT
This rider is applicable to all customers served under Rate Schedules “R”, “RTM”, “GS”, “T”, “MGT LV II, “MGT 3A II ”, “SL”, “EV” “PIV”, “R-PIV” and “R-TOU-P”. Customers served under these Rate Schedules will receive the applicable credit each month based on SOS type (i.e. Residential, Type I and Type II). The purpose of this rider is to return to all customers receiving distribution service a portion of the SOS Administrative Charge revenues received from customers on Standard Offer Service.

The credits paid to customers under Rider “AC” will be calculated in accordance with Paragraphs 12(c), 31(b), 50 (b) and 68 (b) of the Phase I Settlement Agreement in Case No. 8908.

The credit, by SOS type, is a $ per kilowatt-hour rate and is applied to the Customer’s billed kilowatt-hours.

A true-up adjustment will be made to Rider “AC” at least three times per year – effective with the June, November and February billing months. These true-ups will revise the credits to customers based on actual and forecasted collections of the Administrative Charge and payments of the Administrative Credit.

The current applicable Rider “AC” by SOS Type is available on the Company’s website at www.pepco.com.

RESERVED DELIVERY CAPACITY SERVICE

RIDER "RDCS"

AVAILABILITY

This Rider is designed for the reservation of capacity on an alternative delivery service on the Company's electric system. It is available to Customers served under Schedules "MGT LV II", "MGT LV III", "MGT 3A II", "MGT 3A III", "GS LV", "GS 3A", "GT LV", "GT 3A", "GT 3B", and "TM-RT" that contract with the Company to reserve capacity on alternate delivery service facilities to be used when the normal delivery service is unavailable. The Company does not guarantee continuous uninterrupted electric service or continuous uninterrupted electricity flow to the Customer's facility. This Rider does not provide preferential treatment during system emergencies or system restorations. Availability of this Rider is subject to the economic and technical feasibility of the reservation, operation, administration or installation of required Company equipment. The Company, at its sole discretion, reserves the right to limit the total reserved delivery service capacity by geographic area served under this Rider on the Company's electric system.

This Rider in not available for standby or back-up service for generation operating in parallel with the Company's delivery system.

CONTRACT TERM

The Customer shall execute an agreement for each alternative reserved delivery service provided under this Rider. Each agreement shall be for a minimum initial term of five (5) years, and thereafter for successive periods of five (5) years, unless written notice to terminate is given by either party at least two (2) years prior to the expiration date. More specific termination terms may be included in the written contract.

ADDITIONAL FACILITIES TO PROVIDE RESERVED DELIVERY CAPACITY

If any additional facilities are required for the provision of Reserved Delivery Capacity, the Customer shall make a Contribution in Aid of Construction, including any taxes associated with the receipt of a Contribution in Aid of Construction. If a Customer receives Reserved Delivery Capacity Service through existing facilities and the Company determines that new facilities are required to continue that Service, the Customer shall be required to provide a Contribution in Aid of Construction, including any taxes associated with the receipt of a Contribution in Aid of Construction, for such facilities. The Customer shall be notified at least 90 days before a required upgrade and will have the option of paying for the upgrade or forgoing reserved capacity on the second source. If automated transfer is in place, it must be disconnected if the Customer decides not to pay for the upgrade and/or the monthly reserved delivery charge.

MONTHLY CHARGE AND RATE
For a Customer served under this Rider, the Reserved Delivery Service Charge per month shall be equal to the Monthly Rate - Distribution Service Charges for Kilowatt-hours and Kilowatts as applicable, applied to the metered usage for the primary account and discounted by the appropriate factor from the table below.

Discount Factors for Reserved Delivery Capacity Service						
Rate Class	**MGT LV**	**MGT 3A**	**GT LV**	**GT 3A**	**GT 3B**	**TM-RT**
Existing Facilities	**84.99%**	**18.03%**	**85.16%**	**17.77%**	**21.88%**	**12.95%**
New Facilities	**96.27%**	**84.98%**	**95.81%**	**86.15%**	**91.56%**	**86.23%**

METERING AND ASSOCIATED EQUIPMENT
When any additional metering and associated equipment is needed to participate under this Rider, such installation shall be at the Company's sole discretion and such total cost, including applicable tax, shall be at the Customer's expense.

GENERAL TERMS AND CONDITIONS
This rider is subject in all respects to the Company's General Terms and Conditions for Furnishing Electric Service and the Electric Service Rules and Regulations.

BILL STABILIZATION ADJUSTMENT

RIDER "BSA"

BILL STABILIZATION ADJUSTMENT RIDER

This rider is applicable to Schedules "R", "R-TM", "PIV", "R-PIV" and "R-TOU-P" "GS", "GT LV", "GT 3A", "GT 3B", "MGT LV II", "MGT LV III", "MGT 3A II", "MGT 3A III", "T", "EV". The BSA shall be computed monthly for application in the second succeeding billing month. It shall consist of a factor designed to reflect differences between test year and actual base rate revenues adjusted to exclude lost sales from the beginning of each Major Outage Event, as defined by COMAR 20.50.01.03.B (27), until all major outage event-related sustained interruptions are restored, plus a factor designed to reconcile prior period Bill Stabilization Adjustments with actual billed BSA adjustments. The BSA charge or credit shall be applied to monthly bills beginning with the billing month of November, 2007. The BSA shall be combined with the Distribution Charge by designated service classification and applied to customer bills.

CALCULATION OF BSA

The BSA shall be computed by dividing the difference between the actual monthly revenue and the normalized monthly test year revenue adjusted to exclude lost sales from the beginning of each Major Outage Event, as defined by COMAR 20.50.01.03.B (27), until all major outage event-related sustained interruptions are restored, plus any applicable true up amount from previous months, by the forecast kWh sales applicable to the service classification for the second succeeding month. The normalized monthly test year revenue is defined as the average revenue per customer in the test year billing month corresponding to the current billing month at rates approved in the latest base rate proceeding, multiplied by the number of customers in the current billing month.

The storm adjustment (lost revenue) is calculated by multiplying the current storm's lost sales kWh's by the rate per kWh derived from the recently approved test year data. First, the monthly sales from the recently approved test year data are divided by the number of customers for that month to derive the average kWh per customer. Second, the average kWh per customer is divided by current month's billing hours to calculate the load factor. Third, the current outage hours are multiplied by the load factor to calculate the lost sales figure. Fourth, the revenue per kWh taken from the recently approved test year data is divided by the sales of that same period to calculate the rate per kWh. Finally, this rate per kWh is multiplied by lost sales to calculate the lost sales revenue.

(1) Formulaically:

$$BSA = \frac{A - B * C + D}{E}$$

Where:

BSA = the monthly Bill Stabilization Adjustment factor for the class in $ per kWh
A = actual monthly Class Distribution Base Revenue in $
B = Average Class Distribution Base Revenue per customer for the corresponding month in the test period
C = Class customer count for the corresponding month in the current billing month
D = cumulative true up for over/under-collections from the class in previous months in $
E = Class Forecasted kWh sales for the succeeding month

(2) The amount of the adjustment factor for any rate schedule may not exceed + /- 10% of the

average test year rate per kWh for the rate class. Any excess amount above the cap shall be collected in a subsequent month.

FILING

The Company shall file monthly with the Commission a copy of the computation of the BSA current factors and/or reconciliation factors at least ten days prior to application on customers' bills. The Company shall furnish Commission Staff sufficient workpapers for the review and audit of the BSA.

EMPOWER MD CHARGE
RIDER "E-MD"

RIDER “E-MD” – EMPOWER MD CHARGE

This rider is applicable to Schedules "R", "R-TM", “PIV”, “R-PIV”, “R-TOU-P”, GS", "T", “MGT LV II”, “MGT 3A II”, “MGT LV III”, “MGT 3A III”, “GT LV”, “GT 3A”, “GT 3B”, “TM-RT”, “EV”, “SL”, “OL”, and “TN”. Amounts billed to customers shall include a surcharge to reflect demand-side management program costs. Rider “E-MD” will be determined annually by class based on projections of demand-side management program costs and PJM market earnings (including an adjustment for variances between budgeted and actual prior year expenditures) and forecasts of kilowatt hour sales.

Rate Schedule	Rate ($ per kilowatt-hour)
“R "R-TM" “PIV”, “R-PIV” and R-TOU-P”	$ 0.006924
"GS", "T”, "SL, "OL", "EV" and "TN"	$ 0.004484
"MGT LV II”, “MGT 3A II", “MGT LV III”, and “MGT 3A III”	$ 0.004484
"GT LV", GT 3A”, “GT 3B”, and "TM-RT"	$ 0.004484

This surcharge will be effective Billing Month of January 2020 and will be revised on or before January of each subsequent year to reflect each year’s costs. The rider will be applied each year thereafter, and will include cost and revenue effects, effective with the billing month of January.

The surcharge (in dollars per kilowatt hour) will be computed by dividing the total annual amount to be recovered for each class by forecasted Maryland retail sales (in kilowatt hours) for that class.

The total amount to be recovered (R) is computed in accordance with the following formula:

$$R=A+B+C$$

Where A is amortization (paragraph (c) below, B is the capital cost recovery factor (CCRF) (paragraph (d) below), and C is the current year expense (paragraph (e) below). The surcharge will be computed for billing purposes in accordance with the procedure described below:

(a) Current year program costs will be determined by reference to budgeted and projected utility costs minus projected PJM market earnings. Program costs include program design costs, implementation contractor expenses, education costs, marketing costs, rebate and buy-down costs, utility incentives, capital costs, measurement and verification (M&V) and evaluation costs applicable to the conservation and demand side management programs.

(b) The unamortized balance of program costs for each prior year will be determined as of the beginning of the year by subtracting accumulated amortization from cumulative program costs at that date. Such costs and amortization are recorded in a Demand-Side Recovery Account.

(c) For the conservation programs, amortization for the year will be based on a five year amortization period and will be the sum of (i) 20% of estimated current year program costs, and (ii) unamortized balance of program cost for each prior year (as of the beginning of the period) divided by the remaining years in the amortization period (including the current period). NOTE: Through this mechanism, the second through fifth years of amortization related to a given year's program costs will reflect a true-up for any variance between actual and originally projected costs or sales in that year. The demand response program component of the EmPower Md. Charge will be calculated in a similar method as noted above in (i) and (ii), with the costs recovered through two different amortization schedules, which are based on the classification of expenses. Costs associated with equipment installation are amortized over a 15 year period. Program marketing and evaluation costs are amortized over a 5 year period.

(d) The Capital Cost Recovery Factor (CCRF) will be computed for billing purposes by monthly application of the last Commission-authorized rate of return on rate base in a base rate proceeding to the unamortized balance of program costs as of the beginning of the month, plus one-half of current month program costs. The CCRF will be recalculated with each annual update of the tariff with no compounding.

(e) For demand response programs, operations and maintenance expenses will be expensed annually.

RESIDENTIAL DIRECT LOAD CONTROL

RIDER "R-DLC"

RIDER “R-DLC” – RESIDENTIAL DIRECT LOAD CONTROL
This rider is applied to and is a part of Schedules "R", "R-TM", “R-TOU-P and “R-PIV” when a residential distribution customer volunteers for this demand response resource program subject to the following provisions:

1. Company Owned, Installed and Maintained Equipment
. The customer will allow the Company to install, own, and maintain either a smart thermostat(s) or radio controlled switch(es) and associated equipment on the customer's central air conditioner or central heat pump equipment for the purpose of the Company's cycling control over the operation of those appliances as described below.

   Customer may select one of the following three demand response options:

   - RESIDENTIAL DLC-50% CYCLING - Whereby a participating residential customer’s air conditioner compressor will be cycled off for 15 minutes of each half hour period.

   - RESIDENTIAL DLC-75% CYCLING - Whereby a participating residential customer’s air conditioner compressor will be cycled off for 22.5 minutes of each half hour period.

   - RESIDENTIAL DLC-100% CYCLING - Whereby a participating residential customer’s air conditioner compressor will be cycled off completely during each half hour period.

   The customer will receive the following applicable bill credits while participating in the program. The Annual Fixed Credit is paid proportionally during the June through October billing months. In exchange for the One Time Enrollment Installment Credit, participants will be required to remain enrolled in the program option for at least one year. The Enrollment Credit will be credited to the participant after the cycling equipment has been installed.

Demand Response Options Per Controlled Device

	DLC-50%	DLC-75%	DLC-100%
One Time Enrollment Installment Credit	$40.00	$60.00	$80.00
Annual Fixed Credit	$40.00	$60.00	$80.00

2. Customer Owned, Installed and Maintained Equipment (Bring Your Own Device (BYOD))
   The customer will allow the Company to access certain system-supported and customer installed and owned smart thermostat (s) and associated central air conditioner or central heat pump equipment for the purposed of reducing load during demand response conservation periods.

   The customer’s smart thermostat will be controlled by increasing cooling capabilities prior to a demand response conservation event and reducing runtimes of the central air conditioner or central heat pump equipment for a certain duration of the conservation event. This will be achieved by remotely adjusting indoor temperature setpoints and/or cycling compressor on/off times.

   The customer will receive an Annual Credit of $40 paid proportionally during the June through October billing months.

3. The Company may exercise control whenever required for any of the following reasons:
   1) to test cycling equipment,
   2) in response to a PJM dispatcher request to activate the program,
   3) in response to local Pepco electric system constraints, or
   4) in response to regional energy market prices.

   Participant override of conservation events will be limited to two events annually and is not permitted during PJM initiated conservation events.

4. Customers who participate in Rider “R-DLC” are also eligible to participate in Rider “DP”, Dynamic Pricing – Peak Energy Savings Credit. Customer participants in both programs will receive the Rider “R-DLC” enrollment credit if applicable and the specified Rider “R-DLC” annual fixed credit that is paid proportionally over the billing months of June through October. Customer participants in both programs will only be eligible for Rider “DP” Peak Energy Savings Credits that are in excess of the Rider “R-DLC” monthly billing credits paid during the billing months of June through October. Additional Rider “DP” credits earned shall be calculated monthly.

5. Cost recovery established through Rider “E-MD”.

6. The Customer holds Pepco harmless for any damages resulting from participation in the program.

7. Pepco’s incentive will be determined monthly beginning January 2009. It will be equal to a tiered percentage basis between residential ratepayers and the Company of the benefit components of wholesale capacity revenue, wholesale energy revenue and wholesale capacity price mitigation. Prior to the Company receiving any incentive, Pepco will file information with the Commission to demonstrate that its customers are receiving net benefits sufficient to offset the recovery charge.

Megawatts	Incentive
0 – 103	0.00%
104 -136	5.00%
137 -171	5.75%
172-205	6.50%
206+	7.75%

RGGI RATE CREDIT

RIDER "RRC"

RIDER "RRC" – RGGI RATE CREDIT
This rider is applicable to all customers served under Rate Schedules "R", "R-TM" and "R-TOU-P". Customers served under these Rate Schedules shall receive a monthly bill credit on a dollar per customer basis, funded through Regional Greenhouse Gas Initiative ("RGGI") auction proceeds and other monies included in the Maryland Strategic Energy Investment Fund pursuant to Chapters 127 and 128 of the Acts of the General Assembly of 2008.

The credit shall commence with the billing month of June 2009 and shall be subject to update and true up on a quarterly basis.

The current applicable credit is available on the Company's website at www.pepco.com.

MASTER-METERED ("MM") DIRECT LOAD CONTROL

RIDER "MM-DLC"

RIDER "MM DLC" – MM DIRECT LOAD CONTROL

This rider is applied to and is a part of Schedule "GTLV", "MGT LV II", "MGT 3A II", "MGT LV III", "MGT 3A III", "GT 3A", "GT 3B", and "TM-RT" when a master metered account customer (Customer) selected by the Company for voluntary participation in this demand response energy management program subject to the following provisions:

1. The master metered residents (residents) selected by the Customer will allow the Company to install, own, and maintain either a smart thermostat(s) or radio controlled switch(es) and associated equipment on the resident's central air conditioner or central heat pump equipment for the purpose of the Company's cycling control over the operation of those appliances as described below.

2. The following demand response option is proposed for participating customers:

   MM DLC - 50% CYCLING
   MM DLC - 75% CYCLING
   MM DLC - 100% CYCLING

3. The Company may exercise cycling control whenever required for any of the following reasons:

   1) to test cycling equipment,

   2) in response to a PJM dispatcher request to activate the program,

   3) in response to local Pepco electric system constraints, or

   4) in response to regional energy market prices.

   The dwelling unit participant may elect to override cycling events of no more than two events annually and are not permitted during PJM initiated cycling events.

4. The Customer will receive the following applicable bill credits while participating in the program. The Annual Fixed Credit is paid proportionally during the June through October billing months. In exchange for the One Time Enrollment Installment Credit, participants will be required to remain enrolled in the program through one annual billing period. The Enrollment Credit will be credited to the Customer after the cycling equipment has been installed.

Demand Response Options Per Controlled Device

	DLC - 50%
Installation Credit	$15.00
Annual Bill Credit **($3.00/month – June-October)**	$15.00
	DLC - 75%
Installation Credit	$22.00
Annual Bill Credit **($4.40/month – June-October)**	$22.00
	DLC - 100%
Installation Credit	$30.00
Annual Bill Credit **($6.00/month – June-October)**	$30.00

5. The Pepco account holder is responsible for providing the financial value of received Pepco billing credits on an annual basis to individual dwelling unit participants.

6. The Customer and the participating resident holds Pepco harmless for any damages resulting from participation in the program.

7. Program cost recovery shall be through the EmPOWER Maryland surcharge.

AGGREGATE NET ENERGY METERING
RIDER "ANEM"

A. AVAILABILITY

This rider is applied to and is a part of Maryland Schedules "R", "RTM", "GS", "GT LV", "GT 3A", "GT 3B", "MGT LV II", "MGT LV III", "MGT 3A II ", and "MGT 3A III". This rider is available to an individual Customer that owns and operates, leases and operates, or contracts with a third party that owns and operates a customer-generator that:

1. Uses as its primary source of fuel: biomass, micro combined heat and power (MCHP), solar, qualifying closed conduit hydroelectric, fuel cell or wind consistent with Public Utilities Article §7-306, Annotated Code of Maryland;
2. Has a capacity of not more than 2 MW_{AC} except for a MCHP customer-generator which must have a capacity of not more than 30 KW_{AC};
3. Is interconnected and operated in parallel with the Company's transmission and distribution facilities;
4. The Company will consider new dedicated service connections for generators directly connected to its distribution system ("direct connect"). For a generator to be considered for direct connect by the Company, a customer's application to participate under this rider must include at least two individually metered accounts in addition to the account that would be related to facilitate the direct connection of the customer-generator. Such dedicated service connections will be considered in lieu of upgrades, when cost efficiencies will be achieved, or when step-ups/step-downs will be avoided by doing so. The direct connect generator must be located on either (a) a property owned or leased by the Customer or (b) a property contiguous to a property owned or leased by the Customer with) at least one of the Customer's aggregated customer accounts.
5. Meets at least one of the following criteria:
    a. An eligible customer-generator using electrical service for agriculture;
    b. An eligible customer-generator who is a not-for-profit organization or business; or
    c. An eligible customer-generator who is a municipal or county government or its affiliated organizations.
6. Is intended primarily to offset all or part of the Customer's own electricity requirements; and
7. Is owned by one Customer that is the same person or legal entity which has multiple metered accounts, regardless of the physical location and qualified rate class. The Customer may aggregate a minimum of two individually metered accounts (not including dedicated service accounts) for the purpose of net metering regardless of which meter receives energy from a customer-generator provided that:
    a. Before a Customer can participate under this rider and activate the customer-generator, the Customer shall file an application with the Company available at: http://www.pepco.com/home/requests/interconnection/ and include the following information:
        i. A list of up to three host accounts and at least two individually metered accounts that the Customer seeks to aggregate, identified by name, address, rate schedule, and account number, and ranked according to the order in which the Customer desires to apply the Excess kilowatt-hour Credits. The Company reserves the right to limit the number of aggregated accounts to the number of accounts necessary to apply the excess energy generated by the customer-generator(s) and to avoid annual excess credit payments;

For each metered account behind which a customer-generator is to be located ("Host Customer Account"), a description of the customer-generator, including its location, capacity, and fuel type or generating technology.

Customers should allow for up to 90 days after their application is accepted by the Company for preparations to be made for this rider to go into effect.

b. The Customer may provide written notice of a change to its list of host and aggregated metered accounts no more than once annually and should allow for up to 90 days for the change to go into effect;

c. In order to continue under this rider, the Customer must notify the Company of any change in ownership of the accounts by providing the Company 60 days written notice; and

d. The Company may require that a Customer's host and aggregated meters be read on the same billing cycle.

e. To participate in ANEM, all of the Customer's host and aggregate accounts will be transitioned to a single account with a new account number.

f. The Customer's host and aggregated metered accounts must be supplied by a single energy supplier.

The proposed customer-generator's capacity may not exceed 200 percent of the aggregate sum of the Customer's Baseline Annual Usage for the Customer's aggregated metered accounts. The Customer's Baseline Annual Usage is the total of the Customer's previous 12 months of electricity use in kilowatt-hours at the time of the installation or upgrade of the customer-generator. If the Customer does not have 12 months of electric energy use in kilowatt-hours at the time of the installation of the customer-generator, then the Baseline Annual Usage may be estimated based on a mutually agreeable method subject to approval by the Maryland Public Service Commission. Customer-generators applying under this rider may be subject to FERC jurisdiction with respect to net sales of excess generation and interconnection requirements.

For an eligible customer-generator whose electrical services are located close enough to physically interconnect and meter at a single point, the Company may require the Customer to make physical electrical connections and re-establish metering at a single location. Physically aggregated services must meet all applicable requirements of COMAR 20.50.01 and 20.50.02.

B. CONNECTION TO THE COMPANY'S SYSTEM

Any Customer who elects this rider must submit a completed ANEM application and/or generator interconnection application with the Company, in writing, and should allow for up to 90 days before receiving approval to activate the eligible customer-generator. The eligible customer-generator shall not be connected to the Company's system unless it conforms to the National Electrical Code, the Institute of Electrical and Electronic Engineers, Underwriters Laboratories and the applicable codes of the local public authorities. The Customer must obtain, at their expense, all necessary inspections and approvals required by the local public authorities before the eligible customer-generator is connected to the Company's electric system. The eligible customer-generator shall have adequate protection as described in Section H below.

C. DELIVERY VOLTAGE
The delivery voltage of the eligible customer-generator shall be at the same voltage level and at the same delivery point as if the Customer were purchasing all of their electricity from the Company.

D. CONTRACT TERM
The contract term shall be same as that under the Customer's applicable Service Classification.

E. MONTHLY RATES, RATE COMPONENTS AND BILLING UNIT PROVISIONS
The monthly rates, rate components and billing unit provisions shall be those as stated under the Customer's applicable Rate Schedule. Under this rider, only the per kilowatt-hour charge components of the Customer's bill are affected. All other billing components and charges, such as Customer Charge and Demand Charge are not affected by this rider. The monthly charges shall be based on one the following conditions:

1. Excess Generation shall be applied first to the meter through which the customer-generator(s) supplies electricity (Host Accounts).

2. The Company will credit any remaining net excess generation in kilowatt-hours from the Host Account (the Excess kilowatt-hour Credits) to the consumption of the Customer's remaining accounts in the order specified by the Customer in accordance with Section A 7(a)(i) (or as modified Section A 7(b)).

3. For each of the Customer's Accounts that still have energy consumption after Excess kilowatt-hour Credits are applied, the Customer shall be charged for the remaining energy consumption based on the rates and charges under the Customer's applicable generation rate.

4. For each of the Customer's Accounts that do not have any energy consumption after Excess kilowatt-hour Credits are applied, the Customer shall be charged the greater of:
   a. The Customer Charge, and any applicable non-energy charges such as: Demand Charge and Universal Service Charge under the Customer's applicable Rate Schedule, or;
   b. The monthly Minimum Charge under the Customer's applicable Rate Schedule.

5. When the Customer's aggregated accounts deliver more energy to the Company's electric system than the Customer consumes for the billing period ("Excess Generation"), the Company shall take ownership of such Excess Generation and shall carry forward the Excess Generation to be credited in kilowatt-hour to the Host Account in the next billing period. The Company will carry forward the Excess Generation until the Customer's consumption of electricity from the grid eliminates the Excess Generation or until the end of the billing cycle that is completed immediately prior to the end of April of each year. The dollar value of Excess Generation shall be equal to the Generation portion of the rate that the Host Customer Account would have been charged averaged over the previous 12-month period ending with the billing cycle that is complete immediately prior to the end of April multiplied by the number of kilowatt-hours of Excess Generation.

6. On or before 30 days after the billing cycle that is complete immediately prior to the end of April of each year, the Company shall pay each Customer for the dollar value of any accrued Excess Generation remaining at the end of the previous 12-month period ending with the billing cycle that is complete immediately prior to the end of April of that year. Payments for the value of Excess Generation less than $100 may be in the form of a bill credit.

7. Within 60 days after the date the Customer closes the Customer's account, the Company shall pay the Customer for the dollar value of any accrued Excess Generation remaining at the time the Customer closes the account.

8. If all of the host accounts are Time Metered, the application of this rider to Schedules "RTM", "GT LV", "GT 3A", "GT 3B", "MGT LV II", "MGT LV III", "MGT 3A II", and "MGT 3A III", shall be on the basis of each Time Metered pricing instead of on the basis of the total monthly energy.

F. RENEWABLE ENERGY CREDITS

The Renewable Energy Credits generated by the customer-generator are owned entirely by the Customer or the eligible Customer's assignee. However, if the Customer chooses to sell solar Renewable Energy Credits, the Customer must first offer them for sale to an electric company or an electricity supplier that shall apply them toward compliance with the Maryland Renewable Energy Portfolio Standard.

G. METERING

The Company shall furnish, install, maintain and own all the metering and data acquisition equipment needed for measurement of the service supplied. To participate under this rider, the Company must be able to remotely read the meters for the Customer's host and aggregated accounts. Except when the customers-generator is directly-connected to the Company's distribution grid, under this rider the Company shall provide, at no direct charge, a watt-hour energy meter with the capability of reverse registration in order to measure the net watt-hours consumed by the Customer or the net watt-hours delivered by the Customer to the Company for the total billing period. The Company's metering investment shall be limited to that required to serve the Customer under the Customer's applicable Rate Schedule without the eligible customer-generator. Where a larger capacity meter is required to serve the Customer that has an eligible customer-generator, or a larger capacity meter is requested by the Customer, the Customer shall pay the Company the difference between the larger capacity meter investment and the metering investment normally provided under the Customer's Rate Schedule.

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H. INTERCONNECTION WITH THE COMPANY'S SYSTEM

Interconnection with the Company's system requires the installation of protective equipment which provides safety for personnel; affords adequate protection against damage to the Company's system or to its Customer's property; and prevents any interference with the Company's supply of service to other Customers. The Company shall not be liable for any loss, cost, damage or expense to any party resulting from the use or presence of electric current or potential which originates from the Customer's eligible customer-generator, except as the Company would otherwise be liable under the Company's Maryland electric tariff. Such protective equipment shall be installed, owned and maintained by the Customer at their expense. In addition, it may be necessary for the Company to extend or modify portions of its systems to accommodate the delivery of electricity from the eligible customer-generator. Should such extension or modification be necessary, all work shall be performed by the Company at the Customer's expense. For new services, such expense shall be determined by the difference between total costs and the investment the Company would make to install a normal service without the Customer's eligible customer-generator.

The eligible customer-generator shall conform to the National Electrical Code and the applicable codes of the local public authorities. Special attention should be given to the National Electrical Code Sections 690 and 705.

I. CESSATION OF PARALLEL OPERATION

The Customer's equipment must be installed and configured so that parallel operation must cease immediately and automatically during system outages or loss of the Company's primary source. The Customer must also cease parallel operation upon notification by the Company of a system emergency, abnormal condition, or in cases where such operation is determined to be unsafe, interferes with the supply of service to other Customers, or interferes with the Company's system maintenance or operation. The Company accepts no responsibility whatsoever for damage or injury to any person or property caused by failure of the Customer to operate in compliance with Company's requirements.

J. FAILURE TO COMPLY

If the Customer fails to comply with any of the requirements set forth in sections H and I above, the Company may disconnect the Host Customer's service from the Company's electric system until the requirements are met, or the eligible customer-generator is disconnected from the Customer's electric system.

K. RULES AND REGULATIONS

Except as herein modified, the Rules and Regulations set forth in this rider shall govern the provision of service under this rider and under the Customer's applicable Service Classification.

NON-RESIDENTIAL DIRECT LOAD CONTROL

RIDER "NR-DLC"

RIDER "NR-DLC" – NON- RESIDENTIAL DIRECT LOAD CONTROL
This rider is applied to and is a part of Schedules "GS", "MGT-LV II", "MGT 3A ll", "MGT LV III", "MGT 3A III", "GT-LV", "GT 3A", "GT 3B", "TM-RT", "EV", "OL", "SL", "TN" and "T" when a non-residential distribution customer volunteers for this demand response resource program subject to the following provisions:

1. The customer will allow the Company to install, own, and maintain either a smart thermostat(s) or remotely controlled switch(es) and associated equipment on the customer's central air conditioner or central heat pump equipment for the purpose of the Company's cycling control over the operation of those appliances as described below.

2. The customer's central air conditioning or central heat pump equipment must be compatible with the smart thermostat and/or control switches used by the Company for this program.

3. Customer may enroll in the following demand response option:

    o NON-RESIDENTIAL DLC-50% CYCLING - Whereby a participating residential customer's air conditioner compressor will be cycled off for 15 minutes of each half hour period..

4. The Company may exercise cycling control whenever required for any of the following reasons:
    1) to test cycling equipment,
    2) in response to a PJM dispatcher request to activate the program,
    3) in response to local Pepco electric system constraints, or
    4) in response to regional energy market prices.

    Participant override of cycling events will be limited to two events annually and are not permitted during PJM initiated cycling events.

5. The customer will receive the following applicable bill credits while participating in the program. The Annual Fixed Credit is paid proportionally during the June through October billing months. In exchange for the One Time Enrollment Installment Credit, participants will be required to remain enrolled in the program option for at least one year. The Enrollment Credit will be credited to the participant after the cycling equipment has been installed.

Demand Response Payment Per Controlled Device

	DLC-50%
One Time Enrollment Installment Credit	$80.00
Annual Fixed Credit	$80.00

6. Cost recovery established through Rider "E-MD".

7. The Customer holds Pepco harmless for any damages resulting from participation in the program.

DEMAND RESOURCE SURCHARGE
RIDER "DRS"

RIDER "DRS" – DEMAND RESOURCE SURCHARGE

This rider is applicable to Schedules "R", "R-TM", "PIV", "R-PIV","R-TOU-P","GS", "T", "MGT LV II", "MGT 3A II", "MGT LV III", "MGT 3A III", "GT LV", "GT 3A", "GT 3B", "TM-RT", "EV", "SL", "OL", and "TN". Amounts billed to customers shall include a surcharge to recover the costs of Capacity Resource Agreements as provided in Maryland Public Service Commission Order No. 82511 in Case No. 9149. Rider "DRS" will be determined annually by service classification by calculating a Contract for Differences payment (comparing the projections of demand response resource costs against the PJM Reliability Pricing model clearing price and actual delivered capacity for each power planning year), along with approved incremental costs, and distributing that by each service classification's Peak Load Contribution.

Rate Schedule	Rate ($ per kilowatt-hour)
"R", "R-TM" "PIV" "R-PIV" and "R-TOU-P"	$0.00000
"GS", "T", "OL", "EV" and "TN"	$0.00000
"MGT LV II", "MGT 3A II", "MGT LV III", and "MGT 3A III"	$0.00000
"GT LV", GT 3A", "GT 3B", and "TM-RT"	$0.00000
"SL"	$0.00000

This surcharge will be effective the Billing Month of June 2012 and will be revised on or before May of each subsequent year to reflect each year's costs. The rider will be applied each year thereafter, and will include cost and revenue effects, effective with the billing month of June. Any imbalance between the actual costs and the Surcharge amount shall be reconciled annually over the subsequent planning year.

The surcharge (in dollars per kilowatt hour) will be computed by dividing the total annual amount to be recovered for each class by forecasted Maryland retail sales (in kilowatt hours) for that class.

The total amount to be recovered (R) is computed in accordance with the following formula:

$$R= (A+B)$$

Where A is Contract for Differences payments (paragraph (a) below, B is the incremental costs (paragraph (b) below). The surcharge will be computed for billing purposes in accordance with the procedure described below:

(a) Annual Contract for Differences payments will be determined by the differences between the contract price of the demand response resource as stated in the Capacity Resource Agreement and PJM Reliability Model Clearing price for the actual delivered capacity for each power planning period.

(b) The incremental costs are approved costs incurred by the Company in administration of each Capacity Resource Agreement.

Termination of Capacity Resource Agreement

A final, one-time reconciliation shall be conducted upon termination of all Capacity Resource Agreements.

DYNAMIC PRICING - PEAK ENERGY SAVINGS CREDIT

RIDER “DP”

RIDER “DP” – DYNAMIC PRICING - PEAK ENERGY SAVINGS CREDIT

A. APPLICABILITY

This rider is applicable to customers who:

1. Take electric service under Schedule “R” or Schedule “R-TM” “PIV”, “R-PIV” and “R-TOU-P”.
2. Have an activated Advanced Metering Infrastructure (AMI) System smart meter furnished by the Company.

B. CUSTOMERS WITH THIRD PARTY CURTAILMENT SERVICE PROVIDER

Customers choosing to participate in a Third Party Curtailment Service Provider’s demand response program which is monetized in the PJM market are not eligible to participate in Rider “DP”. The Third Party curtailment Service Provider is responsible for informing Pepco of the customers’ participation.

C. BILLING

Peak Energy Savings Credit

The customer’s distribution bill will be modified by a credit computed by applying the Peak Energy Savings price to the difference calculated when actual kWh consumption is subtracted from a Customer Base Line (CBL) level of consumption during certain hours designated by the Company. Credits shall only be positive. All kWh usage, including actual kWh consumption during Peak Energy Savings Events, will be priced at the customer’s normally applicable rates.

PEAK ENERGY SAVINGS CREDIT PRICES

RATE	Peak Energy Savings Credit ($/kWh)
R, R-TM, PIV, R-PIV and R-TOU-P	$ 1.25

D. TERMS AND CONDITIONS:

1. Meter reading
   The hourly readings of the AMI System smart meter will be aggregated in to the Peak Energy Savings period and the non-Peak Energy Savings periods designated by the Company, to the nearest multiple of the meter constant, and bills rendered accordingly.

2. Customer Base Line (CBL)
   The CBL is calculated as the average of the customer’s electricity use during similar Peak Energy Savings hours for the three days with the highest use during the prior 30-day period. Weekends, holidays, the day prior to a critical peak event, and critical peak days are not included in this calculation. If 30 days of interval billing history are not available, the Customer will not be eligible for a Peak Energy Savings Credit for a Peak Energy Savings Event.

3. Peak Energy Savings Events
   Events will normally be called on weekdays during the period from June 1 through September 30. Each Peak Energy Savings Event may occur from 12 p.m. through 8 p.m., and typically last a maximum of 6 hours. Peak Energy Savings Events may be called in situations including, but not limited to, periods when day-ahead PJM regional fixed nodal weighted aggregate Locational Marginal Price (LMP) prices for energy are higher than normal. Peak Energy Savings Events may also be called during periods of PJM or Company system emergencies.

4. Rider “R-DLC” Participant Credits
   Customers who also participate in Rider “R-DLC” are eligible for Peak Energy Savings Credits that are in excess of the monthly billing credits earned by participation in Rider “R-DLC”.

E. NOTIFICATION

The Company will attempt to notify Customers who have provided contact information of an anticipated Peak Energy Savings Event by 9 p.m. of the day prior to an event. Customers will receive an automated phone call, email, or text message, or combination thereof, at the Customer’s option (limited to two), notifying them that a critical peak event will occur on the following day at identified hours. Customers may also contact Pepco customer service via a toll free number for Peak Energy Savings event information or visit the Pepco website at www.pepco.com. In the event of an emergency that prevents the operation of the notification system, notifications may be delayed or not given as stated, at which time the Company will use its best efforts to notify Customers by alternative means and/or at alternative times.

F. TRUE-UP RECOVERY OF CUSTOMER REBATES

Available PJM market earnings and the cost of customer rebates will flow through the EmPower Maryland Charge - Rider “E-MD” on an annual basis.

GRID RESILIENCY CHARGE RIDER – RIDER "GRC"

APPLICABILITY
The Distribution Charges billed under the Schedules "R", "R-TM", "GS", "T", "MGT LV II", "MGT LV III", "MGT 3A II", "MGT 3A III", "GT LV", "GT 3A", "GT 3B", "TM-RT", "SL", "OL", "EV" and "TN" shall be subject to the Grid Resiliency Charge as specified in the terms of this Rider. The Grid Resiliency Charge provides for collection of the monthly charges and rates set forth.

The Grid Resiliency Charge is specifically intended to recover approved expenditures determined to be incremental to those required to meet Maryland electric distribution reliability standards specified in the Maryland Service Quality and Reliability Standards and undertaken in an accelerated timeframe with respect to the baseline planning levels.

DETERMINATION OF CHARGE
The Grid Resiliency Charge will be based on revenue requirements calculated using projected annual expenditures. The revenue requirement will include the following items and adjustments:

1. Return on incremental accelerated capital expenditures placed into service during the period at the authorized rate of return.
2. Recovery of incremental accelerated capital expenditures placed into service during the period through depreciation expense.
3. Incremental accelerated operating and maintenance expenses.
4. Reconciliation of the deferred balance on an annual basis. (See "Adjustment to Charge")
5. The Grid Resiliency Charge is currently expected to remain in effect for approximately three years beginning in January 2014, and thereafter will continue in effect until the completion of the first rate case filed after all of approved grid resiliency-related projects are placed into service.

MONTHLY CHARGES AND RATES:

Rate Schedule		
"R"	$0.00000 per kwhr	
"R-TM"	$0.00000 per kwhr	
"GS", "T", "EV"	$0.00000 per kwhr	
"MGT LV II", "MGT LV III"	$ 0.0000 per kw of maximum demand	
"MGT 3A II", "MGT 3A III"	$ 0.0000 per kw of maximum demand	
"GT LV"	$ 0.0000 per kw of maximum demand	
"GT 3A"	$ 0.0000 per kw of maximum demand	
"GT 3B"	$ 0.0000 per kw of maximum demand	
"TM-RT"	$ 00.00 per month per delivery point	
"SL"	$0.00000 per kwhr	
"TN"	$0.00000 per kwhr	
"OL"		
Mecury Vapor		
175 Watt	$0.00	per lamp per month
250 Watt	$0.00	per lamp per month
400 Watt	$0.00	per lamp per month
High Pressure Sodium		
100 Watt	$0.00	per lamp per month
150 Watt	$0.00	per lamp per month
250 Watt	$0.00	per lamp per month

ADJUSTMENT TO CHARGE

The Grid Resiliency Charge is subject to deferred accounting. A monthly over/under recovery calculation will be performed based on actual revenues received under Grid Resiliency Charge Rider and the actual revenue requirement in each month, and the over/under recovery will be tracked as a deferred balance. Interest on this balance will be calculated monthly using the Company's short term debt rate. The interest rate will be reset each month. The deferred balance will be reconciled on an annual basis.

COMMUNITY NET ENERGY METERING PILOT PROGRAM RIDER "CNM"

A. AVAILABILITY

This rider is available to the Company's distribution customers in the State of Maryland, regardless of rate classification and energy supplier. This rider provides customers the opportunity to participate in the development of distributed solar generation by purchasing a Subscription to a portion of the electricity produced by a Community Solar Energy Generating Facility ("CSEGS") from a Subscriber Organization. For each Subscription, the customer will receive a Community Net Metering Credit ("CNM Credit") on their monthly bill from the Company.

Subscriber Organizations must be approved by the Maryland Public Service Commission to participate in the Community Solar Pilot Program (the "Pilot Program"). Subscriber Organizations approved by the Commission will be assigned a Subscriber Organization Identifications Number. Approved Subscriber Organizations will be listed on the Maryland Public Service Commission website which can be found at www.**psc**.state.**md**.us.

In addition, each CSEGS must be accepted into the Pilot Program by the Electric Utility in which the CSEGS is located. Additional information on the Pilot Program, including a list of CSEGSs that have been accepted into the Pilot Program, can be found on the Company's website at www.pepco.com/greenpowerconnection.

B. SUBSCRIPTIONS

A customer may have Subscriptions to more than one CSEGS, but no more than 4, and may also participate in net-metering. A customer may only subscribe to a CSEGS that is located in the same service territory as the Customer.

A customer may not subscribe for greater than 200% of their baseline annual usage, including any net-metered customer-generator, if applicable. The customer's Baseline Annual Usage is the total of the customer's previous 12 months of electricity use in kilowatt-hours at the time the Company is notified of the Subscription or of a change in the Customer's Subscription. If the customer does not have 12 months of electric energy use in kilowatt-hours at this time, then the Baseline Annual Usage may be estimated based on a mutually agreeable method subject to approval by the Maryland Public Service Commission.

The Company is not a party to and does not have access to any contractual arrangements among the Subscriber Organization, the CSEGS Owner(s), and the Subscribers.

C. COMMUNITY NET METERING CREDIT (CNM CREDIT)

A customer taking service on any electric Tariff Schedule shall be billed the same charges that would be assigned if the Subscriber were not participating in the Pilot Program.

For each Subscription, a customer will receive a monthly CNM Credit on their bill that will be the equivalent of their subscription percentage of the CSEGS monthly generation amount applied to all volumetric charges on the Subscriber's bill. The CMN Credit will be used to offset the Subscriber's total bill.

If the Subscriber is with an Energy Supplier and the supplier rate for the Energy Supplier is available, the monthly dollar credit on their bill will be the equivalent of their subscription allocation of the CSEGS monthly generation amount applied to the lesser of:

1. sum of all of the volumetric charges of their Energy Supplier's supply, or
2. sum of all of the volumetric charges of the Company's Standard Offer Service Rate.

If the Energy Supplier's supply rate is unavailable, or the Subscriber has not chosen an Energy Supplier, the Company's Standard Offer Service Rate will be used.

On or before 30 days after the billing cycle that is complete immediately prior to the end of April each year, the Company shall pay each Subscriber for the dollar value of any accrued account balance, if any, adjusted to exclude the distribution, transmission, and non-commodity portion of the customer's bill. The payment shall equal the Subscriber's accrued account balance reduced by the ratio of the Subscriber's total volumetric (kwh) rate for generation to the Subscriber's total volumetric (kwh) supply and distribution. The Subscriber's total volumetric rate for supply shall be the lesser of the Subscriber's supply rate charged by their Energy Supplier, where available, or the Company Standard Offer Service Rate in effect at the time of payment.

The Subscriber Organization is responsible for providing timely and accurate information on Subscriptions to the Company. Subscriptions may not take effect retroactively.

Depending on timing of notification from the Subscriber Organization of the Subscriber's subscription amount, it may take up to two billing cycles before a bill credit is applied to the Subscriber's bill. Updates received by the Company on or before the 10th of each month will be effective the following month. Subscriptions may not take effect retroactively.
The billing period of shall be the customer's customary billing period for service provided under their applicable Rate Schedule.

Concerns with the accuracy of the CNM Credit on a customer's bill should first be addressed with the Subscriber Organization, as the Company is not a party to the arrangement between the customer and the Subscriber Organization.

D. CONSUMER PROTECTIONS

Section 20.62 of the Code of Maryland Regulations contains Consumer Protections for potential or existing Subscribers.

E. DISPUTE RESOLUTION

If a customer has a disputes related to this Pilot Program, the may file a dispute with the Commission's Office of External Relations.

F. DEFINITIONS

Capitalized Terms not defined in the Company's General Terms and Conditions for Furnishing Electric Service in Maryland are as defined in Maryland Public Utilities Article § 7-306.2 or in Section 20.62 of the Code of Maryland Regulations.

ELECTRIC VEHICLE CHARGING PROGRAM

RIDER "EVCP"

RIDER “EVCP” – ELECTRIC VEHICLE CHARGING PROGRAM DESCRIPTION

The Company’s Electric Vehicle (EV) Charging Program Rider (Rider “EVCP”) includes: (1) rebate programs for eligible residential customers to install EV Level 2 (L2) Smart Chargers; and (2) a rebate program for eligible customers to install EV L2 Smart Chargers at Multi-Unit Dwellings (MUD), as defined below.

RESIDENTIAL L2 SMART CHARGER REBATE AND DISCOUNT PROGRAMS - AVAILABILITY AND OPERATION

The Company has two residential program offerings under Rider “EVCP” to eligible customers who install a qualifying EV L2 Smart Charger and have at least one plug-in vehicle (“PIV”) with a range greater than 30 miles:

1. **Residential Rebate Program:** The Company will offer 750 rebates valued at $300 each to eligible residential customers for the purchase and installation of a qualifying L2 Smart Charger. The Smart Charger would be located behind-the-meter and would be owned and operated by the customer receiving the rebate. The Smart Charger must be located on customer-owned property, or in the case of rental property, with approval from the owner of record. This program offers customers a maximum of one $300 rebate per premise covering the purchase and installation of a qualifying L2 Smart Charger. Applications can be made beginning July 1, 2019 and rebates will be awarded on a first-come basis based on the completed application date and the application meeting all of the program requirements. Customers will be notified by mail when an application is complete.

   Customers are required to take electric service under Schedule “R” or Schedule “R-PIV” in order to be eligible for this program. Customers taking service under Schedule “R” and also Rider “NEM” (Net Energy Metering) are eligible for this program under Rider “EVCP”. Rebate applicants taking service under Schedule ‘R” are not required to receive their energy supply through the Company’s Standard Offer Service.

   The Customer is required to submit an application with all of the necessary documentation within 30 days. Applicants will be required to provide proof of purchase of an eligible EV charger and agree to share the charging data from the Smart Charger with the Company. A list of qualified Smart Charger manufacturers and models is available on the Company’s website as of June 2019 for use by customers in making decisions about qualifying EV charger purchases. Customers must also sign a customer participation agreement with the Company regarding program terms, conditions, and duration. Customers receiving this rebate are enrolled in Pepco’s Demand Response program for EV charging, which allows Pepco to reduce charger output in concert with Pepco’s Peak Energy Savings Events, subject to a customer’s choice to opt out.

   Customers may refer to the Company’s website to find information about applying for a rebate under this program, the complete list of eligibility and documentation requirements, and the online form for submitting applications. The program only applies to Smart Chargers purchased and installed on or after July 1, 2019 and the program will end on December 31, 2023.

2. **Discounted Level 2 Smart Charger Program:** The Company will offer a discounted L2 Smart Charger, discounted installation of the Smart Charger, and free installation of a second Advanced Metering Infrastructure (AMI) System smart meter for eligible. Customers participating in this program are enrolled in Pepco's Demand Response program for EV charging, which allows Pepco to reduce charger output in concert with Pepco's Peak Energy Savings Events, subject to a customer's choice to opt out. This Program is limited to 100 participating customers.

   The Smart Charger would be located behind-the-meter and would be owned and operated by the customer receiving the program incentives under this offering. The Smart Charger must be located on customer-owned property, or in the case of rental property, with approval from the owner of record. Applications will be awarded on a first-come basis based on the completed application date and the application meeting all the program requirements. Customers will be notified by mail when an application is complete.

   Customers are required to take electric service under a future EV-only Time of Use (TOU) schedule to be developed in order to be eligible for this program. Customers taking service under Rider "NEM" (Net Energy Metering) are eligible for this Program under Rider "EVCP". Program applicants under Schedule "R" are not required to receive their energy supply through the Company's Standard Offer Service.

   The Customer is required to submit an application with all of the necessary documentation within 30 days. Applicants will be required to provide proof of purchase of an eligible EV charger and agree to share the charging data from the Smart Charger with the Company. A list of qualified Smart Charger manufacturers and models is available on the Company's website as of June 2019 for use by customers in making decisions about qualifying EV charger purchases. Customers must also sign a customer participation agreement with the Company regarding program terms, conditions, and duration.

   Customers may refer to the Company's website to find information about applying for this program, the incentives offered, the complete list of eligibility and documentation requirements, and the online form for submitting applications. The program only applies to Smart Chargers purchased and installed on or after July 1, 2019 and the program will end on December 31, 2023.

MULTI-UNIT DWELLING SMART CHARGER REBATES - AVAILABILITY AND OPERATION

The Company will offer eligible MUD customers up to two discounted L2 EV Smart Chargers per site (with up to 2 ports per EV charger at the discretion of the property owner) and a single time discounted installation cost at a premise for a maximum of 200 total customer subscriptions. The Smart Charger would be located behind-the-meter and would be owned and operated by the customer receiving the rebate. The Smart Charger must be located on customer-owned property, or in the case of rental property, with approval from the owner of record. Applications will be awarded on a first-come basis based on the completed application date and the application meeting all the program requirements. Customers will be notified by mail when an application is complete.

Customers are required to take electric service under one of the following Schedules in order to be eligible for this program: R, GS, MGT LV II, MGT LV III, MGT 3A II, MGT 3A III, and GT. Customers taking service under Rider "NEM" (Net Energy Metering) are eligible for this Program under Rider "EVCP." Rebate applicants may receive their energy supply from either a competitive energy supplier or through the Company's Standard Offer Service.

The Customer is required to submit an application with all of the necessary documentation within 30 days. Applicants will be required to provide proof of purchase of an eligible EV charger and agree to share the charging data from the Smart Charger with the Company. A list of qualified Smart Charger manufacturers and models is available on the Company's website as of June 2019 for use by customers in making decisions about qualifying EV charger purchases. Customers must also sign a customer participation agreement with the Company regarding program terms, conditions, and duration. Customers may refer to the Company's website to find information about applying for a rebate under this Program, the incentives offered, the complete list of eligibility and documentation requirements, and the online form for submitting applications. The program only applies to Smart Chargers purchased and installed on or after July 1, 2019 and the program will end on December 31, 2023.

COST RECOVERY

Cost recovery will be consistent with Commission Order No. 88997 in Case No. 9478. All EV program costs incurred by the Company, including rebates, program administration, education and outreach (but excluding capital, or fixed assets, and associated costs such as depreciation), shall be deferred to a regulatory asset and amortized over a five-year period.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

GREEN RIDER

RIDER "GREEN"

RIDER "GREEN" – GREEN RIDER
This rider provides 100% renewable energy on an opt-in basis to Schedules "R-PIV" and "PIV", and on a mandatory basis to the Controlling Rate Schedules associated with Schedule "PC-PIV".

This rider is a dollar per kilowatt-hour rate and is applied to the Customer's billed kilowatt-hours. This rider will be updated based on the most up-to-date market prices and the Maryland Renewable Portfolio Standards on or about February 1st and August 1st of each year.

The current applicable Rider "Green" rate is equal to $0.02378 per kilowatt-hour.

ELECTRIC VEHICLE CHARGING DISTRIBUTION DEMAND CHARGE CREDIT RIDER - RIDER "EVCDDCC"

Upon application by the customer and approval by the Company, qualifying non-residential customers who have purchased and installed an eligible Electric Vehicle (EV) charging station within the Company's electric distribution service territory on or after July 1, 2019, may be eligible to receive a credit to partially offset their monthly distribution demand charge. This Rider is available to non-residential workplace, fleet and MUD customers on Schedules "MGT LV II", "MGT LV III", "MGT 3A II", "MGT 3A III", "GT LV", "GT 3A" and "GT 3B".

Application submission will begin on January 9, 2020 and terminate on June 30, 2021. No new applications will be accepted after April 1, 2021, and all project completion documentation must be submitted to the Company by June 30, 2021. The demand credit will be available beginning January 1, 2020 and will be a fixed amount and applied to the Customer's monthly bill for the account with the eligible installed and operational L2 and/or DC Fast EV charging station(s). The maximum allowable term for the demand charge credit is 30 months or through the end of December 2023, whichever comes first, from the date of application and documentation approval.

Demand Charge Credit Structure

EV Charging Station Type	Maximum Credit	Credit Length
Level 2 Charging Station	50% Nameplate Capacity	30 months or through the end of December 2023, whichever comes first
DC Fast Charging Station	50% Nameplate Capacity	30 months or through the end of December 2023, whichever comes first

Demand charge credits are applied to the Customer's bill only for a portion of the maximum distribution demand charge resulting from the addition of EV chargers to the Customer's facility service and metered load. The demand charge credit amount will be calculated as 50% of the maximum nameplate capacity for new or added L2 EV chargers and/or DC Fast EV chargers. The demand charge credit cannot exceed the Customer's monthly distribution demand charge.

The customer must submit an application and documentation of the completed EV Charging station installation to Pepco in order to become eligible for the demand credit (including receipts and/or invoices of the EV chargers, as well as proof of the installation from a certified electrician). Pepco will determine acceptance, calculate the demand charge credit amount and communicate these results to the Customer. Once approved, customers may not add additional EV chargers to the demand charge credit.

<u>**CERTIFICATE OF SERVICE**</u>

I hereby certify that on this 14th day of August, 2020, I caused true and correct copies of the Department of Energy and Environment's Reply Comments on the Notice of Proposed Rulemaking to be emailed to the following:

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