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GOVERNMENT OF THE DISTRICT OF COLUMBIA
OFFICE OF THE ATTORNEY GENERAL

ATTORNEY GENERAL
BRIAN L. SCHWALB

Public Advocacy Division
Housing and Environmental Justice Section

ELECTRONIC FILING

June 2, 2025

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

Re: Formal Case No. 1050 – In the Matter of the Investigation of the Implementation of Interconnection Standards in the District of Columbia.

Dear Ms. Westbrook-Sedgwick:

On behalf of the Advanced Inverter Working Group established in the above-referenced proceeding, please find the enclosed minutes from its May 15, 2025 meeting. Attached to the minutes are meeting presentation materials from Pepco Holdings, Inc., and Solar Solutions. If you have any questions regarding this filing, please do not hesitate to contact the undersigned.

Respectfully submitted,

BRIAN L. SCHWALB
Attorney General

By: /s/ *Brian Caldwell*
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cc: Service List

District of Columbia Public Service Commission
Formal Case No. 1050, Minutes from RM 40 Advanced Inverter Working Group Meeting
May 15, 2025 (10:00 am – noon)

Attachments: (1) Pepco's Presentation on Site-Specific Settings; (2) Proposed RM40 Amendments by Mr. Albert LaFrance / Solar Solutions

Agenda:
I. Introductions
II. Pepco Smart Inverter Site-Specific Settings
III. Discussion on Maryland Public Service Commission Smart Inverter Regulations COMAR 20.50.09.06 (O)
IV. Discussion on Proposed Amendments to 15 D.C.M.R §§ 4002.7, 4005.4, 4007.2, and 4008.4
V. Next Steps

Participating Organizations:

- Potomac Electric Power Company (Pepco) / Pepco Holdings Inc. (PHI)
- Department of Energy and Environment (DOEE) / Office of the Attorney General (collectively DCG)
- Ecogy Solar
- DC Climate Action
- Public Service Commission (Commission) Staff
- Solar Solutions
- Interstate Renewable Energy Council (IREC)
- Center for Renewables Integration (CRI)

Introduction:

DCG is responsible for taking minutes this month. Pepco will be responsible for June meeting minutes, and Office of Peoples Counsel (OPC) will be responsible for July meeting minutes. Commission Staff briefly went through the agenda items.

Pepco Presentation on Smart Inverter Site-Specific Settings:

Presenters: John Budd, Pepco, Capacity Planning and DER Engineering
Tasha Kaewnukultorn, Capacity Planning, PHI

The first site-specific setting is Power Factor. The ideal scenario would be to have a Power Factor of one (1) (a/k/a Unity Power Factor) which involves no curtailment. However, sometimes circumstances require recommending a Power Factor of less than 1. If less than 1, then Pepco will try to make it static because it is the least complicated option. Static means no adjustments are needed to account for dynamic interactions with Pepco's equipment like regulators. But sometimes Pepco will require Power Factor adjustments in which case it will provide a schedule for adjustments to account for on-peak and off-peak periods.

The second site-specific setting discussed was VoltVar. This is a more dynamic setting than Power Factor. This setting regulates the inverter's voltage by controlling when the inverter will supply or absorb the Var. After first conducting a power flow study, Pepco usually recommends a setting of V3 (maximum 1.03 per unit). The maximum setting Pepco will recommend is V4 (maximum 1.09 per unit), however, this may be reduced if additional VAR support is required. This scenario usually occurs where the interconnection point is towards the end of a very long feeder.

The third site-specific setting discussed was VoltWatt. This setting comes into play where the VoltVar setting alone will not mitigate the voltage violation. The VoltWatt will include appropriate time delays. At peak the Company recommends customized VoltWatt set points. It was then mentioned that battery storage can help reduce curtailments at the point of common coupling.

It was stated by Pepco that the overall purpose of site-specific settings is to reduce interconnection costs. Without the ability to control site specific settings, over-voltage and thermal overloads that would otherwise occur will drive up interconnections costs to address. Pepco's engineers conduct a power flow study at "complicated sites" to test different site-specific settings for their ability to limit violations. Pepco starts with the first setting (power factor) to see if this addresses the problem, if not they move to a combination with the second setting (volt var) and if they continue to see violations they see if this can be addressed with a combination of all three settings (including Volt Watt). Based on this analysis Pepco will create a list of recommended site-specific settings to use. Pepco states that these are used to promote their twin goals of ensuring reliability and stability of the system, while minimizing the number of curtailments experienced by the customer.

It was further explained that each site is unique and may require its own set of specific settings. In this regard, Pepco documents the site-specific settings it recommends and may determine that an external sensor is needed to monitor the power flow. One way Pepco does this is to require the customer to show them the on a single line drawing the design they intend to use to implement the site-specific setting recommendations. Another way Pepco documents the recommended site-specific settings is via an "operating requirements document." This document is incorporated into the interconnection agreement with the customer and will list the site-specific settings to be used (if certain settings are recommended). Sometimes (but not always) this may require witness testing to confirm that when the site was tested by the customer and to confirm that the recommended settings were applied.

With that the presentation concluded and questions were taken:

- CRI asked if Pepco could provide further insight as to why an external sensor may be needed if Pepco is performing all this testing? Pepco responded that in reality, in the majority of cases this external sensors will not be needed particularly with smaller

inverters. However, IEEE standards recommend external sensors under certain circumstances usually involving large inverters, the physical configuration of those inverters and where those inverters are located relative to the transformers.

- DC Climate Action asked how Pepco, on a circuit that may already be overloaded, is able to attribute the need for upgrades to a new system that may be trying to interconnect? How can Pepco say that the interconnection customer is causing those costs versus a pre-existing weakness in the circuit that needed upgrades in any event? Pepco responded by saying that is the purpose of the base case study that it conducts in connection with its power flow study analysis – to determine which feeders are at risk of reliability degradation with additional load.. Based on a proposed DER project, Pepco runs tests to see if the proposed added load will lead to reliability issue, in those cases the customer will be told that the system cannot accommodate the current DER proposal and that in order to safely and reliably connect the proposed DER, the reliability issues will need to be resolved. Pepco stated that when a feeder is not experiencing reliability issues in its current status, but the addition of the proposed DER causes voltage issues, than the costs to upgrade the feeder to accommodate that interconnection are assigned to the developer/customer–because it's not a "weak circuit" that is the cause of the upgrade, it is the added DER interconnection that precipitated the need for upgrades.

- DOEE then asked whether Pepco tracks how often the above scenario occurs so that Pepco knows ahead of time what circuits will be overloaded, or must a site-specific analysis be conducted every time? Pepco responded that it needs to perform a site-specific analysis first. If a circuit needs to be upgraded as a result of an interconnection request the customer making the interconnection request will be responsible for upgrading the distribution system or, if applicable, implementing a site specific setting that alleviates the need for the distribution system upgrades. DOEE followed up by asking why Pepco does not perform this review as a matter of course rather than only when a customer applies for interconnection? Pepco responded that they are following the cost-causer model so unless there is a need for a circuit upgrade unrelated to a DER request ahead of time, upgrading feeders that have no constraints is not likely to be deemed a prudent expense. One solution would be to socialize the costs for circuit upgrades to all DER customers, and justify these costs because if there is too much curtailment as a result of too much DER on the system, DER actually becomes counter-productive. DOEE commented that for its CREF developments it would be beneficial to have this information ahead of time to enable the CREF to come online earlier.

- CRI asked whether Pepco requires upgrade costs only after it has studied whether any and all combination of inverter settings like Volt-Var could avoid the need for upgrades? Pepco said yes, and further stated default settings are premised on the assumption that DER will be spread out across the entire feeder and not concentrated in just one point of the feeder.

- Ecogy Solar asked whether it looks at only the particular application site on a feeder when doing its power flow analysis or whether it considers other sites on the feeder? Pepco responded that it is looking at all the inverters on the feeder. The volt/var and volt/watt curves depend on which inverters got to that feeder first. It was then asked if Pepco can revisit existing sites and adjust those inverter settings in a way that could accommodate additional DERs. Pepco stated it depends on the interconnection agreement: some legacy systems allow Pepco to reconfigure the system after its been placed into operation, but there are also complicated legal issues involved.

- DOEE asked whether Pepco plans to do any benchmarking tests? Pepco responded no, but that is an interesting suggestion. DOEE offered to share some ideas on a methodology about benchmarking with Pepco if the company is interested.

- IREC asked whether Pepco has considered using a 1.05 volt/var setting limit since that is what some utilities use? Pepco said there is no central repository for comparing what other utilities recommend for inverter setting limits.

- CRI asked whether Pepco has considered using a cutoff off, by example 250 kw, where any system below that level will not need a site specific study or require any site-specific settings like volt/watt? CRI suggested that this might be a good topic for further exploration and consideration. Pepco stated that as a practical matter Pepco can only do a limited engineering analysis of each and every small system application it receives due to interconnection timelines for smaller systems being shorter. In many cases, Pepco already relies on default settings for small systems. CRI suggested that using a default cutoff of 250 kw may be an appropriate topic of future discussion and consideration if the Commission and Pepco were comfortable exploring this idea. Pepco said it would consider this suggestion and respond at a later point, but cautioned that it has a duty to operate its system in a safe and reliable manner and use its best engineering judgment in all situations. There was general agreement that, from a legal perspective, use of default settings based on a cutoff like 250 kw is permissible.

- DOEE reiterated that it could share its benchmarking methodology with the company and was prepared to do so now unless the Commission wanted this to be done more formally. Commission Staff requested that DOEE first put that methodology on the record for the group's consideration. Staff further suggested that some of these topics may be better suited for discussion in the Interconnection Technical Conference, but acknowledged that many of these topics cross Working Groups. Pepco agreed that the Interconnection Technical Conference would be a better forum for discussion. Staff further suggested that F.C. 1182 may be another docket where this topic could be raised, particularly in comments. Regardless of the forum or docket, Staff indicated that DOEE's benchmarking methodology was a valid topic for consideration and assured that there would be an opportunity to discuss at some point in the future.

- Solar Solution asked whether Pepco has implemented a requirement listed in its interconnection agreements with customers to compile and report to Pepco the amount of curtailment occurring using Volt Watt controls and other inverter settings? Solar Solutions further asked what was the purpose of this requirement? Pepco responded that it has not actually implemented this yet, but wants it in the interconnection agreements in case the need arises because these reports could be used to determine whether there is a high amount of lost energy. CRI suggested that this is data that the inverter may inherently gather. But IREC stated that the inverter automatically does curtailment and many systems don't have the instrumentation to track the number of curtailments. That is why some states like HI have an assumed amount of loss. But AMI can measure voltage data to determine an assumed maximum amount of energy loss per day.

- DOEE observed that other states have advanced inverter controls requirements. It might be helpful to devote time at a future meeting to discuss those requirements in other jurisdictions and explore whether it would be helpful for Pepco to adopt similar requirements here. Staff asked whether IREC already covered this topic in one of their presentations? IREC said they discussed California's setting requirements in their presentation.

The working group took a 5 minute break, and reconvened.

Solar Solutions Presentation on Proposed Changes to Interconnection Regulations:

Presenter: Albert LaFrance.

Proposed changes relate to smart inverter sections only. The first few changes are not substantive. First substantive change is at Section 4005: It mandates that site specific inverter settings be considered – not just those over 250 kw, but all sizes.

The next substantive change applies to level 4 interconnections in Section 4008.1 which requires the utility to maintain records of all site specific settings performed.

Pepco asked what will be the cost implications of these changes to the utility, and whether these proposals have been adopted by other states? If so, did those other states experience cost increases or did these changes result in lowered costs? Solar Solutions said it anticipates that for many small systems this requirement will not be an option, which should mitigate some of the costs. Solar solutions proffered 3 ways to mitigate costs: (1) the flat fee that Pepco is currently proposing; (2) what MD is proposing, which is to limit export settings; or (3) use Volt Watt settings to mitigate over volt situations. Solar Solutions suggested keeping all options on the table.

It was asked whether MD had determined whether their proposal has held up interconnection approvals, and whether any studies have been performed to determine if delays in DER additions added cost to the system? Solar Solutions responded that it did not know. CRI offered that in MD, the utilities have not experienced any revisions to their process as a result of limiting export settings.

CRI stated that in MD, Pepco and other utilities file their settings with the MD PSC, and then parties are allowed to comment on them. However, no revisions to the settings came as a result of this new process of filing and commenting.

Pepco responded that it already publishes its settings on its website, then asked why it is better to require them to submit their settings to the PSC for approval instead? CRI responded that filing at the PSC provided more notice to the public than if Pepco were to simply update its website. Also, filing would provide PSC's technical staff an opportunity to review the changes and potentially discuss with Pepco if there were better options, but the general idea is to open the topic up for public discussion.

Pepco still believes publishing settings on its website is sufficient.

It was reiterated that idea behind filing the settings with the Commission was to open up this procedure to the public. Also, in MD the PSC places setting updates on its administrative docket for decision. This is different than in DC where if no party comments, the updates would be deemed approved without a meeting and vote by the Commissioners.

V. Next Steps

The meeting concluded at approximately 12:25 pm. DOEE said it would post its benchmarking document. An AI generated transcript would be available immediately in Box. The official transcript would be filed in the FC 1050 and RM 40 dockets, and a follow up email would be circulated to the group by Staff in the coming days. DCG's minutes will be circulated to the participants within 10 days for comments / edits and filed in the FC 1050 and RM 40 dockets within 20 days.

Next meeting date: Tuesday, June 17th 10 – noon.

ATTACHMENT 1

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5/15/2025

Inverters Washington DC

PHI Site Specific Settings for Large DER ≥ 250 kVA (January 2024 – Present)

Capacity Planning & DER Engineering | John Budd | Tasha Kaewnukultorn, Ph.D.

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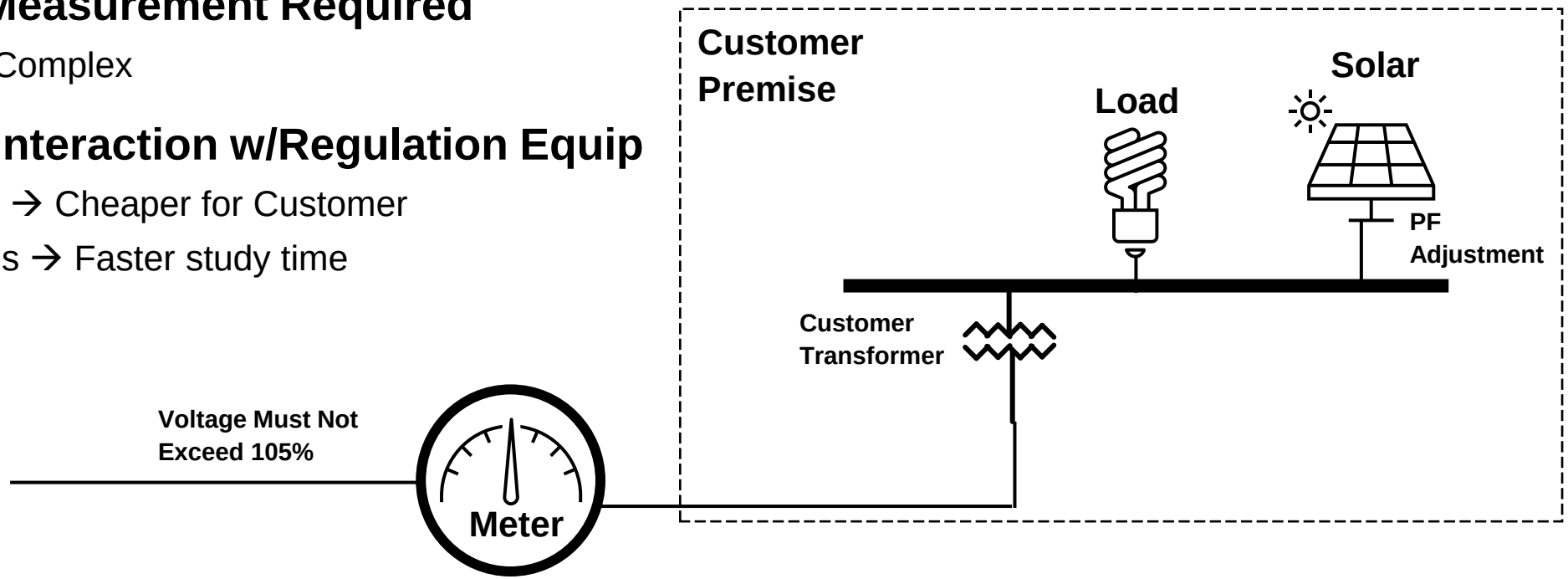
PHI Site Specific Settings

Common Types Of Settings

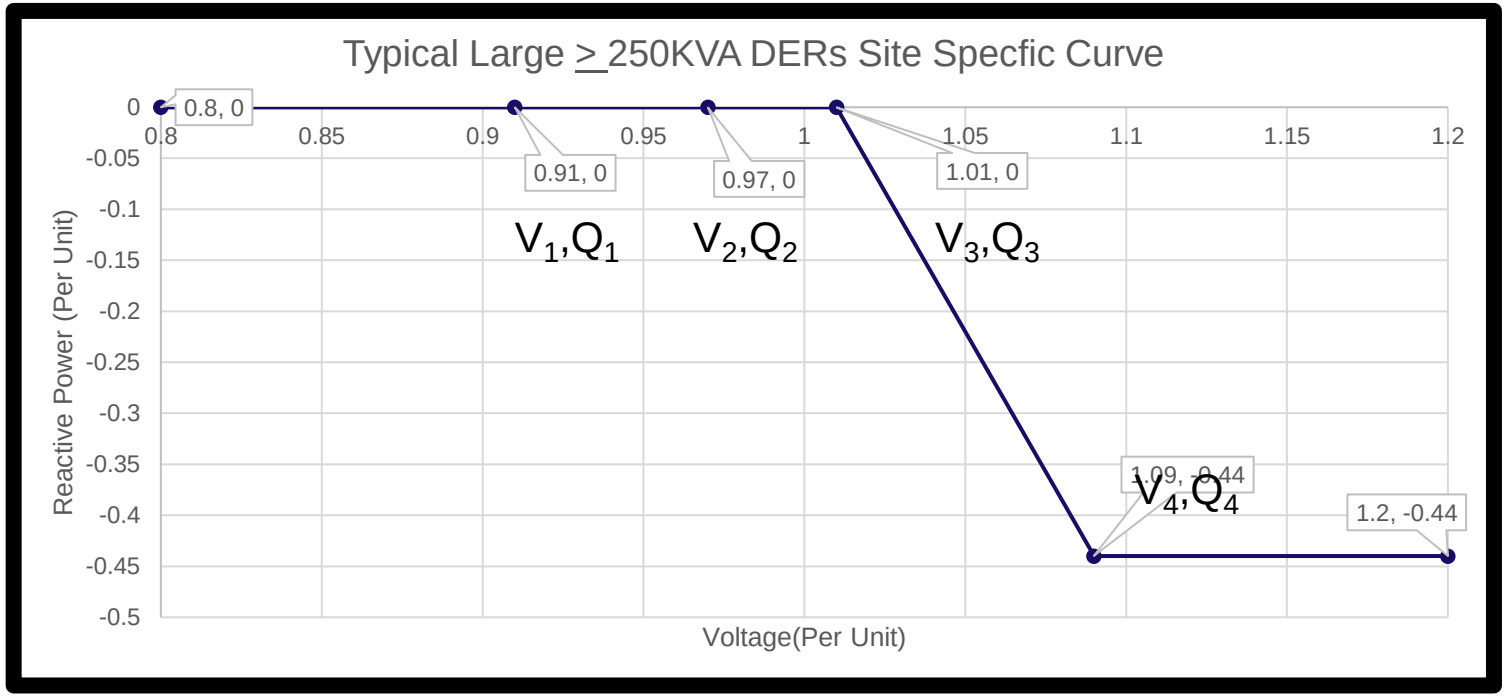
Power Factor Adjustment

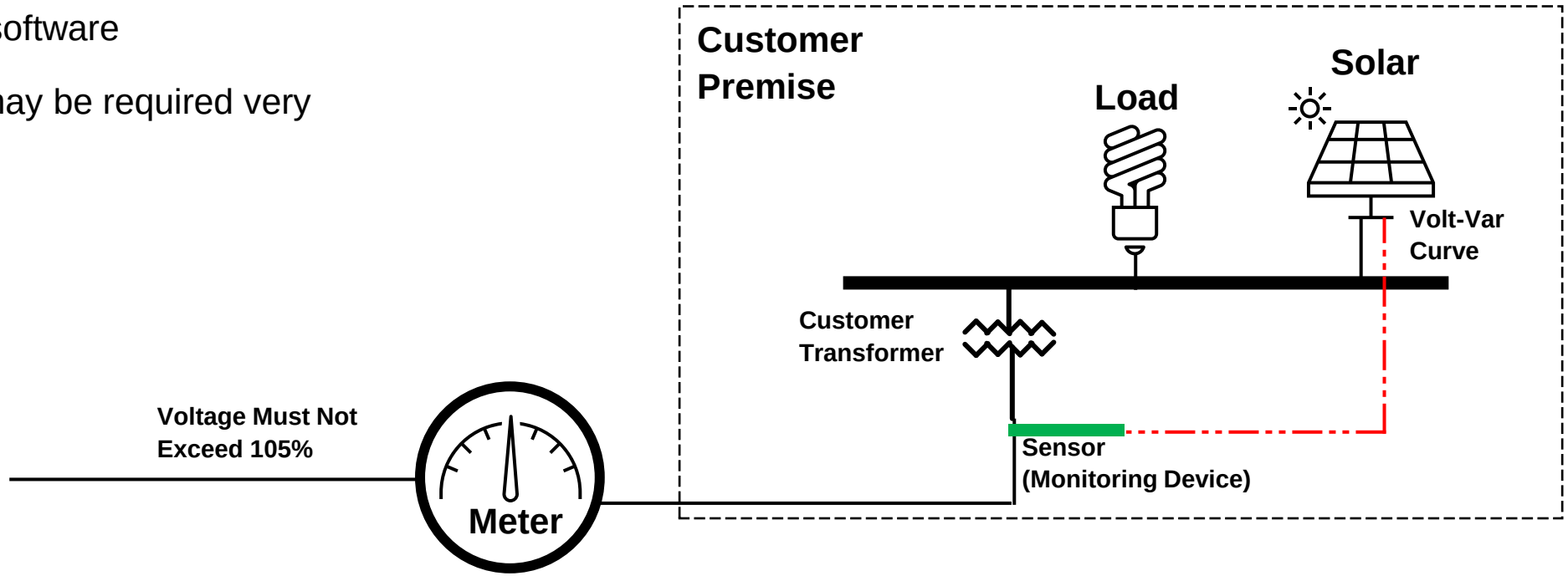
- **Power Factor Altered**
  - 1.0 (No Energy Curtailment)
  - 0.98, 0.95, 0.9 Absorbing
- **Scheduled May Be Provided**
  - Optimize Voltage Profile
- **No External Measurement Required**
  - Cheaper Less Complex
- **No Dynamic Interaction w/Regulation Equip**
  - Less Upgrades → Cheaper for Customer
  - Simpler analysis → Faster study time



Volt-Var Setting

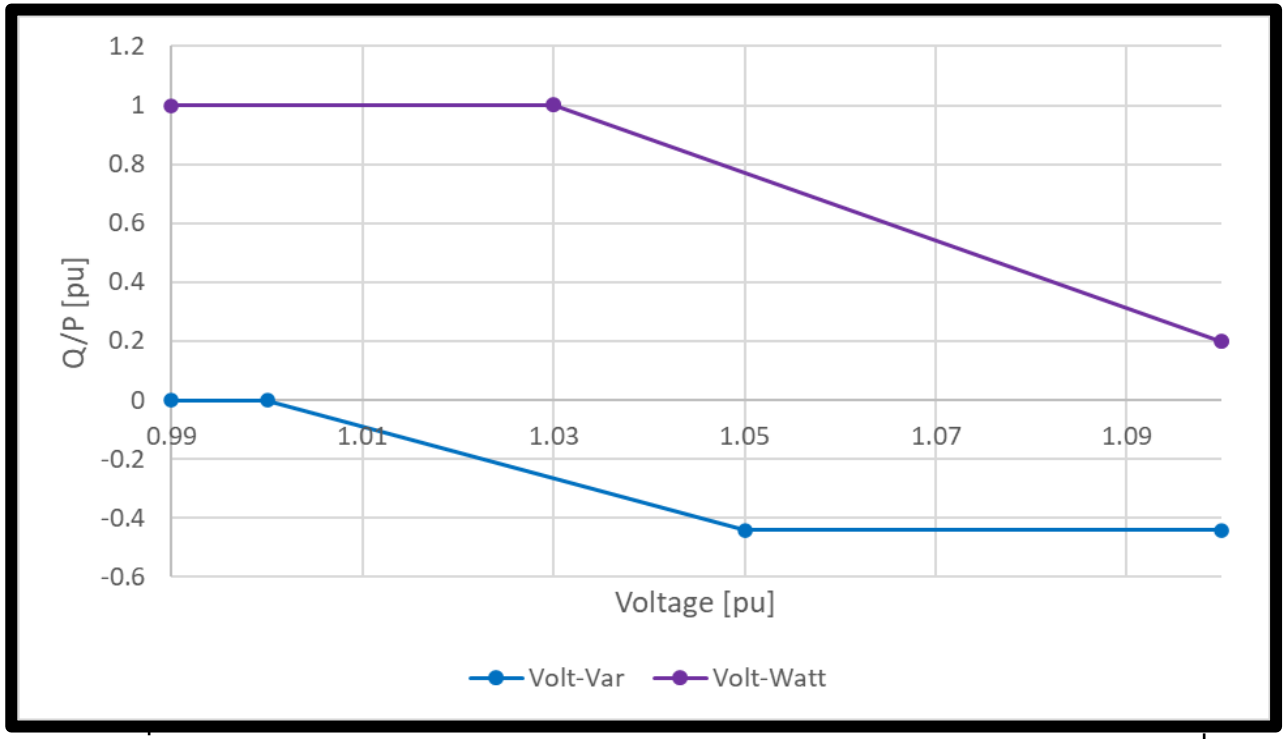
- The starting site specific volt-var curve something shown on the right→
- V3 is adjusted to a minimum of 1.00 per unit or a maximum of 1.03 per unit
- V4 is usually held at 1.09 but may be reduced if additional VAR supported is required
- This curve is modeled in an inverter in static power flow software
- Supplying VARs may be required very long feeders.

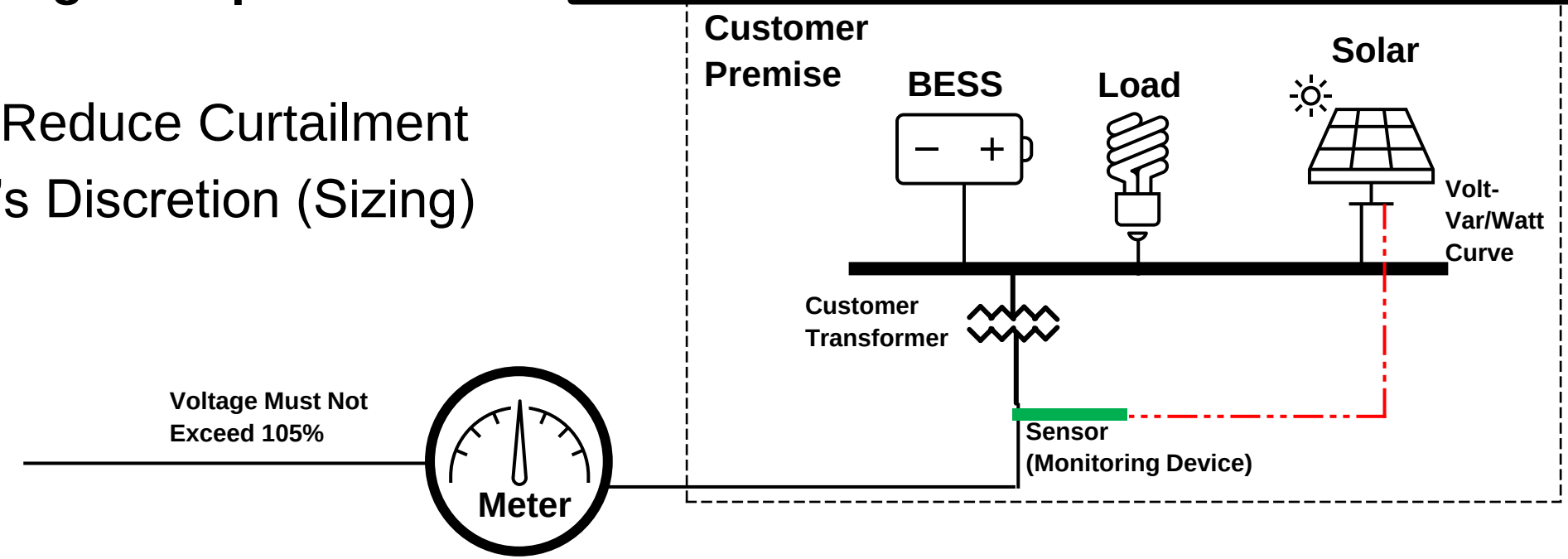




Volt-Watt Setting

- **VOLT-VAR Faster VOLT-WATT**
  - Time Delay Volt Watt
- **VOLT-WATT Settings Custom**
  - Outside 1547 Required Range
  - Pepco Adjust As Needed
- **Energy Storage Coupled with Solar**
  - May Help Reduce Curtailment
  - Customer's Discretion (Sizing)





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PHI Site Specific Settings

Typical Static Power Flow Process

Establishing a Basecase and Limit Violations

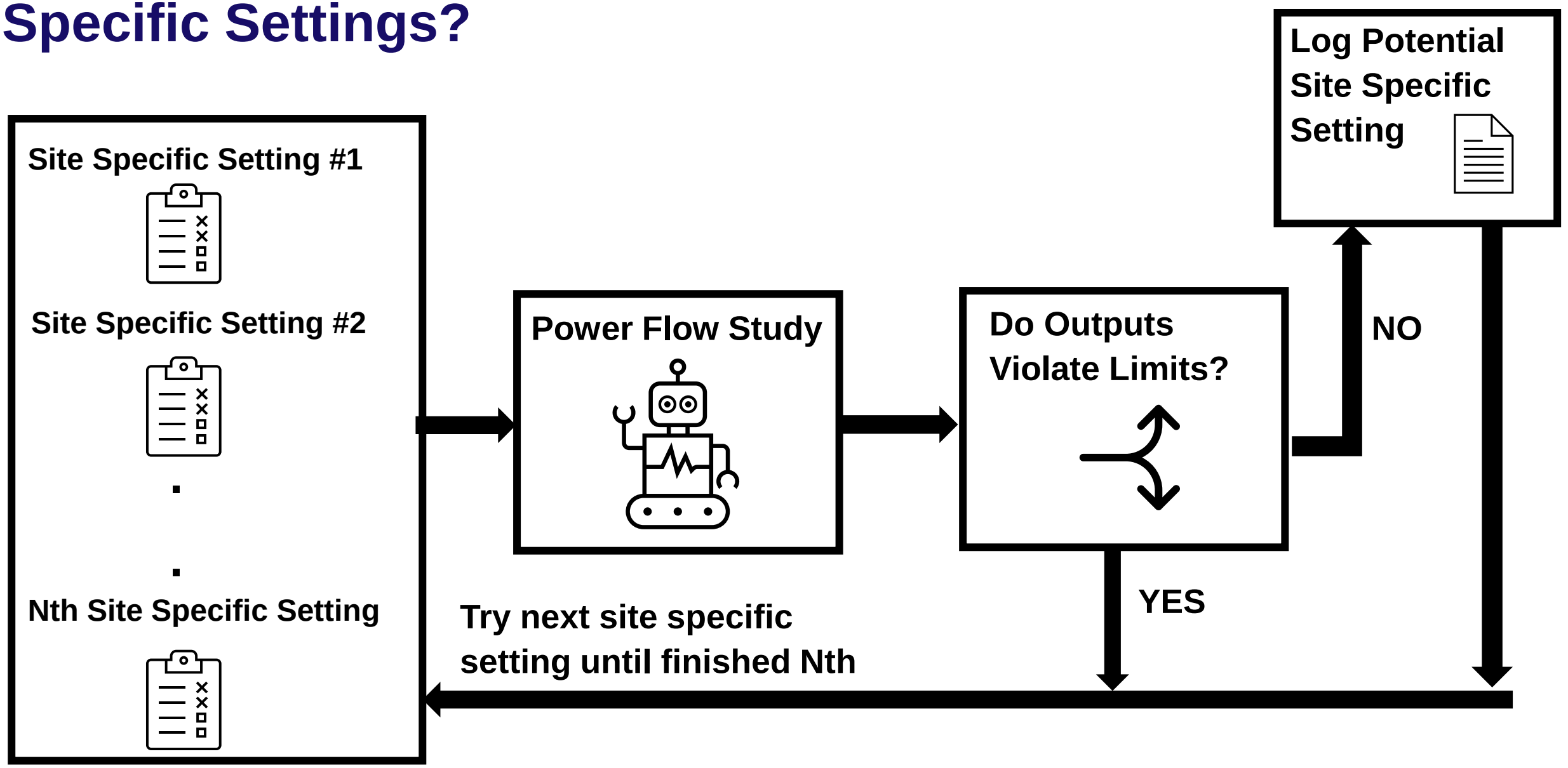
Base Case Violations are Pre-Existing Limit Violations

- These Pre-Existing Limit Violations Restrict Feeders
- Increase DER Interconnection Costs

Limit Violations

- Voltage
- Thermal Overloads
- Etc

How Does Pepco Identify Limit Violations and Test Site Specific Settings?



Testing Various Site Specific Settings on Limit Violations

Overvoltage Limit Violations

Site Specific Setting Test 1
- Unity PF

Site Specific Setting Test 2
- 99-90% PF Absorb

Site Specific Setting Test 3
- Volt-Var V3 (1 – 1.03)
- Volt-Var V4 (1.09 – 1.05)

Site Specific Setting Test 4
- Volt-Var +/or Volt Watt
- Settings Vary
- Time Delay required

Engineer recommends the optimal site specific setting

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PHI Site Specific Settings
Documentation and Verification

Single Line Diagram Documentation

Common Singleline requirements are shown to the right,

For example, if an external measurement point is required to implement volt-var or volt-watt, the instrumentation transformer, controller/inverter and the settings should be shown on the single line drawing →

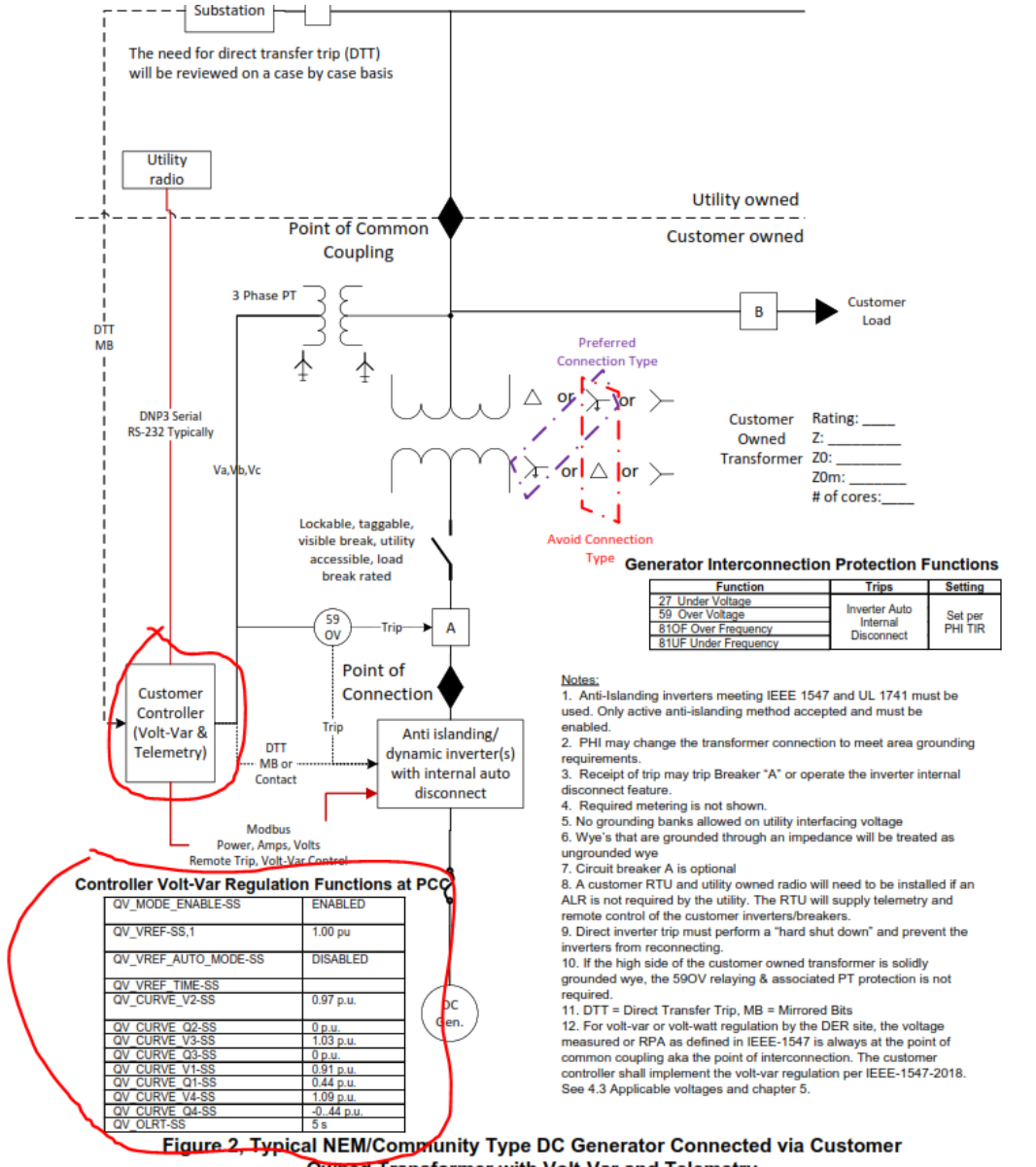
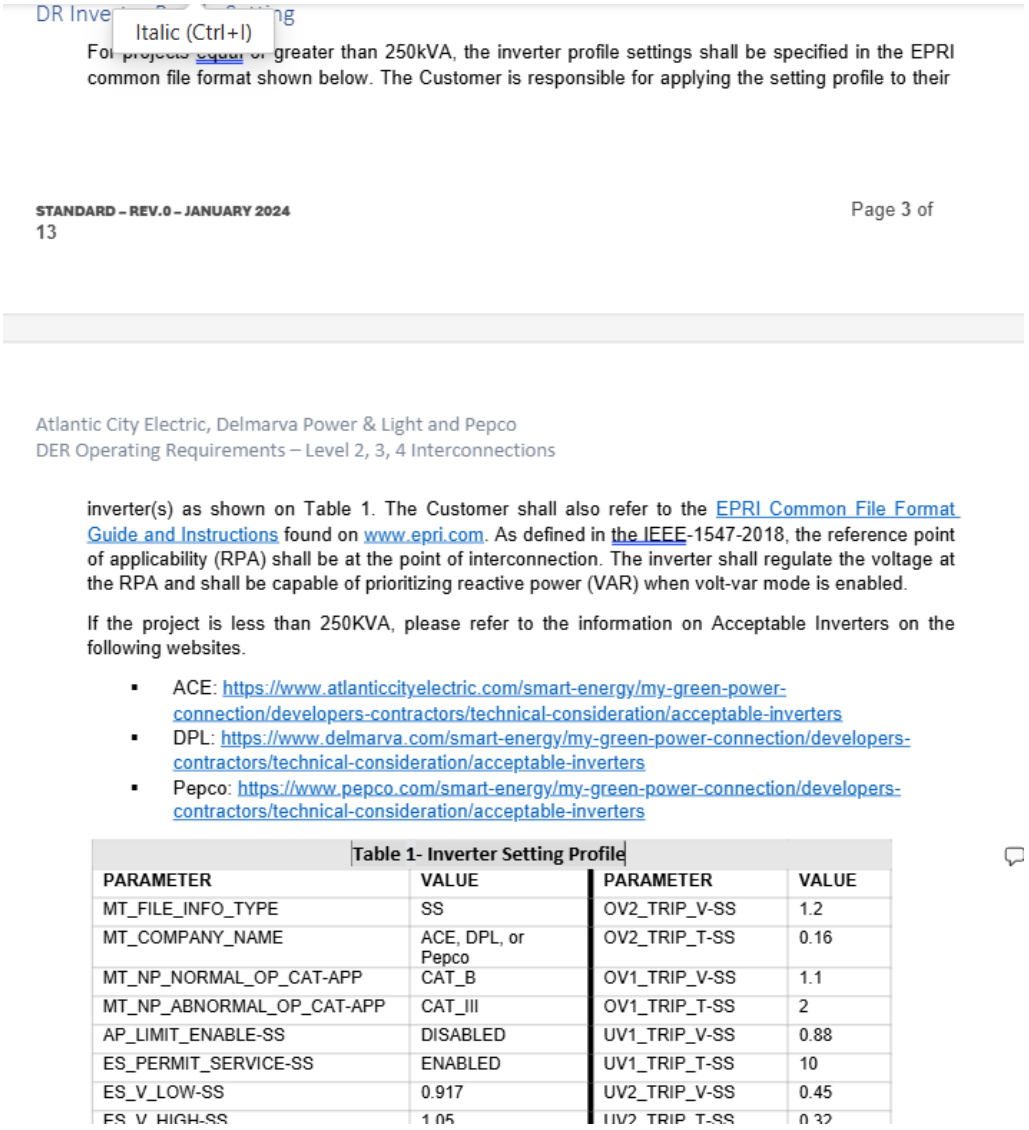


Figure 2, Typical NEM/Community Type DC Generator Connected via Customer Owned Transformer with Volt-Var and Telemetry

Operating Requirements Document

The site specific settings are specified in an operating requirements document shown to the right→

Additionally disclaimers and requirements are also called out in this document.



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For projects equal or greater than 250kVA, the inverter profile settings shall be specified in the EPRI common file format shown below. The Customer is responsible for applying the setting profile to their

STANDARD – REV.0 – JANUARY 2024 Page 3 of 13

Atlantic City Electric, Delmarva Power & Light and Pepco
DER Operating Requirements – Level 2, 3, 4 Interconnections

inverter(s) as shown on Table 1. The Customer shall also refer to the EPRI Common File Format Guide and Instructions found on www.epri.com. As defined in the IEEE-1547-2018, the reference point of applicability (RPA) shall be at the point of interconnection. The inverter shall regulate the voltage at the RPA and shall be capable of prioritizing reactive power (VAR) when volt-var mode is enabled.

If the project is less than 250KVA, please refer to the information on Acceptable Inverters on the following websites.

- ACE: https://www.atlanticcityelectric.com/smart-energy/my-green-power-connection/developers-contractors/technical-consideration/acceptable-inverters
- DPL: https://www.delmarva.com/smart-energy/my-green-power-connection/developers-contractors/technical-consideration/acceptable-inverters
- Pepco: https://www.pepco.com/smart-energy/my-green-power-connection/developers-contractors/technical-consideration/acceptable-inverters

Table 1- Inverter Setting Profile

PARAMETER	VALUE	PARAMETER	VALUE
MT_FILE_INFO_TYPE	SS	OV2_TRIP_V-SS	1.2
MT_COMPANY_NAME	ACE, DPL, or Pepco	OV2_TRIP_T-SS	0.16
MT_NP_NORMAL_OP_CAT-APP	CAT_B	OV1_TRIP_V-SS	1.1
MT_NP_ABNORMAL_OP_CAT-APP	CAT_III	OV1_TRIP_T-SS	2
AP_LIMIT_ENABLE-SS	DISABLED	UV1_TRIP_V-SS	0.88
ES_PERMIT_SERVICE-SS	ENABLED	UV1_TRIP_T-SS	10
ES_V_LOW-SS	0.917	UV2_TRIP_V-SS	0.45
ES_V_HIGH-SS	1.05	UV2_TRIP_T-SS	0.32

Witness Testing and Commissioning

Where site specific setting misapplication could cause reliability or safety issues, Pepco will perform witness testing of the customer to verify the site specific settings are applied correctly.

Pepco - Witness Testing and Commissioning – Spot and Area Grid Networks

The purpose of the witness test is to verify the required operation of the relay and control system at the Customer's generating site. This test is typically performed on systems interconnecting into a spot network, but the Company may require it for other projects, as deemed necessary.

1. The Company shall perform witness testing of protection & control scheme. The Company's testing and commissioning activities may commence following the system's completed installation and the electrical inspection, and approval of the system's as-built one-line diagram.
2. The Company requires no less than a 20-day notice from the Customer prior to the day in which the testing shall be scheduled. However, Customer shall provide an acceptable test plan for review at the time of this notification; delays may occur should the Customer-provided test plan require significant modifications. Scheduling a date for field testing will be agreed upon during the working hours of Tuesday, Wednesday, and Thursday and between the hours of 6:00am and 2:00pm EST.
3. The Customer's test plan shall include the following items:
    - 3.1.1. CTG Project ID, project name and/or site address
    - 3.1.2. Equipment subject to testing
    - 3.1.3. Manufacturer and model of equipment being tested.
    - 3.1.4. CT and PT ratios
    - 3.1.5. Nominal voltage
    - 3.1.6. Directional power set kilowatt limit
    - 3.1.7. Expected ampacity at 208VAC nominal voltage.
    - 3.1.8. Protective elements
    - 3.1.9. Relay setpoint (ampacity)
    - 3.1.10. Settings for 32-power element
    - 3.1.11. Test current (ampacity originating from a test set)
    - 3.1.12. Description of the test procedure
    - 3.1.13. A single-phase or 3-phase test set, as required for the project, should be obtained by the Customer to inject current and voltage to their equipment. The Company will not provide the required test set nor connect to Customer equipment.

ATTACHMENT 2

4002 APPLICABLE STANDARDS

4002.1 Unless one or more of the following standards are waived by the EDC, a Small Generator Facility must comply with the following standards, as applicable:

(a) Institute of Electrical and Electronics Engineers ("IEEE") 1547 Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces;

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

(c) IEEE 1547.2 - Application Guide for IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems;

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

(e) 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 standard 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 (*upon commercial availability*), 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 that was purchased prior January 1, 2022, with an inverter of equal or greater capability than the original inverter, for use at the Small Generator Facility.

(c) The EDC shall establish default EDC required inverter settings profiles for Advanced Inverters pursuant to Subsection 4002.7 (e), and shall publish the default EDC required inverter settings profile on the EDC's website prior to January 1, 2022.

(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.

(e) A default EDC required inverter settings profile shall be established by an EDC 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 curtailments during normal operating conditions and minimal real power curtailments during abnormal operating conditions.

(2) The secondary objectives are to enhance Electric Distribution System hosting capacity and to optimize the provision of grid support services.

(f)

(1) A site-specific EDC required inverter settings profile may be established by an EDC to meet objectives established in Subsection 4002.7 (e).

(2) If distribution system upgrades are determined to be required by the EDC in an interconnection analysis under default EDC required inverter settings profiles, then the EDC shall evaluate whether site-specific settings would reduce or eliminate those costs and, if so, propose them as an alternative at the time the EDC provides the good faith estimate of the distribution system upgrade costs otherwise required.

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

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(h) A list of acceptable Advanced Inverters shall be published on the EDC's website prior to January 1, 2022.

(i) The EDC shall file all proposed changes to default EDC required inverter settings profiles with the Commission for approval.

(j) Proposed changes by the EDC to its default EDC required inverter settings profiles shall be deemed approved within 90 days upon filing, unless directed otherwise by the Commission.

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SOURCE: Final Rulemaking published at 56 DCR 1415 (February 13, 2009); as amended by Final Rulemaking published at 66 DCR 01132 (January 25, 2019); as amended by Final Rulemaking published at 68 DCR 8244 (August 20, 2021).

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

(g) 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) 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) 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) 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) Except as permitted by the modified Level 2 review process in Subsection 4005.6, no construction of facilities by the EDC on its own system other than metering shall be required to accommodate the Small Generator Facility.

(l) 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 Subsection 4005.2 (c), (d), (e), (f), (g), (h), (i), or (j) screens.

(m) 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.

(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) business 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.

(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 the EDC requires the construction of Distribution System Upgrades during the Interconnection Request process, the EDC shall provide a technical explanation that reviews 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, including implementation of a site-specific inverter settings profile.

If requested by the Interconnection Customer, and agreed to by the Interconnection Customer and the EDC, a Modified Level 1 or Level 2 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 Interconnection Facilities and/or a Distribution System Upgrade are being required by the EDC. The Modified Level 1 or Level 2 Scoping Meeting shall take place in person, by telephone, or electronically by a means mutually agreeable to the Interconnection Customer and the EDC. The purpose of this meeting shall be to review the Interconnection Request, existing studies relevant to the Interconnection Request, the conditions at the proposed location, the results of the Level 1 or Level 2 Adverse System Impact screening criteria, and provide a technical explanation in which the EDC reviews the need for the aforementioned facilities and/or system upgrade.

(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 Interconnection Customer and the EDC. 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 Interconnection Customer and the EDC. 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 Interconnection Customer and the EDC, 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. Evidence of approval by an electric code official includes a signed inspection certificate.

(h) The EDC may require the submission of 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 only the addition of Interconnection Facilities to the Electric Distribution System, a non-binding good faith cost estimate and construction schedule for such upgrades, along with an Approval to Install, shall be provided within fifteen (15) business days after notification of the Level 2 Interconnection Review results.

(b) If the Interconnection Request requires more than the addition of Interconnection Facilities to the Electric Distribution System, the EDC may elect to either provide a non-binding good faith cost estimate and construction schedule for such upgrades within thirty (30) business days after notification of the Level 2 Interconnection Review results, or the EDC may notify the Interconnection Customer that the EDC will need to complete a Facilities Study under Subsection 4007.2, paragraphs (d)(3), to determine the necessary Distribution System Upgrades and complete the construction.

(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, subject to availability of funding.

(1) The total Distribution System Upgrade costs for shared allocation as described in Subsection 4005.6 (c) (2) shall be capped at $500,000 per calendar year or as otherwise determined by the Commission.

(2) If funding is available, Distribution System Upgrade cost responsibility shall be assigned as follows:

(A) For Distribution System Upgrade costs of $50,000 or less, fifty percent (50%) of the costs shall be paid for by the CREF Interconnection Customer and fifty percent (50%) of the costs paid for by the EDC.

(B) For Distribution System Upgrade costs of over $50,000, the portion paid by the EDC shall be capped at $25,000. The CREF Interconnection Customer shall pay the balance of the Distribution System Upgrade costs after the EDC portion has been subtracted.

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 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 qualify for interconnection pursuant to Level 2; or

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

4005.8 On an annual basis, if the EDC fails to issue at least ninety percent (90%) of all Approvals to Install in the Level 2 interconnection process (as specified within the timeline(s) specified in Subsections 4005.4 and 4005.6), and it shall be required to develop a corrective action plan.

(a) The corrective action plan shall describe the cause(s) of the EDC's non-compliance with Subsection 4005.8, 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). To the extent automation is an element of the corrective measure(s), this should be described in the plan.

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

(c) The EDC shall report the actual performance of compliance with Subsection 4005.8 during the reporting period in the Small Generator Interconnection Annual Report of the following year, including milestones for the number of Interconnection Requests in total, number and percentage meeting timeline requirements for Approval to Install and estimated cost letter.

SOURCE: Final Rulemaking published at 56 DCR 1415 (February 13, 2009); as amended by Final Rulemaking published at 66 DCR 01132 (January 25, 2019); as amended by Final Rulemaking published at 68 DCR 8244 (August 20, 2021).

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 the request is complete.

(1) If the EDC requires the construction of Distribution System 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, including implementation of a site-specific inverter settings profile.

(b) When the Interconnection Request is deemed incomplete, 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 Interconnection Customer and the EDC 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 the Interconnection Request is complete. The EDC may deem the Interconnection Request withdrawn if it remains incomplete.

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

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

(1) By mutual agreement of the Interconnection Customer and the EDC, 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 Interconnection Customer and the EDC, 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 Interconnection Customer and EDC. 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 Interconnection Customer and EDC agree at a Scoping Meeting that an interconnection feasibility study shall be performed, and if the Interconnection Customer and EDC 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 nonbinding good faith estimate of the cost and time to perform the study;

(4) When the Interconnection Customer and EDC agree at a Scoping Meeting that an interconnection feasibility study is not required, and if the Interconnection Customer and EDC 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 nonbinding good faith estimate of the cost to perform the study; and

(5) When the Interconnection Customer and EDC 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 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 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 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 System Upgrades; and

(v) A nonbinding good faith estimate of cost and time to construct any required Distribution System Upgrades.

(D) The Interconnection Customer and EDC 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 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 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 Interconnection Customer and EDC 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 Interconnection Customer and EDC 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 Interconnection Customer and EDC 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 Interconnection Customer and EDC 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 Interconnection Customer and EDC in the Interconnection Agreement. The Authorization to Operate may not be issued until:

(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 the submission 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 Interconnection Customer and EDC shall use a form of Interconnection Feasibility Study Agreement approved by the Commission.

SOURCE: Final Rulemaking published at 56 DCR 1415 (February 13, 2009); as amended by Final Rulemaking published at 66 DCR 01132 (January 25, 2019); as amended by Final Rulemaking published at 68 DCR 8244 (August 20, 2021).

4008 TECHNICAL REQUIREMENTS

4008.1 Unless one or more of the listed standards are waived by the EDC, a Small Generator Facility must comply with the technical standards listed in Subsection 4002.1, as applicable.[1]

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 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 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;

Deleted: 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; and

Deleted: .

(f) Any site-specific inverter settings profiles issued by the EDC.

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

[1] The PJM Manual, PJM Manual 14G, "Generation Interconnection Requests" Attachment C, which is available at: https://www.pjm.com/-/media/documents/manuals/m14g.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.

(a) The EDC shall include the estimated total amount of renewable energy credits to be obtained 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, capacity (DC and AC), and system type) on the 15th of each month, for the previous month's interconnections.

4008.6 The EDC shall designate a contact person and provide the designee's contact information on its website. The EDC shall also provide 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 understand 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 would otherwise be 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 [RESERVED]

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.

SOURCE: Final Rulemaking published at 56 DCR 1415 (February 13, 2009); as amended by Final Rulemaking published at 66 DCR 01132 (January 25, 2019); as amended by Final Rulemaking published at 68 DCR 8244 (August 20, 2021).

CERTIFICATE OF SERVICE

I hereby certify that on this 2nd day of June, 2025, I caused true and correct copies of the Minutes from the May 15, 2025 Meeting of the Advanced Inverter Working Group to be emailed to the following:

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