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September 3, 2014

VIA ELECTRONIC FILING

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

Re: ***Implementation of the Alternative Energy Portfolio Standards Act of 2004***
Docket No. L-2014-2404361

Dear Secretary Chiavetta:

Pursuant to the Commission's Proposed Rulemaking Order entered February 20, 2014 in the above-referenced proceeding, enclosed herewith for filing are the Comments of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company.

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

Very truly yours,

Tori L. Giesler

dlm
Enclosures

c: Scott Gebhardt, Bureau of Technical Utility Services
Kriss Brown, Law Bureau
Sherri Delbiondo, Law Bureau

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Implementation of the Alternative Energy Portfolio Standards Act of 2004	: :	**Docket No. L-2014-2404361**

COMMENTS OF METROPOLITAN EDISON COMPANY, PENNSYLVANIA ELECTRIC COMPANY, PENNSYLVANIA POWER COMPANY AND WEST PENN POWER COMPANY

I. INTRODUCTION AND BACKGROUND

On February 6, 2014, the Pennsylvania Public Utility Commission ("Commission") entered a Proposed Rulemaking Order ("Order") in the above-captioned docket requesting interested parties to submit written comments addressing various modifications and clarifications to its existing regulations at Chapter 75 of the Public Utility Code supporting the Alternative Energy Portfolio Standards Act of 2004, as amended, 73 P.S. § 1648.1, *et seq.* ("AEPS Act"). These revisions are aimed to update the Commission's regulations to comply with the 2007 and 2008 amendments to the AEPS Act, as well as to clarify certain implementation issues which have arisen over the course of implementation.

Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power") and West Penn Power Company ("West Penn") (collectively "the Companies") respectively submit the following comments in response to the Order.

II. COMMENTS

The Commission's proposed revisions extend to the topics of portfolio standards, interconnection, and net metering rules. In general, the Companies support the proposed revisions as necessary clarifications that are likely to provide efficiency and clarity in the application of the AEPS Act and Chapter 75 of the Commission's regulations. In particular, the Companies strongly support the Commission's effort to clarify within its regulations that a customer-generator is a retail electric customer with native load, as this guidance is consistent with the AEPS Act. Given the level of confusion raised by developers of merchant generation as to what qualifies for net metering, the Companies believe that these revisions are critical to eliminating disputes and gaining efficiencies for customers, the Commission and electric distribution companies ("EDCs") in carrying out the mandates of the AEPS Act and the Commission's associated regulations at Chapter 75. It is the Companies' strong belief that merchant generation was not intended to enjoy the protections and benefits afforded by net metering under the AEPS Act due to the fact that the merchant generation community has the ability to access wholesale energy markets through other avenues. Other portions of the revisions, while not controversial, simply document what exists as an ongoing process today, which the Companies believe is beneficial in creating transparency and consistency for all affected parties. The Companies have specific comments and additional proposed modifications, which are outlined by section in the following comments. Attachment A to these comments also provides the Companies' proposed markup of the revised sections, where text in bold represents proposed insertions and strikethrough represents proposed deletions.

Subchapter A: General Provisions:

§ 75.1 - Definitions

The Order proposes to revise and clarify a number of definitions in an attempt to conform more closely to the intent of the AEPS Act, as well as to coordinate with portions of the Pennsylvania Public Utility Code. The Companies generally agree with the proposed additions and clarifications. However, there are several additional modifications that the Companies propose be adopted as part of any final rulemaking, which are specifically outlined and described in the following paragraphs.

Customer-generator: The revisions include modifications to the definition of "customer-generator" in order to clarify that merchant generators and electric utilities are not considered customer-generators for purposes of the application of the AEPS Act. The proposed clarification to this definition is consistent with the AEPS Act and is fully supported by the Companies, as it supports the theme of additional revisions the Order proposes throughout Chapter 75. By clarifying that this term only applies to retail electric customers, the regulation will support what the Companies believe to be the legislature's intent in limiting certain provisions to only those customers who are NOT merchant-generators.

DSP - Default Service Provider: Default service providers generally provide generation service *and* transmission service. In the case of the Companies, the transmission service included in the price to compare is market based transmission service. Therefore, the Companies propose to add this clarification to the definition of "DSP" in order to align the definition with those services actually provided. Specific proposed language is provided in Attachment A.

Grid Emergencies: The Company supports the proposed definition of Grid emergencies, as well as the source of the definition. However, the definition of grid emergency as currently recognized by PJM might change over time as conditions warrant, such that the definition included in Chapter 75 could, over time, become stale. Therefore, the Companies suggest the following change to the definition of Grid emergencies in order to make the proposed regulations more flexible to future applications. Specific proposed language is provided in Attachment A.

Microgrid: In order to safely utilize distributed resources to support critical infrastructure served by the electric distribution system, the operation of those distributed resources to flow over an EDC's system must be under the control of the EDC's distribution operations center in order to avoid power flow on sections of a line otherwise thought to be de-energized. To permit otherwise would create extremely unsafe situations that would place an EDC's employees at significant risk. For that reason, the Companies have proposed several edits to the definition of "Microgrid" in Attachment A.

Tier II alternative energy source: The Companies believe that the Commission intended for generation of electricity utilizing by-products of the pulping process and wood manufacturing process to be from facilities located *within* the commonwealth rather than *outside*. Therefore, a change has been proposed in Attachment A in order to capture this intent.

Subchapter B: Net Metering

§ 75.12 – Definitions.

"Virtual meter aggregation" has been revised to account for amendments to the AEPS Act which were not captured in its original regulatory language, and to limit those instances where such metering is permitted to only those contemplated by the Act. Additionally, the Commission proposes to modify "year and yearly" in order to align the annual payout period for net metered customers to the highest period of output for solar photovoltaic systems.

Virtual meter aggregation: The Companies support the Commission's proposed changes to the definition of Virtual meter aggregation as being consistent with the AEPS Act in that they will specifically exclude merchant generators from virtual net metering programs. However, the Companies believe that the definition would also benefit from a further clarification of what qualifies for virtual meter aggregation, as there is often confusion in application of this term as to how broadly the legislature intended this term to be applied. Therefore, the Companies suggest that for clarification purposes it also be specified that retail electric accounts in the name of different legal entities or customers should not be included in the virtual meter aggregation of a customer-generator. Specific proposed language reflecting this limitation is provided in Attachment A.

Year and yearly: The proposed revision to this definition changes the application of these programs from a PJM calendar-year basis to one that begins on May 1 and ends on April 30. While the Companies understand that solar output tends to favor the proposed period, there does not appear to be a similar change in reporting period associated with provision of service under these regulations. In addition, aligning this definition with the PJM calendar year has the benefit of allowing for better coordination with the PJM capacity planning year. Therefore, the Companies propose that this revision be deleted to leave the existing definition stand as written.

§ 75.13 – General Provisions

The proposed changes to § 75.13 are intended to further clarify the qualifications a customer-generator must demonstrate in order to net meter, including ownership status, size restrictions, and Commission approval requirements. These proposed additions are consistent with the intent of the legislation, and yet have been a subject of much unnecessary conflict between utilities, developers and the Commission. Due to this pattern of debate in application of these provisions, the Companies fully support the revisions to § 75.13(a), as it is expected that in further outlining the legislature's intent, the additional clarity in the regulations will promote economic efficiency and minimize customer disputes regarding what constitutes a qualifying system.[1] In particular, the Companies support the notion that in order to qualify as a customer-

[1] Consistent with the inclusion of a new definition for Utility, the Companies believe that the Commission intended the "utility" to be capitalized at the end of § 75.13(a)(2).

generator, there necessarily must be native load (i.e., load that would exist absent the customer-owned generation) at the service location which exceeds the customer's anticipated usage. To permit anything other would allow merchant generators to bypass the existing process through which they sell to the wholesale market, at the expense of retail electric customers and EDCs.

Given the statutory possibility of a non-EDC serving as a DSP, it makes sense to add "DSP" to this section of the regulations as proposed, as well. However, the language as drafted is not entirely clear as to the obligations of the EDC in contrast to the obligations of the DSP. Specifically, the question remains as to which of those entities would be responsible for providing what specific credits to a customer-generator in the event that the day comes where the DSP is not the EDC. Likewise, except when a customer-generator is a default service customer, the electricity supplied to the customer by the EDC, yet the DSP (in this case, an EGS) will be different. Therefore, the Companies have proposed modifications in an effort to clarify what they believe to be the Commission's intent on this point, which are reflected in Attachment A.

The proposed changes to new subsections (e) and (f) are intended to clarify the determination of compensation on excess generation at year end for both default service and shopping customers, respectively. The Companies believe that the changes in both sections are consistent with the legislation, provide clarity to market participants, and are largely consistent with existing practices.[2] However, the Companies recently spent significant time and capital to automate the process by which customer-generators are compensated for excess generation, with the automated process fully implemented in August of 2013. As a result, the Companies currently calculate PTC charges by applying the current PTC pricing to the customer's total

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[2] Subsection (e) references the EDC's PTC rate. Considering the Commission's effort to incorporate the use of "DSP" throughout Chapter 75 in anticipation of an alternative DSP, the Companies suggest that an adjustment be made to add DSP to this language.

generated energy, or "metered outflow." The system accumulates both the generated energy and the monthly PTC charges on that generated energy throughout the year. When the customer is netted out and compensated each year end, the system calculates the Weighted Average PTC as being equal to the Accumulated PTC charge on generated energy, divided by the Accumulated generated kWh. The credit is then calculated by applying a weighted average PTC value to any excess generation remaining. Due to the recent automation of the process, and given that the average cash out values are not significant, the Companies request that their process be determined to be compliant with the regulations.

§ 75.14 – Meters and Metering

Section 75.14(e) has been revised to further clarify which systems are eligible for virtual meter aggregation. Consistent with the comments above with respect to the corresponding definition, the Companies generally support the recommended changes to 75.14(e), as the proposed clarifications are consistent with the AEPS Act and will help to align the existing regulations with the Act's intent. However, the Companies believe that substituting "electric distribution service" or "retail electric service" for "electric generation service" as written is necessary. This is because it is highly possible that an EDC will have no idea whether a customer is taking electric generation service, and if so, from which EGS, yet it is the EDC that is asked to comply with the regulations. Adjusting the verbiage for this consideration would make it easier for EDCs to properly carry out the requirements of the regulation. Further, virtual meter aggregation is seen by the Companies as aggregating electric *accounts* rather than *properties*, and therefore have added language to account for the fact that a customer would need to hold each of the electric accounts in order to receive virtual meter aggregation. Finally, the Companies have attempted to further clarify that there must have been electric load at the site prior to the installation of a qualifying net metering system in order to continue throughout the regulations the theme that there is a requirement for native load, and that merchant-generators are not eligible for such a service. Changes have been proposed in Attachment A in order to capture these concepts.

§ 75.17 – Process for obtaining Commission approval of customer-generator status

Section 75.17 outlines the process to be followed in applying for net metering status, as well as provides for instances where Commission review will be required. The Companies support 75.17, as it is anticipated to provide significant assistance in resolving customer disputes regarding status in the future. However, the process outlined is expected to increase the costs borne by EDCs in the processing of net metering applications for units in excess of 500 kW. Therefore, the Companies urge the Commission to increase the fees an EDC may charge for the review of such applications. The existing fee structure was set by the Commission in a Policy Statement adopted on February 26, 2009, setting forth the standard application fees for Level 1 through Level 4 for reviews of generating facilities and completion of the interconnection pursuant to the Commission's regulations of 52 Pa. Code 75.21-75.51. Given the changes proposed by this Order, it makes sense to review the existing fee structure to ensure it aligns with the actual costs of providing the service going forward.

Subchapter D: Alternative Energy Portfolio Requirement

The Companies generally support the proposed revisions to Subchapter D, which aim to incentivize continued system compliance and provide penalties for noncompliance, as well as document various reporting requirements. However, there are a number of additional suggested revisions that the Companies believe would serve to make the compliance process more accurate, administratively convenient and financially stable.

§ 75.63 – Alternative energy credit certification

The Companies actively support the proposed modifications to § 75.63(g), requiring the use of metered data for solar energy systems in excess of 15 kilowatts. The Companies agree that this metering requirement will improve the integrity of measurement and verification of credit production and will bring the solar energy system metering requirements in line with other alternative energy systems, making the requirements consistent.

The Companies also support § 75.63(i), which allows for alternative energy systems to begin to earn RECs from the date a complete application is filed with the administrator. This will avoid a loss of REC production during the certification process which could be drawn out for various reasons and will allow for qualifying facilities to earn credits sooner, providing more supply to the market for the benefit of customers.

§ 75.62 – Alternative energy system qualification; § 75.64 – Alternative energy credit program administrator

With revisions to Section 75.62, the Commission proposes to add subsection (g), which calls for a suspension or revocation of a system's status where instances of false information or violations standards are found. Further, through its revisions to Section 75.64, the Commission adds language to actively address fraudulent REC supplier practices, which ultimately calls for the suspension or revocation of a system's status, as well as withhold or retire past, current or future credits for noncompliance. The Companies agree with the Commission's proactive approach to addressing such concerns. However, the prescribed punishment must be careful not to impact innocent market participants. For instance, where RECs have been purchased and used, or are going to be used for compliance by the purchaser, having the RECs invalidated could place a huge financial and regulatory burden on market participants who have transacted for properly certified RECs for use at the time of purchase. This would implicate the need to purchase new RECs at prices that may be more than what was paid for the original, plus the additional expense of legal remedies to attempt to collect on damages from the fraudulent suppler. This concern could escalate where the RECs were used for compliance and the compliance year has closed, leading to a possible compliance payment requirement. The Companies suggest that, in order to avoid this potential undue harm to innocent parties, RECs from a facility that has been deemed non-compliant but which have already been sold and transferred from the Seller's account to the purchaser remain valid for compliance use by the purchaser. However, current RECs that have not been sold and transferred, as well as future RECs, would be addressed as defined within the Order. The Companies also suggest that the Commission consider a financial penalty, including the disgorgement of profits from the fraudulent Seller, for RECs that have already been sold and transferred in order to create a disincentive for such action without impacting innocent market participants.

§ 75.72 – Reporting requirements for quarterly adjustment of non-solar Tier I obligation

Finally, the Companies would like to suggest modifications to the Commission's formalization of today's practices as identified in its new Section 75.72. With respect to the reporting requirements for the quarterly adjustment of non-solar Tier I obligations under subsections (a) and (b), the proposed practices in some cases impose a more strict time constraint than what exists today. Such a narrowing of deadlines will create a greater burden on EDCs and EGSs to comply. Therefore, the Companies suggest modifications to the proposed reporting and compliance timeline to improve the overall process for all parties, including the Commission. The suggested modifications include:

1. Subsections (a)(1)-(4) call for a reporting of monthly sales data for the preceding quarter by no later than each of October 30, January 30, April 30, and June 30. The Companies suggest that the reporting dates be extended by five calendar days beyond the proposed dates to November 5, February 5, May 5 and July 5, respectively. This extension would serve to address the reporting time constraints associated with the PJM sixty-day reconciliation process. The data being requested herein is either being run from the EDC's settlement system on the proposed reporting date, or in a best case scenario, the day before the proposed reporting date, which makes the timeframe to provide this data very tight and the data susceptible to potential error. By adding five days, EDCs will have an opportunity to complete the sixty-day reconciliation process, validate the data for posting, and then accurately post to the program administrator.

2. Subsection (a)(4) proposes that the 4th quarter data (March, April, May) be due thirty days following the end of the quarter, as opposed to the sixty days allotted for the first three quarters. This means that the May data must always be estimated and will never be actual. Alternatively, if the Commission were to move the compliance period to a deadline of September 30 (or October 5, as noted in the Companies' proposal directly above), EDCs could provide reconciled data for the entire compliance year.

3. Subsections (b)(1)-(4) require EGS verification of sales data in two business days. Today's unofficial practice is closer to five business days. Thus, the Companies would suggest modification of the sales data verification process to at least five

business days in order to continue their current practices and ensure that sales data is properly validated and accurately reported.

Adopting these minor adjustments to the reporting schedule would retain today's common practice and timeline in reporting, while ensuring that the accuracy of data provided has been fully validated and is as reliable as possible.

III. CONCLUSION

Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company appreciate the opportunity to provide comments on this important set of topics. Most significantly, the Companies share the Commission's interest in properly aligning the regulations with the intent of the AEPS Act such that the benefits of net metering are provided to true customer-generators rather than the merchant generator community, which already has access to wholesale energy markets through other means.

Respectfully submitted,

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ANNEX A
TITLE 52. PUBLIC UTILITIES
PART I. PUBLIC UTILITY COMMISSION
Subpart C. FIXED SERVICE UTILITIES
CHAPTER 75: ALTERNATIVE ENERGY PORTFOLIO STANDARDS

Subchapter A: General Provisions

§ 75.1. Definitions.

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<u>*Aggregator* – a person or entity that maintains a contract with individual alternative energy system owners to facilitate the sale of alternative energy credits on behalf of multiple alternative energy system owners.</u>

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Alternative energy sources- The term includes the following existing and new sources for the production of electricity:

* * * * *

(v) Low-impact hydropower consisting of any technology that produces electric power and that harnesses the hydroelectric potential of moving water impoundments[, provided the incremental hydroelectric development] <u>if one of the following applies</u>:

<u>(a) The hydropower source has a federal energy regulatory commission licensed capacity of 21 megawatts or less and was issued its license on or prior to January 1, 1984, and held on July 1, 2007, in whole or in part, by a municipality located wholly within this commonwealth or by an electric cooperative incorporated in this commonwealth.</u>

(b) The incremental hydroelectric development:

[(a)] (1) Does not adversely change existing impacts to aquatic systems.

[(b)] (2) Meets the certification standards established by the low impact hydropower institute and American Rivers, Inc., or their successors.

[(c)] (3) Provides an adequate water flow for protection of aquatic life and for safe and effective fish passage.

[(d)] (4) Protects against erosion.

[(e)] (5) Protects cultural and historic resources.

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(vii) Biomass energy, which means the generation of electricity utilizing the following:

(A) Organic material from a plant that is grown for the purpose of being used to produce electricity or is protected by the Federal Conservation Reserve Program (CRP) and provided further that crop production on CRP lands does not prevent the achievement of the water quality protection, soil erosion prevention or wildlife enhancement purposes for which the land was primarily set aside.

(B) Solid nonhazardous, cellulosic waste material that is segregated from other waste materials, such as waste pallets, crates and landscape or right-of-way tree trimmings or agricultural sources, including orchard tree crops, vineyards, grain, legumes, sugar and other byproducts or residues.

(C) Generation of electricity utilizing by-products of the pulping process and wood manufacturing process, including bark, wood chips, sawdust and lignin in spent pulping liquors from alternative energy systems located inside the commonwealth.

* * * * *

(xiii) Distributed generation systems, which means the small-scale power generation of electricity and useful thermal energy <u>from systems with a nameplate capacity not greater than 5 megawatts</u>.

* * * * *

Customer-generator –A <u>retail electric customer that is a</u> nonutility owner or operator of a net metered distributed generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service or not larger than 3,000 kilowatts at other customer service locations, except for customers whose systems are above 3 megawatts and up to 5 megawatts who make their systems available to operate in parallel with the electric utility during grid emergencies as defined by the regional transmission organization or where a microgrid is in place for the primary or secondary purpose of maintaining critical infrastructure, such as homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants or telecommunications facilities, provided that technical rules for operating generators interconnected with facilities of an EDC, electric cooperative or municipal electric system have been promulgated by the institute of electrical and electronic engineers and the Commission.

* * * * *

DSP – Default service provider – An EDC within its certified service territory or an alternative supplier approved by the Commission that provides generation **and market-based transmission** service when one of the following conditions occurs:
(i) When a contract for electric power, including energy and capacity, and the chosen electric generation supplier does not supply the service to a retail electric customer.
(ii) When a retail electric customer does not choose an alternative electric generation supplier.

* * * * *

Grid emergencies – **An event as defined by PJM Manual 13 - Emergency Operations, as updated or superseded from time to time by PJM.**
~~One of the following abnormal system conditions:~~

~~(i) Manual or automatic action to maintain system frequency to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property.~~

~~(ii) Capacity deficiency or capacity excess conditions.~~

~~(iii) A fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel.~~

~~(iv) An abnormal natural event or man-made threat that would require conservative operations to posture the system in a more reliable state.~~

~~(v) An abnormal event external to the PJM service territory that may require PJM action.~~

* * * * *

Microgrid – A system analogous to the term distributed resources (DR) island system, when parts of the electric **distribution system** ~~grid that~~ have DR and **critical**

infrastructure load **in such a combination so as to give the EDC** ~~have~~ the ability to **safely and** intentionally disconnect **that section of the distribution system** from **the rest of the distribution system** and operate **it as an island during emergency situations**~~in parallel with EPSs~~.

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Moving water impoundment – A physical feature that confines, restricts, diverts or channels the flow of surface water, including in-stream hydroelectric generating technology and equipment.

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Tier II alternative energy source -- Energy derived from:

(i) Waste coal.
(ii) Distributed generation systems.
(iii) Demand-side management.
(iv) Large-scale hydropower.
(v) Municipal solid waste.
(vi) Generation of electricity utilizing by-products of the pulping process and wood manufacturing process, including bark, wood chips, sawdust and lignin in spent pulping liquors from alternative energy systems located ~~outside~~ **inside** the Commonwealth.
(vii) Integrated combined coal gasification technology.

* * * * *

Useful thermal energy – Thermal energy created from the production of electricity and which would otherwise be wasted if not used for other non-electric generation, beneficial purposes. The definition may not apply to the use of thermal energy used in combined-cycle electric generation facilities.

Utility – A person or entity that provides electric generation, transmission, or distribution services, at wholesale or retail, to other persons or entities.

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Subchapter B: Net Metering

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§ 75.12. Definitions.

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Virtual meter aggregation- The combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-generator by means of the EDC's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. Virtual meter aggregation on properties owned or leased and operated by [a] the same customer-generator and located within 2 miles of the boundaries of the customer-generator's property and within a single electric distribution company's service territory shall be eligible for net metering. All service locations to be aggregated must be **listed as accounts held by the same individual or legal entity and shall have been** receiving retail electric service from the same EDC and have measureable electric load independent of the alternative energy system. To be independent of the alternative energy system, the electric load must have a purpose other than to support the operation, maintenance or administration of the alternative energy system.

* * * * *

Year and yearly – [Planning year as determined by the PJM Interconnection, LLC regional transmission organization] ~~The period of time from May 1 through April 30~~.

* * * * *

§ 75.13. General provisions.

(a) EDCs and DSPs shall offer net metering to customer-generators that generate electricity on the customer-generator's side of the meter using Tier I or Tier II alternative energy sources, on a first come, first served basis. To qualify for net metering, the customer-generator must meet the following conditions:

(1) Have electric load, independent of the alternative energy system, behind the meter and point of interconnection of the alternative energy system. To be independent of the alternative energy system, the electric load must have a purpose other than to support the operation, maintenance or administration of the alternative energy system.

(2) The owner or operator of the alternative energy system may not be a U~~u~~tility.

(3) The alternative energy system must be sized to generate no more than 110% of the customer-generator's annual electric consumption at the interconnection meter location when combined with all qualifying virtual meter aggregation locations.

(4) The alternative energy system must have a nameplate capacity of not greater than 50 kilowatts if installed at a residential service location.

(5) The alternative energy system must have a nameplate capacity not larger than 3 megawatts at other customer service locations.

(6) The alternative energy system must have a nameplate capacity not larger than 5 megawatts and meets the conditions set forth in § 75.16 (relating to large customer-generators).

(7) An alternative energy system with a nameplate capacity of 500 kilowatts or greater must have Commission approval for net metering in accordance with § 75.17 (relating to the process for obtaining commission approval of net metering applications).

(b) EGSs may offer net metering to customer-generators, on a first come, first service basis, under the terms and conditions as are set forth in agreements between EGSs and customer-generators taking service from EGSs, or as directed by the Commission.

[(b)] (c) * * *

[(c)] (d) [The] An EDC **shall credit a customer-generator at the EDC's unbundled distribution kWh rate** and **the** DSP**, where it differs from the EDC,** shall credit a customer-generator at the full ~~retail rate, which shall include~~ **generation and market based transmission kwh rate such that the combination equals the total retail kwh rate,** ~~transmission and distribution charges,~~ for each kilowatt-hour produced by a Tier I or Tier II resource installed on the customer-generator's side of the electric revenue meter, up to the total amount of electricity used by that customer during the billing period. **During periods when the customer-generator is a default service customer, i**~~I~~f a [customer generator] customer-generator supplies more electricity to the electric distribution system than the EDC and DSP [delivers] deliver to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward **by the EDC and the DSP** and credited against the customer-generator's usage in subsequent billing periods at the **applicable** ~~full retail~~ rate. Any excess kilowatt hours that are not offset by electricity used by the customer in subsequent billing periods shall continue to accumulate until the end of the year. For customer-generators involved in virtual meter aggregation programs, a credit shall be applied first to the meter through which the generating facility supplies electricity to the distribution system, then through the remaining meters for the customer-generator's account equally at each meter's designated rate.

[(d)] (e) At the end of each year, the [EDC] DSP shall compensate the customer-generator for any remaining excess kilowatt-hours generated by the customer-generator, that were not previously credited against the customer-generator's usage in prior billing periods [over the amount of kilowatt hours delivered by the EDC during the same year] at the ~~EDC~~DSP's price to compare rate. In computing the compensation, the DSP shall use a weighted average of the price to compare rate, with the weighting based on the rate in effect when the excess generation was actually delivered by the customer-generator to the DSP.

[(e)] (f) The credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs shall be stated in the service agreement between the customer-generator and the EGS. EDCs shall credit customer-generators who are EGS customers for each kWh of electricity produced at the EDC's unbundled distribution kWh rate. The distribution credit shall be applied monthly. If the customer-generator supplies more electricity to the electric distribution system than the EDC delivers to the customer-generator in any billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's unbundled distribution usage in subsequent billing periods until the end of the year when all remaining unused distribution credits shall be zeroed-out, and no distribution credits will be carry forward into the next year.

[(f)] (g) * * *

[(g)] (h) * * *

[(h)] (i) * * *

[(i)] (j) An EDC and DSP shall provide net metering at nondiscriminatory rates identical with respect to rate structure, retail rate components and any monthly charges to the rates charged to other customers that are not customer-generators on the same default service rate. An EDC and DSP may use a special load profile for the customer-generator which incorporates the customer-generator's real time generation if the special load profile is approved by the Commission.

[(j)] (k) An EDC or DSP may not charge a customer-generator a fee or other type of charge unless the fee or charge would apply to other customers that are not customer-generators, or is specifically authorized under this chapter or by order of the Commission. The EDC and DSP may not require additional equipment or insurance or impose any other requirement unless the additional equipment, insurance or other requirement is specifically authorized under this chapter or by order of the Commission.

[(k)] (l) * * *

§ 75.14. Meters and metering.

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(e) Virtual meter aggregation on properties owned or leased and operated by [a] the same customer-generator shall be allowed for purposes of net metering. Virtual meter aggregation shall be limited to meters located on properties owned or leased and operated **with active electric accounts held** by the same customer-generator within 2 miles of the boundaries of the customer-generator's property and within a single EDC's service territory. All properties to be aggregated must be receiving **prior** electric **distribution** ~~generation~~ service and have measureable load independent of any alternative energy system. Physical meter aggregation shall be at the customer-generator's expense. The EDC shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the EDC at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis.

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§ 75.16. Large customer-generators.

(a) This section applies to distributed generation systems with a nameplate capacity above 3 megawatts and up to 5 megawatts. The section identifies the standards that these systems must satisfy to qualify for customer-generator status.

(b) A retail electric customer may qualify its alternative energy system for customer-generator status if it makes its system available to operate in parallel with the grid during grid emergencies by satisfying all of the following requirements:

(1) An RTO has designated, pursuant to a FERC approved tariff or agreement, the alternative energy system as a generation resource that may be called upon to respond to grid emergencies.

(2) The alternative energy system is able to provide the emergency support consistent with the tariff or agreement.

(3) The alternative energy system is able to increase and decrease generation delivered to the distribution system in parallel with the EDC's operation of the distribution system during the grid emergency.

(c) A retail electric customer may qualify its alternative energy system located within a microgrid for customer-generator status if it satisfies all of the following requirements:

(1) The alternative energy system complies with IEEE standard 1547.4.

(2) The customer documents that the alternative energy system exists for the primary or secondary purpose of maintaining critical infrastructure.

§ 75.17. Process for obtaining Commission approval of customer-generator status.

(a) This section establishes the process through which EDCs obtain commission approval to net meter alternative energy systems with a nameplate capacity of 500 kilowatts or greater.

(b) An EDC shall submit a completed net metering application to the Commission's Bureau of Technical Utility Services with a recommendation on whether the alternative energy system complies with the applicable provisions of chapter 75 (relating to alternative energy portfolio standards) and the EDC's net metering tariff provisions within 20 days of receiving a completed application. The EDC shall serve its recommendation on the applicant.

(c) The net metering applicant has 20 days to submit to the Bureau of Technical Utility Services a response to the EDC's recommendation.

(d) The Bureau of Technical Utility Services shall review the net metering application, the EDC recommendation and response, and make a determination as to whether the alternative energy system complies with the provisions of chapter 75 (relating to alternative energy portfolio standards) and the EDC's net metering tariff.

(e) The Bureau of Technical Utility Services shall approve or disapprove the net metering application within 30 days of submission and describe in detail the reasons for disapproval. The Bureau of Technical Utility Services shall serve its determination on the EDC and the applicant.

(f) The applicant and the EDC may appeal the determination of the Bureau of Technical Utility Services in accordance with § 5.44 (relating to petitions for appeal from actions of the staff).

Subchapter C: Interconnection

* * * * *

§ 75.22. Definitions.

* * * * *

Electric nameplate capacity- The net maximum or net instantaneous peak electric output capacity measured in volt-amps of the small generator facility, <u>the inverter or the aggregated capacity of multiple inverters at an alternative energy systems location</u> as designated by the manufacturer.

* * * * *

§ 75.31. Applicability.

The interconnection procedures apply to customer-generators with small generator facilities that satisfy the following criteria:

(1) The electric nameplate capacity of the small generator facility is equal to or less than [2] <u>5</u> MW.

* * * * *

§ 75.34. Review procedures.

An EDC shall review interconnection requests using one or more of the following four review procedures:

* * * * *

(2) An EDC shall use Level 2 procedures for evaluating interconnection requests to connect small generation facilities when:

(i) The small generator facility uses an inverter for interconnection.

(ii) The electric nameplate capacity rating is [2] 5 MW or less.

(iii) The customer interconnection equipment proposed for the small generator facility is certified.

(iv) The proposed interconnection is to a radial distribution circuit, or a spot network limited to serving one customer.

(v) The small generator facility was reviewed under Level 1 review procedures but not approved.

(3) An EDC shall use Level 3 review procedures for evaluating interconnection requests to connect small generation facilities with an electric nameplate capacity of [2] 5 MW or less which do not qualify under Level 1 or Level 2 interconnection review procedures or which have been reviewed under Level 1 or Level 2 review procedures, but have not been approved for interconnection.

* * * * *

§ 75.39. Level 3 interconnection review.

(a) Each EDC shall adopt the Level 3 interconnection review procedure in this section. An EDC shall use the Level 3 review procedure to evaluate interconnection requests that meet the following criteria and for interconnection requests considered but not approved under a Level 2 or a Level 4 review if the interconnection customer submits a new interconnection request for consideration under Level 3:

(1) The small generator facility has an electric nameplate capacity that is [2] 5 MW or less.

(2) The small generator facility is less than [2] 5 MW and not certified.

(3) The small generator facility is less than [2] 5 MW and noninverter based.

* * * * *

§ 75.40. Level 4 interconnection review.

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(d) When interconnection to circuits that are not networked is requested, upon the mutual agreement of the EDC and the interconnection customer, the EDC may use the Level 4 review procedure for an interconnection request to interconnect a small generator facility that meets the following criteria:

(1) The small generator facility has an electric nameplate capacity of [2] 5 MW or less.

(2) The aggregated total of the electric nameplate capacity of all of the generators on the circuit, including the proposed small generator facility, is [2] 5 MW or less.

* * * * *

§ 75.51. Disputes.

* * * * *

(c) [When disputes relate to the technical application of this chapter, the Commission may designate a technical master to resolve the dispute. The Commission may designate a Department of Energy National laboratory, PJM Interconnection L.L.C., or a college or university with distribution system engineering expertise as the technical master. When the Federal Energy Regulatory Commission identifies a National technical dispute resolution team, the Commission may designate the team as its technical master. Upon Commission designation, the parties shall use the technical master to resolve disputes related to interconnection. Costs for dispute resolution conducted by the technical master shall be determined by the technical master subject to review by the Commission.

(d)] Pursuit of dispute resolution may not affect an interconnection applicant with regard to consideration of an interconnection request or an interconnection applicant's position in the EDC's interconnection queue.

* * * * *

Subchapter D: ALTERNATIVE ENERGY PORTFOLIO REQUIREMENT

§ 75.61. EDC and EGS obligations.

(a) EDCs and EGSs shall comply with the act through the acquisition of certified alternative energy credits, each of which shall represent one MWh of qualified alternative electric generation or conservation, whether self-generated, purchased along with the electric commodity or separately through a tradable instrument.

(b) For each reporting period, EDCs and EGSs shall acquire alternative energy credits in quantities equal to a percentage of their total retail sales of electricity to all retail electric customers for that reporting period, as measured in MWh. The credit obligation for a reporting period shall be rounded to the nearest whole number. The required quantities of alternative energy credits for each reporting period is identified in the following schedule, <u>subject to the quarterly adjustment of the non-solar Tier I obligation under §75.71 (relating to quarterly adjustment of non-solar Tier I obligations)</u>:

* * * * *

§ 75.62. Alternative energy system qualification.

* * * * *

<u>(g) A facility's alternative energy system status may be suspended or revoked for non-compliance with the provisions of this chapter, including the following circumstances:</u>

<u>(1) Providing false information to the commission, credit registry or program administrator.</u>

<u>(2) Department notification to the Commission of violations of standards set forth in section 2 of the Act.</u>

§ 75.63. Alternative energy credit certification.

* * * * *

(g) For solar photovoltaic alternative energy systems with a nameplate capacity of 15 kilowatts or less that are installed or that increase nameplate capacity on or after 180 days from the effective date of this regulation, alternative energy credit certification shall be verified by the administrator designated under § 75.64 (relating to alternative energy credit program administrator) using metered data. for solar photovoltaic alternative energy systems with a nameplate capacity of 15 kilowatts or less, that are installed before 180 days from the effective date of this regulation, alternative energy credit certification shall be verified by the administrator using either metered data or estimates. The use of estimates is subject to the following conditions:

(1) No revenue grade meter has been installed to measure the output of the alternative energy system.

(2) The alternative energy system has not used actual meter or other monitoring system readings for determining system output in the past.

(3) The solar photovoltaic alternative energy system has either a fixed solar orientation or a one or two axis automated solar tracking system.

(4) The solar photovoltaic alternative energy system is comprised of crystalline silicon modules or a type of module that meets the criteria of the program used by the program administrator to calculate the estimates.

(5) The program administrator has deemed the solar photovoltaic alternative energy system eligible to utilize estimates based on the verified output of the alternative energy system.

(h) An alternative energy credit represents the attributes of 1 MWh of electric generation that may be used to satisfy the requirements of § 75.61 (relating to EDC and EGS obligations). The alternative energy credit shall remain the property of the alternative energy system until voluntarily transferred. A certified alternative energy credit does not automatically include environmental, emissions or other attributes associated with 1 MWh of electric generation. Parties may bundle the attributes unrelated to compliance with § 75.61 with an alternative energy credit, or, alternatively, sell, assign, or trade them separately.

(i) An alternative energy system may begin to earn alternative energy credits on the date a complete application is filed with the administrator, provided that a meter or inverter reading is included with the application.

(j) An alternative energy system application may be rejected if the applicant does not respond to a program administrator request for information or data within 90 days. Any application that is not approved within 180 days of its submission due to the applicant's failure to provide information or data to the program administrator will be deemed rejected unless affirmatively held open by the program administrator.

(k) Alternative energy system generation or conservation data entered into the credit registry shall be allocated to the compliance year in which the generation or conservation occurred to ensure that alternative energy credits are certified with the correct vintage year.

§ 75.64. Alternative energy credit program administrator.

* * * * *

(b) The program administrator will have the following powers and duties in regard to alternative energy system qualification:

* * * * *

(6) The program administrator may suspend or revoke the qualification of an alternative energy system and withhold or retire past, current or future alternative energy

credits attributed to an alternative energy system for non-compliance with the provisions of this chapter, including the following circumstances:

(i) It no longer satisfies the alternative energy system qualification standards in § 75.62 (relating to alternative energy system qualification).

(ii) The owner or aggregator of the alternative energy system provides false or incorrect information in an application.

(iii) The owner or aggregator of the alternative energy system fails to notify the program administrator of changes to the alternative energy system that effect the alternative energy system's generation output.

(iv) The owner or aggregator of the alternative energy system fails to notify the program administrator of a change in ownership or aggregator of the alternative energy system.

(v) The owner or aggregator provides false or inaccurate information to the credit registry.

(vi) The owner or aggregator fails to respond to data and information requests from the Commission, Department or program administrator.

(c) The program administrator shall have the following powers and duties regarding the verification of compliance with this chapter:

(1) At the end of each reporting period, the program administrator shall verify EDC and EGS [compliance with § 75.61 (relating to EDC and EGS obligations)] reported load, and provide written notice to each EDC and EGS [of an initial assessment] of their compliance [status] obligations within 45 days of the end of the reporting period.

(2) At the end of each true-up period, the administrator shall verify compliance with § 75.61 for all EDCs and EGSs [who were in violation of § 75.61 at the end of the reporting period]. The administrator will provide written notice to each EDC and EGS of a final assessment of their compliance status within [15] 45 days of the end of the true-up period.

(3) EDCs and EGSs shall provide all information to the program administrator necessary to verify compliance with § 75.61 including the prices paid for the alternative

energy credits used for compliance. The pricing information shall include a per credit price for any credits used for compliance that were not self-generated or bundled with energy.

(4) The program administrator shall provide a report to the [Commission] Commission's Bureau of Technical Utility Services within 45 days of the end of [each reporting period and] the true-up period that identifies the compliance status of all EDCs and EGSs. The report provided after the end of the true-up period shall propose alternative compliance payment amounts for each EDC and EGS that is noncompliant with § 75.61 for that reporting period. As part of this report, the administrator shall identify the average market value of alternative energy credits derived from solar photovoltaic energy sold in the reporting period for each RTO that manages a portion of this Commonwealth's transmission system.

(d) The program administrator shall have the following powers and duties relating to alternative energy credit certification:

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(3) The program administrator may not certify an alternative energy credit that does not meet the requirements of § 75.63 (relating to alternative energy credit certification).

* * * * *

§ 75.65. Alternative compliance payments.

(a) Within 15 days of receipt of the report identified in § 75.64(c)(4) (relating to alternative energy credit program administrator), the [Commission] The Commission's Bureau of Technical Utility Services will provide written notice to each EDC and EGS that was noncompliant with § 75.61 (relating to EDC and EGS obligations) of their alternative compliance payment for that reporting period.

* * * * *

(c) EDCs and EGSs shall advise the [Commission] <u>Commission's Bureau of Technical Utility Services</u> in writing within 15 days of the issuance of this notice of their acceptance of the alternative compliance payment determination or, if they wish to contest the determination, file a petition to modify the level of the alternative compliance payment. The petition must include documentation supporting the proposed modification. The [Commission] <u>Commission's Bureau of Technical Utility Services</u> will refer the petition to the [Office of Administrative Law Judge] <u>Commission's Bureau of Investigation and Enforcement</u> for further [proceedings] <u>actions</u> as may be [necessary] <u>warranted</u>. Failure of an EDC or EGS to respond to the [Commission] <u>Commission's Bureau of Technical Utility Services</u> within 15 days of the issuance of this notice shall be deemed an acceptance of the alternative compliance payment determination.

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<u>**§ 75.71. Quarterly adjustment of non-solar Tier I obligation.**</u>

<u>(a) The Tier I non-solar photovoltaic obligation of EDCs and EGSs shall be adjusted quarterly during the reporting period to comply with 66 Pa.C.S. § 2814(c).</u>

<u>(b) The quarterly requirement will be determined as follows:</u>

<u>(1) The non-solar photovoltaic Tier I quarterly percentage increase equals the ratio of the available new Tier I MWh generation to total quarterly EDC and EGS MWh retail sales (new Tier I MWh generation/EDC and EGS MWh retail sales = non-solar pv Tier I % increase).</u>

(2) The new quarterly non-solar photovoltaic Tier I requirement equals the sum of the new non-solar photovoltaic Tier I percentage increase and the annual non-solar photovoltaic Tier I percentage requirement in § 75.61(b) (non-solar photovoltaic Tier I % increase + annual non-solar photovoltaic Teir I % = new quarterly non-solar photovoltaic Tier I % requirement).

(3) An EDC's or EGS's quarterly MWh retail sales multiplied by the new quarterly non-solar photovoltaic Tier I requirement (EDC and EGS quarterly MWh x new quarterly non-solar photovoltaic Tier I % = EDCs' and EGSs' quarterly non-solar photovoltaic Tier I requirement) yields the quantity of alternative energy credits required by that EDC or EGS for compliance. The EDC and EGS final total annual compliance obligations shall be determined by the program administrator at the end of the compliance year in accordance with § 75.64(c) (relating to alternative energy credit program administrator).

(c) Alternative energy systems qualified consistent with 66 Pa.C.S. §§ 2814(a) and (b) shall grant the program administrator access to their credit registry account information as a condition of certification of any alternative energy credits created pursuant to these sections.

§ 75.72. Reporting requirements for quarterly adjustment of non-solar Teir I obligation.

(a) For purposes of implementing the provisions of § 75.71 (relating to quarterly adjustment of non-solar Tier I obligation) EDCs and EGSs shall report their monthly retail sales on a quarterly basis during the reporting period. An EDC shall submit its monthly sales data and the monthly sales data for each EGS serving in its service territory to the program administrator each quarter as follows:

(1) First quarter (June, July and August) due by October 30.

(2) Second quarter (September, October and November) due by January 30.

(3) Third quarter (December, January and February) due by April 30.

(4) Fourth quarter (March, April and May) due by June 30.

(b) Each EGS shall verify its monthly sales data each quarter as follows:

(1) First quarter (June, July and August) due by the second business day after October 30.

(2) Second quarter (September, October and November) due by the second business day after January 30.

(3) Third quarter (December, January and February) due by the second business day after April 30.

(4) Fourth quarter (March, April and May) due by the second business day after June 30.

(c) For purposes of implementing the provisions of § 75.71 (relating to quarterly adjustment of non-solar Tier I obligation), all Tier I alternative energy systems qualified pursuant to 66 Pa.C.S. §§ 2814 (a) and (b) shall provide the following information on a monthly basis:

(1) The facility's total generation from qualifying alternative energy sources for the month in MWh, broken down by source.

(2) The amount of alternative energy credits sold in the month to each EDC and EGS with a compliance obligation under the Act.

(3) The amount of alternative energy credits sold in the month to any other entity, including EDCs, EGSs and other users for compliance with another state's alternative/renewable energy portfolio standard or sold on the voluntary market. Listing each alternative energy credit and the entity they were transferred to.

(4) The amount of alternative energy credits created and eligible for sale during the month but not yet sold.

(5) The sale or other disposition of alternative energy credits created in prior months and transferred in the month, itemized by compliance status (Pennsylvania portfolio standard, other state compliance, voluntary market, and the like).

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Implementation of the Alternative Energy Portfolio Standards Act of 2004	: :	**Docket No. L-2014-2404361**

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a true and correct copy of the foregoing document upon the individuals listed below, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

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