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

August 14, 2014

Docket Number: L-2014-2404361

Attached to this comment letter is the Regulatory Analysis Form that the PUC was required to file with the PA Attorney General prior to their recently proposed rulemaking. Many people are not aware of the RAF, which is a mandatory filing in which the PUC must justify the need for a new regulation. Among other things, the PUC is required to address the following:

- Why the regulation is needed
- The compelling public interest that justifies it
- Who will benefit from the regulation
- The degree to which stakeholders were involved
- The type and number of persons, businesses and small businesses affected
- The financial, economic and social impact of the regulation
- How the benefits outweigh the cost and adverse effects

The RAF is where the rubber meets the road. It is a must-read for anyone who cares about the integrity of the regulatory review process here in Pennsylvania. If you are familiar with the PUC's recently proposed rulemaking, you will be shocked to read what they wrote (see attachment). The RAF is strewn with mischaracterizations and factually incorrect statements about the AEPS Act, the proposed rulemaking and the impact that the new regulations will have on stakeholders.

This is an important document for renewable energy advocates to read. Please take the time. It gives insights into how far the PUC will go in pursuit of their goals. Remember that this information is read (and relied upon) by the organizations that provide the checks and balances in our regulatory review process (the Attorney General, the Independent Regulatory Review Commission, the standing committees of the House and Senate). This is a legally mandated process, and all of these organizations count on the information in the RAF to be factual and accurate. In fact, for some this may be the only document they read before they publish their review / comments on a new regulation. The deliberate mischaracterizations in this document are unacceptable, and we must correct them.

Given the fact that there is now a 30 day extension for comments, it would be beneficial for everyone who cares about renewable energy in Pennsylvania to review this form and develop further comments. You won't have to look very far to find errors; there are many of them. Unless we correct what the PUC has submitted in the RAF, many in government will believe everything that was written. We can't let this document go unanswered.

Regards,

A handwritten signature in black ink, appearing to read "D. Hommrich".

David N. Hommrich
President
Sunrise Energy, LLC

Regulatory Analysis Form

(Completed by Promulgating Agency)

INDEPENDENT REGULATORY
REVIEW COMMISSION

(All Comments submitted on this regulation will appear on IRRC's website)

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(1) Agency
Public Utility Commission ("PUC")

(2) Agency Number: L-2014-2404361
Identification Number: 57-304

IRRC Number: 3061

(3) PA Code Cite: 52 Pa. Code §§ 75.1, 75.12, 75.13, 75.14, 75.16, 75.17, 75.22, 75.31, 75.34, 75.39, 75.40, 75.51, 75.61, 75.62, 75.63, 75.64, 75.65, 75.71, and 75.72.

(4) Short Title: Implementation of the Alternative Energy Portfolio Standards Act of 2004

(5) Agency Contacts (List Telephone Number and Email Address):

Primary Contact: Kriss Brown (717) 787-4518 kribrown@pa.gov
Secondary Contact: Ken Stark (717) 787-5558 kenstark@pa.gov

(6) Type of Rulemaking (check applicable box):

Proposed Regulation

Final Regulation

Final Omitted Regulation

Emergency Certification Regulation;

Certification by the Governor

Certification by the Attorney General

(7) Briefly explain the regulation in clear and nontechnical language. (100 words or less)

Under its statutory duty to implement and enforce the Alternative Energy Portfolio Standards Act ("AEPS Act" or "Act"), 73 P.S. §§ 1648.1-1648.8 and 66 Pa. C.S. § 2814, the Pennsylvania Public Utility Commission seeks to revise its regulations pertaining to net metering, interconnection, and portfolio standard compliance provisions of the Act to comply with the Act 35 of 2007 and Act 129 of 2008 amendments to the AEPS Act and to clarify certain issues of law, administrative procedure, and policy.

(8) State the statutory authority for the regulation. Include specific statutory citation.

1 Pa. C.S. § 1932; 66 Pa. C.S. §§ 501, 504-506, 523, 1301, 1501, 1504, 2807(e), 2814; 45 P.S. §§ 1201-1202; 1 Pa. Code §§ 7.1, 7.2, and 7.5; The Commonwealth Attorneys Act, 71 P.S. § 732-204(b); The Regulatory Review Act, 71 P.S. § 745.5; The Administrative Code, 71 P.S. § 232; The Alternative Energy Portfolio Standards Act of 2004, 73 P.S. §§ 1648.5 and 1648.7(a)-(b), 25 Pa. Code §§ 75.1 *et seq.*; and Act 129 of 2008, 66 Pa. C.S. § 2814.

(9) Is the regulation mandated by any federal or state law or court order, or federal regulation? Are there any relevant state or federal court decisions? If yes, cite the specific law, case or regulation as well as, any deadlines for action.

The proposed regulation changes are not mandated by federal law, federal regulation, or court order. However, the Pennsylvania state statute, the Alternative Energy Portfolio Standards (AEPS) Act of 2004, requires the PUC to develop technical and net metering interconnection rules for customer-generators, 73 P.S. § 1648.5, and to implement and enforce the AEPS Act, 73 P.S. § 1648.7(a)-(b). Accordingly, the PUC proposes changes to the regulations pertaining to the net metering, interconnection, and portfolio standard compliance provisions of the AEPS Act to comply with the Act 35 of 2007 and Act 129 of 2008 amendments to the AEPS Act and to clarify certain issues of law, administrative procedure, and policy.

(10) State why the regulation is needed. Explain the compelling public interest that justifies the regulation. Describe who will benefit from the regulation. Quantify the benefits as completely as possible and approximate the number of people who will benefit.

As discussed above, these regulation changes are needed and proposed pursuant to state law in order to comply with the AEPS Act, the Act 35 of 2007 and Act 129 of 2008 amendments to the AEPS Act and to clarify certain issues of law, administrative procedure, and policy.

All stakeholders and interested parties, including electric distribution companies (EDCs), electric generation suppliers (EGSs), alternative energy system developers and customer-generators seeking net metering, will benefit from these regulations, which clarify issues of law, administrative procedure, and policy by reducing uncertainty regarding which generation resources qualify for alternative energy system status, interconnection and net metering. In particular, the approximately one-hundred alternative energy system development companies and installation companies will benefit from these clarifications, as it should reduce the time and money spent on developing, installing and qualifying alternative energy systems. It should also reduce or even eliminate the time and money spent by these companies in the past on investigating and beginning initial development of systems that they later learn will not qualify.

These regulation changes will also balance the benefits provided to developers, owners of alternative energy systems, and net metering customer-generators with the costs borne by EDCs, EGSs and electric utility ratepayers to meet the requirements of the AEPS Act in a cost-effective manner. These proposed changes will benefit the millions of EDC ratepayers and EGS customers. The Commission, In its 2012 AEPS Act Annual Report, is projecting that it could cost over \$60 million to comply with the AEPS Act's 18% of retail sales requirements. The 2012 Annual report is available at: http://www.puc.pa.gov/electric/pdf/AEPS/AEPS_Ann_Rpt_2012.pdf. The net metering costs that are also borne by the ratepayers will be in addition to those costs. Therefore, based on these magnitudes, it is imperative that this program be implemented in a cost-effective manner.

(11) Are there any provisions that are more stringent than federal standards? If yes, identify the specific provisions and the compelling Pennsylvania interest that demands stronger regulations.

These proposed regulations do not contain any provisions that are more stringent than federal standards. Renewable/alternative energy portfolio standards are currently only enacted at the state level.

(12) How does this regulation compare with those of the other states? How will this affect Pennsylvania's ability to compete with other states?

As discussed in the PUC's Proposed Rulemaking Order of February 20, 2014, Docket No. L-2014-2404361, the proposed regulation's changes regarding net metering are consistent with the regulatory treatment of net metering in other states. See Proposed Rulemaking Order at 13, fn. 6. Just like Pennsylvania's proposed regulations in 52 Pa. Code § 75.13(a)(3), Delaware regulations state: "The customer-Generator Facility is designed to produce no more than 110% of the Customer's aggregate electrical consumption..." Del. Pub. Serv. Comm'n, DE. ADC 26 3000 3001, §8.6.2 (Westlaw) (2014). New Jersey regulations similarly provide that EDCs "shall offer net metering . . . provided that the generating capacity of the customer-generator's facility does not exceed the amount of electricity supplied . . . to the customer over an historical 12-month period . . ." N.J. Admin. Code 14:8-4.3(a) (Westlaw) (2014). Additionally, "The generating capacity of the eligible customer's system [should] not exceed the combined metered annual energy usage of the customer's qualified facilities." N.J. Admin. Code 14:8-7.3(a)(2) (Westlaw) (2014).

Each state has its own distinct alternative/renewable energy portfolio standards. Generally speaking, Pennsylvania's standards run the middle of the gamut and are not as stringent as many other states in the northeast and elsewhere that have alternative/renewable energy portfolio standards. Many other states do not have mandatory alternative/renewable energy portfolio standards. The proposed regulations under Pennsylvania's Alternative Energy Portfolio Standards Act should not materially affect Pennsylvania's ability to compete with other states.

(13) Will the regulation affect any other regulations of the promulgating agency or other state agencies? If yes, explain and provide specific citations.

Pursuant to the AEPS Act, 73 P.S. § 1648.7, the PUC and the Department of Environmental Protection (DEP) "shall work cooperatively to monitor the performance of all aspects of [the AEPS Act] and provide an annual report to the chairman and minority chairman of the Environmental Resources and Energy Committee of the Senate and the chairman and minority chairman of the Environmental Resources and Energy Committee of the House of Representatives."

The proposed changes to these regulations do not effect this cooperation. Under the proposed revised regulations, the Commission, in cooperation with DEP, will continue to provide this annual report. A copy of the latest Annual Report is available at <http://www.puc.pa.gov/electric/pdf/AEPS/AEPS Ann Rpt 2012.pdf>.

In addition, DEP is to “ensure that all qualified alternative energy sources meet all applicable environmental standards and shall verify that an alternative energy source meets the standards set forth in section 2.” *See*, 73 P.S. § 1648.7(b).

The proposed regulation changes will not affect the regulations of DEP or other state agencies. To date, the DEP has not promulgated regulations related to the AEPS Act. Regarding DEP’s responsibility to verify that an alternative energy source meets the standards set forth in Section 2 of the AEPS Act, 73 P.S. § 1648.2 (Definitions), the proposed changes to the definitions section of the regulations simply incorporate new definitions contained in the Act 129 of 2008 amendments, 66 Pa. C.S. § 2814, or provide guidance on the meaning of words used throughout the regulations. These proposed regulation definition changes are intended to provide clarity and better understanding to all stakeholders and have been developed based on experience with implementing the AEPS Act over the past ten years.

(14) Describe the communications with and solicitation of input from the public, any advisory council/group, small businesses and groups representing small businesses in the development and drafting of the regulation. List the specific persons and/or groups who were involved. (“Small business” is defined in Section 3 of the Regulatory Review Act, Act 76 of 2012.)

During the development and drafting of the regulation changes, there were no formal communications with nor solicitations for input from the public, any advisory council/groups, small businesses or groups representing small businesses. However, during the ten years the Commission has been implementing the AEPS Act, there have been innumerable communications and solicitations from the public, small and large alternative energy system developers and installers, customer-generators from all rate classes, small and large businesses that buy and sell alternative energy credits, small and large EGSs, and EDCs, as well as groups and associations that represent these various interests. As previously noted, most of the proposed changes to the regulations are intended to clarify certain issues of law, administrative procedure, and policy based on these innumerable communications and solicitations.

(15) Identify the types and number of persons, businesses, small businesses (as defined in Section 3 of the Regulatory Review Act, Act 76 of 2012) and organizations which will be affected by the regulation. How are they affected?

Eleven electric distribution companies, of which four are considered Pennsylvania based small businesses, will be impacted by the proposed changes. However, the impact should be minimal as most of the changes that impact EDCs simply provide more clarity on what has been expected of them or provide clearer administrative processes that match current practices or provide more complete guidance on processes needed to comply with the AEPS Act as amended.

Currently, ninety-two electric generation suppliers, of which seven are considered Pennsylvania based small businesses, will be impacted by the proposed changes. However, the impact to EGSs are minimal in that most of the proposed changes affecting EGS are mandated by the Act 129 of 2008 amendment, that requires the Commission to adjust the Tier I requirements for EGSs and EDCs on a quarterly basis.

It is estimated that approximately one-hundred alternative energy system development companies and alternative energy system installation companies, most of which are considered Pennsylvania based small businesses, will be impacted by the proposed changes. However, while the proposed changes may impact the size of some of the alternative energy systems these entities develop and install, it is expected to have minimal impact on the number of systems they develop or install as past experience shows that most customer-generator systems currently being installed meet the new requirements. Furthermore, the clarifying changes will provide these entities more regulatory certainty as the changes make current practice explicit, where it had previously been implicit in the regulations.

Currently, there are 90 known active alternative energy credit aggregators, of which 57 are Pennsylvania based small businesses, that will be impacted by the proposed changes. However, the impacts are minimal and intended to ensure an appropriate level of consumer protection for system owners and other parties who contract with aggregators to buy and sell their alternative energy credits and to ensure the validity of the credits.

Three facilities that generate electricity in Pennsylvania from pulping processes, of which two are considered Pennsylvania based small businesses, will be impacted by these regulations. However, the proposed changes related to these wood manufacturers are mandated by the Act 129 of 2008 amendments, which primarily benefits these entities by making them Tier I (higher value) resources.

(16) List the persons, groups or entities, including small businesses, that will be required to comply with the regulation. Approximate the number that will be required to comply.

Eleven Electric Distribution Companies, of which four are considered Pennsylvania based small businesses.

Currently, ninety-two Electric Generation Suppliers, of which seven are considered Pennsylvania based small businesses.

Currently, 90 active alternative energy credit aggregators, of which 57 are considered Pennsylvania based small businesses.

Three facilities that generate electricity in Pennsylvania from pulping processes, of which two are considered Pennsylvania based small businesses.

Future customer-generators and owners of alternative energy systems.

(17) Identify the financial, economic and social impact of the regulation on individuals, small businesses, businesses and labor communities and other public and private organizations. Evaluate the benefits expected as a result of the regulation.

It is possible that there may be a minor increase in the cost of future small solar photovoltaic system installations with a nameplate capacity of 15kilowatts or less due to the proposed metering requirements. Only a few installations would be effected as all installations of this type use inverters that register the generation output and most, if not all, can install a qualifying meter at minimal cost. The current

regulations do not require inverter or meter readings to verify the output of these systems. Under the current regulations, these small systems have been able to use estimates of the system output, provided they meet specific requirements, such as the type of solar photovoltaic panel material and directional orientation. Experience demonstrates that while the proposed metering requirements on these small systems will increase the costs and administrative burdens on the system owners, those costs are minimal compared to the need for system integrity to ensure that the credits being claimed are valid. In addition, we note that these metering requirements are currently required for all other alternative energy systems and have not proven to be a barrier to development of those systems. Finally, we note that the elimination of the use of estimates for these small systems will result in reduced time spent by the Commission's contracted program administrator to run modeling software to estimate the generation output of these systems. The cost savings associated with this are deemed insignificant but there is greater confidence in the long-term reliability of the claimed alternative energy credits by not relying on estimates of generation. This is consistent with the direction being taken by many other states, including New Jersey. *See e.g.*, N.J. Admin. Code 14:8-2.9(c) (Westlaw) (2014).

(18) Explain how the benefits of the regulation outweigh any cost and adverse effects.

The proposed regulations will add clarity to definitions and administrative processes that will reduce uncertainty for all stakeholders. Costs associated with these clarifications and administrative processes should be offset by the benefits of obtaining more certainty as to the benefits available to qualified alternative energy systems, as well as any potential alternative energy system development. This increased certainty should decrease developmental costs associated with the development of alternative energy systems.

(19) Provide a specific estimate of the costs and/or savings to the **regulated community** associated with compliance, including any legal, accounting or consulting procedures which may be required. Explain how the dollar estimates were derived.

Although a specific cost study was not conducted, any costs related to the additional administrative processes were either mandated by the AEPS Act or the Act 129 of 2008 amendment that required the Commission to adjust the Tier I requirement on a quarterly basis or will be offset by avoided costs attributable to the increased regulatory certainty.

(20) Provide a specific estimate of the costs and/or savings to the **local governments** associated with compliance, including any legal, accounting or consulting procedures which may be required. Explain how the dollar estimates were derived.

Except to the extent that a local government owns an alternative energy system, in which case it will be treated the same as any other system owner, local governments are not impacted by these regulations as they have no compliance obligations under the AEPS Act and therefore, should incur no costs and/or savings as a result of these regulations.

(21) Provide a specific estimate of the costs and/or savings to the **state government** associated with the implementation of the regulation, including any legal, accounting, or consulting procedures which may be required. Explain how the dollar estimates were derived.

Except to the extent that the state government owns an alternative energy system, in which case it will be treated the same as any other system owner, the state government is not impacted by these regulations as the state government has no compliance obligations under the AEPS Act and therefore, should incur no costs and/or savings as a result of these regulations.

(22) For each of the groups and entities identified in items (19)-(21) above, submit a statement of legal, accounting or consulting procedures and additional reporting, recordkeeping or other paperwork, including copies of forms or reports, which will be required for implementation of the regulation and an explanation of measures which have been taken to minimize these requirements.

Regarding the proposed requirement at § 75.13(a)(3), customer-generators, the owners, developers or installers of these systems will now have to submit documentation demonstrating that the alternative energy system is designed to provide no more than 110% of the electric customer's historical load requirements. While this is a new requirement under the current regulations, the regulated community has experience with this requirement under the Commission's policy statement for third-party owned and operated systems. In that policy statement, the Commission made it a policy of the Commission to allow interconnection and net metering of alternative energy systems that are owned and operated by third-parties that place the alternative energy system on the customers property and sell the power from those systems to the customer, provided the systems were sized to provide no more than 110% of the customer's historical load. *See, Net Metering – Use of Third Party Operators*, Final Order at Docket No. M-2011-2249441 (entered March 29, 2012). In addition, as mentioned above, both New Jersey and Delaware have similar requirements. Based on two years of operating under this policy statement and the experiences of New Jersey and Delaware, we do not believe that this requirement will be burdensome or be a barrier to the development of alternative energy systems.

Regarding the proposed requirements at § 75.17 (process for obtaining approval of customer-generator status) EDCs will have to provide applications for net metering to the Commission along with a recommendation as to whether the alternative energy system qualifies for net metering for all applications for net metering of systems with a nameplate capacity of 500 kilowatts or greater. While the submission of this information to the Commission for review is a new requirement, EDCs currently obtain this information and provide feedback to the applicant as to whether a system qualifies for net metering. Therefore, the additional burden of submitting this information to the Commission for review should be minimal and not pose a barrier to the development of qualified alternative energy systems. Furthermore, we note that this step provides the added benefit of increased regulatory certainty for both the applicant and the EDC.

Regarding the proposed requirement at § 75.64(c)(3) that EDCs and EGSs provide pricing information on alternative energy credits used for compliance, this information is needed to calculate the solar alternative compliance payment, which pursuant to the AEPS Act, equals 200% of the average market value of solar renewable energy credits. *See, 73 P.S. § 1648.3(f)(4)*. In addition, the credit price information is needed to comply with the requirement to provide a report to the General Assembly that contains the "[c]urrent costs of alternative energy on a per kilowatt hour basis for all alternative energy technology types." *See 73 P.S. § 1648.7(c)*. Furthermore, while this information has been provided in

the past, the proposed changes provide clarity on the information to be provided and will ensure consistent reporting by all EDCs and EGSs.

Regarding the proposed reporting requirements in §75.72 (reporting requirements for quarterly adjustment of non-solar Tier I obligation), EDCs and EGSs will be required to report their monthly retail sales data on a quarterly basis, with the EDCs being required to report monthly sales data for its default service and the EGSs serving in the EDC's service territory. This data is required to make the quarterly adjustment to the EDC and EGS Tier I requirements as mandated in the Act 129 of 2008 amendments to the AEPS Act. *See*, 66 Pa. C.S. § 2814(c). In addition, the qualifying hydropower and biomass energy facilities seeking Tier I status will also be required to report their total monthly generation in megawatt-hours, as well as the number of alternative energy credits created, sold to EDCs and EGSs, sold to other entities and unsold credits. Again, this data is required to make the quarterly adjustment to the EDC and EGS Tier I requirements as mandated in the Act 129 of 2008 amendments to the AEPS Act. *See*, 66 Pa. C.S. § 2814(c). We note that since May of 2009, the EDCs, EGSs and qualifying facilities have been providing this information. The proposed changes simply codify what the Commission previously established by Order. *See, Implementation of Act 129 of 2008 Phase 4 – Relating to the Alternative Energy Portfolio Standards Act*, Final Order at Docket No. M-2009-2093383 (entered May 28, 2009).

(23) In the table below, provide an estimate of the fiscal savings and costs associated with implementation and compliance for the regulated community, local government, and state government for the current year and five subsequent years.

	Current FY Year	FY +1 Year	FY +2 Year	FY +3 Year	FY +4 Year	FY +5 Year
SAVINGS:	\$	\$	\$	\$	\$	\$
Regulated Community	minimal	minimal	minimal	minimal	minimal	minimal
Local Government	0	0	0	0	0	0
State Government	minimal	minimal	minimal	minimal	minimal	minimal
Total Savings						
COSTS:						
Regulated Community	minimal	minimal	minimal	minimal	minimal	minimal
Local Government	0	0	0	0	0	0
State Government	minimal	minimal	minimal	minimal	minimal	minimal
Total Costs						
REVENUE LOSSES:						
Regulated Community	minimal	minimal	minimal	minimal	minimal	minimal
Local Government	0	0	0	0	0	0
State Government	0	0	0	0	0	0
Total Revenue Losses						

(23a) Provide the past three year expenditure history for programs affected by the regulation.

Program	FY -3	FY -2	FY -1	Current FY
EDC reporting requirements for quarterly adjustments for 75.72	Estimated at \$17,000	Estimated at \$17,000	Estimated at \$17,000	Estimated at \$17,000
EGS reporting requirements for quarterly adjustments for 75.72	Estimated at \$37,000	Estimated at \$37,000	Estimated at \$37,000	Estimated at \$37,000
Generator reporting requirements for quarterly adjustments for 75.72	Estimated at \$2,700	Estimated at \$2,700	Estimated at \$2,700	Estimated at \$2,700

(24) For any regulation that may have an adverse impact on small businesses (as defined in Section 3 of the Regulatory Review Act, Act 76 of 2012), provide an economic impact statement that includes the following:

(a) An identification and estimate of the number of small businesses subject to the regulation. Four electric distribution companies, seven electric generation suppliers, approximately one-hundred alternative energy system development and installation companies, 57 alternative energy credit aggregators, and two facilities that generate electricity in Pennsylvania from pulping processes.

(b) The projected reporting, recordkeeping and other administrative costs required for compliance with the proposed regulation, including the type of professional skills necessary for preparation of the report or record. The four electric distribution companies are anticipated to have annual reporting, record keeping and other administrative costs of \$1,545/EDC to comply with the reporting requirements in § 75.72, which involves tracking and reporting electric sales in their service territory.

The seven electric generation suppliers are anticipated to have annual reporting, record keeping and other administrative costs of \$400/EGS to comply with the reporting requirements in § 75.72, which involves tracking and reporting their electric sales in each EDC service territory where they have sales.

The two facilities that generate electricity in Pennsylvania from pulping processes are anticipated to have annual reporting, record keeping and other administrative costs of \$900/company to comply with the reporting requirements in § 75.72, which involves tracking and reporting their electric generation.

Alternative energy system developers and installers will have some additional reporting requirements when developing customer-generator installations. These additional reporting requirements include the customer's historical annual electric usage and the design output of the alternative energy system to demonstrate that the system is not designed to exceed 110% of the customer's historical annual usage. These costs are anticipated to be minimal as the customer can obtain the usage data from the EDC and the developer already needs the design output of the system to ensure a safe and reliable installation.

(c) A statement of probable effect on impacted small businesses.

As explained and demonstrated above, the costs and impacts on small businesses are expected to be minimal. Many of these costs and impacts will be offset by more regulatory clarity and certainty, which should reduce development costs.

(d) A description of any less intrusive or less costly alternative methods of achieving the purpose of the proposed regulation.

Many of the proposed regulation changes were added to provide clarity and certainty to minimize cost and time needed to develop projects, obtain certification and to comply with the Act. Where additional administrative and reporting requirements were added, § 75.17 (process for obtaining Commission approval of customer-generator status for systems with a nameplate capacity of 500 kilowatts or greater) or § 75.72 (reporting requirements for quarterly adjustment of non-solar Tier I obligation), the known least intrusive and least costly alternative method was used.

(25) List any special provisions which have been developed to meet the particular needs of affected groups or persons including, but not limited to, minorities, the elderly, small businesses, and farmers.

None.

(26) Include a description of any alternative regulatory provisions which have been considered and rejected and a statement that the least burdensome acceptable alternative has been selected.

None.

(27) In conducting a regulatory flexibility analysis, explain whether regulatory methods were considered that will minimize any adverse impact on small businesses (as defined in Section 3 of the Regulatory Review Act, Act 76 of 2012), including:

- a) The establishment of less stringent compliance or reporting requirements for small businesses;
- b) The establishment of less stringent schedules or deadlines for compliance or reporting requirements for small businesses;
- c) The consolidation or simplification of compliance or reporting requirements for small businesses;
- d) The establishment of performing standards for small businesses to replace design or operational standards required in the regulation; and
- e) The exemption of small businesses from all or any part of the requirements contained in the regulation.

Other than providing additional clarity and regulatory certainty, the proposal to require Commission approval of applications for net metering was limited to systems with a nameplate capacity of 500

kilowatts or greater, which are systems not typically installed by small businesses. In addition, regarding the quarterly reporting requirement in § 75.72, the Commission only required the EGSs to verify the monthly sales data submitted by the EDCs. This method reduces the burden on small EGSs by not requiring them to enter data for sales in each EDC service territory; they simply have to verify that the data entered by the EDC is correct.

(28) If data is the basis for this regulation, please provide a description of the data, explain in detail how the data was obtained, and how it meets the acceptability standard for empirical, replicable and testable data that is supported by documentation, statistics, reports, studies or research. Please submit data or supporting materials with the regulatory package. If the material exceeds 50 pages, please provide it in a searchable electronic format or provide a list of citations and internet links that, where possible, can be accessed in a searchable format in lieu of the actual material. If other data was considered but not used, please explain why that data was determined not to be acceptable.

Experience in implementing the AEPS Act has provided the basis for most of the proposed regulation changes. Much of the data contained in the Commission's AEPS Act annual report also informed the Commission on the need for the proposed changes. A copy of the latest Annual Report is available at http://www.puc.pa.gov/electric/pdf/AEPS/AEPS_Ann_Rpt_2012.pdf.

(29) Include a schedule for review of the regulation including:

- | | |
|---|------------------------------|
| A. The date by which the agency must receive public comments: | 30 days after publication |
| B. The date or dates on which public meetings or hearings will be held: | as needed |
| C. The expected date of promulgation of the proposed regulation as a final-form regulation: | 1 st quarter 2015 |
| D. The expected effective date of the final-form regulation: | upon publication as final |
| E. The date by which compliance with the final-form regulation will be required: | upon publication as final |
| F. The date by which required permits, licenses or other approvals must be obtained: | N/A |

(30) Describe the plan developed for evaluating the continuing effectiveness of the regulations after its implementation.

The Commission will continue to work with EDCs, EGSs, customer-generators, other interested members of the public, and other state agencies to determine whether the regulatory provisions of the AEPS Act require further interpretation or clarification.

FACE SHEET
FOR FILING DOCUMENTS
WITH THE LEGISLATIVE REFERENCE BUREAU

(Pursuant to Commonwealth Documents Law)

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2014 JUN 23 PM 3:53

DO NOT WRITE IN THIS SPACE

Copy below is hereby approved as to form and legality. Attorney General.

BY *Amy M. Elliott*
(DEPUTY ATTORNEY GENERAL)

JUN 17 2014

DATE OF APPROVAL

Check if applicable
Copy not approved. Objections attached

Copy below is hereby certified to be true and correct copy of a document issued, prescribed or promulgated by:

Pennsylvania Public Utility Commission
(AGENCY)

DOCUMENT/FISCAL NOTE NO. L-2014-2404361/57-304

DATE OF ADOPTION February 20, 2014

BY *Rosemary Chiavetta*
Rosemary Chiavetta

TITLE *Secy*
(SECRETARY)

Copy below is hereby approved as to form and legality. Executive or independent Agencies.

BY *Bohdan R. Pankiw*
Bohdan R. Pankiw
Chief Counsel

2-20-2014
DATE OF APPROVAL

Check if applicable. No Attorney General approval or objection within 30 days after submission.

L-2014-2404361/57-304
Proposed Rulemaking
Implementation of the Alternative Energy
Portfolio Standards Act of 2004
52 Pa Code, Chapter 75

The Pennsylvania Public Utility Commission on February 20, 2014, adopted a proposed rulemaking order amending existing regulations to comply with Act 129 of 2008 and Act 35 of 2007, and to clarify issues of law, administrative procedure and policy. The contact person is Assistant Counsel Kriss Brown, Law Bureau, 717 787-4518.

EXECUTIVE SUMMARY

L-2014-2404361/57-304

Proposed Rulemaking

Implementation of the Alternative Energy Portfolio Standards Act of 2004

The Alternative Energy Portfolio Standards (AEPS) Act of 2004, effective February 28, 2005, establishes alternative energy portfolio standards for electric distribution companies (EDCs) and electric generation suppliers (EGSs) operating in Pennsylvania. 73 P.S. §§ 1648.1-1648.8 and 66 Pa. C.S. § 2814. EDCs and EGSs must supply 18 percent of their retail electric sales using alternative energy resources by 2021, meeting their AEPS requirements through the purchase of alternative energy credits (AECs) in amounts corresponding to the percentage of retail electric sales required from alternative energy sources. 52 Pa. Code § 75.61.

The AEPS Act requires that the Pennsylvania Public Utility Commission (PUC) and the state Department of Environmental Protection (DEP) work cooperatively to monitor the performance of all aspects of the AEPS Act and prepare an annual report for the state Senate Environmental Resources and Energy Committee and the state House Environmental Resources and Energy Committee.

The AEPS Act requires the PUC to develop technical and net metering interconnection standards for customer-generator facilities. 73 P.S. § 1648.5. Act 35 of 2007 amended certain net metering and interconnection definitions and provisions. Act 129 of 2008 amended the AEPS Act by modifying the scope of eligible Tier I alternative energy sources and Tier I compliance obligations. 66 Pa. C.S. § 2814.

The Commission has previously implemented rulemakings to implement the AEPS Act and its subsequent legislative amendments. Now, the Commission proposes to revise its regulations pertaining to the net metering, interconnection, and portfolio standards provisions of the AEPS Act pursuant to Act 35 of 2007 and Act 129 of 2008, as well as to clarify certain issues of law, administrative procedure, and policy.

The contact persons for this Proposed Rulemaking are Assistant Counsel Kriss Brown (717) 787-4518, Assistant Counsel Ken Stark (717) 787-5558, Analyst Joseph Sherrick (717) 787-5369, and Analyst Scott Gebhardt (717) 425-2860.

**PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265**

Public Meeting held February 20, 2014

Commissioners Present:

Robert F. Powelson, Chairman
John F. Coleman, Jr., Vice Chairman
James H. Cawley
Pamela A. Witmer
Gladys M. Brown

Implementation of the Alternative Energy
Portfolio Standards Act of 2004

Docket No. L-2014-2404361

PROPOSED RULEMAKING ORDER

The Commission is charged with carrying out the provisions of the Alternative Energy Portfolio Standards Act of 2004 (the "AEPS Act"), 73 P.S. § 1648.1, *et seq.* This obligation includes the adoption of any regulations necessary for its implementation and enforcement. The Commission has promulgated regulations pertaining to the net metering, interconnection and portfolio standard provisions of the AEPS Act.

Based on our experience to date in implementing the current regulations, the Commission finds that it is necessary to update and revise these regulations to comply with Act 129 of 2008, and Act 35 of 2007, and to clarify certain issues of law, administrative procedure and policy. These proposed revisions are being issued for public comment. After receipt and review of public comment, the Commission will issue a final rule for approval consistent with regulatory review process.

BACKGROUND

The AEPS Act, which became effective February 28, 2005, establishes an alternative energy portfolio standard for Pennsylvania. The Pennsylvania General Assembly charged the Commission with implementing and enforcing this mandate in cooperation with the Pennsylvania Department of Environmental Protection (DEP). 73 P.S. §§ 1648.7(a) and (b). The Commission determined that the Act is in *pari materia* with the Public Utility Code, and that it would develop the necessary regulations to be codified at Title 52 of the Pennsylvania Code. 1 Pa.C.S. § 1932.

The AEPS Act has been amended on two occasions. Act 35 of 2007, which took effect July 19, 2007, amended certain definitions and provisions for net metering and interconnection. Act 129 of 2008, which became effective on November 14, 2008, amended the AEPS Act by modifying the scope of eligible Tier I alternative energy sources and the Tier I compliance obligation. *See* 66 Pa.C.S. § 2814.

The Commission has previously issued the following rulemakings to implement the AEPS Act and its subsequent amendments:

- The Commission issued final, uniform net metering regulations for customer-generators. *Final Rulemaking Re Net Metering for Customer-generators pursuant to Section 5 of the Alternative Energy Portfolio Standards Act, 73 P.S. § 1648.5*, L-00050174 (Final Rulemaking Order entered June 23, 2006). These regulations were approved by the Independent Regulatory Review Commission (IRRC) and became effective on December 16, 2006.
- The Commission issued final, uniform interconnection regulations for customer-generators. *Final Rulemaking Re Interconnection Standards for Customer-generators pursuant to Section 5 of the Alternative Energy Portfolio Standards Act, 73 P.S. § 1648.5*, L-00050175 (Final Rulemaking Order entered August 22, 2006, as modified on Reconsideration September

19, 2006). These regulations were approved by the IRRC and became effective on December 16, 2006.

- The Commission revised the net metering regulations and certain definitions to be consistent with the Act 35 of 2007 amendments through a final omitted rulemaking. *Implementation of Act 35 of 2007; Net Metering and Interconnection*, Docket No. L-00050174 (Final Omitted Rulemaking Order entered July 2, 2008). These revisions were approved by IRRC and became effective November 29, 2008.
- The Commission issued final regulations governing the portfolio standard obligation. *Implementation of the Alternative Energy Portfolio Standards Act of 2004*, L-00060180 (Final Rulemaking Order entered September 29, 2008). These regulations were approved by IRRC and became legally effective December 20, 2008.

The above-referenced regulations are codified at Chapter 75 of the Public Utility Code, 52 Pa. Code §§ 75.1, *et seq.*

The Commission issued an Order to implement the AEPS related provisions of Act 129 in 2009. *Implementation of Act 129 of 2008 Phase 4 – Relating to the Alternative Energy Portfolio Standards Act*, Docket M-2009-2093383 (Order entered May 28, 2009). This rulemaking will also codify the processes and standards identified in that Order.

SUMMARY OF CHANGES

For reasons of efficiency, the Commission will propose revisions to the portfolio standard, interconnection and net metering rules through a single rulemaking proceeding. The proposed changes to the existing regulations include, but are not limited to, the following:

- The addition of definitions for aggregator, default service provider, grid emergencies, microgrids and moving water impoundments.

- Revisions to the interconnection rules to reflect the increase in limits on customer-generator capacity contained in the Act 35 of 2007 amendments.
- Revisions to net metering rules and inclusion of a process for obtaining Commission approval to net meter alternative energy systems with a nameplate capacity of 500 kilowatts or greater.
- Clarification of the virtual meter aggregation language.
- Clarification of net metering compensation for customer-generators receiving generation service from electric distribution companies (EDCs), default service providers (DSPs) and electric generation suppliers (EGSs).
- Revisions to the definitions for low-impact hydropower and biomass to conform with the Act 129 of 2008 amendment.
- Addition of provisions for adjusting Tier I compliance obligations on a quarterly basis to comply with the Act 129 of 2008 amendments.
- Addition of provisions for reporting requirements for new low-impact hydropower and biomass facilities in Pennsylvania to comply with the Act 129 of 2008 amendments.
- Clarification of Commission procedures and standards regarding generator certification and the use of estimated readings for solar photovoltaic facilities.
- Clarification of the authority given to the Program Administrator to suspend or revoke the qualification of an alternative energy system and to withhold or retire past, current or future alternative energy credits for violations.
- Clarification of the process for verification of compliance with the AEPS Act.
- Standards for the qualification of large distributed generation systems as customer-generators.

DISCUSSION

The following sections identify proposed revisions to the rules and the Commission's rationale.

A. General Provisions: § 75.1 Definitions

We have revised and clarified several definitions to conform with the amendments to and the intent of the AEPS Act. Furthermore, we have added definitions to provide clarity and guidance in accordance with the intent of the AEPS Act as amended.

1. Aggregator

We have added a definition for aggregator as this term is used later in these regulations. In the context of the AEPS Act, an aggregator is a person or entity that maintains a contract with alternative energy system owners to combine the alternative energy credits from multiple alternative system owners to facilitate the sale of the credits. In implementing the AEPS Act, we have found that, due to the small size of many residential solar photovoltaic systems and the fact that one alternative energy credit equals one megawatt, most of these small alternative energy system owners have difficulty selling the few credits they produce due to the administrative burdens and costs associated with finding a buyer. Due to these barriers, persons and entities have stepped in to assist these small system owners by combining or aggregating the credits produced by many of these small systems and selling those bundled credits. These aggregators are often the point of contact for EDCs and the program administrator when the systems are certified and the output is verified. As such, we have included aggregators in these regulations where the regulations address the interaction between the program administrator and system owners.

2. Alternative Energy Sources

The definition of alternative energy sources is revised to reflect the amendments to the definition for low-impact hydropower and biomass facilities from Act 129. The definition of Tier II alternative energy source will also be revised consistent with the change to the definition for biomass facilities in Act 129.

3. Distributed Generation System

We have also proposed more precise definitions for elements of the definition for distributed generation systems, which is defined as “the small-scale power generation of electricity and useful thermal energy.” *See* Annex A at 3. The current regulation simply repeats the definition in the AEPS Act. This definition is too ambiguous to be useful, and does not provide satisfactory regulatory guidance to potential applicants regarding whether they can qualify a system as an alternative energy source. To provide clarity we have added a capacity limit to provide guidance on what small-scale facilities qualify. In addition, we have added a definition for useful thermal energy that is technology and fuel neutral but does not include common merchant generation facilities, such as combined-cycle electric generation facilities. We believe the proposed definition captures the intent of the General Assembly to use the waste heat from the generation of electricity to offset the use of another fuel source to generate heat for a purpose other than the generation of electricity. The proposed definition will permit a combined heat and power facility with a nameplate capacity of five megawatts or less to qualify as a Tier II alternative energy source.

Defining small-scale is more difficult. Unlike useful thermal energy, the phrase small-scale is not a commonly recognized or defined term in the context of the regulation of electric generation. However, given that this is a form of distributed generation, we

find it reasonable to apply the capacity limits for customer-generators, who are eligible to net meter and interconnect distributed generation resources, to the definition of distributed generation systems. The AEPS Act places a cap of five megawatts on customer-generators. Accordingly, we will limit this Tier II alternative energy source to five megawatts of capacity as well. We note, however, that such distributed generation does not have to qualify as a customer-generator to qualify as a Tier II alternative energy source.

4. Customer-Generator and Utility

We also revised the definition of customer-generator and added a definition for utility to make it clear that the definition applies to retail electric customers and not electric utilities, such as EDCs and merchant generators that are in the business of providing electric services. In addition, the changes make it clear that non-electric utilities, such as water and wastewater utilities are not included in the definition's prohibition against utilities qualifying as a customer-generator.

The AEPS Act defines customer-generator as “[a] 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....” 73 P.S. § 1648.2. In analyzing this definition, we note that the legislature used the word customer in this term. Customer is defined as “one that purchases a commodity or service.”¹ Furthermore, it must be noted that the Public Utility Code defines customer as a retail electric customer in the context of the electric utility industry. *See* 66 Pa.C.S. § 2803. The Public Utility Code further defines a retail electric customer as a direct purchaser of electric power. *Id.* In the context of the AEPS Act, the commodity or service being provided is electricity or electric service. Accordingly, the

term customer-generator by itself connotes an entity which is primarily an end user of electricity or electric service from EDCs, EGSs and merchant generators that provide these services by a person or entity that owns or operates the distributed generation system. The person or entity must purchase electricity or electric service to be considered a customer under the AEPS Act.

Furthermore, this definition specifically identifies a customer-generator as a “nonutility owner or operator” of the distributed generation system. While the AEPS Act does not define what a utility or nonutility is, common usage of the term utility, in the context of the purchase of electricity or electric service, is defined as “a service (as light, power, or water) provided by a public utility.”² Thus, a nonutility would be one who does not provide a service, such as electric service in the context of the AEPS Act. A customer-generator is one who is not in the business of providing electric power to the grid or other electric users. As such, we have defined a utility in this context as a person or entity whose primary business is electric generation, transmission, or distribution services, at wholesale or retail, to other persons or entities.

5. Grid Emergencies and Microgrid

The AEPS Act permits facilities with a nameplate capacity of between three megawatts and up to five megawatts to qualify as customer-generator facilities provided that they make their systems available to operate in parallel with the electric utility during grid emergencies as defined by the regional transmission organization (RTO) or where a microgrid is in place for the primary or secondary purpose of maintaining critical infrastructure. We have added definitions for grid emergencies and microgrid to provide

¹ See WEBSTER'S NINTH NEW COLLEGIATE DICTIONARY 318 (1983).

² See WEBSTER'S NINTH NEW COLLEGIATE DICTIONARY 1300 (1983).

guidance on when facilities with a nameplate capacity of between three megawatts and up to five megawatts meet the conditions to qualify as a customer-generator.

The definition for grid emergencies comes from PJM Manual 13 Emergency Operations.³ As PJM is currently the only RTO serving Pennsylvania, we believe this definition is appropriate.

The definition for microgrid references and incorporates the description of a microgrid provided by the Institute of Electrical and Electronic Engineers (IEEE) standard 1547.4. This standard can be found in the IEEE Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems.

6. Moving Water Impoundment

The definitions for large-scale hydropower and low-impact hydropower in the AEPS Act both contain the phrase “the hydroelectric potential of moving water impoundments.” The AEPS Act, however, does not define what moving water impoundments are. We have added a definition for moving water impoundments to provide guidance and clarity. This definition is intended to make it clear that in addition to hydroelectric facilities that utilize dams to impound water, electric turbines placed in rivers or streams without a dam also qualify as hydropower within the AEPS Act.

7. Default Service Provider

We have addressed the role of default service providers (DSPs) in net metering provisions of the regulations. While we acknowledge that EDCs currently fill the role of

³ See PJM Manual 13, PJM Manual for Emergency Operations at 3, which is available at the following link: <http://www.pjm.com/~media/documents/manuals/m13.ashx>.

DSP, the Public Utility Code does provide for an alternative supplier to supply default service upon Commission approval. Therefore, we propose a definition for DSP that is consistent with the definition found in the Pennsylvania Public Utility Code at 66 Pa.C.S. § 2803.

B. Net Metering: § 75.13. General Provisions

This section features several revisions related to who can qualify for net metering and the compensation they receive. In addition, we have addressed the role of DSPs in net metering and the compensation they provide. While we acknowledge that EDCs currently fill the role of DSP, the Public Utility Code does provide for an alternative supplier to supply default service upon Commission approval. The addition of DSPs to this section simply acknowledges this possibility and provides guidance and clarity regarding a DSP's role in providing net metering and compensation under net metering.

1. Section 75.13(a)

Currently, Section 75.13(a) requires EDCs to offer net metering to customer-generators and provides that EGSs may offer net metering to customer-generators under the terms and conditions set forth in agreements between the EGS and the customer-generator taking service from the EGS. The current regulation is silent as to which customer-generators can net meter, other than that they must be using Tier I or Tier II alternative energy sources.

We have added a provision for DSPs and have moved the EGS net metering role to subsection 75.13(b) and re-lettered the remaining subsections. In our proposed new section (a), we require EDCs and DSPs to 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, provided they meet certain conditions.

The first condition requires the customer-generator to have load, independent of the alternative energy system, behind the meter and point of interconnection of the alternative energy system. To be independent, the electric load must have a purpose other than to support the operation, maintenance or administration of the alternative energy system. This provision makes explicit what was previously implied in the AEPS Act and the regulations.

This requirement is implied in the AEPS Act definition of net metering where it states that net metering is the means of measuring the difference between the electricity supplied by an electric utility and the electricity generated by the customer-generator when any portion of the electricity generated by the alternative energy generating system is used to offset part or all of the customer-generator's requirements for electricity. If there is no independent load behind the meter and point of interconnection for the alternative energy system, by definition, the customer-generator has no requirement for electricity to offset. In addition, this requirement is implied in the current regulations, where it states that EDCs shall offer net metering to customer-generators that generate electricity on the customer-generator's side of the meter. Again, there would be no need for a customer's electric meter if there was no independent demand for electricity. Furthermore, we note that both alternative and traditional electric generation facilities require electric service to start, operate and maintain those facilities. Thus, to preclude utilities, such as merchant generators, from qualifying for net metering, we require load independent of the generation facility. To do otherwise would be contrary to the definition of a customer-generator that only includes nonutility owners and operators of alternative energy systems.

The second condition requires that the owner or operator of the alternative energy system may not be a utility. As noted previously, the AEPS Act defines a customer-generator as a nonutility owner or operator of a net metered distributed generation system. Again, this condition makes explicit in the rule what is required by the AEPS Act.

The third condition requires that the alternative energy system be sized to generate no more than 110 percent of the customer-generator's annual electric consumption at the interconnection meter and all qualifying virtual meter aggregation locations. The AEPS Act sets maximum nameplate capacity limits for customer-generators by customer class, with 50 kilowatts for residential service and three megawatts at other service locations and up to five megawatts under certain circumstances. To this point, the Commission has not set more restrictive size limitations on customer-generators, except in a policy statement permitting net metering of third-party owned and operated systems. *See Net Metering – Use of Third Party Operators*, Final Order at Docket No. M-2011-2249441 (entered March 29, 2012). In that order, the Commission set the 110 percent size limit as a reasonable way to limit the possibility of merchant generators posing as customer-generators. The Commission further noted that the majority of comments supported the limit as a reasonable and balanced approach to support the intent of the AEPS Act and limiting the potential for merchant generators to use net metering to circumvent the wholesale electric market and gain excessive retail rate subsidies at retail customer expense. *See Net Metering – Use of Third Party Operators*, Final Order at 8.

While we declined to extend the application of the 100 percent limitation of systems owned or operated by a customer-generator in the policy statement,⁴ we now believe that this same reasonable and balanced approach should apply to all new customer-generators as it more appropriately supports the intent of the AEPS Act. Again,

⁴ *See Net Metering – Use of Third Party Operators*, Final Order at 9.

we point out that the AEPS Act defines net metering as a means for a customer-generator to offset part or all of the customer-generator's requirements for electricity. In addition, it ensures that the customer-generator is not acting like a utility or merchant generator, receiving excessive retail rate subsidies from other retail rate customers.

As we adopted in the policy statement, the 110 percent limit is a design limit to be based on historical or estimated annual system output and customer usage, both of which are affected by weather that is beyond the control of the customer.⁵ It is not to be used as a hard kilowatt-hour cap on the customer-generator's system output. We believe that this approach appropriately captures the intent of the AEPS Act regarding net metering and is consistent with how net metering is treated in other states.⁶

The fourth, fifth and sixth conditions simply require that the customer-generator's alternative energy system cannot exceed the nameplate capacity limits, by rate class, set forth in the AEPS Act. As noted above, these are maximum limits on the size of net metered systems. We recognize that even with the 110 percent of annual electric consumption size limitation, some systems may be able to exceed the statutory maximum size limits due to large annual electric demand. Accordingly, we have included these conditions to make it clear that customer-generator systems cannot exceed the statutory nameplate capacity limits.

Finally, in the seventh condition, we have imposed a requirement that all alternative energy systems with a nameplate capacity of 500 kilowatts or greater obtain

⁵ *Id.* at 10.

⁶ *See*, 26 Del. Admin. Code 3001-8.6.2: "The customer-Generator Facility is designed to produce no more than 110% of the Customer's aggregate electrical consumption...." *See also*, N.J.A.C. 14:8-4.3(a): EDCs "shall offer net metering . . . provided that the generating capacity of the customer-generator's facility does not exceed the amount of electricity supplied . . . to the customer over an historical 12-month period . . ." And, N.J.A.C. 14:8-7.3(a)(2): "The generating capacity of the eligible customer's system does not exceed the combined metered annual energy usage of the customer's qualified facilities."

Commission approval for net metering in accordance with a process we have added to the regulations and discuss below. We believe that this approval process will ensure uniform application of the net metering rules throughout the Commonwealth. We believe that the limiting of Commission review to systems equal to or greater than 500 kilowatts appropriately balances the need for consistent application with the additional administrative efforts and costs such a review imposes. We believe that customer-generators who have the capital to invest in these large and more costly systems will have the resources to comply with this review process. In addition, we believe that the total number of such systems applying for net metering in a year will remain relatively small such that it will not burden the EDCs or the Commission.

2. Section 75.13(b)

As noted above, we moved the reference to EGSs offering net metering to subsections (b) and re-lettered the remaining subsections. In addition, we added the phrase “or as directed by the Commission” to this subsection. This phrase is intended to make it clear that the Commission has the authority to direct EGSs to offer net metering in certain circumstances. In particular, the Commission would have the authority to direct EGSs to offer net metering if the EGSs are acting in the role of default service provider. This provides consistent and clear guidance along with the addition of references to DSPs added to these rules.

3. Section 75.13(d)

Formerly subsection (c), subsection (d) is revised to include DSP, add a hyphen between the words “customer” and “generator” and to provide clarity on how excess generation in one billing period is to be treated in subsequent billing periods. These changes are not intended to change how net metering has been implemented; we are

simply providing clarity so the regulation accurately reflects the Commission's intent and actual practice.

4. Section 75.13(e)

The re-lettered subsection (e) is being revised to provide clarity on how excess generation amounts are determined at the end of the year and how the compensation is to be computed. These changes are not intended to change how net metering has been implemented; we are simply providing clarity so the regulation accurately reflects the Commission's intent. The revision makes it clear that only the customer-generator's excess generation that was not offset by that customer's usage is to be compensated at the price-to-compare rate. In addition, we make it clear that the EDC/DSP is to use a weighted average of the price-to-compare rate based on the rate in effect when the excess generation was actually delivered. This is intended to compensate the customer-generator in a manner that more accurately represents the value of the excess generation.

5. Section 75.13(f)

The issue in the re-lettered subsection (f) involves the compensation level for customer-generators who exercise the option for retail choice. When a customer shops, they cease to pay the default service provider's price to compare (which includes all generation and transmission charges) and instead takes this service at a price offered by an EGS.

The current regulation acknowledges this fact, noting that the compensation for kilowatt-hours produced is a matter between an EGS and customer-generator. The regulation merely requires that the terms of the compensation be clearly stated in the service agreement. However, the regulation is silent as to how distribution charges are to

be treated by the EDC. Customer-generators who shop are still responsible for the regulated distribution rates of the EDC. Like customer-generators who currently net meter while taking service from the EDC/DSP, customer-generators who take supply service from an EGS shall also receive a credit against the unbundled kilowatt-hour based distribution charges. This credit shall be equal to the unbundled kilowatt-hour distribution charge of the EDC for the customer-generator's kilowatt-hour rate schedule. As with the generation charges for customer-generators taking EDC/DSP service, any excess kilowatt-hours in any billing period are to be carried forward and credited against the customer-generator's kilowatt-hour distribution charges in subsequent billing periods until the end of the year. Any kilowatt-hour distribution credits remaining at the end of the year are zeroed-out such that the customer-generator receives no payments from the EDC, or any remaining kilowatt-hour distribution charge credits into the next year. This language is intended to provide clarity, not to change the current practice under the existing rules.

6. Section 75.13(j)

In the re-lettered subsection (j), we added references to default service and the default service rate. This change simply recognizes DSPs and the role EDCs currently play in providing default service.

7. Section 75.13(k)

In the re-lettered subsection (k), we added references to DSPs and clarify when charges may be applied to customer-generators. The current rule states that an EDC may not charge a customer-generator a fee or other type of charge unless the fee or charge would apply to other customers. This prohibition conflicts with regulation 75.14(e), which states that “[i]f the customer-generator requests virtual meter aggregation, it shall

be provided by the EDC at the customer-generator's expense." In addition, rule 75.14(e) states that "[t]he customer-generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis." The re-lettered subsection k now allows EDCs to charge a fee that is specifically authorized under this chapter or by order of the Commission. This is intended to remove any conflicts in the regulations and provide clarity.

C. Net Metering: §§75. 12 and 75.14. Meters and Metering

We are proposing to clarify the definition of virtual meter aggregation in Section 75.12 and the application of virtual meter aggregation in Section 75.14(e). In addition, we are proposing to revise the definition of year and yearly in Section 75.12.

1. Virtual Meter Aggregation

We are proposing several changes to the provisions regarding virtual meter aggregation to clarify when it is available.⁷ Virtual metering was initially proposed in this regulation for the purpose of facilitating the development of distributed generation in the agricultural setting, particularly for systems referred to as anaerobic or methane biodigesters. The Commission learned that it was not uncommon for a farmer to own multiple, non-contiguous parcels of land that were separately metered to measure the load served at each location. The Commission chose to permit the virtual metering of these parcels to achieve the policy objectives of the AEPS Act:

⁷ The amendments proposed in this section include, but are not limited to, the concerns noted by the Commission in *Larry Moyer v. PPL Electric Utilities Corp.*, Opinion and Order, Docket No. C-2011-2273645 at 17-20 (entered January 9, 2014), in which the Commission referred the issue of whether an interconnected alternative energy system qualifies for net or virtual metering if there is no non-generational load at the interconnection point, to the Law Bureau to consider whether the regulations need to be clarified.

The fundamental intent of Act is the expansion and increased use of alternative energy systems and energy efficiency practices. Regulatory and economical barriers have been in place that prevented systems such as anaerobic digesters from being more economical or further developed. This rulemaking provides an opportunity to advance the use of these alternative energy systems in a way that will benefit the customer-generator, ratepayers and the environment by allowing exceptions for this important class of customers. Accordingly, we will permit virtual meter aggregation for customer-generators.

As pointed out by the Pennsylvania Farm Bureau, the proposed definition and application of virtual meter aggregation do not fit the reality of a typical Pennsylvania farm operation that has adequate animal units to produce required amounts of manure for anaerobic digesters to operate efficiently. The Pennsylvania Department of Agriculture recently surveyed 26 farms in the state that either have manure digesters operating, digesters under construction or in the planning stages. Out of the 21 farm operations that responded to the survey, there are 148 individual meters involved, which represents an average of seven meters per farm.

Additionally, a study completed by Dr. James Cobb from the University of Pittsburgh, in 2005, titled *Anaerobic Digesters on Dairy Farms*, indicates a potential of 50-60 digesters being developed on Pennsylvania dairy farms in the foreseeable future. The digesters will not be developed to this extent if the proposed metering aggregation restrictions remain in place.

Final Rulemaking Re Net Metering for Customer-Generators Pursuant to Section 5 of the Alternative Energy Portfolio Standards Act, Docket L-00050174 at 21 (Order entered June 22, 2006).

Subsequent to the Commission's 2006 rulemaking, the General Assembly amended the AEPS Act and included the definition for virtual meter aggregation within the definition of net metering in 73 P.S. § 1648.2.⁸ The language in the amended AEPS Act is nearly identical to the language adopted by the Commission in this proposed rulemaking.

⁸ See P.L. 114, No. 35 of 2007.

Since the Commission's regulations became effective, various parties have presented scenarios to the Commission for virtual metering that do not comport with our intent to permit a limited amount of virtual meter aggregation. This includes fact patterns where distributed generation is proposed to be installed at a location with no load, but then virtually aggregated with another location that has no distributed generation. Another example includes a retail customer hosting distributed generation that it neither owns nor operates and then aggregating it with the distributed generation owned and operated by an entirely different customer at another location within the two mile limit. We, therefore, propose revisions to Sections 75.12 and 75.14 clarify the acceptable scope of virtual metering.

2. Year and Yearly

In the existing regulations, the term year and yearly, as it applies to net metering, is defined as the planning year as determined by the PJM Interconnection, LLC regional transmission organization. The Commission selected this definition initially to avoid confusion, as it is the same as the AEPS Act compliance year of June 1 through May 31.⁹ In implementing these regulations over the last seven years, it has become clear that the vast majority of net metered customer-generator systems are solar photovoltaic systems. We recognize that these solar photovoltaic systems produce their peak outputs during the months of May through September. Accordingly, with a year ending in May, many of these systems may have excess generation that receives a payment at the price-to-compare rate as opposed to receiving a fully bundled credit toward their subsequent billing periods. Therefore, we propose to revise the definition for year and yearly as it applies to net metering to the period of time from May 1 through April 30.

⁹ See *Implementation of Act 35 of 2007 Net Metering and Interconnection*, Final Omitted Rulemaking Order at Docket No. L-00050174, entered on July 22, 2008 at 11 and 12.

D. Net Metering: § 75.16. Large Customer-Generators

This section has been added to address distributed generation systems with a nameplate capacity of greater than three megawatts and up to five megawatts, which for purposes of this rulemaking we will refer to as large customer-generators. The AEPS Act states that systems of this size may qualify for customer-generator status if they meet certain conditions, such as being able to support the transmission grid during an emergency, or being part of a microgrid and able to maintain critical infrastructure.

In the existing regulations at 52 Pa. Code § 75.1, the definition for customer-generator found in the Act is repeated word for word. In the proposed section 75.16 we provide clarification so that potential applicants have a reasonable level of certainty that their systems will qualify for customer-generator status before making an investment to purchase and install such a system.

The newly proposed Section 75.16 identifies the standards that must be met to qualify as a large customer-generator. A customer-generator will be considered to be supporting the grid if an RTO, such as PJM, has formally designated it as a resource that the RTO will call upon during a grid emergency. For example, the PJM Operating Agreement and Open Access Transmission Tariff (OATT) identifies certain emergency rules and procedures in which it may call upon generation resources to run at maximum output to provide support during a generation or transmission emergency. These procedures and associated rules are also delineated in PJM's Reliability Assurance Agreement on file with FERC. Should a customer with a distributed generation system of between three megawatts and five megawatts have all or a portion of its system designated an emergency type support resource by an RTO, it may seek qualification as a customer-generator from the Commission. The applicant will have the burden of

demonstrating through appropriate documentation that it has been designated by the RTO as a grid support generation resource.

We note that the customer-generator definition requiring the large facilities to operate in parallel with the local utility during grid emergencies or a microgrid is in place to support critical infrastructure implies that a customer-generator is capable of operating off the grid under certain circumstances. In the case of the grid emergency requirement, the generation facility is able to increase generation output supplied to the local grid or remove all output to the local grid during a grid emergency. Thus, entities that own facilities with a nameplate capacity of between three megawatts and up to five megawatts that normally supply most or all of its output to the local utility cannot qualify as a customer-generator as they cannot make their generation available to operate in parallel only during grid emergencies. In contrast, this definition implies that where a microgrid exists to support critical infrastructure, the generating facility can normally supply energy to and operate in parallel with the local utility, but is able to operate off the local utility grid during grid emergencies to support the continued operation of critical infrastructure. For a large distributed generation system may also qualify for customer-generator status if it is part of a microgrid and provides generation to critical infrastructure. Examples of critical infrastructure are provided within the AEPS Act and have been included in the definition of customer-generator in the regulation.

E. Net Metering: § 75.17. Process for Obtaining Commission Approval of Customer-Generator Status.

Since the inception of the AEPS Act and these regulations, the EDCs have been solely responsible for interconnecting and approving net metering for all customer-generators. While this has worked well for EDCs and customer-generators, the Commission has received some reports of inconsistent application of the net metering

rules. In addition, as the Commission is imposing a 110 percent of annual load limit on the size of customer-generators, we are proposing a process for seeking Commission approval of all customer-generators with a nameplate capacity of 500 kilowatts or greater.

Under the proposed process, EDCs are to submit completed net metering applications for alternative energy systems with a nameplate capacity of 500 kilowatts or greater to the Commission's Bureau of Technical Utility Services, within 20 days of receiving them, along with a recommendation on whether the proposed alternative energy system complies with these rules and the EDC's net metering tariff. The EDC is to serve its recommendation on the applicant, who has 20 days to submit a response to the Bureau of Technical Utility Services. The Bureau of Technical Utility Services must review the application, EDC recommendation and applicant response and, pursuant to delegated Commission authority, approve or disapprove the application within 30 days of its submission. The Bureau is to describe in detail its reasons for disapproval of an application. The applicant or the EDC may appeal the Bureau's determination to the Commission within 20 days after service of notice in accordance with rule 5.44 (relating to petitions for appeal from actions of staff).

F. Interconnection: §75.22. Definitions.

The Commission is proposing a revision to the definition for "electric nameplate capacity." Parties have asked for clarification in the solar photovoltaic context as to whether it is the capacity of the panels that should be measured, or that of the inverter that converts the electricity from direct current (DC) to alternating current (AC). For example, while the panels of a particular residential location may have a DC capacity of 50 kW, the inverter may only be able to convert a maximum of 45 kW to AC. The other five kW is lost in the conversion process.

The Commission has been asked to designate the capacity limit as that of the inverter to enable customer-generators to maximize their output and possible compensation. Accordingly, under the above fact pattern, a residential customer might install panels with 55 kW of DC capacity, but so long as the inverter's AC capacity was no greater than 50 kW, it would qualify as a customer-generator.

The AEPS Act describes a customer-generator in the residential context as the owner or operator of a "net-metered distributed generation system with a nameplate capacity of not greater than 50 kilowatts." *See* 73 P.S. § 1648.2. The key word in this description is "system." The definition does not refer to individual components of a generator, such as panels or inverters, but to the entire generation system. Therefore, the Commission finds that as the General Assembly referred to the distributed generation system, the General Assembly intended for customer-generators to have the full benefit of the capacity capabilities of the entire generation system, which in the case of a solar photovoltaic system is the output at the inverter, not the panels. Therefore, electric nameplate capacity will be revised to refer to the limits of the inverter or inverters (if more than one is needed) at a particular customer-generator location, as opposed to the generation device.

G. Interconnection: §§ 75.31, 75.34, 75.39, and 75.40. Capacity Limits.

These sections have been revised to reflect the increase of the capacity limit resulting from Act 35 for customer-generators from 2 MW to 5 MW.

H. Interconnection: § 75.51. Disputes.

The current regulations at § 75.51(c) provides that the Commission may designate a Department of Energy National Laboratory, PJM Interconnection L.L.C., or college or

university with distribution system engineering expertise as a technical master. Once the Commission designates a technical master, the parties to a dispute are to use the technical master to help resolve the dispute.

To date the Commission has not designated a technical master. This is due to the fact that there are costs involved in identifying and retaining such expertise, which are not justified by the number of disputes. To date we are not aware of any interconnection disputes that have not been resolved through the normal Commission complaint or alternative dispute resolution processes. As such, we are proposing to delete this subsection.

I. Alternative Energy Portfolio Requirement: § 75.61. EDC and EGS Obligations.

This section has been revised to note that the requirements are subject to the quarterly adjustment provisions of Act 129 of 2008. *See* 66 Pa.C.S. § 2814(c).

J. Alternative Energy Portfolio Requirement: § 75.62. Alternative Energy System Qualification.

Section 75.62(g) has been added to note that alternative energy system status may be suspended or revoked for violations of the provisions of this chapter. The penalty provision is primarily intended to discourage and, if necessary, punish fraudulent behavior by owners of alternative energy systems. While this authority was implied in the current regulations, we propose adding this provision to make this authority explicit to provide clarity.

K. Alternative Energy Portfolio Requirement: § 75.63. Alternative Energy Credit Certification.

Section 75.63(g) has been supplemented with a proposed end to the use of estimates for future small solar photovoltaic systems and to clarify when estimated readings may be used by existing small solar photovoltaic systems. To begin with, the revision provides that small solar photovoltaic systems installed or that increase capacity on or after 180 days from the effective date of the regulation must use metered data to verify alternative energy credit certification. In adopting the current regulations, we allowed for the use of estimates for small solar photovoltaic systems of 15 kilowatts or less to reduce the cost of installing and operating such systems. Since then, the cost of solar photovoltaic panels have decreased such that the minimal cost of a revenue grade meter no longer provides a barrier to the installation of these small systems. As such, we propose to require all new solar photovoltaic systems to have a revenue grade meter to measure system output for alternative energy credit certification.

The other revisions to Section 75.63(g) provides that estimated reads may be used for existing small solar photovoltaic systems only when no other technology is available, and that once actual metered data begins to be used, estimates are no longer permitted. The revision also prevents estimated data in the context of panels whose orientation can be manually adjusted by the owner/operator, given the problems associated with production verification in this circumstance. Finally, the revisions define the solar modules that are eligible for use with estimates and provide the program administrator express authority to verify the output of those systems.

Three additional subsections have been added in order to resolve issues that have been identified in implementation of the Act. Subsection (i) has been added to clarify that credits can be certified from the time the application is filed with the Commission, so

long as either metered data is available, or an inverter reading is included when PV Watts estimates are permitted to be used. This is done to avoid penalizing an applicant for the time it takes the administrator to review and approve the application.

Subsection (j) is being proposed to address incomplete or incorrect applications. The Commission's preference is that the program administrator give an applicant a reasonable period of time, at the administrator's discretion depending on the nature of the issue, to correct the deficiency before rejecting the application. When an application is rejected, the applicant is penalized because it loses the opportunity to earn credits for the period when the application was first filed to the time when it was rejected. Credits may only be earned from the time of the filing of the second application. This section puts applicants on notice of the importance of filing a complete and correct application, the need to timely respond to the administrator's notice to them, and the penalty for failing to do so.

Subsection (k) has been added to resolve an ambiguity over the vintage of alternative energy credits. Generally, credits may only be banked for use for two years. It is therefore necessary that the right vintage year be assigned to a credit, as documented by the certificate created in PJM-EIS's credit registry, the Generator Attribute Tracking System (GATS). Sometimes data may be entered in the credit registry for production that overlaps two different reporting periods. This section confirms that credits will be allocated to the appropriate reporting period, regardless of when the data is entered into the credit registry.

L. Alternative Energy Portfolio Requirement: § 75.64. Alternative Energy Credit Program Administrator.

We have added provisions to Section 75.64(b) to note that alternative energy system status may be suspended or revoked and that the credits from a suspended or revoked system may be withheld or retired for violations of the provisions of this chapter. The penalty provision is primarily intended to discourage, and if necessary, punish, fraudulent behavior by owners or aggregators of alternative energy systems. While this authority was implied in the current regulations, we propose adding this provision to make this authority explicit to provide clarity.

In Section 75.64(c) we have proposed revisions that more accurately reflect the current reporting requirements, timing and processes for determining and verifying EDC and EGS compliance with the AEPS Act obligations.

Finally, in Section 75.64(d) we have proposed a provision that expressly states that 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). This provision is being proposed to provide explicit authority to the program administrator that was previously implied.

M. Alternative Energy Portfolio Requirement: § 75.65. Alternative Compliance Payments.

In this section we are clearly identifying the Commission's Bureau of Technical Utility Services as the Bureau with the responsibility of providing notice of and processing alternative compliance payments.

**N. Alternative Energy Portfolio Requirement: §§ 75.71 and 75.72.
Quarterly Adjustment of Non-Solar Tier I Obligation.**

In 2008, the General Assembly again amended the AEPS Act¹⁰ by adding two new Tier I resources and requiring the Commission to increase the percentage share of Tier I requirements on a quarterly basis to reflect the addition of the new Tier I resources, which was codified in 66 Pa.C.S. § 2814. The Commission issued an Order to implement the AEPS related provisions of Act 129 in 2009. *See, Implementation of Act 129 of 2008 Phase 4 – Relating to the Alternative Energy Portfolio Standards Act, Docket M-2009-2093383* (Order entered May 28, 2009). This rulemaking will also codify the processes and standards identified in that Order in this Chapter at Sections 75.71 and 75.72.

CONCLUSION

Accordingly, under 66 Pa.C.S. §§ 501, 1501, 2807(e), Sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004, 73 P.S. §§ 1648.7(a), 1648.3(e)(2); the Commonwealth Documents Law, 45 P.S. §§ 1201 *et seq.*, and the regulations promulgated hereunder at 1 Pa. Code §§ 7.1, 7.2, and 7.5, the Commission proposes revisions to its regulations pertaining to the alternative energy portfolio standard obligation, and its provisions for net metering and interconnection, as noted and set forth in Annex A; **THEREFORE,**

IT IS ORDERED:

1. That the Proposed Rulemaking at Docket L-2014-2404361 will consider the regulations set forth in Annex A.

¹⁰ See P.L. 1592, No. 129 of 2008.

2. That the Secretary shall submit this order and Annex A to the Office of Attorney General for approval as to legality.

3. That the Secretary shall submit this order and Annex A to the Governor's Budget Office for review of fiscal impact.

4. That the Secretary shall submit this order and Annex A for review by the designated standing committees of both houses of the General Assembly, and for review by the Independent Regulatory Review Commission.

5. That a copy of this order and Annex be served on the Pennsylvania Department of Environmental Protection, all jurisdictional electric distribution companies, the Office of Consumer Advocate, the Office of Small Business Advocate, the Commission's Bureau of Investigation and Enforcement, the Energy Association of Pennsylvania, the Retail Energy Supply Association and the parties in the matter of *Larry Moyer v. PPL Electric Utilities Corp.*, at Docket No. C-2011-2273645.

6. That the Secretary shall deposit this order and Annex A with the Legislative Reference Bureau for publication in the *Pennsylvania Bulletin*.

7. An original of written comments referencing the docket number of the proposed rulemaking shall be submitted within 30 days of publication in the *Pennsylvania Bulletin* to the Pennsylvania Public Utility Commission, Attn: Secretary, P.O. Box 3265, Harrisburg, PA 17105-3265.

8. That the contact person for technical issues related to this rulemaking is Scott Gebhardt, Bureau of Technical Utility Services, 717-787-2139. That the contact person for legal issues related to this rulemaking is Kriss Brown, Assistant Counsel, Law Bureau, 717-787-4518. Alternate formats of this document are available to persons with disabilities and may be obtained by contacting Sherri Delbiondo, Regulatory Coordinator, Law Bureau, 717-772-4597.

BY THE COMMISSION

A handwritten signature in black ink, appearing to read "Rosemary Chiavetta". The signature is written in a cursive style with a large initial "R".

Rosemary Chiavetta
Secretary

(SEAL)

ORDER ADOPTED: February 20, 2014

ORDER ENTERED: February 20, 2014

**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.

* * * * *

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.

* * * * *

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] if one of the following applies:

(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.

(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.

*** * * * ***

(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 from systems with a nameplate capacity not greater than 5 megawatts.

* * * * *

Customer-generator –A retail electric customer that is a 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 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 – 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 grid that have DR and load have the ability to intentionally disconnect from and operate in parallel with EPSs.

* * * * *

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.

* * * * *

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 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 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 utility.

(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 and DSP shall credit a customer-generator at the full retail rate, which shall include generation, 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. If 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 and credited against the customer-generator's usage in subsequent billing periods at the 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'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.

* * * * *

(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 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 electric 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.

* * * * *

§ 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, the inverter or the aggregated capacity of multiple inverters at an alternative energy systems location 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] 5 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.

* * * * *

(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, 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):

* * * * *

§ 75.62. Alternative energy system qualification.

* * * * *

(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:

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

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

§ 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:

* * * * *

(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] Commission's Bureau of Technical Utility Services 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] Commission's Bureau of Technical Utility Services will refer the petition to the [Office of Administrative Law Judge] Commission's Bureau of Investigation and Enforcement for further [proceedings] actions as may be [necessary] warranted. Failure of an EDC or EGS to respond to the [Commission] Commission's Bureau of Technical Utility Services within 15 days of the issuance of this notice shall be deemed an acceptance of the alternative compliance payment determination.

* * * * *

§ 75.71. Quarterly adjustment of non-solar Tier I obligation.

(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).

(b) The quarterly requirement will be determined as follows:

(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).

(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 Tier 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 Tier 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).



COMMONWEALTH OF PENNSYLVANIA
PUBLIC UTILITY COMMISSION
400 NORTH STREET
HARRISBURG, PA 17120

ROBERT F. POWELSON
CHAIRMAN

June 23, 2014

The Honorable John F. Mizner, Chairman
Independent Regulatory Review Commission
14th Floor, HARRISTOWN II
333 Market Street
Harrisburg, PA 17101

**Re: L-2014-2404361/57-304; Proposed Rulemaking Re Implementation of the
Alternative Energy Portfolio Standards Act of 2004; 52 Pa. Code, Chapter 75**

Dear Chairman Mizner:

Enclosed please find 1 copy of the proposed rulemaking and the Regulatory Analysis Form prepared in compliance with Executive Order 1996-1, "Regulatory Review and Promulgation." Pursuant to Section 5(a) of the Regulatory Review Act of June 30, 1989 (P.L. 73, No. 19) (71 P.S. §§745.1-745.15), the Commission is submitting today a copy of the proposed rulemaking and Regulatory Analysis Form to the Chairman of the House Committee on Consumer Affairs and to the Chairman of the Senate Committee on Consumer Protection and Professional Licensure.

The purpose of this proposal is to amend existing regulations to comply with Act 129 of 2008 and Act 35 of 2007, and to clarify issues of law, administrative procedure and policy. The contact person is Assistant Counsel Kriss Brown, Law Bureau, 717 787-4518.

The proposal has been deposited for publication with the Legislative Reference Bureau.

Sincerely,

Handwritten signature of Robert F. Powelson in black ink.
Robert F. Powelson

Enclosures

cc: The Honorable Robert M. Tomlinson
The Honorable Lisa Boscola
The Honorable Robert Godshall
The Honorable Peter J. Daley, II
Legislative Affairs Director Perry
Chief Counsel Pankiw
Assistant Counsel K. Brown
Regulatory Coordinator DelBiondo

TRANSMITTAL SHEET FOR REGULATIONS SUBJECT
TO THE REGULATORY REVIEW ACT

ID Number: L-2014-2404361/57-304

Subject: Proposed Rulemaking Re Implementation of the Alternative
Energy Portfolio Standards Act of 2004
52 Pa. Code Chapter 75

Pennsylvania Public Utility Commission

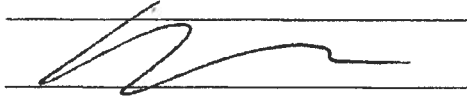
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TYPE OF REGULATION

Proposed Regulation
 Final Regulation with Notice of Proposed Rulemaking
Omitted.
 Final Regulation
 120-day Emergency Certification of the Attorney General
 120-day Emergency Certification of the Governor

FILING OF REPORT

<u>Date</u>	<u>Signature</u>	<u>Designation</u>
6/23/14	S. Gifflet	HOUSE COMMITTEE (Godshall) Consumer Affairs
6/23/14	Mary Walmer	SENATE COMMITTEE (Tomlinson) Consumer Protection and Professional Licensure
6/23/14	K Cooper	Independent Regulatory Review Commission Attorney General
6.23.14		Legislative Reference Bureau