RULES AND REGULATIONS

Title 52—PUBLIC UTILITIES

PENNSYLVANIA PUBLIC UTILITY COMMISSION

[52 PA. CODE CH. 59]

[L-2014-2404361]

Implementation of the Alternative Energy Portfolio Standards Act of 2004; Advance Notice of Final Rulemaking

Public Meeting held
April 23, 2015

Commissioners Present: Robert F. Powelson, Chairperson; John F. Coleman, Jr., Vice Chairperson; James H. Cawley, statement follows; Pamela A. Witmer; Gladys M. Brown

Implementation of the Alternative Energy Portfolio Standards Act of 2004; Doc. No. L-2014-2404361

Advance Notice of Final 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 the 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 previously-referenced regulations are codified in the Commission's regulations in Chapter 75 of the *Pennsylvania 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.

The Commission issued a Notice of Proposed Rulemaking for comment on February 20, 2014. See Implementation of the Alternative Energy Portfolio Standards Act of 2004, Proposed Rulemaking Order, Docket No. L-2014-2404361 (Order entered February 20, 2014). The Proposed Rulemaking Order and proposed rules were published in the *Pennsylvania Bulletin* on July 5, 2014, at 44 Pa.B. 4179. Comments were due within 30 days of the publication of the proposed rules in the *Pennsylvania Bulletin* or August, 4, 2014. On August 1, 2014, the Commission, at the request of the Pennsylvania Department of Agriculture, issued a Secretarial Letter extending the comment period to September 3, 2014. Comments were received from the Independent Regulatory Review Commission and many other interested parties.

Other parties filing comments included Acuity Advisors and CPAs; the Ad Hoc Coalition of Customer Generators; Robin Alexander; the American Biogas Council; Karen Berry; Brubaker Farms; Vincent Cahill & Claire Hunter; the Center for Dairy Excellence; Chesapeake Bay Commission; Chesapeake Bay Foundation; Citizen Power; Citizens for Pennsylvania's Future (PennFuture) and the PennFuture Energy Center; Crayola, Inc.; Dauphin County Board of Commissioners; the Dauphin County Industrial Development Authority (DCIDA); Pennsylvania

Department of Agriculture (PDA); Duquesne Light; the Distributed Wind Energy Association and United Wind et al.; the Energy Association of Pennsylvania; Enviro-Organic Technologies, Inc.; the Estate Security Formula / Gary L. James; State Representative Garth Everett; State Representative Robert L. Freeman; State Representatives Mindy Fee & David Hickernell; Granger Energy of Honey Brook LLC and Granger Energy of Morgantown LLC; Keith Hodge; the House Committee on Agriculture and Rural Affairs; Ideal Family Farms, LLC; Kish View Farm; L&S Sweetners; Lancaster County Agriculture Council; Lancaster County Conservation District; Lancaster Veterinary Associates; Lancaster County Solid Waste Management Authority (LCSWMA); Lehigh County Authority; Elsa Limbach; Kurt Limbach; Lycoming County Commissioners; the Mid-Atlantic Renewable Energy Association; the FirstEnergy Pennsylvania-certificated electric public utilities; the Pennsylvania Milk Marketing Board; Larry Moyer; the Neighbors of Yippee Farms; the Office of Consumer Advocate (OCA); Oregon Dairy, Inc.; the Office of Small Business Advocate (OSBA); Paradise Energy Solutions; Professional Dairy Managers of Pennsylvania; PECO Energy Company; PennAg Industries Association; Pa Biomass Energy Association; Pennsylvania Department of Environmental Protection (DEP); Pennsylvania Farm Bureau; Pennsylvania Municipal Authorities Association; Pennsylvania State University; Pennsylvania Waste Industries Association; PJM Interconnection, LLC; PPL Electric Utilities Corporation; RCM International LLC; Reinford Farms; the Retail Energy Supply Association (RESA); the Sustainable Energy Education & Development Support of Northeast Pennsylvania; Sensenig Dairy; Sierra Club and Sierra Club Members & Supporters; Solare America; SRECTrade, Inc.; Sunrise Energy, LLC; the Sustainable Energy Fund; Tetra Tech, Inc.; the United States Department of Justice, Federal Bureau of Prisons; State Representative Greg Vitali; Wanner's Pride-N-Joy Farm, LLC; John R. Williamson; State Senator Gene Yaw; and Yippee Farms.

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 to 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 Independent Regulatory Review Commission (IRRC), in its comments suggested that the Commission issue an advanced notice of final rulemaking "to engage the regulated community in meaningful dialogue as it develops the final-form rulemaking." IRRC Comments at 4. In review of all the comments presented to date, the Commission has revised the proposed AEPS regulations and issues this advanced notice of final rulemaking to receive additional comments on the revisions. 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 to 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. See Annex A.

1. *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. For the definition of incremental hydroelectric development, language was added to clarify that only changes made to an existing hydroelectric power plant after the effective date of the AEPS Act will be considered incremental.

2. *Grid Emergencies*

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 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.

In the proposed rulemaking, the definition for grid emergencies came from PJM Manual 13 Emergency Operations.[1] As PJM is currently the only RTO serving

[1] 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.

Pennsylvania, we believed this definition was appropriate. PECO Energy Company (PECO) pointed out that PJM Manual 13 provides guidance, instructions and rules for operating during an emergency condition, whereas the PJM Open Access Transmission Tariff (OATT) defines what an emergency condition is and suggested that we reference this PJM document. Since the APES Act specifically references the RTO definition for a grid emergency, we agree with PECO and have proposed a revision to the definition of "grid emergency" to reference the PJM OATT. See Annex A.

3. *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.

As we stated in the proposed rulemaking, the definition of customer-generator 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 proposed defining 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. See Annex A.

As IRRC notes in its comments, several commentators suggested that this definition is overly broad such that it could be interpreted as including persons or entities not intended by the Commission, such as landlords or third-party owned and operated systems permitted to net meter under the Commission's policy statement. IRRC Comments at 5. The Commission agrees and has proposed language intended to exclude persons or entities that own or operate alternative energy systems that are clearly not merchant generators.

B. *Net Metering: § 75.13. General Provisions*

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. In the proposed rulemaking, we proposed language in section (a), that EDCs and DSPs may 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.

In the proposed rulemaking, we proposed a third condition that required the alternative energy system to 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. As we stated in the proposed rulemaking, 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 had 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.[3] 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.

In the proposed rulemaking, we stated 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, we pointed 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 ensured that the customer-generator is not acting like a utility or merchant generator, receiving excessive retail rate subsidies from other retail rate customers.

We further stated that 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. We stressed that it was not to be used as a hard kilowatt-hour cap on the customer-generator's system output. We stated that this approach appropriately captures the intent of the AEPS Act regarding net metering and was consistent with how net metering is treated in other states.[4]

As IRRC notes in its comments, the Pennsylvania Department of Environmental Protection (DEP), the Pennsylvania Department of Agriculture (PDA) and other commentators raised concerns with the effect the rulemaking will have on the environment and waterways in the Commonwealth. IRRC Comments at 3. IRRC also notes that some commentators express concern whether the proposed rule would affect existing customer-generators and those currently under development. IRRC Comments at 4. IRRC further notes that some commentators express concerns about how the percentage is calculated for new construction and whether those with fluctuating electric usage face the potential for loss of customer-generator status. IRRC Comments at 6.

[2] See *Webster's Ninth New Collegiate Dictionary 1300* (1983).

[3] The Commission intends to review whether to maintain the 110 percent limit on third-party owned and operated systems contained in the Net Metering—Use of Third Party Operators, policy statement at Docket No. M-2011-2249441 after the completion of this rulemaking.

[4] 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."

In this Advance Notice of Final Rulemaking, we propose language to address each of these concerns raised by IRRC and various commentators. See Annex A. To begin with, we propose increasing the alternative energy size limit from 110 percent to 200 percent. This proposal will increase the number of systems that can qualify for net metering, while at the same time meeting the intent of the AEPS Act to exclude generation utilities and merchant generators from obtaining customer-generator status. The intent to exclude generation utilities and merchant generators from net metering is found in the definition of "customer-generator" contained in the AEPS Act. This definition specifically references customers in its title and states that a customer-generator is "a nonutility owner or operator of a net metered distributed generation system. . . ." 73 P. S. § 1648.2. There would be no reason to reference net metered systems as "customer"-generators or to further define a customer-generator as a nonutility if the intent was to permit generation utilities and merchant generators to net meter.

This limit is also consistent with how net metering is treated in other states.[5] In addition, we added language limiting the assessment as to whether the alternative energy system is sized to generate no more than 200 percent of the customer-generator's annual electric consumption to the date of the interconnection application. We reiterate that this is a design limit that is determined at the system installation stage. Customer-generators that meet this requirement and receive net metering will not lose net metering status if the generation from their alternative energy system exceeds 200 percent of the customer-generator's annual electric consumption in any subsequent year, provided that the alternative energy system's capacity was not increased subsequent to its initial approval.

In this proposal, we also added language directing how the customer-generator's annual electric consumption is to be determined for both existing and new service locations. Specifically, for existing service locations, the customer can use electric usage data from any 12 consecutive month period occurring within 60 months prior to submission of the interconnection request. For new service locations, the customer can use an annual electric consumption estimate based on the building type, size and anticipated usage or electric equipment and fixtures planned for the new service location. See Annex A.

Regarding concerns about the impact of this provision on existing customer-generators or those in development, we added language to clearly indicate the Commission's intent that it not be applied to existing customer-generators. In addition, the language provides an avenue for systems currently in development to be excluded from this provision, provided the customer-generator submits an interconnection application within 180 days of the date this provision becomes effective. See Annex A.

Finally, to address the concerns raised by DEP, PDA and the Chesapeake Bay Commission, we propose language excluding from this 200 percent limit those alternative energy systems where the DEP provides confirmation that the alternative energy system is used to comply with the DEP's Chesapeake Watershed Implementation Plan or is an integral element for compliance with the Nutrient Management Act. We recognize that these systems are only sized to handle the waste products that are the subject of the Chesapeake Watershed Implementation Plan and Nutrient Management Act.

[5] The Maryland Public Service Commission also limits customer-generators to 200 percent of the customer-generator's baseline annual usage. COMAR 20.50.10.01(D)(1)(b).

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*

In the proposed rulemaking, we proposed several changes to the provisions regarding virtual meter aggregation to clarify when it is available. We noted the history of the development of virtual meter aggregation to provide context and explain the intent of that provision. As further noted, since the Commission's regulations became effective, various parties have presented scenarios to the Commission for virtual metering that did 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.

The Commission is proposing language to clarify that the meter accounts to be aggregated must be held by the same person or entity. This clarifying language is to ensure consistency with the AEPS Act requirement that the meters to be virtually aggregated must be on properties owned or leased and operated by one customer-generator and must be located within a single EDC service territory. See Annex A.

2. *Year and Yearly*

In the proposed rulemaking, we noted that 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.[6] The Commission noted that in implementing these regulations over the last seven years, it had become clear that the vast majority of net metered customer-generator systems were solar photovoltaic systems. We recognized that these solar photovoltaic systems produce their peak outputs during the months of May through September. Accordingly, we suggested that 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 proposed 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. See Annex A.

As IRRC notes in its comments, some commentators point out that the proposed change would impose added costs on EDCs and may confuse some customers. After considering these comments, the Commission is now proposing to retain the current yearly period of June 1 through May 31.

[6] 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: § 75.17. Process for Obtaining Commission Approval of Customer-Generator Status.*

In the proposed rulemaking, we stated that 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 200 percent of annual load limit on the size of customer-generators, with some exceptions, we continue to propose a process for seeking Commission approval of all customer-generators with a nameplate capacity of 500 kilowatts or greater.

Under the process, as proposed in the proposed rulemaking, EDCs were to submit completed net metering applications 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 was to serve its recommendation on the applicant, who had 20 days to submit a response to the Bureau of Technical Utility Services. The Bureau of Technical Utility Services was required to 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 was to describe in detail its reasons for disapproval of an application. The applicant or the EDC was permitted to 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).

As IRRC notes in its comments, some commentators raise concerns whether this process will delay the development of an alternative energy system and whether this process will run concurrent with the review procedures related to interconnection standards. The Commission recognizes these concerns and is proposing changes that will shorten the review process, while maintaining the due process rights of the parties involved. Initially, we note that it was our intent that this process is to run concurrently with the interconnection review process in Subchapter C. Specifically, we shortened the time EDCs have to submit an application with its recommendation to the Bureau of Technical Utility Services (TUS) from 20 to 15 days. In addition, TUS now has 10 days, as opposed to 30 days, to review an EDC recommendation to approve a net metering application. Finally, for review of an EDC recommendation to deny a net metering application, TUS is to issue its determination within 30 days of receipt of the EDC's recommendation or within five days of receipt of an applicant's reply, whichever is earlier. See Annex A.

We note that under the original proposal, an applicant would have had to wait 70 days to receive the determination from TUS. Whereas, under the new proposal, an applicant will only have to wait 25 days for an application that an EDC recommends approving or no more than 40 days for an application that an EDC recommends denying. These time frames appropriately balance the rights of all interested parties while providing little or no delay in the development of new alternative energy systems by persons or entities seeking customer-generator status.

Conclusion

The Commission issues this advance notice of final rulemaking proposing 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 for comment; *Therefore*,

It Is Ordered That:

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

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

3. 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, the parties in the matter of *Larry Moyer v. PPL Electric Utilities Corp.*, at Docket No. C-2011-2273645, and all parties that filed comments at this Docket.

4. An original of written comments referencing the docket number of the proposed rulemaking shall be submitted within 20 days of publication in the *Pennsylvania Bulletin* to the Pennsylvania Public Utility Commission, Attn: Secretary, P. O. Box 3265, Harrisburg, PA 17105-3265.

5. The contact person for technical issues related to this rulemaking is Scott Gebhardt, Bureau of Technical Utility Services, (717) 425-2860. 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.

ROSEMARY CHIAVETTA,
Secretary

Statement of Commissioner James H. Cawley

Before us are updates and revisions to regulations to comply with Act 129 of 2008 and Act 35 of 2007, and certain clarifications regarding 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 the regulatory review process.

I wish to draw particular attention to the revisions related to the provision that would require all new alternative energy systems to be sized to generate no more than 200 percent of the customer-generator's annual electric consumption at the interconnection meter and all qualifying virtual meter aggregation locations.[7] Before now, the Commission did not set more restrictive size limitations on customer-generators, except in a policy statement permitting net metering of third-party owned and operated systems.[8] In our previous proposed rulemaking, we proposed 110 percent, consistent with that policy statement.

[7] Existing net metered installations are grandfathered. For existing service locations, the customer can use electric usage data from any 12 consecutive month period occurring within 60 months prior to submission of the interconnection request. For new service locations, the customer can use an annual electric consumption estimate based on the building type, size, and anticipated usage or electric equipment and fixtures planned for the new service location. The design limit is determined at the system installation stage. Customer-generators that meet this requirement and receive net metering will not lose net metering status if the generation from their alternative energy system exceeds 200 percent of the customer-generator's annual electric consumption in any subsequent year, provided that the alternative energy system's capacity was not increased subsequent to its initial approval.

[8] See Net Metering—Use of Third Party Operators, Final Order, Docket No. M-2011-2249441 (entered March 29, 2012).

Choosing between 110 and 200 percent appears to be largely driven by a review of the output of existing customer-generator systems. On the one hand, a higher percentage provides greater flexibility to early adopters of these distributed generation (DG) systems. Economies of scale, for example, could play a role in encouraging installation of such systems. Conversely, when and if DG systems become more commonplace, these early higher volume DG systems may crowd out future DG systems if local distribution system constraints either make future net-meter interconnect applications impossible or more costly to accommodate. In that instance, a high opportunity cost could be imposed on future DG customers. I welcome further comments on what the optimal solution is regarding this issue.

Secondly, many of these DG customer-generator systems are solar photovoltaic (PV) systems. PV and wind systems require an inverter to convert direct current (DC) from the generating resource to the voltage and frequency of the alternating current (AC) distribution system. Today's "smart inverters" have many capabilities, including:

• The delivery of DC power into an AC system, such as photovoltaic power to the AC grid; and the delivery of AC power to a DC load, as in charging a battery from the grid.

• The generation or absorption of reactive power so as to raise or lower the voltage at its terminals.

• Delivery of power in four quadrants, that is, positive real power and positive reactive power; positive real power and negative reactive power; negative real power and negative reactive power; and negative real power and positive reactive power.

• The detection of voltage and frequency at its terminals and the ability to react autonomously to mitigate abnormal conditions: to provide reactive power if the voltage is low; to increase real power output if the frequency is low.

• In combination with a communication link, to deliver real and reactive power and to charge and discharge storage facilities in accordance with signals from the utility.

Smart inverters can improve the performance of the distribution grid and the network as a whole, or, conversely, if improperly applied, can present serious problems in terms of voltage control, the clearing of short circuits, and the creation of dangerous "islanding" conditions. As greater numbers of renewable generating resources interconnect with the grid, the influence of the smart inverter will grow.

While the rulemaking before us does not address interconnect requirements related to smart inverters, I would encourage comment on the benefits and necessity of adopting further updates to our interconnect regulations that incorporate the capabilities of these new smart inverters. A discussion of benefits should address whether adopting new regulations related to smart meters inverters can enable more market penetration of DG systems, and what safety and operational benefits to the distribution grid can result from adoption of new future regulations.

JAMES H. CAWLEY,
Commissioner

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.

The following words and terms, when used in this chapter, have the following meanings unless the context clearly indicates otherwise:

Act—The Alternative Energy Portfolio Standards Act (73 P. S. §§ 1648.1—1648.8 **as amended by 66 Pa.C.S. § 2814**).

***Aggregator*—A person or entity that maintains a contract with multiple individual alternative energy system owners to facilitate the sale of alternative energy credits on behalf of multiple alternative energy system owners.**

Alternative energy credit—A tradable instrument that is used to establish, verify and monitor compliance with the act. A unit of credit must equal 1 megawatt hour of electricity from an alternative energy source. An alternative energy credit shall remain the property of the alternative energy system until the alternative energy credit is voluntarily transferred by the alternative energy system.

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 (FERC) licensed capacity of 21 MW or less and was issued its license by January 1, 1984, and was 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)] (I) Does not adversely change existing impacts to aquatic systems.

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

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

[(D)] (IV) Protects against erosion.

[(E)] (V) Protects cultural and historic resources.

(VI) Was completed after the effective date of the Alternative Energy Portfolio Standards Act.

(vi) Geothermal energy, which means electricity produced by extracting hot water or steam from geothermal reserves in the earth's crust and supplied to steam turbines that drive generators to produce electricity.

(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 in this Commonwealth.

(viii) Biologically derived methane gas, which includes methane from the anaerobic digestion of organic materials from yard waste, such as grass clippings and leaves, food waste, animal waste and sewage sludge. The term also includes landfill methane gas.

* * * * *

(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 MW**.

* * * * *

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) A contract for electric power, including energy and capacity, and the chosen EGS does not supply the service to a retail electric customer.

(ii) A retail electric customer does not choose an alternative EGS.

Department—The Department of Environmental Protection of the Commonwealth.

* * * * *

Force majeure—

* * * * *

(iv) If the Commission modifies the EDC or EGS obligations under the act, the Commission may require the EDC or EGS to acquire additional alternative energy credits in subsequent years equivalent to the obligation reduced by a force majeure declaration when the Commission determines that sufficient alternative energy credits exist in the marketplace.

***Grid emergencies*—An emergency condition as defined in the PJM Interconnection, LLC, open access transmission tariff or successor document.**

kW—Kilowatt—A unit of power representing 1,000 watts. A kW equals 1/1000 of a MW.

MW—Megawatt—A unit of power representing 1,000,000 watts. An MW equals 1,000 kWs.

***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 electric power systems.**

***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.**

Municipal solid waste—The term includes energy from existing waste to energy facilities which the Department has determined are in compliance with current environmental standards, including the applicable requirements of the Clean Air Act (42 U.S.C.A. §§ 7401—7671q) and associated permit restrictions and the applicable requirements of the Solid Waste Management Act (35 P. S. §§ 6018.101—6018.1003).

RTO—Regional transmission organization—An entity approved by the **[Federal Energy Regulatory Commission (FERC)] FERC** that is created to operate and manage the electrical transmission grids of the member electric transmission utilities as required under FERC Order 2000, Docket No. RM99-2-000, FERC Chapter 31.089 (1999) or any successor organization approved by the FERC.

* * * * *

Tier II alternative energy source—Energy derived from:

* * * * *

(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 this Commonwealth**.

(vii) Integrated combined coal gasification technology.

True-up period—The period each year from the end of the reporting year until September 1.

***Useful thermal energy*—**

(i) Thermal energy created from the production of electricity which would otherwise be wasted if not used for other nonelectric generation, beneficial purposes.

(ii) The term does 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. An owner or operator of an alternative energy system that is designed to produce no more than 200% of a customer-generator's annual electric consumption shall be exempt from the definition of a utility in this chapter.**

Subchapter B. NET METERING

§ 75.12. Definitions.

The following words and terms, when used in this subchapter, have the following meanings unless the context clearly indicates otherwise:

* * * * *

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] EDC's** service territory shall be eligible for net metering. **Service locations to be aggregated must be EDC service location accounts, held by the same individual or legal entity, 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 June 1 through May 31.**

§ 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 shall 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 200% of the customer-generator's annual electric consumption at the interconnection meter location when combined with all qualifying virtual meter aggregation locations as of the date of the interconnection application.

(i) For existing service location accounts, annual electric consumption shall be based on electric usage data from any 12 consecutive month period occurring within 60 months prior to submission of the customer-generator's interconnection request.

(ii) For new service location accounts, annual electric consumption shall be based on the building type, size and anticipated usage of electric equipment and fixtures planned for the new service location.

(iii) The 200% of the customer-generator's annual electric consumption limitation applies to any interconnection application for a new alternative energy system or expansion of an existing alternative energy system submitted on or after ________ . (*Editor's Note*: The blank refers to 180 days after the effective date of adoption of this proposed rulemaking.)

(iv) The 200% of the customer-generator's annual electric consumption limitation may not apply to alternative energy systems when the Department provides confirmation to the Commission that a customer-generator's alternative energy system is used to comply with the Department's Pennsylvania Chesapeake Watershed Implementation Plan in compliance with section 303 of the Federal Clean Water Act at 33 USC § 1313 or is an integral element for compliance with the Nutrient Management Act at 3 Pa.C.S. §§ 501, et seq.

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

(5) The alternative energy system must have a nameplate capacity not larger than 3 MW at other customer service locations, except when the alternative energy system has a nameplate capacity not larger than 5 MW and meets the conditions in § 75.16 (relating to large customer-generators).

(6) An alternative energy system with a nameplate capacity of 500 kW or more must have Commission approval to net meter in accordance with § 75.17 (relating to process for obtaining Commission approval of customer-generator status).

(b) EGSs may offer net metering to customer-generators, on a first come, first served 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) An EDC shall file a tariff with the Commission that provides for net metering consistent with this chapter. An EDC shall file a tariff providing net metering protocols that enable EGSs to offer net metering to customer-generators taking service from EGSs. To the extent that an EGS offers net metering service, the EGS shall prepare information about net metering consistent with this chapter and provide that information with the disclosure information required in § 54.5 (relating to disclosure statement for residential and small business customers).

[(c) The EDC] (d) 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 **[delivers] and DSP 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 **[over the amount of kilowatt hours delivered by the EDC during the same year] that were not previously credited against the customer-generator's usage in prior billing periods** at the **DSP's** price to compare **rate**. **In computing the compensation, the DSP shall use a weighted average of the price to compare rate with the weighting based on the rate in effect when the excess generation was actually delivered by the customer-generator to the DSP.**

[(e)] (f) The credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs shall be stated in the service agreement between the customer-generator and the EGS. **EDCs shall credit customer-generators who are EGS customers for each kilowatt-hour of electricity produced at the EDC's unbundled distribution kilowatt-hour 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. Distribution credits are not carried forward into the next year.**

[(f)] (g) If a customer-generator switches electricity suppliers, the EDC shall treat the end of the service period as if it were the end of the year.

[(g)] (h) An EDC and EGS which offer net metering shall submit an annual net metering report to the Commission. The report shall be submitted by July 30 of each year, and include the following information for the reporting period ending May 31 of that year:

(1) The total number of customer-generator facilities.

(2) The total estimated rated generating capacity of its net metering customer-generators.

[(h)] (i) A customer-generator that is eligible for net metering owns the alternative energy credits of the electricity it generates, unless there is a contract with an express provision that assigns ownership of the alternative energy credits to another entity or the customer-generator expressly rejects any ownership interest in alternative energy credits under § 75.14(d) (relating to meters and metering).

[(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) Nothing in this subchapter abrogates a person's obligation to comply with other applicable law.

§ 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 service locations to be aggregated must be EDC service location accounts held by the same individual or legal entity receiving retail electric service from the same EDC 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 MW and up to 5 MW. The section identifies the standards that distributed generation 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 the following requirements:

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

(2) 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 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 kW 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 this chapter and the EDC's net metering tariff provisions within 15 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 a response to the EDC's recommendation to reject an application to the Bureau of Technical Utility Services.

(d) The Bureau of Technical Utility Services will review the net metering application, the EDC recommendation and applicant response, and make a determination as to whether the alternative energy system complies with this chapter and the EDC's net metering tariff.

(e) The Bureau of Technical Utility Services will approve or disapprove the net metering application within 10 days of a submission recommending approval and describe in detail the reasons for disapproval. The Bureau of Technical Utility Services will approve or disapprove a net metering application within 5 days of an applicant's response to an EDC's recommendation to deny approval, but no more than 30 days after an EDC submits an application with a recommendation to deny approval, whichever is earlier. The Bureau of Technical Utility Services will 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 reconsideration from actions of the staff).

Subchapter C. INTERCONNECTION STANDARDS

GENERAL

§ 75.22. Definitions.

The following words and terms, when used in this subchapter, have the following meanings unless the context clearly indicates otherwise:

* * * * *

Electric nameplate capacity—The net maximum or net instantaneous peak electric output **[capability] capacity** measured in volt-amps of a small generator facility**, the inverter or the aggregated capacity of multiple inverters at an alternative energy systems location** as designated by the manufacturer.

* * * * *

INTERCONNECTION PROVISIONS

§ 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.

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§ 75.40. Level 4 interconnection review.

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

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

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

* * * * *

DISPUTE RESOLUTION

§ 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)] (c) 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.

* * * * *

(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 are identified in the following schedule**, subject to the quarterly adjustment of the nonsolar Tier I obligation under § 75.71 (relating to quarterly adjustment of nonsolar Tier I obligation)**:

* * * * *

§ 75.62. Alternative energy system qualification.

* * * * *

(f) A facility may not be qualified unless the Department has verified compliance with applicable environmental regulations, and the standards set forth in section 2 of the act (73 P. S. § 1648.2).

(g) A facility's alternative energy system status may be suspended or revoked for noncompliance with 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 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] kW** or less **that are installed or that increase nameplate capacity on or after ________ (*Editor's Note*: The blank refers to 180 days after the effective date of adoption of this proposed rulemaking.)**, alternative energy credit certification shall be verified by the administrator designated under § 75.64 **using metered data**. **For solar photovoltaic alternative energy systems with a nameplate capacity of 15 kW or less that are installed before ________ , (*Editor's Note*: The blank refers to 180 days after the effective date of adoption of this proposed rulemaking.) 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) A revenue grade meter has not 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-axis 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. An 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 will

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:

* * * * *

(5) The program administrator will provide written notice to applicants of its qualification decision within 30 days of receipt of a complete application form.

(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 noncompliance with this chapter, including the following circumstances:

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

(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 **the** 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] of its** 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 **(relating to EDC and EGS obligations)** 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] its** 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 must 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:

(1) The program administrator may not certify an alternative energy credit already purchased by individuals, businesses or government bodies that do not have a compliance obligation under the act unless the individual, business or government body sells those credits to the EDC or EGS.

(2) The program administrator may not certify an alternative energy credit for a MWh of electricity generation or electricity conservation that has already been used to satisfy another state's renewable energy portfolio standard, alternative energy portfolio standard or other comparable standard.

(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).

(e) A decision of the program administrator may be appealed consistent with § 5.44 (relating to petitions for **[appeal] reconsideration** from actions of the staff).

* * * * *

§ 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] 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] 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] 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] 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 nonsolar Tier I obligation.

(a) The Tier I nonsolar photovoltaic obligation of EDCs and EGSs shall be adjusted quarterly during the reporting period to comply with section 2814(c) of the act (relating to additional alternative energy sources).

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

(1) The nonsolar 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 = nonsolar pv Tier I % increase).

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

(3) An EDC's or EGS's quarterly MWh retail sales multiplied by the new quarterly nonsolar photooltaic Tier I requirement (EDC and EGS quarterly MWh x new quarterly nonsolar photovoltaic Tier I % = EDCs' and EGSs' quarterly nonsolar photooltaic 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 section 2814(a) and (b) of the act shall grant the program administrator access to their credit registry account information as a condition of certification of any alternative energy credits created under these sections.

§ 75.72. Reporting requirements for quarterly adjustment of nonsolar Tier I obligation.

(a) For purposes of implementing § 75.71 (relating to quarterly adjustment of nonsolar 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 § 75.71, all Tier I alternative energy systems qualified under section 2814(a) and (b) of the act (relating to additional alternative energy sources) 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. Each alternative energy credit and the entity they were transferred to must be listed.

(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).

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