CHAPTER 75. ALTERNATIVE ENERGY PORTFOLIO STANDARDS

Authority

The provisions of this Chapter 75 issued under section 501 of the Public Utility Code, 66 Pa.C.S. § 501; and section 5 of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. § 1648.5), unless otherwise noted.

Source

The provisions of this Chapter 75 adopted December 15, 2006, effective December 16, 2006, 36 Pa.B. 7574, unless otherwise noted.

Cross References

This chapter cited in 52 Pa. Code § 54.187 (relating to default service rate design and the recovery of reasonable costs).

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 (relating to additional alternative energy sources).

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:

(i) Solar photovoltaic or other solar electric energy.

(ii) Solar thermal energy.

(iii) Wind power.

(iv) Large-scale hydropower, which means the production of electric power by harnessing the hydroelectric potential of moving water impoundments, including pumped storage that does not meet the requirements of low-impact hydropower.

(v) Low-impact hydropower consisting of any technology that produces electric power and that harnesses the hydroelectric potential of moving water impoundments 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:

(I) Does not adversely change existing impacts to aquatic systems.

(II) Meets the certification standards established by the Low Impact Hydropower Institute and American Rivers, Inc., or their successors.

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

(IV) Protects against erosion.

(V) Protects cultural and historic resources.

(VI) Was completed after the effective date of the 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.

(ix) Fuel cells, which means any electrochemical device that converts chemical energy in a hydrogen-rich fuel directly into electricity, heat and water without combustion.

(x) Waste coal, which includes the combustion of waste coal in facilities in which the waste coal was disposed or abandoned prior to July 31, 1982, or disposed of thereafter in a permitted coal refuse disposal site regardless of when disposed of, and used to generate electricity, or other waste coal combustion meeting alternate eligibility requirements established by regulation. Facilities combusting waste coal shall use at a minimum a combined fluidized bed boiler and be outfitted with a limestone injection system and a fabric filter particulate removal system. Alternative energy credits shall be calculated based upon the proportion of waste coal utilized to produce electricity at the facility.

(xi) Coal mine methane, which means methane gas emitting from abandoned or working coal mines.

(xii) Demand-side management consisting of the management of customer consumption of electricity or the demand for electricity through the implementation of:

(A) Energy efficient technologies, management practices or other strategies in residential, commercial, industrial, institutional and government customers that shift electric load from periods of higher demand to periods of lower demand.

(B) Load management or demand response technologies, management practices or other strategies in residential, commercial, industrial, institutional and government customers that shift electric load from periods of higher demand to periods of lower demand.

(C) Industrial by-product technologies consisting of the use of a by-product from an industrial process, including reuse of energy from exhaust gases or other manufacturing by-products that are used in the direct production of electricity at the facility of a customer.

(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.

Alternative energy system—A facility or energy system that uses a form of alternative energy source to generate electricity and delivers the electricity it generates to the distribution system of an EDC or to the transmission system operated by a regional transmission organization.

Competitive transition charge—A nonbypassable charge applied to the bill of every customer accessing the transmission or distribution network which charge is designed to recover an electric utility's transition or stranded costs.

Cost recovery period—The longer of:

(i) The period during which competitive transition charges under 66 Pa.C.S. § 2808 (relating to competitive transition charge) or intangible transition charges under 66 Pa.C.S. § 2812 (relating to approval of transition bonds) are recovered.

(ii) The period during which an EDC operates under a Commission-approved generation rate plan that has been approved prior to or within 1 year of February 28, 2005, but the cost-recovery period under the act may not extend beyond December 31, 2010.

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.

EDC—Electric distribution company—The public utility providing facilities for the jurisdictional transmission and distribution of electricity to retail customers, except building or facility owners/operators that manage the internal distribution system serving the building or facility and that supply electric power and other related electric power services to occupants of the building or facility.

EGS—Electric generation supplier—

(i) A person or corporation, including municipal corporations which choose to provide service outside their municipal limits except to the extent provided prior to December 16, 2006, brokers and marketers, aggregators or any other entities, that sells to end-use customers electricity or related services utilizing the jurisdictional transmission and distribution facilities of an EDC or that purchases, brokers, arranges or markets electricity or related services for sale to end-use customers utilizing the jurisdictional transmission and distribution facilities of an EDC.

(ii) The term excludes building or facility owner/operators that manage the internal distribution system serving the building or facility and that supply electric power and other related power services to occupants of the building or facility.

(iii) The term excludes electric cooperative corporations except as provided in 15 Pa.C.S. Chapter 74 (relating to generation choice for customers of electric cooperatives).

Force majeure—

(i) Upon its own initiative or upon a request of an EDC or an EGS, the Commission, within 60 days, will determine if alternative energy resources are reasonably available in the marketplace in sufficient quantities for the EDCs and the EGSs to meet their obligations for that reporting period under the act. In making this determination, the Commission will consider whether EDCs or EGSs have made a good faith effort to acquire sufficient alternative energy to comply with their obligations. Evidence of good faith efforts include:

(A) Banking alternative energy credits during transition periods.

(B) Seeking alternative energy credits through competitive solicitations.

(C) Seeking to procure alternative energy credits or alternative energy through long-term contracts.

(D) Other competent evidence the commission credits as demonstrating a good faith effort.

(ii) In further making its determination, the Commission will assess the availability of alternative energy credits in the Generation Attributes Tracking System or its successor, and the availability of alternative energy credits generally in this Commonwealth and other jurisdictions in the PJM Interconnection, LLC regional transmission organization or its successor. The Commission may also require solicitations for alternative energy credits as part of default service before requests of force majeure may be made.

(iii) If the Commission determines that alternative energy resources are not reasonably available in sufficient quantities in the marketplace for the EDCs and EGSs to meet their obligations under the act, the Commission will modify the underlying obligation of the EDC or EGS or recommend to the General Assembly that the underlying obligation be eliminated. Commission modification of the EDC or EGS obligations under the act will be for that compliance period only. Commission modification may not automatically reduce the obligation for subsequent compliance years.

(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 energycredits 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 distribution system have DR and critical infrastructure load in a combination so as to give the EDC the ability to safely and intentionally disconnect that section of the distribution system from the rest of the distribution system and operate it as an island during emergency situations.

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 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.

Reporting period—The 12-month period from June 1 through May 31. A reporting year shall be numbered according to the calendar year in which it begins and ends.

Retail electric customer—

(i) A direct purchaser of electric power.

(ii) The term excludes an occupant of a building or facility where the following apply:

(A) The owners/operators manage the internal distribution system serving the building or facility and supply electric power and other related power services to occupants of the building or facility.

(B) The owners/operators are direct purchasers of electric power.

(C) The occupants are not direct purchasers.

Stranded costs—An electric utility's known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market and which the Commission determines will remain following mitigation by the electric utility.

Tier I alternative energy source—Energy derived from:

(i) Solar photovoltaic and solar thermal energy.

(ii) Wind power.

(iii) Low-impact hydropower.

(iv) Geothermal energy.

(v) Biologically derived methane gas.

(vi) Fuel cells.

(vii) Biomass energy.

(viii) Coal mine methane.

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 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—

(i) A business, person or entity whose primary purpose, character or nature is the generation, transmission, distribution or sale of electricity at wholesale or retail.

(ii) The term excludes building or facility owners or operators that manage the internal distribution system serving the building or facility and that supply electric power and other related power services to occupants of the building or facility.

Authority

The provisions of this § 75.1 amended 66 Pa.C.S. §§ 501, 1501 and 2807(e); and sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)).

Source

The provisions of this § 75.1 amended November 28, 2008, effective November 29, 2008, 38 Pa.B. 6473; amended November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448. Immediately preceding text appears at serial pages (340985) to (340986), (340013) to (340014) and (342487) to (342488).

Cross References

This section cited in 52 Pa. Code § 69.2103 (relating to definitions); and 52 Pa. Code § 75.66 (relating to force majeure).

Subchapter B. NET METERING

Sec.

§ 75.11. Scope.

This subchapter sets forth net metering requirements that apply to EGSs and EDCs which have customer-generators intending to pursue net metering opportunities in accordance with the act.

§ 75.12. Definitions.

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

Base year—For customer-generators who initiated self generation on or after January 1, 1999, the base year will be the immediate prior calendar year; for all other customer generators, the base year will be 1996.

Billing month—The term has the same meaning as set forth in § 56.2 (relating to definitions).

Customer-generator facility—The equipment used by a customer-generator to generate, manage, monitor and deliver electricity to the EDC.

Electric distribution system—That portion of an electric system which delivers electricity from transformation points on the transmission system to points of connection at a customer's premises.

Meter aggregation—The combination of readings from and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-generator for properties located within the service territory of a single EDC. Meter aggregation may be completed through physical or virtual meter aggregation.

Net metering—The means of measuring the difference between the electricity supplied by an electric utility or EGS and the electricity generated by a 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.

Physical meter aggregation—The physical rewiring of all meters regardless of rate class on properties owned or leased and operated by a customer-generator to provide a single point of contact for a single meter to measure electric service for that customer-generator.

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 the same customer-generator and located within 2 miles of the boundaries of the customer-generator's property and within a single 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*—The period of time from June 1 through May 31.

Authority

The provisions of this § 75.12 amended under 66 Pa.C.S. §§ 501, 1501 and 2807(e); and sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)).

Source

The provisions of this § 75.12 amended November 28, 2008, effective November 29, 2008, 38 Pa.B. 6473; amended November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448. Immediately preceding text appears at serial pages (340017) to (340018).

§ 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 have a nameplate capacity of not greater than 50 kW if installed at a residential service location.

(4) 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).

(5) 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.

(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 enables 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 under § 54.5 (relating to disclosure statement for residential and small business customers).

(d) An EDC and DSP shall credit a customer-generator at the full retail kilowatt-hour 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 supplies more electricity to the electric distribution system than the EDC 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 kilowatt-hour 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.

(e) At the end of each year, the 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 at the DSP's price to compare rate.

(f) The credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs must 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 kilowatt-hour rate credit shall be applied monthly against kilowatt-hour distribution usage. 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 kilowatt-hour distribution usage in subsequent billing periods until the end of the year when all remaining unused kilowatt-hour distribution credits shall be zeroed-out. Distribution credits are not carried forward into the next year.

(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.

(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.

(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).

(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.

(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.

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

Authority

The provisions of this § 75.13 amended under 66 Pa.C.S. §§ 501, 1501 and 2807(e); and sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)).

Source

The provisions of this § 75.13 amended November 28, 2008, effective November 29, 2008, 38 Pa.B. 6437; amended November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448. Immediately preceding text appears at serial pages (340018) to (340020).

§ 75.14. Meters and metering.

(a) A customer-generator facility used for net metering must be equipped with a single bidirectional meter that can measure and record the flow of electricity in both directions at the same rate. If the customer-generator agrees, a dual meter arrangement may be substituted for a single bidirectional meter.

(b) If the customer-generator's existing electric metering equipment does not meet the requirements in subsection (a), the EDC shall install new metering equipment for the customer-generator at the EDC's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator.

(c) When the customer-generator intends to take title or transfer title to any alternative energy credits which may be produced by the customer-generator's facility, the customer-generator shall bear the cost of additional net metering equipment required to qualify the alternative energy credits in accordance with the act.

(d) When the customer-generator expressly rejects ownership of alternative energy credits produced by the customer-generator's facility, the EDC may supply additional metering equipment required to qualify the alternative energy credit at the EDC's expense. In those circumstances, the EDC shall take title to any alternative energy credit produced. An EDC shall, prior to taking title to any alternative energy credits produced by a customer-generator, fully inform the customer-generator of the potential value of the alternative energy credits and other options available to the customer-generator for the disposition of those credits. A customer-generator is not prohibited from having a qualified meter service provider install metering equipment for the measurement of generation, or from selling alternative energy credits to a third party other than an EDC.

(e) Virtual meter aggregation on properties owned or leased and operated by 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.

Authority

The provisions of this § 75.13 amended under 66 Pa.C.S. §§ 501, 1501 and 2807(e); and sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)).

Source

The provisions of this § 75.14 amended November 28, 2008, effective November 29, 2008, 38 Pa.B. 6437; amended November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448. Immediately preceding text appears at serial pages (340020) and (342489).

Cross References

This section cited in 52 Pa. Code § 75.13 (relating to general provisions).

§ 75.15. Treatment of stranded costs.

If a net metering small commercial, commercial or industrial customer's self-generation results in a 10% or more reduction in the customer's purchase of electricity through the EDC's transmission and distribution network for an annualized period when compared to the prior annualized period, the net metering small commercial, commercial or industrial customer shall be responsible for its share of stranded costs to prevent interclass or intraclass cost shifting under 66 Pa.C.S. § 2808(a) (relating to competitive transition charge). The net metering small commercial, commercial or industrial customer's stranded cost obligation shall be calculated based upon the applicable ''base year'' as defined in this chapter.

§ 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.

Authority

The provisions of this § 75.16 issued under 66 Pa.C.S. §§ 501, 1501 and 2807(e); and sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)).

Source

The provisions of this § 75.16 adopted November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448.

Cross References

This section cited in 52 Pa. Code § 75.13 (relating to general provisions).

§ 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 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 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 an EDC's submission recommending approval. If disapproved, the Bureau of Technical Utility Services will describe in detail the reasons for disapproval. The Bureau of Technical Utility Services will serve its determination on the EDC and the applicant.

(f) The Bureau of Technical Utility Services will approve or disapprove the 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.

(g) 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).

Authority

The provisons of this § 75.17 issued under 66 Pa.C.S. §§ 501, 1501 and 2807(e); and sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)).

Source

The provisions of this § 75.17 adopted November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448.

Cross References

This section cited in 52 Pa. Code § 75.13 (relating to general provisions).

Subchapter C. INTERCONNECTION STANDARDS

GENERAL

INTERCONNECTION PROVISIONS

DISPUTE RESOLUTION

GENERAL

§ 75.21. Scope.

This subchapter sets forth the interconnection standards that apply to EDCs which have customer-generators intending to pursue net metering opportunities in accordance with the act.

Cross References

This section cited in 52 Pa. Code § 69.2101 (relating to statement of scope); 52 Pa. Code § 2102 (relating to statement of purpose); and 52 Pa. Code § 69.2104 (relating to interconnection application fees).

§ 75.22. Definitions.

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

Adverse system impact—A negative effect, due to technical or operational limits on conductors or equipment being exceeded, that compromises the safety and reliability of the electric distribution system.

Anti-islanding—The protective function which prevents electrical generating equipment from exporting electrical energy when connected to a de-energized electrical system.

Applicant—A person who has submitted an interconnection request to interconnect a small generator facility to an EDC's electric distribution system, also referred to as the interconnection customer.

Area network—

(i) A type of electric distribution system served by multiple transformers interconnected in an electrical network circuit, which is generally used in large metropolitan areas that are densely populated.

(ii) The term has the same meaning as the term ''distribution secondary grid network'' as stated in IEEE Standard 1547 Section 4.1.4 (published July 2003), as amended and supplemented.

Center tapped neutral transformer—A transformer with a tap in the middle of the secondary winding, usually used as a grounded neutral connection, intended to provide an option for the secondary side to use the full available voltage output or just half of it according to need.

Certificate of completion—A certificate in a form approved by the Commission containing information about the interconnection equipment to be used, its installation and local inspections.

Certified—A designation that the interconnection equipment to be used by a customer-generator complies with the following standards, as applicable:

(i) IEEE Standard 1547, ''Standard for Interconnecting Distributed Resources with Electric Power Systems,'' as amended and supplemented.

(ii) UL Standard 1741, ''Inverters, Converters and Controllers for use in Independent Power Systems'' (January 2001), as amended and supplemented.

Distribution upgrade—A required addition or modification to the EDC's electric distribution system at or beyond the point of interconnection. Distribution upgrades do not include interconnection facilities.

Draw-out type circuit breaker—A switching device capable of making, carrying and breaking currents under normal circuit conditions and also, making and carrying for a specified time and breaking currents under specified abnormal circuit conditions, such as those of a short circuit. A draw-out circuit breaker has two parts, the base, which is bolted and wired to the frame and the actual breaker, which slides into and electrically mates with the base. A draw-out circuit breaker can be physically removed from its enclosure creating a visible break in the circuit.

Electric distribution system—

(i) The facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries from interchanges with higher voltage transmission networks that transport bulk power over longer distances. The voltage levels at which electric distribution systems operate differ among areas but generally carry less than 69 kilovolts of electricity.

(ii) Electric distribution system has the same meaning as the term Area EPS, as defined in 3.1.6.1 of IEEE Standard 1547.

Electric nameplate capacity—The net maximum or net instantaneous peak electric output 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.

Equipment package—A group of components connecting an electric generator with an electric delivery system, and includes all interface equipment including switchgear, inverters or other interface devices. An equipment package may include an integrated generator or electric source.

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

IEEE standard 1547—The Institute of Electrical and Electronics Engineers, Inc. (IEEE) Standard 1547 (2003) ''Standard for Interconnecting Distributed Resources with Electric Power Systems,'' as amended and supplemented, at the time the interconnection request is submitted.

IEEE standard 1547.1—The IEEE Standard 1547.1 (2005) ''Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems,'' as amended and supplemented, at the time the interconnection request is submitted.

Interconnection customer—An entity that proposes to interconnect a small generator facility to an electric distribution system.

Interconnection equipment—A group of components or integrated system connecting an electric generator with an electric distribution system that includes all interface equipment including switchgear, protective devices, inverters or other interface devices. Interconnection equipment may be installed as part of an integrated equipment package that includes a generator or other electric source.

Interconnection facilities—Facilities and equipment required by the EDC to interconnect the small generator facility and the interconnection customer's interconnection equipment. Collectively, interconnection facilities include the facilities and equipment between the small generator facility and the point of common coupling, including any modification, additions that are necessary to physically and electrically interconnect the small generator facility to the EDC's electric distribution system. Interconnection facilities are sole use facilities and do not include electric distribution system upgrades.

Interconnection facilities study—A study conducted by the EDC or a third party consultant for the interconnection customer to determine a list of facilities (including EDC's interconnection facilities and required distribution upgrades to the electric distribution system as identified in the interconnection system impact study), the cost of those facilities, and the time required to interconnect the small generator facility with the EDC's electric distribution system.

Interconnection facilities study agreement—An agreement in a form approved by the Commission which details the terms and conditions under which an EDC will conduct an interconnection facilities study.

Interconnection feasibility study—A preliminary evaluation of the system impact and cost of interconnecting the small generator facility to the EDC's electric distribution system.

Interconnection feasibility study agreement—An agreement in a form approved by the Commission which details the terms and conditions under which an EDC will conduct an interconnection feasibility study.

Interconnection request—An interconnection customer's request, in a form approved by the Commission, requesting the interconnection of a new small generator facility, or to increase the capacity or operating characteristics of an existing small generator facility that is interconnected with the EDC's electric distribution system.

Interconnection study—Any of the following studies:

(i) The Interconnection Feasibility Study.

(ii) The Interconnection System Impact Study.

(iii) The Interconnection Facilities Study.

Interconnection system impact study—An engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of an EDC's electric distribution system.

Interconnection system impact study agreement—An agreement in a form approved by the Commission which details the terms and conditions under which an EDC will conduct an interconnection system impact study.

Line section—That portion of an EDC's distribution system connected to an interconnection customer, bounded by automatic sectionalizing devices or the end of the distribution line.

Minor equipment modification—Changes to the proposed small generator facility that do not have a material impact on safety or reliability of the electric distribution system.

NRTL—Nationally recognized testing laboratory—A qualified private organization that meets the requirements of the Occupational Safety and Health Administration's (OSHA) regulations. NRTLs perform independent safety testing and product certification. Each NRTL must meet the requirements as set forth by OSHA in the NRTL program.

Parallel operation-parallel—The state of operation which occurs when a small generator facility is connected electrically to the electric distribution system and the potential exists for electricity to flow from the small generator facility to the electric distribution system.

Point of common coupling—The point where the customer's interconnection equipment connects to the electric distribution system at which harmonic limits or other operational characteristics (IEEE Standard 1547 requirements) are applied.

Point of interconnection—The point where the interconnection equipment connects to the EDC's electric distribution system.

Queue position—The order of a valid interconnection request, relative to all other pending valid interconnection requests, that is established based upon the date and time of receipt of the valid interconnection request by the EDC.

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

SGIA—Standard small generator interconnection agreement—A set of standard forms of interconnection agreements approved by the Commission which is applicable to interconnection requests pertaining to a small generating facilities.

Scoping meeting—A meeting between representatives of the interconnection customer and EDC conducted for the purpose of discussing alternative interconnection options, exchanging information including any electric distribution system data and earlier study evaluations that would be reasonably expected to impact interconnection options, analyzing information, and determining the potential feasible points of interconnection.

Secondary line—A service line subsequent to the utility's primary distribution line, also referred to as the customer's service line.

Small generator facility—The equipment used by an interconnection customer to generate, or store electricity that operates in parallel with the electric distribution system. A small generator facility typically includes an electric generator, prime mover, and the interconnection equipment required to safely interconnect with the electric distribution system.

Spot network—The term has the same meaning as the term ''spot network'' under IEEE Standard 1547 Section 4.1.4, (published July 2003), as amended and supplemented. As of August, 2005, IEEE Standard 1547 defined ''Spot Network'' as ''a type of electric distribution system that uses two or more inter-tied transformers to supply an electrical network circuit.'' A spot network is generally used to supply power to a single customer or a small group of customers.

UL Standard 174—Underwriters Laboratories' standard titled ''Inverters Converters, and Controllers for Use in Independent Power Systems,'' as amended and supplemented.

Witness test—The EDC's interconnection installation evaluation required by IEEE Standard 1547 Section 5.3 and the EDC's witnessing of the commissioning test required by IEEE Standard 1547 Section 5.4. For interconnection equipment that has not been certified, the witness test shall also include the witnessing by the EDC of the onsite design tests as required by IEEE Standard1547 Section 5.1 and witnessing by the EDC of production tests required by IEEE Standard 1547 Section 5.2. Tests witnessed by the EDC are to be performed in accordance with IEEE Standard 1547.1.

Authority

The provisions of this § 75.22 amended under 66 Pa.C.S. §§ 501, 1501 and 2807(e); and sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)).

Source

The provisions of this § 75.22 amended November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448. Immediately preceding text appears at serial pages (342490), (324593) to (324594) and (342491) to (342492).

Cross References

This section cited in 52 Pa. Code § 69.2101 (relating to statement of scope); 52 Pa. Code § 69.2102 (relating to statement of purpose); and 52 Pa. Code § 69.2104 (relating to interconnection application fees).

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 5 MW.

(2) The small generator facility is not subject to the interconnection requirements of an RTO.

(3) The small generator facility is designed to operate in parallel with the electric distribution system.

Authority

The provisions of this § 75.31 amended under 66 Pa.C.S. §§ 501, 1501 and 2807(e); and sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)).

Source

The provisions of this § 75.31 amended November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448. Immediately preceding text appears at serial pages (342492) to (342493).

Cross References

This section cited in 52 Pa. Code § 69.2101 (relating to statement of scope); 52 Pa. Code § 69.2102 (relating to statement of purpose); and 52 Pa. Code § 69.2104 (relating to interconnection application fees).

§ 75.32. Interconnection requests.

Interconnection customers seeking to interconnect a small generator facility shall submit an interconnection request to the EDC that owns the electric distribution system to which interconnection is sought. EDCs shall establish processes for accepting interconnection requests electronically.

Cross References

This section cited in 52 Pa. Code § 69.2101 (relating to statement of scope); 52 Pa. Code § 69.2102 (relating to statement of purpose); and 52 Pa. Code § 69.2104 (relating to interconnection application fees).

§ 75.33. Fees and forms.

The Commission will determine the appropriate interconnection fees for Levels 1, 2, 3 and 4. In circumstances when standard forms are used for the interconnection process, examples of those forms shall be posted on the EDCs' websites.

Cross References

This section cited in 52 Pa. Code § 69.2101 (relating to statement of scope); 52 Pa. Code § 69.2102 (relating to statement of purpose); 52 Pa. Code § 69.2103 (relating to definitions); and 52 Pa. Code § 69.2104 (relating to interconnection application fees).

§ 75.34. Review procedures.

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

(1) An EDC shall use Level 1 procedures for evaluation of all interconnection requests to connect inverter-based small generation facilities when:

(i) The small generator facility has an electric nameplate capacity of 10 kW or less.

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

(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 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 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.

(4) Interconnection customers that do not qualify for Level 1 or Level 2 review and do not export power beyond the point of common coupling may request to be evaluated under Level 4 review procedures which provide for a potentially expedited review process.

Cross References

This section cited in 52 Pa. Code § 69.2101 (relating to statement of scope); 52 Pa. Code § 69.2102 (relating to statement of purpose); 52 Pa. Code § 69.2104 (relating to interconnection application fees); and 52 Pa. Code § 75.37 (relating to level 1 interconnection review); and 52 Pa. Code § 75.38 (relating to review procedures).

§ 75.35. Technical standards.

The technical standards to be used in evaluating all interconnection requests under Level 1, Level 2, Level 3 and Level 4 reviews, unless otherwise provided for in these procedures, are IEEE 1547 and U. L. 1741, as they may be amended and modified.

Cross References

This section cited in 52 Pa. Code § 69.2101 (relating to statement of policy); 52 Pa. Code § 69.2102 (relating to statement of purpose); and 52 Pa. Code § 69.2104 (relating to interconnection application fees).

§ 75.36. Additional general requirements.

Additional general requirements include:

(1) When an interconnection request is for a small generator facility that includes multiple energy production devices at a site for which the interconnection customer seeks a single point of interconnection, the interconnection request shall be evaluated on the basis of the aggregate electric nameplate capacity of multiple devices.

(2) When an interconnection request is for an increase in capacity for an existing small generator facility, the interconnection request shall be evaluated on the basis of the new total electric nameplate capacity of the small generator facility.

(3) An EDC shall maintain records of:

(i) The total interconnection requests received.

(ii) The number of days required to complete interconnection request approvals and disapprovals.

(iii) The number of interconnection requests denied or moved to another review level.

(iv) The justifications for the actions taken on the interconnection requests.

(v) The number of requests that were not processed within the timelines established in this subchapter.

(4) An EDC shall provide a report to the Commission containing the information required in paragraph (3) within 30 calendar days of the close of each annualized period. The EDC shall keep the records on file for a minimum of 3 years.

(5) Each EDC shall establish the specific mailing address and email address to which interconnection requests and questions shall be sent. These designated addresses shall be placed in the EDC's tariff and on its website. An EDC shall designate a contact person from whom information on the interconnection request and the EDC's electric distribution system can be obtained through informal requests regarding a proposed project. The information must include studies and other materials useful to an understanding of the feasibility of interconnecting a small generator facility at a particular point on the EDC's electric distribution system, except to the extent providing the materials would violate security requirements or confidentiality agreements, or be contrary to law or State or Federal regulations. In appropriate circumstances, the EDC may require confidentiality prior to release of this information.

(6) When an interconnection request is deemed complete, a modification other than a minor equipment modification that is not agreed to in writing by the EDC, shall require submission of a new interconnection request.

(7) When an interconnection customer is not currently a customer of the EDC, upon request from the EDC, the interconnection customer shall provide proof of site control evidenced by a property tax bill, deed, lease agreement or other legally binding contract.

(8) To minimize the costs to customer-generators, an EDC may propose to interconnect more than one small generator facility at a single point of interconnection when a customer-generator requests a single point of interconnection for multiple generation facilities, the EDC may not unreasonably refuse a request to do so. When an EDC proposes a single interconnection point for multiple generation facilities of a customer-generator, and the customer-generator elects not to accept and the EDC's proposal, the customer-generator shall pay the entire cost of a separate point of interconnection for each generation facility.

(9) Small generator facilities shall be capable of being isolated from the EDC by means of a lockable, visible-break isolation device accessible by the EDC. The isolation device shall be installed, owned and maintained by the owner of the small generation facility and located between the small generation facility and the point of interconnection. A draw-out type circuit breaker with a provision for padlocking at the draw-out position can be considered an isolation device for purposes of this requirement.

(10) An interconnection customer may elect to provide the EDC access to an isolation device that is contained in a building or area that may be unoccupied and locked or not otherwise readily accessible to the EDC, by installing a lockbox provided by the EDC that shall provide ready access to the isolation device. The interconnection customer shall install the lockbox in a location that is readily accessible by the EDC and the interconnection customer shall permit the EDC to affix a placard in a location of its choosing that provides clear instructions to EDC operating personnel on access to the isolation device.

Cross References

This section cited in 52 Pa. Code § 69.2102 (relating to statement of purpose); 52 Pa. Code § 69.2103 (relating to definitions); and 52 Pa. Code § 69.2104 (relating to interconnection application fees).

§ 75.37. Level 1 interconnection review.

(a) An EDC shall use the Level 1 interconnection review procedure for an interconnection request that meets the criteria in § 75.34(1) (relating to review procedures). An EDC may not impose additional requirements for Level 1 reviews not specifically authorized under this subchapter.

(b) The Level 1 screening criteria must consist of:

(1) For interconnection of a proposed small generator facility to a radial distribution circuit, the aggregated generation on the circuit, including the proposed small generator facility, may not exceed 15% of the line section annual peak load as most recently measured at the sub station.

(2) For interconnection of a proposed small generator facility to the load side of spot network protectors, the proposed small generator facility shall utilize an inverter-based equipment package. The customer interconnection equipment proposed for the small generator facility must be certified, and when aggregated with other generation, may not exceed 5% of the spot network's maximum load.

(3) When a proposed small generator facility is to be interconnected on a single-phase shared secondary line, the aggregate generation capacity on the shared secondary line, including the proposed small generator facility, may not exceed 20 kW.

(4) When a proposed small generator facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition may not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

(5) Construction of facilities by the EDC on its own system is not required to accommodate the small generator facility.

(c) The Level 1 interconnection review procedure must consist of:

(1) An EDC shall, within 10 business days after receipt of the interconnection request, inform the applicant that the interconnection request is complete or incomplete and what materials are missing.

(2) The EDC shall, within 15 business days after the end of the 10 business days noted in paragraph (1), verify that the small generator facility equipment can be interconnected safely and reliably using Level 1 screens. When an EDC does not have a record of receipt of the interconnection request, and the applicant can demonstrate that the original interconnection request was delivered, the EDC shall expedite its review to complete the evaluation of the interconnection request within 15 days of the applicant's resubmittal.

(3) Upon notice, within 10 business days after receipt of the certificate of completion, an EDC may conduct a witness test at a mutually convenient time. If the EDC does not conduct the witness test within 10 business days or within the time otherwise mutually agreed to by the parties, the witness test is deemed waived.

(4) Unless an EDC determines and demonstrates that a small generator facility cannot be interconnected safely and reliably, the EDC shall approve the interconnection request form subject to the following conditions:

(i) The small generator facility has been approved by local or municipal electric code officials with jurisdiction over the interconnection.

(ii) A certificate of completion has been returned to the EDC. Completion of local inspections may be designated on inspection forms used by local inspecting authorities.

(iii) The witness test has been successfully completed or waived.

(iv) The interconnection customer has signed a standard small generator interconnection agreement. When an interconnection customer does not sign the agreement within 30 business days after receipt from the EDC, the interconnection request will be deemed withdrawn unless the interconnection customer requests to have the deadline extended. The request for extension may not be unreasonably denied by the EDC.

(5) When a small generator facility is not approved under a Level 1 review, the interconnection customer may submit a new interconnection request for consideration under Level 2, Level 3 or Level 4 procedures specified in this chapter without sacrificing the applicant's original queue position.

Cross References

This section cited in 52 Pa. Code § 69.2101 (relating to statement of scope); 52 Pa. Code § 69.2102 (relating to statement of purpose); 52 Pa. Code § 69.2103 (relating to definitions); and 52 Pa. Code § 69.2104 (relating to interconnection application fees).

§ 75.38. Level 2 interconnection review.

(a) An EDC shall use the Level 2 interconnection review procedure for an interconnection request that meets the criteria in § 75.34(2) (relating to review procedures). An EDC may not impose additional requirements for Level 2 reviews not specifically authorized under this subchapter.

(b) The Level 2 screening criteria must consist of:

(1) For interconnection of a proposed small generator facility to a radial distribution circuit, the aggregated generation on the circuit, including the proposed small generator facility, may not exceed 15% of the line section annual peak load.

(2) For interconnection of a proposed small generator facility to the load side of spot network protectors, the proposed small generator facility shall utilize an inverter-based equipment package. The customer interconnection equipment proposed for the small generator facility must be certified and, when aggregated with other generation, may not exceed 5% of a spot network's maximum load.

(3) The proposed small generator facility, in aggregation with other generation on the distribution circuit, may not contribute more than 10 % to the distribution circuit's maximum fault current at the point on the primary voltage distribution line nearest the point of common coupling.

(4) The proposed small generator facility, in aggregate with other generation on the distribution circuit, may not cause any distribution protective devices and equipment (including substation breakers, fuse cutouts, and line reclosers), or other customer equipment on the electric distribution system to be exposed to fault currents exceeding 85% of the short circuit interrupting capability. The interconnection request may not request interconnection on a circuit that already exceeds 85% of the short circuit interrupting capability.

(5) The proposed small generator facility's point of interconnection may not be on a transmission line.

(6) When a customer-generator facility is to be connected to 3 phase, 3 wire primary EDC distribution lines, a 3 phase or single-phase generator shall be connected phase-to-phase.

(7) When a customer-generator facility is to be connected to 3 phase, 4 wire primary EDC distribution lines, a 3 phase or single phase generator will be connected line-to-neutral and will be effectively grounded.

(8) This Level 2 screen includes a review of the type of electrical service provided to the interconnection customer, including line configuration and the transformer connection to limit the potential for creating over voltages on the

EDC's electric distribution system due to a loss of ground during the operating time of any anti-islanding function.

(9) When the proposed small generator facility is to be interconnected on single-phase shared secondary line, the aggregate generation capacity on the shared secondary line, including the proposed small generator facility, will not exceed 20 kW.

(10) When a proposed small generator facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition may not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

(11) A small generator facility, in aggregate with other generation interconnected to the distribution side of a substation transformer feeding the circuit where the small generator facility proposes to interconnect, may not exceed 2 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity (for example, three or four distribution busses from the point of interconnection).

(12) Except as permitted by an additional review under the standard small generator interconnection agreement, no construction of facilities by an EDC on its own system will be required to accommodate the small generator facility.

(c) The Level 2 interconnection procedure must consist of the following:

(1) An EDC shall, within 10 business days after receipt of the interconnection request, inform the applicant that the interconnection request is complete or incomplete and what materials are missing.

(2) When an EDC determines additional information is required to complete an evaluation, the EDC shall request the information. The time necessary to complete the evaluation may be extended, but only to the extent of the delay required for receipt of the additional information. The EDC may not revert to the start of the review process or alter the interconnection customer's queue position.

(3) When an interconnection request is complete, the EDC shall assign a queue position. The queue position of the interconnection request shall be used to determine the potential adverse system impact of the small generator facility based on the relevant screening criteria. The EDC shall schedule a scoping meeting to notify the interconnection customer about other higher-queued interconnection customers on the same substation bus or spot network for which interconnection is sought.

(4) Within 20 business days after the EDC notifies the interconnection customer it has received a completed interconnection request, the EDC shall:

(i) Evaluate the interconnection request using the Level 2 screening criteria.

(ii) Review the interconnection customer's analysis, if provided by interconnection customer, using the same criteria.

(iii) Provide the interconnection customer with the EDC's evaluation, including a comparison of the results of its own analyses with those of interconnection customer, if applicable. When an EDC does not have a record of receipt of the interconnection request and the applicant can demonstrate that the original interconnection request was delivered, the EDC shall expedite its review to complete the evaluation of the interconnection request within 20 business days of the applicant's resubmittal.

(5) Upon notice within 10 business days after receipt of the certificate of completion, the EDC may conduct a witness test at a mutually convenient time. If the EDC does not conduct the witness test within 10 business days or within the time otherwise mutually agreed to by the parties, the witness test is deemed waived.

(d) When an EDC determines that the interconnection request passes the Level 2 screening criteria, or fails one or more of the Level 2 screening criteria but determines that the small generator facility can be interconnected safely and reliably, it shall provide the interconnection customer a standard small generator interconnection agreement within 5 business days after the determination.

(e) Additional review may be appropriate when a small generator facility has failed to meet one or more of the Level 2 screens. An EDC shall offer to perform additional review to determine whether minor modifications to the electric distribution system would enable the interconnection to be made consistent with safety, reliability and power quality criteria. The EDC shall provide the applicant with a nonbinding, good faith estimate of the costs of additional review and minor modifications. The EDC shall undertake the additional review or modifications only after the applicant consents to pay for the review and modifications.

(f) An interconnection customer shall have 30 business days or another mutually agreeable time frame after receipt of the standard small generator interconnection agreement to sign and return the agreement. When an interconnection customer does not sign the agreement within 30 business days, the interconnection request will be deemed withdrawn unless the interconnection customer requests to have the deadline extended. The request for extension may not be unreasonably denied by the EDC. When construction is required, the interconnection of the small generator facility will proceed according to any milestones agreed to by the parties in the standard small generator interconnection agreement. The interconnection agreement may not become final until:

(1) The milestones agreed to in the standard small generator interconnection agreement are satisfied.

(2) The small generator facility is approved by electric code officials with jurisdiction over the interconnection.

(3) The interconnection customer provides a certificate of completion to the EDC. Completion of local inspections may be designated on inspection forms used by local inspecting authorities.

(4) There is a successful completion of the witness test, unless waived.

(g) If the small generator facility is not approved under a Level 2 review, the interconnection customer may submit a new interconnection request for consideration under a Level 3 or Level 4 interconnection review; however, the queue position assigned to the Level 2 interconnection request shall be retained.

Cross References

This section cited in 52 Pa. Code § 69.2101 (relating to statement of scope); 52 Pa. Code § 69.2102 (relating to statement of purpose); 52 Pa. Code § 69.2103 (relating to definitions); and 52 Pa. Code § 69.2104 (relating to interconnection application fees).

§ 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 5 MW or less.

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

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

(b) The Level 3 interconnection review process shall consist of the following:

(1) By mutual agreement of the parties, the scoping meeting, interconnection feasibility study, interconnection impact study or interconnection facilities studies under Level 3 procedures may be waived.

(2) Within 10 business days from receipt of an interconnection request, the EDC shall notify the interconnection customer whether the request is complete. When the interconnection request is not complete, the EDC shall provide the interconnection customer a written list detailing information that shall be provided to complete the interconnection request. The interconnection customer shall have 10 business days to provide appropriate data to complete the interconnection request or the interconnection request will be considered withdrawn. The parties may agree to extend the time for receipt of the additional information. The interconnection request shall be deemed complete when the required information has been provided by the interconnection customer, or the parties have agreed that the interconnection customer may provide additional information at a later time.

(3) When an interconnection request is complete, the EDC shall assign a queue position. The queue position of an interconnection request shall be used to determine the cost responsibility necessary for the facilities to accommodate the interconnection. The EDC shall notify the interconnection customer at the scoping meeting about other higher-queued interconnection customers.

(4) A scoping meeting will be held within 10 business days, or as agreed to by the parties, after the EDC has notified the interconnection customer that the interconnection request is deemed complete, or the interconnection customer has requested that its interconnection request proceed after failing the requirements of a Level 2 review or Level 4 review. The purpose of the meeting must be to review the interconnection request, existing studies relevant to the interconnection request, and the results of the Level 1, Level 2 or Level 4 screening criteria.

(5) When the parties agree at a scoping meeting that an interconnection feasibility study shall be performed, the EDC shall provide to the interconnection customer, no later than 5 business days after the scoping meeting, an interconnection feasibility study agreement, including an outline of the scope of the study and a nonbinding good faith estimate of the cost to perform the study.

(6) When the parties agree at a scoping meeting that an interconnection feasibility study is not required, the EDC shall provide to the interconnection customer, no later than 5 business days after the scoping meeting, an interconnection system impact study agreement, including an outline of the scope of the study and a nonbinding good faith estimate of the cost to perform the study.

(7) When the parties agree at the scoping meeting that an interconnection feasibility study and system impact study are not required, the EDC shall provide to the interconnection customer, no later than 5 business days after the

scoping meeting, an interconnection facilities study agreement including an outline of the scope of the study and a nonbinding good faith estimate of the cost to perform the study.

(c) An interconnection feasibility study must include the following analyses for the purpose of identifying a potential adverse system impact to the EDC's electric distribution system that would result from the interconnection:

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

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

(3) Initial review of grounding requirements and system protection.

(4) Description and nonbinding estimated cost of facilities required to interconnect the small generator facility to the EDC's electric distribution system in a safe and reliable manner.

(5) When an interconnection customer requests that the interconnection feasibility study evaluate multiple potential points of interconnection, additional evaluations may be required. Additional evaluations shall be paid by the interconnection customer.

(6) An interconnection system impact study is not required when the interconnection feasibility study concludes there is no adverse system impact, or when the study identifies an adverse system impact, but the EDC is able to identify a remedy without the need for an interconnection system impact study.

(7) The parties shall use a form of interconnection feasibility study agreement approved by the Commission.

(d) An interconnection system impact study must evaluate the impact of the proposed interconnection on the safety and reliability of the EDC's electric distribution system. The study must identify and detail the system impacts that result when a small generator facility is interconnected without project or system modifications, focusing on the adverse system impacts identified in the interconnection feasibility study; or potential impacts including those identified in the scoping meeting. The study must consider all generating facilities that, on the date the interconnection system impact study is commenced, are directly interconnected with the EDC's system, have a pending higher queue position to interconnect to the system, or have a signed interconnection agreement.

(1) An interconnection system impact study must:

(i) Consider the following criteria:

(A) A short circuit analysis.

(B) A stability analysis.

(C) Voltage drop and flicker studies.

(D) Protection and set point coordination studies.

(E) Grounding reviews.

(ii) State the underlying assumptions of the study.

(iii) Show the results of the analyses.

(iv) List any potential impediments to providing the requested interconnection service.

(v) Indicate required distribution upgrades and provide a nonbinding good faith estimate of cost and time to construct the upgrades.

(2) A distribution interconnection system impact study shall be performed when a potential distribution system adverse system impact is identified in the interconnection feasibility study. The EDC shall send the interconnection customer an interconnection system impact study agreement within 5 business

days of transmittal of the interconnection feasibility study report. The agreement will include an outline of the scope of the study and a good faith estimate of the cost to perform the study. The study must include:

(i) A load flow study.

(ii) An analysis of equipment interrupting ratings.

(iii) A protection coordination study.

(iv) Voltage drop and flicker studies.

(v) Protection and set point coordination studies.

(vi) Grounding reviews.

(vii) Impact on system operation.

(3) The parties shall use an interconnection impact study agreement or a distribution interconnection impact study as approved by the Commission.

(e) The interconnection facilities study shall be conducted as follows:

(1) Within 5 business days of completion of the interconnection system impact study, a report will be transmitted to the interconnection customer with an interconnection facilities study agreement, which includes an outline of the scope of the study and a nonbinding good faith estimate of the cost to perform the study.

(2) The interconnection facilities study shall estimate the cost of the equipment, engineering, procurement and construction work, including overheads, needed to implement the conclusions of the interconnection feasibility study and the interconnection system impact study to interconnect the small generator facility. The interconnection facilities study must identify:

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

(ii) The nature and estimated cost of the EDC's interconnection facilities and distribution upgrades necessary to accomplish the interconnection.

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

(3) The parties may agree to permit an interconnection customer to separately arrange for a third party to design and construct the required interconnection facilities. The EDC may review the design of the facilities under the interconnection facilities study agreement. When the parties agree to separately arrange for design and construction, and to comply with security and confidentiality requirements, the EDC shall make all relevant information and required specifications available to the interconnection customer to permit the interconnection customer to obtain an independent design and cost estimate for the facilities, which must be built in accordance with the specifications.

(4) Upon completion of the interconnection facilities study, and with the agreement of the interconnection customer to pay for the interconnection facilities and distribution upgrades identified in the interconnection facilities study, the EDC shall provide the interconnection customer with a standard small generator interconnection agreement within 5 business days.

(5) The parties shall use an interconnection facility study agreement approved by the Commission.

(f) When an EDC determines, as a result of the studies conducted under Level 3 review, that it is appropriate to interconnect the small generator facility, the EDC shall provide the interconnection customer with a standard small generator interconnection agreement. If the interconnection request is denied, the EDC shall provide a written explanation.

(g) Upon providing notice within 10 business days after receipt of the certificate of completion, the EDC may conduct a witness test at a mutually convenient time. If the EDC does not conduct the witness test within 10 business days, or within the time otherwise mutually agreed to by the parties, the witness test is deemed waived.

(h) An interconnection customer shall have 30 business days, or another mutually agreeable time frame after receipt of the standard small generator interconnection agreement to sign and return the agreement. When an interconnection customer does not sign the agreement within 30 business days, the interconnection request will be deemed withdrawn unless the interconnection customer requests to have the deadline extended. The request for extension may not be unreasonably denied by the EDC. When construction is required, the interconnection of the small generator facility shall proceed according to milestones agreed to by the parties in the standard small generator interconnection agreement. The interconnection agreement may not be final until:

(1) The milestones agreed to in the standard small generator interconnection agreement are satisfied.

(2) The small generator facility is approved by electric code officials with jurisdiction over the interconnection.

(3) The interconnection customer provides a certificate of completion to the EDC. Completion of local inspections may be designated on inspection forms used by local inspecting authorities.

(4) There is a successful completion of the witness test, unless waived.

Authority

The provisions of this § 75.39 amended under 66 Pa.C.S. §§ 501, 1501 and 2807(e); and sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)).

Source

The provisions of this § 75.39 amended November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448. Immediately preceding text appears at serial pages (342501) to (342505).

Cross References

This section cited in 52 Pa. Code § 69.2101 (relating to statement of scope); 52 Pa. Code § 69.2102 (relating to statement of purpose); 52 Pa. Code § 69.2103 (relting to definitions); and 52 Pa. Code § 69.2104 (relating to interconnection application fees).

§ 75.40. Level 4 interconnection review.

(a) Interconnection customers desiring to interconnect a small generator facility that does not qualify for a Level 1 or Level 2 review may request to be evaluated under Level 4 procedures.

(b) When an interconnection request is complete, the EDC shall assign a queue position. The queue position of each interconnection request will be used to determine the potential adverse system impact of the small generator facility based on the relevant screening criteria. The EDC shall schedule a scoping meeting to notify the interconnection customer about other higher-queued interconnection customers on the same substation bus or area network to which the interconnection customer seeks interconnection.

(c) When an interconnection customer submits an interconnection request to be interconnected to the load side of an area network, the EDC, notwithstanding any conflicting requirements in IEEE Standard 1547, shall use the following procedures:

(1) When a small generator facility is less than or equal to 10 kW, the EDC shall use the review procedures for a Level 4 review, when the small generator facility meets the following criteria:

(i) The electric nameplate capacity of the small generator facility is equal to or less than 10 kW.

(ii) The proposed small generator facility utilizes a certified inverter-based equipment package for interconnection.

(iii) The customer-generator installs reverse power relays or other protection functions, or both, that prevent power flow beyond the point of interconnection.

(iv) The aggregated other generation on the area network does not exceed 5% of an area network's maximum load.

(2) Construction of facilities by the EDC on its own system is not required to accommodate the small generator facility.

(3) The proposed small generator facility meeting the criteria under paragraph (1) shall be presumed appropriate for interconnecting to an area network and shall be further evaluated by the EDC based on the following procedures:

(i) The EDC shall evaluate an interconnection request under Level 1 interconnection review procedures. The EDC shall have 20 business days to conduct an area network impact study to determine potential adverse impacts of interconnecting to the EDC's area network.

(ii) When an area network impact study identifies potential adverse system impacts, the EDC may determine that it is inappropriate for the small generator facility to interconnect to the area network and the interconnection request shall be denied. The interconnection customer may elect to submit a new interconnection request for consideration under Level 3 procedures. The queue position assigned to the Level 4 interconnection request shall be retained.

(iii) An EDC shall conduct the area network impact study at its own expense.

(4) When an EDC denies an interconnection request, the EDC shall provide the interconnection customer with a copy of the area network impact study and a written justification for denying the interconnection request.

(5) When a small generator facility is greater than 10 kW and equal to or less than 50 kW, an EDC shall use the review procedures set forth for a Level 4 application to interconnect a small generator facility that meets the following criteria:

(i) The electric nameplate capacity of the small generator facility is greater than 10 kW and equal to or less than 50 kW.

(ii) The proposed small generator facility utilizes a certified inverter-based equipment package for interconnection.

(iii) The customer-generator installs reverse power relays or other protection functions that prevent power flow beyond the point of interconnection.

(iv) The aggregated other generation on the area network does not exceed 5% of an area network's maximum load.

(6) Construction of facilities by the EDC on its own system is not required to accommodate the small generator facility.

(7) The proposed small generator facility meeting the criteria under paragraph (5) shall be presumed to be appropriate for interconnecting to an area network and shall be further evaluated by an EDC using the following procedures:

(i) An EDC shall evaluate the interconnection request under Level 2 interconnection review procedures. The EDC shall have 25 calendar days to conduct an area network impact study to determine any potential adverse impacts of interconnecting to the EDC's area network.

(ii) When an area network impact study identifies potential adverse system impacts, an EDC may determine that it is inappropriate for the small generator facility to interconnect to the area network and the interconnection request shall be denied. The interconnection customer may elect to submit a new interconnection request for consideration under Level 3 procedures. The queue position assigned to the Level 4 interconnection request shall be retained.

(iii) An EDC shall conduct the area network impact study at its own expense.

(iv) When an EDC denies an interconnection request, the EDC shall provide the interconnection customer with a copy of its area network impact study and a written justification for denying the interconnection request.

(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 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 5 MW or less.

(3) The small generator facility uses reverse power relays or other protection functions that prevent power flow onto the utility grid.

(4) The small generator facility will be interconnected with a radial distribution circuit.

(5) The small generator facility is not served by a shared transformer.

(6) Construction of facilities by the EDC on its own system is not required to accommodate the small generator facility.

(e) When a small generator facility meets the criteria under subsection (d), an EDC shall interconnect under the Level 4 review if it meets the following requirements:

(1) A proposed small generator facility, in aggregation with other generation on the distribution circuit, may not contribute more than 10% to the distribution circuit's maximum fault current at the point on the primary voltage distribution line nearest the point of common coupling.

(2) The aggregate generation capacity on the distribution circuit to which the small generator facility shall interconnect, including its capacity, may not cause any distribution protective equipment, or customer equipment on the distribution system, to exceed 85% of the short-circuit interrupting capability of the equipment. A small generator facility may not be connected to a circuit that already exceeds 85% of the short circuit interrupting capability.

(3) When there are known or posted transient stability limits to generating units located in the general electrical vicinity of the proposed point of common coupling, the proposed customer-generator shall be subject to a Level 3 review.

(4) When a customer-generator facility is to be connected to 3-phase, 3 wire primary EDC distribution lines, a 3-phase or single-phase generator shall be connected phase-to-phase. When a customer-generator facility is to be connected to 3-phase, 4 wire primary EDC distribution lines, a 3-phase or single phase generator shall be connected line-to-neutral and shall be effectively grounded. This review must include examination of the type of electrical service provided to the interconnection customer, including line configuration and the transformer connection, to limit the potential for over voltages on the EDC's electric distribution system due to a loss of ground during the operating time of any anti-islanding function.

(f) When a small generator facility fails to meet the criteria under subsection (e), an EDC shall use the Level 3 interconnection procedures. The queue position assigned to the Level 4 interconnection request shall be retained.

(g) When a small generator facility satisfies the criteria under subsection (e), an EDC may, upon providing reasonable notice, within 10 business days after receipt of the Certificate of Completion, conduct a witness test at a mutually convenient time. If the EDC does not conduct the witness test within 10 business days or within the time otherwise mutually agreed to by the parties, the witness test is deemed waived.

(h) When a small generator facility satisfies the criteria for a Level 4 Interconnection, an EDC shall approve the interconnection request and provide a standard interconnection agreement to the interconnection customer for signature.

(i) The interconnection customer shall have 30 business days, or another mutually agreeable time frame after receipt of the standard small generator interconnection agreement to sign and return the agreement. If the interconnection customer does not sign the agreement within 30 business days, the interconnection request shall be deemed withdrawn unless the parties mutually agree to extend the time period for executing the agreement. After the agreement is signed by the parties, interconnection of the small generator facility will proceed according to milestones agreed to by the parties in the agreement. The agreement may not be final until:

(1) The milestones agreed to in the standard small generator interconnection agreement are satisfied.

(2) The small generator facility is approved by electric code officials with jurisdiction over the interconnection.

(3) The interconnection customer provides a certificate of completion to the EDC. Completion of local inspections may be designated on inspection forms used by local inspecting authorities.

(4) There is a successful completion of the witness test, unless waived.

Authority

The provisions of this § 75.40 amended under 66 Pa.C.S. §§ 501, 1501 and 2807(e); and sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)).

Source

The provisions of this § 75.40 amended November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448. Immediately preceding text appears at serial pages (342505) to (342509).

Cross References

This section cited in 52 Pa. Code § 69.2101 (relating to statement of scope); 52 Pa. Code § 69.2102 (relating to statement of purpose); 52 Pa. Code § 69.2103 (relating to definitions); and 52 Pa. Code § 69.2104 (relating to interconnection application fees).

DISPUTE RESOLUTION

§ 75.51. Disputes.

(a) A party shall attempt to resolve all disputes regarding interconnection as provided in this chapter promptly, equitably and in a good faith manner.

(b) When a dispute arises, a party may seek immediate resolution through complaint procedures available through the Commission, or an alternative dispute resolution process approved by the Commission, by providing written notice to the Commission and the other party stating the issues in dispute. Dispute resolution will be conducted in an informal, expeditious manner to reach resolution with minimal costs and delay. When available, dispute resolution may be conducted by phone.

(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.

Authority

The provisions of this § 75.51 amended under 66 Pa.C.S. §§ 501, 1501 and 2807(e); and sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)).

Source

The provisions of this § 75.51 amended November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448. Immediately preceding text appears at serial pages (342509) to (342510).

Cross References

This section cited in 52 Pa. Code § 69.2101 (relating to statement of scope); 52 Pa. Code § 69.2102 (relating to statement of purpose); and 52 Pa. Code § 69.2104 (relating to interconnection application fees).

Subchapter D. ALTERNATIVE ENERGY PORTFOLIO REQUIREMENT

Sec.

Source

The provisions of this Subchapter D adopted December 19, 2008, effective December 20, 2008, 38 Pa.B. 6908, unless otherwise noted.

§ 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 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):

(1) For June 1, 2006, through May 31, 2007: The Tier I requirement is 1.5% of all retail sales, of which at least 0.0013% of all retail sales are to come from solar photovoltaic sources and the remaining from nonsolar photovoltaic Tier I sources, and the Tier II requirement is 4.2% of all retail sales.

(2) For June 1, 2007, through May 31, 2008: The Tier I requirement is 1.5% of all retail sales, of which at least 0.0030% of all retail sales are to come from solar photovoltaic sources and the remaining from nonsolar photovoltaic Tier I sources, and the Tier II requirement is 4.2% of all retail sales.

(3) For June 1, 2008, through May 31, 2009: The Tier I requirement is 2% of all retail sales, of which at least 0.0063% of all retail sales are to come from solar photovoltaic sources and the remaining from nonsolar photovoltaic Tier I sources, and the Tier II requirement is 4.2% of all retail sales.

(4) For June 1, 2009, through May 31, 2010: The Tier I requirement is 2.5% of all retail sales, of which at least 0.0120% of all retail sales are to come from solar photovoltaic sources and the remaining from nonsolar photovoltaic Tier I sources, and the Tier II requirement is 4.2% of all retail sales.

(5) For June 1, 2010, through May 31, 2011: The Tier I requirement is 3% of all retail sales, of which at least 0.0203% of all retail sales are to come from solar photovoltaic sources and the remaining from nonsolar photovoltaic Tier I sources, and the Tier II requirement is 6.2% of all retail sales.

(6) For June 1, 2011, through May 31, 2012: The Tier I requirement is 3.5% of all retail sales, of which at least 0.0325% of all retail sales are to come from solar photovoltaic sources and the remaining from nonsolar photovoltaic Tier I sources, and the Tier II requirement is 6.2% of all retail sales.

(7) For June 1, 2012, through May 31, 2013: The Tier I requirement is 4% of all retail sales, of which at least 0.0510% of all retail sales are to come from solar photovoltaic sources and the rest from nonsolar photovoltaic Tier I sources, and the Tier II requirement is 6.2% of all retail sales.

(8) For June 1, 2013, through May 31, 2014: The Tier I requirement is 4.5% of all retail sales, of which at least 0.0840% of all retail sales are to come from solar photovoltaic sources and the remaining from nonsolar photovoltaic Tier I sources, and the Tier II requirement is 6.2% of all retail sales.

(9) For June 1, 2014, through May 31, 2015: The Tier I requirement is 5% of all retail sales, of which at least 0.1440% of all retail sales are to come from solar photovoltaic sources and the rest from nonsolar photovoltaic Tier I sources, and the Tier II requirement is 6.2% of all retail sales.

(10) For June 1, 2015, through May 31, 2016: The Tier I requirement is 5.5% of all retail sales, of which at least 0.25% of all retail sales are to come from solar photovoltaic sources and the remaining from nonsolar photovoltaic Tier I sources, and the Tier II requirement is 8.2% of all retail sales.

(11) For June 1, 2016, through May 31, 2017: The Tier I requirement is 6% of all retail sales, of which at least 0.2933% of all retail sales are to come from solar photovoltaic sources and the remaining from nonsolar photovoltaic Tier I sources, and the Tier II requirement is 8.2% of all retail sales.

(12) For June 1, 2017, through May 31, 2018: The Tier I requirement is 6.5% of all retail sales, of which at least 0.3400% of all retail sales are to come from solar photovoltaic sources and the remaining from nonsolar photovoltaic Tier I sources, and the Tier II requirement is 8.2% of all retail sales.

(13) For June 1, 2018, through May 31, 2019: The Tier I requirement is 7% of all retail sales, of which at least 0.3900% of all retail sales are to come from solar photovoltaic sources and the remaining from nonsolar photovoltaic Tier I sources, and the Tier II requirement is 8.2% of all retail sales.

(14) For June 1, 2019, through May 31, 2020: The Tier I requirement is 7.5% of all retail sales, of which at least 0.4433% of all retail sales are to come from solar photovoltaic sources and the remaining from nonsolar photovoltaic Tier I sources, and the Tier II requirement is 8.2% of all retail sales.

(15) For June 1, 2020, through May 31, 2021, and each successive 12 month period thereafter: The Tier I requirement is 8% of all retail sales, of which at least 0.5% of all retail sales are to come from solar photovoltaic sources and the remaining from nonsolar photovoltaic Tier I sources, and the Tier II requirement is 10% of all retail sales.

(c) EDCs are exempt from these requirements for the duration of their cost-recovery period. An EDC shall be required to comply with the requirements in effect during the reporting period, as identified in subsection (b), in which its exemption expires.

(d) EGSs are exempt from these requirements in the service territories of EDCs in their cost-recovery period. EGS compliance shall be measured against their total MWh sales to all retail electric customers in all EDC service territories that have exited their cost-recovery periods.

(e) A 90-day true-up period shall commence at the end of each reporting period. EDCs and EGSs not in compliance with this chapter at the end of a reporting period, as determined by the program administrator under § 75.64(c)(2) (relating to alternative energy credit program administrator), may acquire additional alternative energy credits during the true-up period to satisfy the requirements of this chapter.

Authority

The provisons of this § 75.61 amended under 66 Pa.C.S. §§ 501, 1501 and 2807(e); and sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)).

Source

The provisions of this § 75.61 amended November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448. Immediately preceding text appears at serial pages (340991) to (340993).

Cross References

This section cited in 52 Pa. Code § 75.63 (relating to alternative energy credit certification); 52 Pa. Code § 75.64 (relating to alternative energy credit program administrator); 52 Pa. Code § 75.65 (relating to alternative compliance payments); 52 Pa. Code § 75.66 (relating to force majeure); 52 Pa. Code § 75.67 (relating to alternative energy cost-recovery); 52 Pa. Code § 75.68 (relating to alternative energy market integrity); and 52 Pa. Code § 75.71 (relating to quarterly adjustment of nonsolar Tier I obligation).

§ 75.62. Alternative energy system qualification.

(a) An application for alternative energy system status shall be submitted on a form developed and made available by the Commission. A copy of the application form will be made available on the Commission's public Internet domain. An application shall be verified by oath or affirmation as required under § 1.36 (relating to verification).

(b) A completed application and supporting attachments shall be filed with the alternative energy credit program administrator, the Department of Environmental Protection and any other parties that may be designated by the Commission.

(c) A facility, to be qualified for alternative energy system status, shall demonstrate that it is physically located in either:

(1) This Commonwealth.

(2) The control area of an RTO that manages a portion of the electric transmission system in this Commonwealth.

(d) Alternative energy credits derived from alternative energy sources located outside the geographical boundaries of this Commonwealth but within the control area of an RTO that manages the transmission system in any part of this Commonwealth shall only be eligible to meet the compliance requirements of EDCs or EGSs located within the service territory of the same RTO. For purposes of compliance with the act, alternative energy sources located in the control area of the PJM Interconnection, LLC RTO or its successor shall be eligible to fulfill compliance obligations of all Pennsylvania EDCs and EGSs.

(e) A facility, to be qualified for alternative energy system status, shall demonstrate that it generates electricity from or conserves electricity through a Tier I or Tier II alternative energy source.

(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.

Authority

The provisions of this § 75.62 amended under 66 Pa.C.S. §§ 501, 1501 and 2807(e); and sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)).

Source

The provisions of this § 75.62 amended November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448. Immediately preceding text appears at serial pages (340993) to (340994).

Cross References

This section cited in 52 Pa. Code § 75.64 (relating to alternative energy credit program administrator).

§ 75.63. Alternative energy credit certification.

(a) An alternative energy credit may be certified by the Commission for each MWh of electricity generated by qualified alternative energy systems on or after February 28, 2005.

(b) An alternative energy credit may be certified by the Commission for each MWh of electricity conserved by qualified alternative energy systems or demand side management on or after November 30, 2004.

(c) An alternative energy credit may not be certified 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.

(d) An alternative energy credit already purchased by individuals, businesses or government bodies that do not have a compliance obligation under the act may not be certified for a MWh of electricity generation or electricity conservation unless the individual, business or government body sells those credits to the EDC or EGS.

(e) When an alternative energy system relies on more than one fuel source or technology, alternative energy credits shall be certified for that portion of the electric generation that is derived from an alternative energy fuel source or technology.

(f) For all alternative energy systems except solar photovoltaic systems with a nameplate capacity of 15 kilowatts or less, alternative energy credit certification shall be verified by metered data obtained from or by one of the following:

(1) An RTO.

(2) The credits registry designated under § 75.70 (relating to alternative energy credit registry).

(3) The administrator designated under § 75.64 (relating to alternative energy credit program administrator).

(g) For solar photovoltaic alternative energy systems with a nameplate capacity of 15 kW or less that are installed or that increase nameplate capacity on or after May 18, 2017, 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 May 18, 2017, 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.

Authority

The provisions of this § 75.63 amended under 66 Pa.C.S. §§ 501, 1501 and 2807(e); and sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)).

Source

The provisions of this § 75.63 amended November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448. Immediately preceding text appears at serial pages (340994) to (340995).

Cross References

This section cited in 52 Pa. Code § 75.64 (relating to alternative energy credit program administrator).

§ 75.64. Alternative energy credit program administrator.

(a) The Commission may select an independent entity to act as a program administrator and perform administrative functions necessary to the implementation of this chapter. If an independent entity is not selected to act as a program administrator, the Commission will perform the functions identified in this section.

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

(1) Distribute, receive and review applications for alternative energy system qualification.

(2) Reject applications that are incomplete or do not adhere to the application instructions.

(3) Determine whether an application satisfies the geographic eligibility standard in § 75.62(c) (relating to alternative energy system qualification) and reject applications that fail this standard.

(4) Qualify applicants for alternative energy system status who have filed a complete application, adhered to application instructions, satisfied the geographic eligibility standard, complied with environmental regulations and utilized an alternative energy fuel source or technology.

(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 reported load, and provide written notice to each EDC and EGS of its compliance 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. The administrator will provide written notice to each EDC and EGS of a final assessment of its compliance status within 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's Bureau of Technical Utility Services within 45 days of the end of 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 reconsideration from actions of the staff).

(f) The Commission may delegate other responsibilities to the program administrator as may be necessary for the implementation of the act.

Authority

The provisions of this § 75.64 amended under 66 Pa.C.S. §§ 501, 1501 and 2807(e); and sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)).

Source

The provisions of this § 75.64 amended November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448. Immediately preceding text appears at serial pages (340995) to (340996).

Cross References

This section cited in 52 Pa. Code § 75.61 (relating to EDC and EGS obligations); 52 Pa. Code § 75.63 (relating to alternative energy credit certification); 52 Pa. Code § 75.65 (relating to alternative compliance payments); 52 Pa. Code § 75.67 (relating to alternative energy cost-recovery); and 52 Pa. Code § 75.71 (relating to quarterly adjustment of nonsolar Tier I obligation).

§ 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'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.

(b) Each EDC and EGS shall be assessed an alternative compliance payment according to the following formula:

(1) For noncompliance with the solar photovoltaic requirements identified in § 75.61, an EDC and EGS shall make an alternative compliance payment equal to the following:

(i) The average market value for solar photovoltaic alternative energy credits sold during the reporting period in the RTO control area where the noncompliance occurred.

(ii) Add to value in subparagraph (i), the levelized up-front rebates received by sellers of solar renewable energy credits (calculated as follows: total amount of rebates paid within the previous 20 years, divided by the total kilowatt capacity for which rebates were given in the previous 20 years, divided by 20 (the useful life of a solar photovoltaic system), multiplied by the percentage of alternative energy used during the reporting period originating from jurisdictions where rebates were given).

(iii) Multiply the value in subparagraph (ii) by 200%.

(2) For noncompliance with all other requirements identified in § 75.61, an EDC and EGS shall make an alternative compliance payment equal to $45 times the number of additional alternative energy credits necessary for compliance in that reporting period.

(3) The costs of alternative compliance payments made under this section may not be recoverable from ratepayers.

(c) EDCs and EGSs shall advise the 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 Bureau of Technical Utility Services will refer the petition to the Commission's Bureau of Investigation and Enforcement for further actions as may be warranted. Failure of an EDC or EGS to respond to the Bureau of Technical Utility Services within 15 days of the issuance of this notice will be deemed an acceptance of the alternative compliance payment determination.

(d) EDCs and EGSs shall send their alternative compliance payments to a special fund designated by the Commission within 30 days of acceptance of their payment determination, or the conclusion of proceedings before the Commission regarding the modification of the level of payment.

(e) Alternative compliance payments shall be made available to the sustainable energy funds established through the Commission's orders entered under 66 Pa.C.S. § 2806(f) (relating to implementation, pilot programs and performance-based rates), under procedures and standards proposed by the Pennsylvania Sustainable Energy Board and approved by the Commission at Docket M-00031715. See 33 Pa.B. 4263 (August 23, 2003).

(f) Alternative compliance payments made available to the sustainable energy funds shall be utilized solely for projects that increase the amount of electric energy generated from alternative energy resources for purposes of compliance with § 75.61.

(g) The Commission may utilize up to 5% of alternative compliance payments made by EDCs and EGSs for administrative expenses directly associated with the implementation of this chapter, including the costs of the program administrator.

Source

The provisions of this § 75.65 amended November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448. Immediately preceding text appears at serial pages (340996) to (340998).

§ 75.66. Force majeure.

(a) No earlier than 60 days prior to the beginning of a reporting period and no more than 60 days after the conclusion of the true-up period, the Commission, upon its own initiative or upon the request of an EDC or EGS, may issue an order declaring that force majeure exists for some or all EDCs and EGSs for that reporting period. The order will include separate force majeure determinations for the Tier I alternative energy source, Tier II alternative energy source and solar photovoltaic requirements of § 75.61 (relating to EDC and EGS obligations).

(b) The Commission will provide public notice of all requests for force majeure determination.

(c) The Commission may find that force majeure exists if there are insufficient alternative energy credits to satisfy the aggregate Tier I alternative energy source, Tier II alternative energy source or solar photovoltaic obligation for all EDCs and EGSs under § 75.61 for that reporting period.

(d) The Commission may find that force majeure exists for the nonsolar photovoltaic requirement of § 75.61 if the average price for a nonsolar photovoltaic alternative energy credit purchased by a Pennsylvania EDC and EGS exceeds $45 in the 6-month period preceding the issuance of the order referenced in subsection (a).

(e) If the Commission determines that force majeure exists for a reporting period, EDCs and EGSs shall have the option of making alternative compliance payments in lieu of compliance with § 75.61 for that reporting period.

(1) This payment must equal $45 for each alternative energy credit needed to satisfy the Tier I nonsolar photovoltaic and Tier II requirements of § 75.61 or the Commission may choose to reduce the required level of Tier I nonsolar photovoltaic and Tier II compliance for the reporting period.

(2) For the solar photovoltaic requirement, EDCs and EGSs shall have the option of making an alternative compliance payment equal to the market value of solar photovoltaic credits in the applicable RTO service territory, or the Commission may choose to reduce the required level of solar photovoltaic compliance for that reporting period.

(3) A payment shall be accompanied by a statement with supporting facts, filed with the Commission and verified by oath or affirmation, consistent with § 1.36 (relating to verification), that the EDC or EGS has made a good faith effort to comply with this chapter as outlined in subparagraph (i) of the definition of ''force majeure'' in § 75.1 (relating to definitions), that they are unable to acquire a sufficient quantity of alternative energy credits to meet their obligations under § 75.61 as outlined in subparagraph (ii) of the definition of ''force majeure'' in § 75.1, and that an alternative compliance payment is the least cost method of compliance.

(4) The option to make an alternative compliance payment in lieu of compliance with § 75.61 may not be available to EDCs and EGSs that have already acquired sufficient alternative energy credits for compliance with the requirements of that reporting period.

(5) If the Commission modifies any compliance requirements, the Commission may increase the compliance requirements of an equivalent type and amount in subsequent years when the Commission determines that sufficient alternative energy credits of an equivalent type exist in the marketplace.

(f) Alternative compliance payments made by EDCs under subsection (e) shall be deemed a cost of compliance with this chapter and may be recovered under § 75.67 (relating to alternative energy cost-recovery).

(g) EDCs and EGSs shall provide the Commission all information necessary for it to render a force majeure determination, as outlined in the definition of ''force majeure'' in § 75.1.

§ 75.67. Alternative energy cost-recovery.

(a) A default service provider may recover from default service customers the following reasonable and prudently incurred costs for compliance with the act:

(1) The costs of electricity generated by an alternative energy system, purchased by a default service provider, and delivered to default service customers for purposes of compliance with § 75.61 (relating to EDC and EGS obligations).

(2) The costs of alternative energy credits purchased and used within the same reporting period for purposes of compliance with § 75.61.

(3) The costs of alternative energy credits purchased in one reporting period and banked for use in later reporting periods, consistent with § 75.69 (relating to banking of alternative energy credits).

(4) The costs of alternative energy credits purchased in the true-up period to satisfy compliance obligations for the most recently concluded reporting period, consistent with § 75.61(e)

(5) Payments to the alternative energy credits program administrator for its costs of administering an alternative energy credits program, consistent with § 75.64 (relating to alternative energy credit program administrator).

(6) Payments to a third party for its costs in operating an alternative energy credits registry, consistent with § 75.70 (relating to the alternative energy credit registry).

(7) The costs levied by a regional transmission organization to ensure that alternative energy sources are reliable.

(8) The costs of alternative compliance payments made under § 75.66 (relating to force majeure).

(b) A default service provider shall demonstrate compliance with the requirements of § 75.61 and the default service provisions of Chapter 54 (relating to electricity generation customer choice) by identifying a competitive procurement process for acquiring alternative energy credits in default service implementation plans filed with the Commission.

(c) A competitive procurement process for alternative energy and alternative energy credits shall comply with the standards for competitive procurement processes identified in the default service provisions in Chapter 54.

(d) The costs of compliance with the alternative energy portfolio standards act shall be recovered through an automatic adjustment clause within the meaning of 66 Pa.C.S. § 1307 (relating to sliding scale of rates; adjustments) and consistent with § 54.187 (relating to default service rate design and the recovery of reasonable costs) according to the following standards:

(1) Costs incurred by a default service provider during the cost-recovery period shall be deferred as a regulatory asset and fully recovered with a return on the unamortized balance during the first full 12-month reporting period after the expiration of the cost-recovery period in the EDC service territory where it is acting as the default service provider.

(2) Costs incurred by a default service provider after the expiration of a cost-recovery period shall be recovered during the reporting period in which they are incurred, except as provided for in paragraph (7).

(3) The default service implementation plan shall include a schedule of rates for the recovery of these costs as required under 66 Pa.C.S. § 1307(a).

(4) A default service provider shall file a report with the Commission within 30 days of the conclusion of each reporting period that includes the information identified in 66 Pa.C.S. § 1307(e)(1).

(5) The Commission will hold public hearings on the substance of these reports, and other matters pertaining to this subject, as required by 66 Pa.C.S. § 1307(e)(2).

(6) The Commission will order the default service provider to provide refunds to or recover additional costs from default service customers consistent with 66 Pa.C.S. § 1307(e)(3).

(7) The costs of alternative energy credits purchased by the default service provider during the true-up period under section 3(e)(5) of the act (73 P.S. § 1648.3(e)(5)) shall be recovered during the reporting period in which these costs are incurred.

(e) The Commission will perform fuel costs audits, on at least an annual basis, of each default service provider that recovers costs using the automatic adjustment clause provided for under this section.

Cross References

This section cited in 52 Pa. Code § 75.66 (relating to force majeure).

§ 75.68. Alternative energy market integrity.

(a) Sales of electricity by EDCs and EGSs to retail electric customers marketed as deriving from alternative energy sources shall be tracked and counted separately from alternative energy credits used to support compliance with § 75.61 (relating to EDC and EGS obligations).

(b) When EDCs and EGSs market their generation as deriving from alternative energy sources, they shall include information to substantiate their claims. Disclosure of alternative energy sources shall be traceable to specific alternative energy sources by an auditable contract trail or equivalent, such as a tradable commodity system, that provides verification that the alternative energy source claimed has been sold only once to a retail customer.

§ 75.69. Banking of alternative energy credits.

(a) An EDC and EGS may bank alternative energy credits certified in one reporting period for use in either or both of the two immediately following reporting periods.

(b) An EDC and EGS may bank alternative energy credits certified during a cost-recovery period for use in the reporting period in which the cost-recovery period expires, and the reporting period that immediately follows.

(c) Alternative energy credits acquired by EDCs and EGSs not used within the time limits identified in subsections (a) and (b) shall be retired within the alternative energy credits registry and not available for the compliance requirements of this chapter.

(d) EDCs and EGSs shall satisfy the requirements of this chapter for the present reporting period before banking alternative energy credits produced in that same reporting period for use in either or both of the two subsequent reporting periods.

(e) The Commission will determine the volume of sales, measured in MWh, by EDCs and EGSs to retail customers in the 12-month period that immediately preceded the effective date of the act derived from specific alternative energy systems. EDCs and EGSs may bank credits during the cost-recovery period for the generation output of qualified alternative energy systems that exceed their volume of alternative energy sales to retail customers during this 12-month period.

Cross References

This section cited in 52 Pa. Code § 75.67 (relating to alternative energy cost-recovery).

§ 75.70. Alternative energy credit registry.

(a) The Commission will designate an alternative energy credit registry to track the creation and transfer of certified alternative energy credits among qualified alternative energy systems, EDCs, and EGSs. EDCs and EGSs shall record the price paid for each alternative energy credit in the alternative energy credit registry.

(b) The Commission may direct EDCs and EGSs to enter into agreements with an alternative energy credit registry to verify compliance with this chapter and for compliance with section 3(e)(8) of the act (73 P.S. § 1648.3(e)(8)). EDCs and EGSs shall comply with the rules, policies and procedures of the designated alternative energy credit registry identified in the registry's terms of use, subscriber agreement or other comparable document.

(c) EDCs and EGSs shall provide the Commission and the program administrator with access to information in this registry necessary to verify compliance with this chapter and for compliance with section 3(e)(8) of the act.

(d) The prices paid for individual credits will be treated as confidential information by the Commission. Aggregate pricing data on alternative energy credits will be made available to the public by the Commission or the program administrator on a regular basis.

Cross References

This section cited in 52 Pa. Code § 75.63 (relating to alternative energy credit certification); and 52 Pa. Code § 75.67 (relating to alternative energy cost-recovery).

§ 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 66 Pa.C.S. § 2814(c) (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 nonsolar 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 photovoltaic Tier I requirement (EDC and EGS quarterly MWh × new quarterly nonsolar photovoltaic Tier I % = EDCs' and EGSs' quarterly nonsolar photovoltaic Tier I requirement) yields the quantity of alter-

native 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 under these sections.

Authority

The provisions of this § 75.71 issued under 66 Pa.C.S. §§ 501, 1501 and 2807(e); and sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)).

Source

The provisions of this § 75.71 adopted November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448.

Cross References

This section cited in 52 Pa. Code § 75.61 (relating to EDC and EGS obligations); and 52 Pa. Code § 75.72 (relating to reporting requirements for quarterly adjustment of nonsolar Tier I obligation).

§ 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 November 4.

(2) Second quarter (September, October and November) due by February 4.

(3) Third quarter (December, January and February) due by May 5.

(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 November 4.

(2) Second quarter (September, October and November) due by the second business day after February 4.

(3) Third quarter (December, January and February) due by the second business day after May 5.

(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 66 Pa.C.S. § 2814(a) and (b) (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).

Authority

The provisions of this § 75.72 issued under 66 Pa.C.S. §§ 501, 1501 and 2807(e); and sections 1648.7(a) and 1648.3(e)(2) of the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.7(a) and 1648.3(e)(2)).

Source

The provisions of this § 75.72 adopted November 18, 2016, effective November 19, 2016, 46 Pa.B. 7277, 7448.

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