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HOUSE BILL NO. 2155

Offered January 14, 2015

Prefiled January 14, 2015

A BILL to amend and reenact § 56-585.1 of the Code of Virginia and to amend the Code of Virginia by adding in Title 56 a chapter numbered 28, consisting of sections numbered 56-610 through 56-620, relating to a requirement that certain electric utilities advance energy diversification by acquiring energy from new zero-emitting energy facilities and demand-side efficiencies; cost recovery; noncompliance payments; civil penalties; reports.

Patron—Sickles

Referred to Committee on Commerce and Labor

Be it enacted by the General Assembly of Virginia:

1. That § 56-585.1 of the Code of Virginia is amended and reenacted and that the Code of Virginia is amended by adding in Title 56 a chapter numbered 28, consisting of sections numbered 56-610 through 56-620, as follows:

§ 56-585.1. Generation, distribution, and transmission rates after capped rates terminate or expire.

A. During the first six months of 2009, the Commission shall, after notice and opportunity for hearing, initiate proceedings to review the rates, terms and conditions for the provision of generation, distribution and transmission services of each investor-owned incumbent electric utility. Such proceedings shall be governed by the provisions of Chapter 10 (§ 56-232 et seq.), except as modified herein. In such proceedings the Commission shall determine fair rates of return on common equity applicable to the generation and distribution services of the utility. In so doing, the Commission may use any methodology to determine such return it finds consistent with the public interest, but such return shall not be set lower than the average of the returns on common equity reported to the Securities and Exchange Commission for the three most recent annual periods for which such data are available by not less than a majority, selected by the Commission as specified in subdivision 2 b, of other investor-owned electric utilities in the peer group of the utility, nor shall the Commission set such return more than 300 basis points higher than such average. The peer group of the utility shall be determined in the manner prescribed in subdivision 2 b. The Commission may increase or decrease such combined rate of return by up to 100 basis points based on the generating plant performance, customer service, and operating efficiency of a utility, as compared to nationally recognized standards determined by the Commission to be appropriate for such purposes. In such a proceeding, the Commission shall determine the rates that the utility may charge until such rates are adjusted. If the Commission finds that the utility's combined rate of return on common equity is more than 50 basis points below the combined rate of return as so determined, it shall be authorized to order increases to the utility's rates necessary to provide the opportunity to fully recover the costs of providing the utility's services and to earn not less than such combined rate of return. If the Commission finds that the utility's combined rate of return on common equity is more than 50 basis points above the combined rate of return as so determined, it shall be authorized either (i) to order reductions to the utility's rates it finds appropriate, provided that the Commission may not order such rate reduction unless it finds that the resulting rates will provide the utility with the opportunity to fully recover its costs of providing its services and to earn not less than the fair rates of return on common equity applicable to the generation and distribution services; or (ii) to direct that 60 percent of the amount of the utility's earnings that were more than 50 basis points above the fair combined rate of return for calendar year 2008 be credited to customers' bills, in which event such credits shall be amortized over a period of six to 12 months, as determined at the discretion of the Commission, following the effective date of the Commission's order and be allocated among customer classes such that the relationship between the specific customer class rates of return to the overall target rate of return will have the same relationship as the last approved allocation of revenues used to design base rates. Commencing in 2011, the Commission, after notice and opportunity for hearing, shall conduct biennial reviews of the rates, terms and conditions for the provision of generation, distribution and transmission services by each investor-owned incumbent electric utility, subject to the following provisions:

1. Rates, terms and conditions for each service shall be reviewed separately on an unbundled basis, and such reviews shall be conducted in a single, combined proceeding. The first such review shall utilize the two successive 12-month test periods ending December 31, 2010. However, the Commission may, in its discretion, elect to stagger its biennial reviews of utilities by utilizing the two successive

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12-month test periods ending December 31, 2010, for a Phase I Utility, and utilizing the two successive 12-month test periods ending December 31, 2011, for a Phase II Utility, with subsequent proceedings utilizing the two successive 12-month test periods ending December 31 immediately preceding the year in which such proceeding is conducted. For purposes of this section, a Phase I Utility is an investor-owned incumbent electric utility that was, as of July 1, 1999, not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002, and a Phase II Utility is an investor-owned incumbent electric utility that was bound by such a settlement.

2. Subject to the provisions of subdivision 6, fair rates of return on common equity applicable separately to the generation and distribution services of such utility, and for the two such services combined, shall be determined by the Commission during each such biennial review, as follows:

a. The Commission may use any methodology to determine such return it finds consistent with the public interest, but such return shall not be set lower than the average of the returns on common equity reported to the Securities and Exchange Commission for the three most recent annual periods for which such data are available by not less than a majority, selected by the Commission as specified in subdivision 2 b, of other investor-owned electric utilities in the peer group of the utility subject to such biennial review, nor shall the Commission set such return more than 300 basis points higher than such average.

b. In selecting such majority of peer group investor-owned electric utilities, the Commission shall first remove from such group the two utilities within such group that have the lowest reported returns of the group, as well as the two utilities within such group that have the highest reported returns of the group, and the Commission shall then select a majority of the utilities remaining in such peer group. In its final order regarding such biennial review, the Commission shall identify the utilities in such peer group it selected for the calculation of such limitation. For purposes of this subdivision, an investor-owned electric utility shall be deemed part of such peer group if (i) its principal operations are conducted in the southeastern United States east of the Mississippi River in either the states of West Virginia or Kentucky or in those states south of Virginia, excluding the state of Tennessee, (ii) it is a vertically-integrated electric utility providing generation, transmission and distribution services whose facilities and operations are subject to state public utility regulation in the state where its principal operations are conducted, (iii) it had a long-term bond rating assigned by Moody's Investors Service of at least Baa at the end of the most recent test period subject to such biennial review, and (iv) it is not an affiliate of the utility subject to such biennial review.

c. The Commission may, consistent with its precedent for incumbent electric utilities prior to the enactment of Chapters 888 and 933 of the Acts of Assembly of 2007, increase or decrease the utility's combined rate of return based on the Commission's consideration of the utility's performance.

d. In any Current Proceeding, the Commission shall determine whether the Current Return has increased, on a percentage basis, above the Initial Return by more than the increase, expressed as a percentage, in the United States Average Consumer Price Index for all items, all urban consumers (CPI-U), as published by the Bureau of Labor Statistics of the United States Department of Labor, since the date on which the Commission determined the Initial Return. If so, the Commission may conduct an additional analysis of whether it is in the public interest to utilize such Current Return for the Current Proceeding then pending. A finding of whether the Current Return justifies such additional analysis shall be made without regard to any enhanced rate of return on common equity awarded pursuant to the provisions of subdivision 6. Such additional analysis shall include, but not be limited to, a consideration of overall economic conditions, the level of interest rates and cost of capital with respect to business and industry, in general, as well as electric utilities, the current level of inflation and the utility's cost of goods and services, the effect on the utility's ability to provide adequate service and to attract capital if less than the Current Return were utilized for the Current Proceeding then pending, and such other factors as the Commission may deem relevant. If, as a result of such analysis, the Commission finds that use of the Current Return for the Current Proceeding then pending would not be in the public interest, then the lower limit imposed by subdivision 2 a on the return to be determined by the Commission for such utility shall be calculated, for that Current Proceeding only, by increasing the Initial Return by a percentage at least equal to the increase, expressed as a percentage, in the United States Average Consumer Price Index for all items, all urban consumers (CPI-U), as published by the Bureau of Labor Statistics of the United States Department of Labor, since the date on which the Commission determined the Initial Return. For purposes of this subdivision:

"Current Proceeding" means any proceeding conducted under any provisions of this subsection that require or authorize the Commission to determine a fair combined rate of return on common equity for a utility and that will be concluded after the date on which the Commission determined the Initial Return for such utility.

"Current Return" means the minimum fair combined rate of return on common equity required for any Current Proceeding by the limitation regarding a utility's peer group specified in subdivision 2 a.

"Initial Return" means the fair combined rate of return on common equity determined for such utility by the Commission on the first occasion after July 1, 2009, under any provision of this subsection pursuant to the provisions of subdivision 2 a.

e. In addition to other considerations, in setting the return on equity within the range allowed by this section, the Commission shall strive to maintain costs of retail electric energy that are cost competitive with costs of retail electric energy provided by the other peer group investor-owned electric utilities.

f. The determination of such returns shall be made by the Commission on a stand-alone basis, and specifically without regard to any return on common equity or other matters determined with regard to facilities described in subdivision 6.

g. If the combined rate of return on common equity earned by the generation and distribution services is no more than 50 basis points above or below the return as so determined or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, such return is no more than 70 basis points above or below the return as so determined, such combined return shall not be considered either excessive or insufficient, respectively. However, for any test period commencing after December 31, 2012, for a Phase II Utility, and after December 31, 2013, for a Phase I Utility, if the utility has, during the test period or periods under review, earned below the return as so determined, whether or not such combined return is within 70 basis points of the return as so determined, the utility may petition the Commission for approval of an increase in rates in accordance with the provisions of subdivision 8 a as if it had earned more than 70 basis points below a fair combined rate of return, and such proceeding shall otherwise be conducted in accordance with the provisions of this section.

h. Any amount of a utility's earnings directed by the Commission to be credited to customers' bills pursuant to this section shall not be considered for the purpose of determining the utility's earnings in any subsequent biennial review.

3. Each such utility shall make a biennial filing by March 31 of every other year, beginning in 2011, consisting of the schedules contained in the Commission's rules governing utility rate increase applications; however, if the Commission elects to stagger the dates of the biennial reviews of utilities as provided in subdivision 1, then Phase I utilities shall commence biennial filings in 2011 and Phase II utilities shall commence biennial filings in 2012. Such filing shall encompass the two successive 12-month test periods ending December 31 immediately preceding the year in which such proceeding is conducted, and in every such case the filing for each year shall be identified separately and shall be segregated from any other year encompassed by the filing. If the Commission determines that rates should be revised or credits be applied to customers' bills pursuant to subdivision 8 or 9, any rate adjustment clauses previously implemented pursuant to subdivision 5 or those related to facilities utilizing simple-cycle combustion turbines described in subdivision 6, shall be combined with the utility's costs, revenues and investments until the amounts that are the subject of such rate adjustment clauses are fully recovered. The Commission shall combine such clauses with the utility's costs, revenues and investments only after it makes its initial determination with regard to necessary rate revisions or credits to customers' bills, and the amounts thereof, but after such clauses are combined as herein specified, they shall thereafter be considered part of the utility's costs, revenues, and investments for the purposes of future biennial review proceedings. A Phase I utility shall delay for one year the filing of its biennial review from March 31, 2013, to March 31, 2014, and shall not defer on its books for future recovery any costs incurred during calendar year 2011, other than as provided in subdivision 7 or § 56-249.6, and its subsequent biennial filing shall be made by March 31, 2016, and every two years thereafter.

4. The following costs incurred by the utility shall be deemed reasonable and prudent: (i) costs for transmission services provided to the utility by the regional transmission entity of which the utility is a member, as determined under applicable rates, terms and conditions approved by the Federal Energy Regulatory Commission, and (ii) costs charged to the utility that are associated with demand response programs approved by the Federal Energy Regulatory Commission and administered by the regional transmission entity of which the utility is a member. Upon petition of a utility at any time after the expiration or termination of capped rates, but not more than once in any 12-month period, the Commission shall approve a rate adjustment clause under which such costs, including, without limitation, costs for transmission service, charges for new and existing transmission facilities, administrative charges, and ancillary service charges designed to recover transmission costs, shall be recovered on a timely and current basis from customers. Retail rates to recover these costs shall be designed using the appropriate billing determinants in the retail rate schedules.

5. A utility may at any time, after the expiration or termination of capped rates, but not more than once in any 12-month period, petition the Commission for approval of one or more rate adjustment clauses for the timely and current recovery from customers of the following costs:

a. Incremental costs described in clause (vi) of subsection B of § 56-582 incurred between July 1, 2004, and the expiration or termination of capped rates, if such utility is, as of July 1, 2007, deferring such costs consistent with an order of the Commission entered under clause (vi) of subsection B of § 56-582. The Commission shall approve such a petition allowing the recovery of such costs that comply with the requirements of clause (vi) of subsection B of § 56-582;

b. Projected and actual costs for the utility to design and operate fair and effective peak-shaving programs. The Commission shall approve such a petition if it finds that the program is in the public interest; provided that the Commission shall allow the recovery of such costs as it finds are reasonable;

c. Projected and actual costs for the utility to design, implement, and operate energy efficiency programs, including a margin to be recovered on operating expenses, which margin for the purposes of this section shall be equal to the general rate of return on common equity determined as described in subdivision 2. The Commission shall only approve such a petition if it finds that the program is in the public interest. As part of such cost recovery, the Commission, if requested by the utility, shall allow for the recovery of revenue reductions related to energy efficiency programs. The Commission shall only allow such recovery to the extent that the Commission determines such revenue has not been recovered through margins from incremental off-system sales as defined in § 56-249.6 that are directly attributable to energy efficiency programs.

None of the costs of new energy efficiency programs of an electric utility, including recovery of revenue reductions, shall be assigned to any customer that has a verifiable history of having used more than 10 megawatts of demand from a single meter of delivery. Nor shall any of the costs of new energy efficiency programs of an electric utility, including recovery of revenue reductions, be incurred by any large general service customer as defined herein that has notified the utility of non-participation in such energy efficiency program or programs. A large general service customer is a customer that has a verifiable history of having used more than 500 kilowatts of demand from a single meter of delivery. Non-participation in energy efficiency programs shall be allowed by the Commission if the large general service customer has, at the customer's own expense, implemented energy efficiency programs that have produced or will produce measured and verified results consistent with industry standards and other regulatory criteria stated in this section. The Commission shall, no later than November 15, 2009, promulgate rules and regulations to accommodate the process under which such large general service customers shall file notice for such an exemption and (i) establish the administrative procedures by which eligible customers will notify the utility and (ii) define the standard criteria that must be satisfied by an applicant in order to notify the utility. In promulgating such rules and regulations, the Commission may also specify the timing as to when a utility shall accept and act on such notice, taking into consideration the utility's integrated resource planning process as well as its administration of energy efficiency programs that are approved for cost recovery by the Commission. The notice of non-participation by a large general service customer, to be given by March 1 of a given year, shall be for the duration of the service life of the customer's energy efficiency program. The Commission on its own motion may initiate steps necessary to verify such non-participants' achievement of energy efficiency if the Commission has a body of evidence that the non-participant has knowingly misrepresented its energy efficiency achievement. A utility shall not charge such large general service customer, as defined by the Commission, for the costs of installing energy efficiency equipment beyond what is required to provide electric service and meter such service on the customer's premises if the customer provides, at the customer's expense, equivalent energy efficiency equipment. In all relevant proceedings pursuant to this section, the Commission shall take into consideration the goals of economic development, energy efficiency and environmental protection in the Commonwealth;

d. Projected and actual costs of participation in a renewable energy portfolio standard program pursuant to § 56-585.2 that are not recoverable under subdivision 6. The Commission shall approve such a petition allowing the recovery of such costs as are provided for in a program approved pursuant to § 56-585.2; ~~and~~

e. Projected and actual costs of projects that the Commission finds to be necessary to comply with state or federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations. The Commission shall approve such a petition if it finds that such costs are necessary to comply with such environmental laws or regulations*; and*

f. Reasonable and prudent costs incurred by the utility in complying with the quantified energy diversification requirement and the demand-side efficiency requirement imposed on the utility pursuant to Chapter 28 (§ 56-610 et seq.), to the extent such costs constitute recoverable costs as defined in § 56-610. In determining the reasonableness and prudence of the costs incurred by a utility in providing energy and capacity to its customers from zero-emission energy facilities, the Commission shall consider the extent to which such facilities, whether utility-owned or by contract, further the objectives of the Commonwealth Energy Policy set forth in §§ 67-101 and 67-102, and shall also consider whether the costs of such resources are likely to result in unreasonable increases in bills paid by consumers. The determination of unreasonable increases in bills shall consider long range electricity inflation indicators consistent with the period of the deployment of the technology and programs.

The Commission shall have the authority to determine the duration or amortization period for any adjustment clause approved under this subdivision.

6. To ensure the generation and delivery of a reliable and adequate supply of electricity, to meet the utility's projected native load obligations and to promote economic development, a utility may at any time, after the expiration or termination of capped rates, petition the Commission for approval of a rate adjustment clause for recovery on a timely and current basis from customers of the costs of (i) a coal-fueled generation facility that utilizes Virginia coal and is located in the coalfield region of the Commonwealth, as described in § 15.2-6002, regardless of whether such facility is located within or without the utility's service territory, (ii) one or more other generation facilities, (iii) one or more major unit modifications of generation facilities, or (iv) one or more new underground facilities to replace one or more existing overhead distribution facilities of 69 kilovolts or less located within the Commonwealth; however, subject to the provisions of the following sentence, the utility shall not file a petition under clause (iv) more often than annually and, in such petition, shall not seek any annual incremental increase in the level of investments associated with such a petition that exceeds five percent of such utility's distribution rate base, as such rate base was determined for the most recently ended 12-month test period in the utility's latest biennial review proceeding conducted pursuant to subdivision 3 and concluded by final order of the Commission prior to the date of filing of such petition under clause (iv). In all proceedings regarding petitions filed under clause (iv), the level of investments approved for recovery in such proceedings shall be in addition to, and not in lieu of, levels of investments previously approved for recovery in prior proceedings under clause (iv). Such a petition concerning facilities described in clause (ii) that utilize nuclear power, facilities described in clause (ii) that are coal-fueled and will be built by a Phase I utility, or facilities described in clause (i) may also be filed before the expiration or termination of capped rates. A utility that constructs any such facility shall have the right to recover the costs of the facility, as accrued against income, through its rates, including projected construction work in progress, and any associated allowance for funds used during construction, planning, development and construction costs, life-cycle costs, costs related to assessing the feasibility of potential sites for new underground facilities, and costs of infrastructure associated therewith, plus, as an incentive to undertake such projects, an enhanced rate of return on common equity calculated as specified below; however, in determining the amounts recoverable under a rate adjustment clause for new underground facilities, the Commission shall not consider, or increase or reduce such amounts recoverable because of (a) the operation and maintenance costs attributable to either the overhead distribution facilities being replaced or the new underground facilities or (b) any other costs attributable to the overhead distribution facilities being replaced. Notwithstanding the preceding sentence, the costs described in clauses (a) and (b) thereof shall remain eligible for recovery from customers through the utility's base rates for distribution service. A utility seeking approval to construct a generating facility shall demonstrate that *(1)* it has considered and weighed alternative options, including third-party market alternatives, in its selection process *and (2) the utility's proposed generating facility will provide electric power at costs that are equal to or less than the costs of electric power from third-party market alternatives delivering power from the same type of generation facility*. The costs of the facility, other than return on projected construction work in progress and allowance for funds used during construction, shall not be recovered prior to the date a facility described in clause (i), (ii), or (iii) begins commercial operation or new underground facilities are classified by the utility as plant in service. Such enhanced rate of return on common equity shall be applied to allowance for funds used during construction and to construction work in progress during the construction phase of the facility and shall thereafter be applied to the entire facility during the first portion of the service life of the facility. The first portion of the service life shall be as specified in the table below; however, the Commission shall determine the duration of the first portion of the service life of any facility, within the range specified in the table below, which determination shall be consistent with the public interest and shall reflect the Commission's determinations regarding how critical the facility may be in meeting the energy needs of the citizens of the Commonwealth and the risks involved in the development of the facility. After the first portion of the service life of the facility is concluded, the utility's general rate of return shall be applied to such facility for the remainder of its service life. As used herein, the service life of the facility shall be deemed to begin on the date a facility described in clause (i), (ii), or (iii) begins commercial operation or new underground facilities are classified by the utility as plant in service, and such service life shall be deemed equal in years to the life of that facility as used to calculate the utility's depreciation expense. Such enhanced rate of return on common equity shall be calculated by adding the basis points specified in the table below to the utility's general rate of return, and such enhanced rate of return shall apply only to the facility that is the subject of such rate adjustment clause. Allowance for funds used during construction shall be calculated for any such facility utilizing the utility's actual capital structure and overall cost of capital, including an enhanced rate of return on common equity as determined pursuant to this subdivision, until such construction work in progress is included in rates. The construction of any facility described in clause (i) is in the public

interest, and in determining whether to approve such facility, the Commission shall liberally construe the provisions of this title. In determining whether to approve petitions for rate adjustment clauses for new underground facilities, and in determining the level of costs to be recovered thereunder, the Commission shall liberally construe the provisions of this title and shall give due consideration to the public policy goals of increased electric service reliability and reduced outage times associated with the replacement of existing overhead distribution facilities with new underground facilities. The basis points to be added to the utility's general rate of return to calculate the enhanced rate of return on common equity, and the first portion of that facility's service life to which such enhanced rate of return shall be applied, shall vary by type of facility, as specified in the following table:

Type of Generation Facility	Basis Points	First Portion of Service Life
Nuclear-powered	200	Between 12 and 25 years
Carbon capture compatible, clean-coal powered	200	Between 10 and 20 years
Renewable powered, other than landfill gas powered	200	Between 5 and 15 years
Coalbed methane gas powered	150	Between 5 and 15 years
Landfill gas powered	200	Between 5 and 15 years
Conventional coal or combined-cycle combustion turbine	100	Between 10 and 20 years

For generating facilities other than those utilizing nuclear power or those utilizing energy derived from offshore wind, as of July 1, 2013, only those facilities as to which a rate adjustment clause under this subdivision has been previously approved by the Commission, or as to which a petition for approval of such rate adjustment clause was filed with the Commission, on or before January 1, 2013, shall be entitled to the enhanced rate of return on common equity as specified in the above table during the construction phase of the facility and the approved first portion of its service life.

For generating facilities within the Commonwealth utilizing nuclear power or those utilizing energy derived from offshore wind projects located in waters off the Commonwealth's Atlantic shoreline, such facilities shall continue to be eligible for an enhanced rate of return on common equity during the construction phase of the facility and the approved first portion of its service life of between 12 and 25 years in the case of a facility utilizing nuclear power and for a service life of between 5 and 15 years in the case of a facility utilizing energy derived from offshore wind, provided, however, that, as of July 1, 2013, the enhanced return for such facilities shall be 100 basis points, which shall be added to the utility's general rate of return as determined under subdivision 2. Thirty percent of all costs of such a facility utilizing nuclear power that the utility incurred between July 1, 2007, and December 31, 2013, and all of such costs incurred after December 31, 2013, may be deferred by the utility and recovered through a rate adjustment clause under this subdivision at such time as the Commission provides in an order approving such a rate adjustment clause. The remaining 70 percent of all costs of such a facility that the utility incurred between July 1, 2007, and December 31, 2013, shall not be deferred for recovery through a rate adjustment clause under this subdivision; however, such remaining 70 percent of all costs shall be recovered ratably through existing base rates as determined by the Commission in the test periods under review in the utility's next biennial review filed after July 1, 2014. Thirty percent of all costs of such a facility utilizing energy derived from offshore wind that the utility incurred between July 1, 2007, and December 31, 2013, and all of such costs incurred after December 31, 2013, may be deferred by the utility and recovered through a rate adjustment clause under this subdivision at such time as the Commission provides in an order approving such a rate adjustment clause. The remaining 70 percent of all costs of such a facility that the utility incurred between July 1, 2007, and December 31, 2013, shall not be deferred for recovery through a rate adjustment clause under this subdivision; however, such remaining 70 percent of all costs shall be recovered ratably through existing base rates as determined by the Commission in the test periods under review in the utility's next biennial review filed after July 1, 2014.

In connection with planning to meet forecasted demand for electric generation supply and assure the adequate and sufficient reliability of service, consistent with § 56-598, planning and development activities for a new nuclear generation facility or facilities are in the public interest.

In connection with planning to meet forecasted demand for electric generation supply and assure the adequate and sufficient reliability of service, consistent with § 56-598, planning and development activities for a new generating facility or facilities utilizing energy derived from offshore wind are in the public interest.

Neither generation facilities described in clause (ii) that utilize simple-cycle combustion turbines nor new underground facilities shall receive an enhanced rate of return on common equity as described herein, but instead shall receive the utility's general rate of return during the construction phase of the facility and, thereafter, for the entire service life of the facility. No rate adjustment clause for new underground facilities shall allocate costs to, or provide for the recovery of costs from, customers that are served within the large power service rate class for a Phase I utility and the large general service rate classes for a Phase II utility. New underground facilities are hereby declared to be ordinary extensions or improvements in the usual course of business under the provisions of § 56-265.2.

As used in this subdivision, a generation facility is ~~(1)~~ *(A)* "coalbed methane gas powered" if the facility is fired at least 50 percent by coalbed methane gas, as such term is defined in § 45.1-361.1, produced from wells located in the Commonwealth, and ~~(2)~~ *(B)* "landfill gas powered" if the facility is fired by methane or other combustible gas produced by the anaerobic digestion or decomposition of biodegradable materials in a solid waste management facility licensed by the Waste Management Board. A landfill gas powered facility includes, in addition to the generation facility itself, the equipment used in collecting, drying, treating, and compressing the landfill gas and in transmitting the landfill gas from the solid waste management facility where it is collected to the generation facility where it is combusted.

For purposes of this subdivision, "general rate of return" means the fair combined rate of return on common equity as it is determined by the Commission from time to time for such utility pursuant to subdivision 2. In any proceeding under this subdivision conducted prior to the conclusion of the first biennial review for such utility, the Commission shall determine a general rate of return for such utility in the same manner as it would in a biennial review proceeding.

Notwithstanding any other provision of this subdivision, if the Commission finds during the biennial review conducted for a Phase II utility in 2018 that such utility has not filed applications for all necessary federal and state regulatory approvals to construct one or more nuclear-powered or coal-fueled generation facilities that would add a total capacity of at least 1500 megawatts to the amount of the utility's generating resources as such resources existed on July 1, 2007, or that, if all such approvals have been received, that the utility has not made reasonable and good faith efforts to construct one or more such facilities that will provide such additional total capacity within a reasonable time after obtaining such approvals, then the Commission, if it finds it in the public interest, may reduce on a prospective basis any enhanced rate of return on common equity previously applied to any such facility to no less than the general rate of return for such utility and may apply no less than the utility's general rate of return to any such facility for which the utility seeks approval in the future under this subdivision.

7. Any petition filed pursuant to subdivision 4, 5, or 6 shall be considered by the Commission on a stand-alone basis without regard to the other costs, revenues, investments, or earnings of the utility. Any costs incurred by a utility prior to the filing of such petition, or during the consideration thereof by the Commission, that are proposed for recovery in such petition and that are related to subdivision 5 a, or that are related to facilities and projects described in clause (i) of subdivision 6, or that are related to new underground facilities described in clause (iv) of subdivision 6, shall be deferred on the books and records of the utility until the Commission's final order in the matter, or until the implementation of any applicable approved rate adjustment clauses, whichever is later. Except as otherwise provided in subdivision 6, any costs prudently incurred on or after July 1, 2007, by a utility prior to the filing of such petition, or during the consideration thereof by the Commission, that are proposed for recovery in such petition and that are related to facilities and projects described in clause (ii) of subdivision 6 that utilize nuclear power, or coal-fueled facilities and projects described in clause (ii) of subdivision 6 if such coal-fueled facilities will be built by a Phase I Utility, shall be deferred on the books and records of the utility until the Commission's final order in the matter, or until the implementation of any applicable approved rate adjustment clauses, whichever is later. Any costs prudently incurred after the expiration or termination of capped rates related to other matters described in subdivision 4, 5, or 6 shall be deferred beginning only upon the expiration or termination of capped rates, provided, however, that no provision of this act shall affect the rights of any parties with respect to the rulings of the Federal Energy Regulatory Commission in PJM Interconnection LLC and Virginia Electric and Power Company, 109 F.E.R.C. P 61,012 (2004). A utility shall establish a regulatory asset for regulatory accounting and ratemaking purposes under which it shall defer its operation and maintenance costs incurred in connection with (i) the refueling of any nuclear-powered generating plant and (ii) other work at such plant normally performed during a refueling outage. The utility shall amortize such deferred costs over the refueling cycle, but in no case more than 18 months, beginning with the month in which such plant resumes operation after such refueling. The refueling cycle shall be the applicable period of time between planned refueling outages for such plant. As of January 1, 2014, such amortized costs are a component of base rates, recoverable in base rates only ratably over the refueling cycle rather than when such outages occur, and are the only nuclear refueling costs recoverable in base rates. This provision shall apply to any nuclear-powered generating plant refueling outage commencing after December 31, 2013, and the Commission shall treat the deferred and amortized costs of such regulatory asset as part of the utility's costs for the purpose of proceedings conducted (a) with respect to biennial filings under

subdivision 3 made on and after July 1, 2014, and (b) pursuant to § 56-245 or the Commission's rules governing utility rate increase applications as provided in subsection B. This provision shall not be deemed to change or reset base rates.

The Commission's final order regarding any petition filed pursuant to subdivision 4, 5, or 6 shall be entered not more than three months, eight months, and nine months, respectively, after the date of filing of such petition. If such petition is approved, the order shall direct that the applicable rate adjustment clause be applied to customers' bills not more than 60 days after the date of the order, or upon the expiration or termination of capped rates, whichever is later.

8. In any biennial review proceeding, the following utility generation and distribution costs not proposed for recovery under any other subdivision of this subsection, as recorded per books by the utility for financial reporting purposes and accrued against income, shall be attributed to the test periods under review: costs associated with asset impairments related to early retirement determinations made by the utility prior to December 31, 2012, for utility generation plant; costs associated with severe weather events; and costs associated with natural disasters. Such costs shall be deemed to have been recovered from customers through rates for generation and distribution services in effect during the test periods under review unless such costs, individually or in the aggregate, together with the utility's other costs, revenues, and investments to be recovered through rates for generation and distribution services, result in the utility's earned return on its generation and distribution services for the combined test periods under review to fall more than 50 basis points below the fair combined rate of return authorized under subdivision 2 for such periods or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, to fall more than 70 basis points below the fair combined rate of return authorized under subdivision 2 for such periods. In such cases, the Commission shall, in such biennial review proceeding, authorize deferred recovery of such costs and allow the utility to amortize and recover such deferred costs over future periods as determined by the Commission. The aggregate amount of such deferred costs shall not exceed an amount that would, together with the utility's other costs, revenues, and investments to be recovered through rates for generation and distribution services, cause the utility's earned return on its generation and distribution services to exceed the fair rate of return authorized under subdivision 2, less 50 basis points, for the combined test periods under review or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, to exceed the fair rate of return authorized under subdivision 2 less 70 basis points. Nothing in this section shall limit the Commission's authority, pursuant to the provisions of Chapter 10 (§ 56-232 et seq.), including specifically § 56-235.2, following the review of combined test period earnings of the utility in a biennial review, for normalization of nonrecurring test period costs and annualized adjustments for future costs, in determining any appropriate increase or decrease in the utility's rates for generation and distribution services pursuant to subdivision 8 a or 8 c.

If the Commission determines as a result of such biennial review that:

a. The utility has, during the test period or periods under review, considered as a whole, earned more than 50 basis points below a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points below a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, the Commission shall order increases to the utility's rates necessary to provide the opportunity to fully recover the costs of providing the utility's services and to earn not less than such fair combined rate of return, using the most recently ended 12-month test period as the basis for determining the amount of the rate increase necessary. However, the Commission may not order such rate increase unless it finds that the resulting rates are necessary to provide the utility with the opportunity to fully recover its costs of providing its services and to earn not less than a fair combined rate of return on both its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, using the most recently ended 12-month test period as the basis for determining the permissibility of any rate increase under the standards of this sentence, and the amount thereof;

b. The utility has, during the test period or test periods under review, considered as a whole, earned more than 50 basis points above a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points above a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, the Commission shall, subject to the provisions of subdivision 9, direct that 60 percent of the amount of such earnings that were more than 50 basis points, or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, that 70 percent of the amount of such earnings that were more than 70 basis points, above such fair combined rate of return for the test period or periods under review, considered as a whole, shall be credited to customers' bills. Any such credits shall be amortized over a period of six to 12 months, as determined at the discretion of the Commission, following the effective date of the Commission's order, and shall be allocated among customer classes such that the relationship between the specific customer class rates of return to the overall target rate of return will have the same relationship as the last approved allocation of revenues used to design base rates; or

c. Such biennial review is the second consecutive biennial review in which the utility has, during the test period or test periods under review, considered as a whole, earned more than 50 basis points above a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points above a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matter determined with respect to facilities described in subdivision 6, the Commission shall, subject to the provisions of subdivision 9 and in addition to the actions authorized in subdivision b, also order reductions to the utility's rates it finds appropriate. However, the Commission may not order such rate reduction unless it finds that the resulting rates will provide the utility with the opportunity to fully recover its costs of providing its services and to earn not less than a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, using the most recently ended 12-month test period as the basis for determining the permissibility of any rate reduction under the standards of this sentence, and the amount thereof.

The Commission's final order regarding such biennial review shall be entered not more than eight months after the date of filing, and any revisions in rates or credits so ordered shall take effect not more than 60 days after the date of the order. The fair combined rate of return on common equity determined pursuant to subdivision 2 in such biennial review shall apply, for purposes of reviewing the utility's earnings on its rates for generation and distribution services, to the entire two successive 12-month test periods ending December 31 immediately preceding the year of the utility's subsequent biennial review filing under subdivision 3.

9. If, as a result of a biennial review required under this subsection and conducted with respect to any test period or periods under review ending later than December 31, 2010 (or, if the Commission has elected to stagger its biennial reviews of utilities as provided in subdivision 1, under review ending later than December 31, 2010, for a Phase I Utility, or December 31, 2011, for a Phase II Utility), the Commission finds, with respect to such test period or periods considered as a whole, that (i) any utility has, during the test period or periods under review, considered as a whole, earned more than 50 basis points above a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points above a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, and (ii) the total aggregate regulated rates of such utility at the end of the most recently-ended 12-month test period exceeded the annual increases in the United States Average Consumer Price Index for all items, all urban consumers (CPI-U), as published by the Bureau of Labor Statistics of the United States Department of Labor, compounded annually, when compared to the total aggregate regulated rates of such utility as determined pursuant to the biennial review conducted for the base period, the Commission shall, unless it finds that such action is not in the public interest or that the provisions of subdivisions 8 b and c are more consistent with the public interest, direct that any or all earnings for such test period or periods under review, considered as a whole that were more than 50 basis points, or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points, above such fair combined rate of return shall be credited to customers' bills, in lieu of the provisions of subdivisions 8 b and c. Any such credits shall be amortized and allocated among customer classes in the manner provided by subdivision 8 b. For purposes of this subdivision:

"Base period" means (i) the test period ending December 31, 2010 (or, if the Commission has elected to stagger its biennial reviews of utilities as provided in subdivision 1, the test period ending December 31, 2010, for a Phase I Utility, or December 31, 2011, for a Phase II Utility), or (ii) the most recent test period with respect to which credits have been applied to customers' bills under the provisions of this subdivision, whichever is later.

"Total aggregate regulated rates" shall include: (i) fuel tariffs approved pursuant to § 56-249.6, except for any increases in fuel tariffs deferred by the Commission for recovery in periods after December 31, 2010, pursuant to the provisions of clause (ii) of subsection C of § 56-249.6; (ii) rate adjustment clauses implemented pursuant to subdivision 4 or 5; (iii) revisions to the utility's rates pursuant to subdivision 8 a; (iv) revisions to the utility's rates pursuant to the Commission's rules governing utility rate increase applications, as permitted by subsection B, occurring after July 1, 2009; and (v) base rates in effect as of July 1, 2009.

10. For purposes of this section, the Commission shall regulate the rates, terms and conditions of any utility subject to this section on a stand-alone basis utilizing the actual end-of-test period capital structure and cost of capital of such utility, unless the Commission finds that the debt to equity ratio of such capital structure is unreasonable for such utility, in which case the Commission may utilize a debt to equity ratio that it finds to be reasonable for such utility in determining any rate adjustment pursuant to subdivisions 8 a and c, and without regard to the cost of capital, capital structure, revenues, expenses or investments of any other entity with which such utility may be affiliated. In particular, and without limitation, the Commission shall determine the federal and state income tax costs for any such utility that is part of a publicly traded, consolidated group as follows: (i) such utility's apportioned state income tax costs shall be calculated according to the applicable statutory rate, as if the utility had not filed a consolidated return with its affiliates, and (ii) such utility's federal income tax costs shall be calculated according to the applicable federal income tax rate and shall exclude any consolidated tax liability or benefit adjustments originating from any taxable income or loss of its affiliates.

B. Nothing in this section shall preclude an investor-owned incumbent electric utility from applying for an increase in rates pursuant to § 56-245 or the Commission's rules governing utility rate increase applications; however, in any such filing, a fair rate of return on common equity shall be determined pursuant to subdivision A 2. Nothing in this section shall preclude such utility's recovery of fuel and purchased power costs as provided in § 56-249.6.

C. Except as otherwise provided in this section, the Commission shall exercise authority over the rates, terms and conditions of investor-owned incumbent electric utilities for the provision of generation, transmission and distribution services to retail customers in the Commonwealth pursuant to the provisions of Chapter 10 (§ 56-232 et seq.), including specifically § 56-235.2.

D. The Commission may determine, during any proceeding authorized or required by this section, the reasonableness or prudence of any cost incurred or projected to be incurred, by a utility in connection with the subject of the proceeding. A determination of the Commission regarding the reasonableness or prudence of any such cost shall be consistent with the Commission's authority to determine the reasonableness or prudence of costs in proceedings pursuant to the provisions of Chapter 10 (§ 56-232 et seq.). In determining the reasonableness or prudence of a utility providing energy and capacity to its customers from renewable energy resources, the Commission shall consider the extent to which such renewable energy resources, whether utility-owned or by contract, further the objectives of the Commonwealth Energy Policy set forth in §§ 67-101 and 67-102, and shall also consider whether the costs of such resources is likely to result in unreasonable increases in rates paid by consumers.

E. *In any proceeding under this section, a utility's earnings shall include any revenue paid to or other consideration received by the utility in connection with the sale or transfer of a new zero-emitting energy facility credit or demand-side efficiency credit pursuant to Chapter 28 (§ 56-610 et seq.).*

F. The Commission shall promulgate such rules and regulations as may be necessary to implement the provisions of this section.

CHAPTER 28.

ENERGY DIVERSIFICATION REQUIREMENTS.

§ 56-610. Definitions.

As used in this chapter:

"Administrator" means the Department or, if the Department has appointed a person to administer provisions of this chapter related to credits, the appointee.

"Combined heat and power system" means a system that uses waste heat to produce electricity or useful, measurable thermal or mechanical energy at a facility owned or operated by a retail customer.

"Cost-effective energy efficiency program" means an energy efficiency program, whether or not implemented prior to July 1, 2015, that is determined by the administrator to be cost-effective pursuant to the provisions of § 56-612.

"Credit" means a DSE credit or an NZEEF credit.

"Demand response" means activities, programs, or initiatives undertaken by an LSE to reduce retail customers' electricity use during peak demand periods. "Demand response" includes load management, including management by retail consumers in response to communications from an LSE, interruptible load, price-responsive demand, and similar programs that demonstrate reduced demand during peak periods.

"Demand-side efficiency" or "DSE" means (i) distributed generation and (ii) demand-side management.

"Demand-side efficiency credit" or "DSE credit" means a tradable instrument that is used to track and verify compliance with the DSE requirement and is issued by the administrator in accordance with

the requirements of § 56-612.

"Demand-side efficiency requirement" or "DSE requirement" means the amount of DSE an LSE is required to achieve in a year pursuant to subsection A of § 56-611.

"Demand-side management" or "DSM" means (i) cost-effective energy efficiency programs or (ii) demand response on the customer premises.

"Department" means the Department of Mines, Minerals and Energy.

"Distributed generation" means electricity that an LSE forgoes selling to retail customers as a result of the retail customers' generation of electricity from fuel cells, combined heat and power, or a zero-emitting resource or technology at a generation facility on a retail customer's premises, at the retail customer's side of its electric meter. "Distributed generation" includes electric generation added to an LSE's distribution system by an eligible customer-generator pursuant to its participation in the net energy metering program established under § 56-594.

"Energy efficiency program" means an activity, initiative, or program that after July 1, 2015, (i) reduces the total amount of electricity that is required for the same consumer process or activity, (ii) decreases the annual consumption of electricity or total electricity bill of participating retail customers, or (iii) reduces or prevents electricity costs or consumption that the retail customer may otherwise have incurred. "Energy efficiency program" includes (a) natural gas fuel switching, (b) retail customer behavioral efficiency or engagement programs that result in measurable and verifiable energy savings or lead to efficient use patterns and practices, (c) transmission and distribution system efficiency improvements that result in measured and verified reduction in line loss through superconducting or other technology, and (d) programs that result in improvements in lighting design; heating, ventilation, and air conditioning systems; appliances; building envelopes; and industrial and commercial processes.

"Load serving entity" or "LSE" means an investor-owned electric utility other than one to which the provisions of Chapter 23 (§ 56-576 et seq.) are suspended pursuant to subsection G of § 56-580.

"New zero-emitting energy facility" or "NZEEF" means a zero-emitting energy facility that is first placed into service on or after July 1, 2015.

"New zero-emitting energy facility credit" or "NZEEF credit" means a tradable instrument that is used to track and verify compliance with the NZEEF requirements and is issued by the administrator in accordance with the requirements of § 56-612.

"Offshore facility" shall be deemed to be a facility located in the Commonwealth if it is at a location in the Atlantic Outer Continental Shelf Region at which Virginia is the nearest state.

"Participant Cost Test" means a test that compares participant benefits, including incentives and bill savings, with participant costs, including incremental or capital cost, installation, and maintenance.

"Program Administrator Cost Test" or "Utility Cost Test" means a test that compares an LSE's avoided cost benefits with energy efficiency program expenditures, including incentives and administrative costs.

"Quantified energy diversification" or "QED" means the sum of (i) the megawatts of electricity generated or acquired by an LSE from new zero-emitting energy facilities for sale to its retail customers and (ii) the amount of demand-side efficiency, expressed in megawatts of electricity, achieved or acquired by an LSE.

"Quantified energy diversification requirement" or "QED requirement" means the amount of quantified energy diversity that an LSE is required to achieve in a year pursuant to subsection A of § 56-611.

"Rate Impact Measure Test" means a test that compares the LSE's avoided cost benefits with the cost of administering energy efficiency programs plus lost revenue from reductions in customer energy consumption.

"Recoverable costs" means costs incurred by an LSE in complying with the QED requirements and DSE requirements that an LSE is authorized to recover pursuant to § 56-617.

"Retail customer" means any person that purchases electric energy from an LSE for its own consumption at one or more metering points or nonmetered points of delivery located in the Commonwealth.

"Retail sales" means the amount of electric energy, expressed as kilowatt hours or megawatt hours, sold by an LSE to its retail customer for the retail customer's own consumption.

"Thermal energy equivalent" means the electrical equivalent in megawatt hours of thermal energy produced at a zero-emitting energy facility calculated by dividing (i) the heat content, measured in British thermal units (BTUs), of the thermal energy at the point of transfer to a residential, commercial, institutional, or industrial process by (ii) the standard conversion factor of 3.413 million BTUs per megawatt hour.

"Total Resource Cost Test" is a test of the cost effectiveness of an energy efficiency program that compares benefits to society as a whole, including avoided supply-side cost benefits and additional resource savings benefits, with the participant's cost of installing the measure plus the cost of energy

efficiency program administration, including non-incentive costs. Incentives are considered a transfer payment from program to participant and thus are not explicitly accounted for in the calculation.

"True-up period" means the period each year from the end of a calendar year until the next following March 1.

"Zero-emitting energy facility" means any of the following types of facilities located in the Commonwealth at which electricity or thermal energy is generated for sale to wholesale or retail customers:

1. A commercial nuclear energy plant licensed by the U.S. Nuclear Regulatory Commission;

2. An onshore or offshore wind turbine facility;

3. A solar water heating system;

4. A combined heat and power system;

5. A solar thermal facility that produces thermal energy;

6. A solar photovoltaic system;

7. A hydroelectric power station;

8. A geothermal electric facility;

9. A facility at which electricity is generated from methane produced by anaerobic digestion;

10. A tidal or wave energy facility; or

11. Any facility of a type that the Department, by regulation, determines is appropriate to designate as a zero-emitting energy facility on grounds that the technology utilized in such a facility to generate electricity or thermal energy and does not emit measurable quantities of air pollutants.

"Zero-emitting energy facility" does not include any facility that qualifies as a distributed generation facility.

"Zero-emitting energy resource or technology" means solar photovoltaic, solar thermal electric, thermal energy of combined heat and power, wind, hydroelectric, geothermal electric, anaerobic digestion, tidal energy, wave energy, nuclear energy, or any technology that the Department by regulation determines is appropriate to designate as a zero-emitting energy technology on grounds that the technology used to generate electricity or thermal energy became commercially feasible after July 1, 2015, and does not emit measurable quantities of air pollutants.

§ 56-611. Energy diversification goals established.

A. During calendar year 2016 and thereafter, (i) each LSE shall achieve quantified energy diversification in amounts not less than the required percentages of the LSE's retail sales in each such year as stated in the following table and (ii) not less than 40 percent of the amount of quantified energy diversification required to be achieved by an LSE in each such year shall be achieved as a result of implementing DSE, which DSE requirement is expressed as a percentage of the LSE's retail sales in each such year as stated in the following table:

Calendar Year	*QED Requirement (NZEEF and DSE)*	*DSE Requirement*
2016	*0.25 percent of retail sales*	*0.10 percent of retail sales*
2017	*1.0 percent of retail sales*	*0.4 percent of retail sales*
2018	*2.5 percent of retail sales*	*1.0 percent of retail sales*
2019	*4.5 percent of retail sales*	*1.8 percent of retail sales*
2020	*7.0 percent of retail sales*	*2.8 percent of retail sales*
2021	*10 percent of retail sales*	*4.0 percent of retail sales*
2022	*14 percent of retail sales*	*5.6 percent of retail sales*
2023	*17 percent of retail sales*	*6.8 percent of retail sales*
2024	*20 percent of retail sales*	*8.0 percent of retail sales*
2025	*23 percent of retail sales*	*9.2 percent of retail sales*
2026	*24 percent of retail sales*	*9.6 percent of retail sales*
2027	*27 percent of retail sales*	*10.8 percent of retail sales*
2028	*30 percent of retail sales*	*12 percent of retail sales*
2029	*33 percent of retail sales*	*13.2 percent of retail sales*
2030 and after	*35 percent of retail sales*	*14 percent of retail sales*

B. An LSE shall demonstrate the amount of quantified energy diversification that it achieved in a calendar year only by submitting to the administrator (i) the requisite amount of eligible credits that have been issued pursuant to § 56-612 and (ii) such additional documentation as is required by § 56-614.

C. An LSE shall demonstrate the amount of demand-side efficiency that it achieved in a calendar year only by submitting to the administrator (i) the requisite amount of eligible DSE credits that have been issued pursuant to § 56-612 and (ii) such additional documentation as is required by § 56-614.

D. Notwithstanding any provision of this chapter to the contrary, an LSE shall implement, or acquire credits that verify the implementation of, all cost-effective demand-side efficiency programs prior to implementing, or acquiring credits that verify the implementation of, any other action to satisfy a QED requirement or DSE requirement.

§ 56-612. Credits.

A. The Department shall establish and administer a program for the issuance, certification, reporting, tracking, and retiring of NZEEF credits and DSE credits. The Department shall establish procedures for determining when and how credits are created, accounted for, transferred, and retired. The program shall include protocols for determining if a generation facility qualifies as an NZEEF or distributed generation facility.

B. The Department may appoint a person independent of any regulatory body to serve as administrator and in such capacity to implement the procedures established by the Department that pertain to the issuing, certifying, reporting, tracking, and retiring of credits. If the Department appoints a person to serve as administrator, the Department shall remain responsible for monitoring compliance with enforcing the requirements of this chapter. The provisions of the Virginia Public Procurement Act (§ 2.2-4300 et seq.) shall not apply to the appointment by the Department of a person to administer such aspects of the credits program. A person appointed to serve as administrator shall submit reports to the Department at such times and in such manner as the Department shall direct.

C. A credit shall not be eligible to be used by an LSE to demonstrate compliance with any NZEEF requirement or DSE requirement unless the credit has been issued by the administrator pursuant to this section.

D. The administrator, upon reviewing and approving an application submitted by an LSE or other entity that operates an NZEEF, shall issue one NZEEF credit for each megawatt hour of electricity or its equivalent in thermal energy that was generated within the calendar year preceding the date on which the application was submitted at an NZEEF owned by the LSE or other entity. Thermal energy produced at a solar-thermal or combined-heat-and-power NZEEF shall be converted to electricity based on its thermal energy equivalent.

E. The administrator, upon reviewing and approving an application submitted by an LSE or other entity that operates a distributed generation facility or conducts a DSM program, shall issue one DSE credit for the equivalent of one megawatt hour of electricity savings achieved within the calendar year preceding the date on which the application was submitted through the operation of the distributed generation facility or the implementation of the DSM program. However, the administrator shall not issue a DSE credit in connection with an energy efficiency program unless the administrator has found that the program is a cost-effective energy efficiency program. Credits may be issued for a DSE program that was placed in service or was first implemented, as applicable, prior to July 1, 2015, but no DSE credit shall be issued for DSE produced or achieved prior to July 1, 2015.

The Department shall adopt protocols to be used by the administrator in determining if an energy efficiency program is cost effective. The protocols shall require, among other factors, that the net present value of the benefits exceed the net present value of the costs as determined by not less than any three of the following benefit cost tests: (i) the Total Resource Cost Test, (ii) the Program Administrator Cost Test (also referred to as the Utility Cost Test); (iii) the Participant Cost Test; and (iv) the Rate Impact Measure Test. In addition, an energy efficiency program may be deemed to be "in the public interest" if the program provides measurable and verifiable energy savings to low-income customers or elderly customers. The administrator shall oversee all evaluation, measurement, and validation required with respect to determining whether an energy-efficiency program is cost effective.

F. The protocols established by the Department shall include methods for determining ownership of credits that are derived from a distributed generation facility owned by a retail customer as a result of any action by a retail customer that is independent of a net energy metering program implemented by an LSE.

G. A credit shall exist for three years after the calendar year in which it was issued unless the credit is retired sooner by (i) an LSE that submits the credit to the administrator in order to demonstrate compliance with an NZEEF requirement or DSE requirement or (ii) any other entity that owns the credit and retires the credit for any purpose. An expired credit shall not be eligible for use in meeting the LSE's QED requirement or DSE requirement.

H. The owner of an NZEEF shall own the NZEEF credits issued with respect to the electricity generated at the facility. The owner of a distributed generation facility shall own the DSE credits issued with respect to the electricity generated at the facility. The LSE or other entity that conducts or implements a demand-side management program, including a cost-effective energy efficiency program, shall own the DSE credits issued with respect to the electricity savings achieved through the DSM program.

I. Planning and development activities for cost-effective energy efficiency programs are in the public *interest.*

J. The administrator shall consider fuel-cycle analysis measurement with regard to its issuance of credits, in accordance with protocols adopted by the Department.

§ 56-613. Credit registry and trading system.

A. The Department or its designee shall develop a registry of pertinent information regarding all available NZEEF credits and DSE credits and the number of such credits sold or transferred, including:

1. The number of NZEEF credits and DSE credits expected to be available to LSEs in each calendar year;

2. The number of credits produced in each calendar year or the number of credits available for purchase; and

3. The market price of such credits.

B. The registry shall be available to the general public, but shall not include or disclose any competitively sensitive information such as the names of parties to specific transactions, the number of credits created, purchased, or owned by any specific party, or the price received or paid for credits by any specific party, unless the party so named agrees to inclusion or disclosure, or both, of such information, except as the inclusion or disclosure, or both, of such information may be necessary to demonstrate compliance with other portions of this chapter.

C. The Department shall establish protocols for a market-based trading system to facilitate the transfer of credits. The administrator shall operate the trading system in accordance with the protocols. An LSE may transfer to another LSE credits that are in excess of the amount of credits required for the transferring LSE to meet its NZEEF requirement and DSE requirement for the applicable calendar year.

D. The Department may develop, implement, and maintain a website for the online tracking of credits in order to verify the compliance of LSEs with the QED requirements and DSE requirements and to facilitate the establishment of the market-based trading system for the transferring of credits.

§ 56-614. Reporting by LSEs; determination of compliance.

A. By April 1 of each year, each LSE shall provide to the administrator documentation of its compliance with the QED requirements and DSE requirements, in such format as the Department shall direct and with any supporting information that the administrator requests, that includes for the preceding calendar year (i) the amount of the LSE's retail sales and (ii) the amount of the LSE's NZEEF credits and DSE credits being submitted for purposes of demonstrating compliance with the NZEEF requirement and DSE requirement.

B. Only the following shall be eligible for use by an LSE in meeting the QED requirements for a calendar year:

1. NZEEF credits representing the generation of electric power at an NZEEF during that calendar year or in any of the preceding three calendar years; and

2. DSE credits representing distributed generation, cost-effective energy efficiency programs, or demand response during that calendar year or in any of the preceding three calendar years.

C. Only DSE credits representing distributed generation, cost-effective energy efficiency programs, or demand response during that year or in any of the preceding three calendar years shall be eligible for use by the LSE in meeting the DSE requirements for a calendar year.

D. A credit shall be eligible for submission by an LSE if it has not expired, has not been previously submitted or retired, and is in compliance with the requirements of subsection D of § 56-611. A credit shall be permanently retired upon its submission to the administrator.

E. A DSE credit submitted by an LSE may be applied toward satisfying both the QED requirement and DSE requirement for the applicable calendar year.

F. To prevent double-counting, no LSE shall use credits that have been:

1. Used to satisfy another state's portfolio requirements to satisfy the energy diversification requirements established by this chapter; or

2. Used to satisfy the energy diversification requirements established by this chapter to satisfy another state's portfolio requirements.

G. Each LSE shall include in its compliance documentation submitted to the administrator:

1. Whether the LSE sells electricity in any other state and is subject to energy portfolio requirements in that state; and

2. If so, information identifying any such energy portfolio requirements in that state and documenting how the LSE satisfied that state's energy portfolio requirements.

H. The failure of an LSE to acquire credits during a calendar year shall not prevent the LSE from satisfying its QED requirement or DSE requirement for that year by purchasing or otherwise acquiring NZEEF credits or DSE credits during the true-up period to make up for any shortfall of credits the LSE might otherwise experience.

I. The Department shall conduct a review of the documentation submitted to the administrator by an LSE pursuant to subsection A. If, after notice and hearing, the Department determines that an LSE supplier has failed to comply with the QED requirement or DSE requirement for that year, the

Department shall order the LSE to make a noncompliance payment.

J. An LSE may bank or place in reserve credits acquired in one calendar year for compliance in future calendar years, provided that such action shall not extend the credit beyond the three calendar years following the calendar year for which it was issued. In addition, the LSE shall demonstrate to the satisfaction of the Department that such credits:

1. Have not previously been used to comply with a QED requirement or a DSE requirement; and

2. Have not otherwise been and will not be sold, retired, claimed, or represented to demonstrate compliance with energy portfolio standards in other states.

§ 56-615. Noncompliance payments; collection; civil penalty.

A. If, after notice and opportunity for a hearing, the Department determines that an LSE has failed to meet its QED requirement or DSE requirement for a calendar year, the Department shall order the LSE to make a noncompliance payment.

B. The amount of an LSE's noncompliance payment shall be:

1. $200 for each megawatt hour or portion thereof by which the LSE's QED for a calendar year is less than the QED requirement for that year, regardless of whether the LSE satisfied its DSE requirement for that year; and

2. $200 for each megawatt hour or portion thereof by which the LSE's DSE for a calendar year is less than the DSE requirement for that year, regardless of whether the LSE satisfied its QED requirement for that year.

C. Noncompliance payments shall be paid into the Deployment Investment Fund established pursuant to § 56-616.

D. Noncompliance payments made by an LSE shall be a recoverable cost to the extent provided in subdivision 5 of § 56-617.

E. Any LSE that fails to pay a noncompliance payment assessed by the Department shall be assessed a civil penalty by the Director. Such civil penalty shall be in the amount of the unpaid noncompliance payment. If the Department has provided the LSE notice and opportunity for a hearing with respect to the assessment of the noncompliance payment, no further opportunity for a public hearing shall be required. Any hearing under this section shall be a formal adjudicatory hearing in accordance with the Administrative Process Act (§ 2.2-4000 et seq.). If an LSE that is required to pay a civil penalty fails to do so, the Director may transmit a true copy of the final order assessing such penalty to the clerk of the court of any county or city wherein it is ascertained that the LSE owing the penalty has any estate, and the clerk to whom such copy is so sent shall record it, as a judgment is required by law to be recorded, and shall index the same as well in the name of the Commonwealth as of the person owing the civil penalty, and thereupon there shall be a lien in favor of the Commonwealth on the property of the LSE within such county or city in the amount of the penalty. The Director may collect civil penalties that are owed in the same manner as provided by law in respect to judgment of a court of record. All civil penalties shall be paid into the Deployment Investment Fund established pursuant to § 56-616.

§ 56-616. Deployment Investment Fund.

There is hereby created in the state treasury a special nonreverting fund to be known as the Deployment Investment Fund, hereafter referred to as "the Fund." The Fund shall be established on the books of the Comptroller. All noncompliance payments collected by the Department pursuant to this chapter shall be paid into the state treasury and credited to the Fund. Interest earned on moneys in the Fund shall remain in the Fund and be credited to it. Any moneys remaining in the Fund, including interest thereon, at the end of each fiscal year shall not revert to the general fund but shall remain in the Fund. Moneys in the Fund shall be used solely for the purposes of payment of grants for projects that will increase (i) the amount of electric energy generated from zero-emission energy resources and technologies within the Commonwealth and (ii) the implementation of cost-effective energy efficiency programs within the Commonwealth. The moneys may be distributed to existing programs in the Commonwealth administered by agencies, political subdivisions, and universities. Unallocated moneys in the Fund in any year shall remain in the Fund and be available for allocation for grants under this section in ensuing fiscal years. Expenditures and disbursements from the Fund shall be made by the State Treasurer on warrants issued by the Comptroller upon written request signed by the director of the Department or its designee.

§ 56-617. Recovery by LSEs of compliance costs.

An LSE shall be allowed to recover, through a rate adjustment clause as provided in subdivision A 5 f of § 56-585.1, the following costs incurred by the LSE in activities undertaken to comply with the QED requirement and the DSE requirement, to the extent such costs are reasonable and prudent:

1. The costs of the LSE's internal cost-effective energy efficiency programs and demand response programs to the extent such programs result in the issuance to the LSE of DSE credits, and provided such costs do not include any costs that are recoverable by an LSE pursuant to subdivision A 5 c of § 56-585.1;

2. Administrative costs directly related to complying with the QED requirement and the DSE requirement;

3. The incremental cost of electricity generated by a NZEEF owned by an LSE to the extent the LSE's generation of such electricity results in the issuance to the LSE of NZEEF credits. The incremental cost of such electricity is the difference between the levelized annual delivered cost of the electricity generated by an NZEEF owned by the utility and the levelized annual delivered cost of an equivalent amount of reasonably available electricity that is not generated by an NZEEF. The incremental cost of such electricity generated by an LSE shall not be deemed to be reasonable and prudent to the extent such incremental cost exceeds $200 per megawatt hour;

4. All payments for credits that are voluntarily acquired by an LSE in the trading system market operated pursuant to subsection C of § 56-613, provided that (i) the LSE may recover the costs of a credit only with respect to the calendar year for which the credit is applied to meet a QED requirement or DSE requirement and (ii) any amount paid in excess of $200 per credit shall not be deemed to be a reasonable or prudent cost; and

5. Any noncompliance payment paid by the LSE if the market price for credits needed for the LSE to achieve compliance with the QED requirement or DSE requirement for the calendar year, determined at the end of the calendar year and during the true-up period, exceeds $200 per credit. The market price of a credit shall be the market price as reported in the registry pursuant to subdivision A 3 of § 56-613. Civil penalties assessed as a result of failure to pay a noncompliance payment shall not be recoverable.

§ 56-618. Interagency responsibilities.

The Commission and the Department shall work cooperatively to monitor the performance of all aspects of this chapter.

§ 56-619. Regulations.

A. The Department shall adopt such rules and regulations as are necessary or convenient to implement the provisions of this chapter.

B. Final regulations required to implement this chapter shall be adopted by September 1, 2016.

§ 56-620. Reports.

A. The Department shall provide an annual report to the Governor and General Assembly by June 1 of each year that includes:

1. The status of compliance with the provisions of this chapter by suppliers;

2. Costs of renewable energy credits on a per-kilowatt-hour basis for all zero-emitting energy facilities, resources, and technologies;

3. Costs associated with the credits program under this chapter, including the number and amount of noncompliance payments;

4. The status of the credits registry within the Commonwealth; and

5. Recommendations for program improvements.

B. The Department shall establish a process to provide for annual reviews of the credit registry within the Commonwealth. The Department shall use the results of this study to identify any changes to the noncompliance payment program amounts that would be likely to induce LSEs to satisfy the QED requirement and DSE requirement by means other than by submitting noncompliance payments. If the Department finds that the noncompliance payment program needs to be changed to have the intended effect, the Department shall present these findings to the General Assembly with a recommendation for legislative enactment.

2. That the Director of the Department of Mines, Minerals and Energy shall promulgate regulations to implement the provisions of this act to be effective within 280 days of its enactment.