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**HOUSE BILL NO. 839**

Offered January 12, 2022

Prefiled January 12, 2022

*A BILL to amend and reenact §§ 56-585.1, 56-585.1:11, and 56-585.5 of the Code of Virginia, relating to electric utilities; recovery of costs; rate adjustment clause proceedings; construction or acquisition of certain facilities.*

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Patron—Wilt

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Committee Referral Pending

**Be it enacted by the General Assembly of Virginia:**

**1. That §§ 56-585.1, 56-585.1:11, and 56-585.5 of the Code of Virginia are amended and reenacted 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 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. Pursuant to subsection A of § 56-585.1:1, the Commission shall conduct a review for a Phase I Utility in 2020, utilizing the three successive 12-month test periods beginning January 1, 2017, and ending December 31, 2019. Thereafter, reviews for a Phase I Utility will be on a triennial basis with subsequent proceedings utilizing the three successive 12-month test periods ending December 31 immediately preceding the year in which such review proceeding is conducted. Pursuant to subsection A of § 56-585.1:1, the Commission shall

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59 conduct a review for a Phase II Utility in 2021, utilizing the four successive 12-month test periods  
60 beginning January 1, 2017, and ending December 31, 2020, with subsequent reviews on a triennial basis  
61 utilizing the three successive 12-month test periods ending December 31 immediately preceding the year  
62 in which such review proceeding is conducted. All such reviews occurring after December 31, 2017,  
63 shall be referred to as triennial reviews. For purposes of this section, a Phase I Utility is an  
64 investor-owned incumbent electric utility that was, as of July 1, 1999, not bound by a rate case  
65 settlement adopted by the Commission that extended in its application beyond January 1, 2002, and a  
66 Phase II Utility is an investor-owned incumbent electric utility that was bound by such a settlement.

67 2. Subject to the provisions of subdivision 6, the fair rate of return on common equity applicable  
68 separately to the generation and distribution services of such utility, and for the two such services  
69 combined, and for any rate adjustment clauses approved under subdivision 5 or 6, shall be determined  
70 by the Commission during each such triennial review, as follows:

71 a. The Commission may use any methodology to determine such return it finds consistent with the  
72 public interest, but for applications received by the Commission on or after January 1, 2020, such return  
73 shall not be set lower than the average of either (i) the returns on common equity reported to the  
74 Securities and Exchange Commission for the three most recent annual periods for which such data are  
75 available by not less than a majority, selected by the Commission as specified in subdivision 2 b, of  
76 other investor-owned electric utilities in the peer group of the utility subject to such triennial review or  
77 (ii) the authorized returns on common equity that are set by the applicable regulatory commissions for  
78 the same selected peer group, nor shall the Commission set such return more than 150 basis points  
79 higher than such average.

80 b. In selecting such majority of peer group investor-owned electric utilities for applications received  
81 by the Commission on or after January 1, 2020, the Commission shall first remove from such group the  
82 two utilities within such group that have the lowest reported or authorized, as applicable, returns of the  
83 group, as well as the two utilities within such group that have the highest reported or authorized, as  
84 applicable, returns of the group, and the Commission shall then select a majority of the utilities  
85 remaining in such peer group. In its final order regarding such triennial review, the Commission shall  
86 identify the utilities in such peer group it selected for the calculation of such limitation. For purposes of  
87 this subdivision, an investor-owned electric utility shall be deemed part of such peer group if (i) its  
88 principal operations are conducted in the southeastern United States east of the Mississippi River in  
89 either the states of West Virginia or Kentucky or in those states south of Virginia, excluding the state of  
90 Tennessee, (ii) it is a vertically-integrated electric utility providing generation, transmission and  
91 distribution services whose facilities and operations are subject to state public utility regulation in the  
92 state where its principal operations are conducted, (iii) it had a long-term bond rating assigned by  
93 Moody's Investors Service of at least Baa at the end of the most recent test period subject to such  
94 triennial review, and (iv) it is not an affiliate of the utility subject to such triennial review.

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

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

119 "Current Proceeding" means any proceeding conducted under any provisions of this subsection that  
120 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. The provisions of this subdivision are subject to the provisions of subdivision 8.

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 triennial review.

3. Each such utility shall make a triennial filing by March 31 of every third year, with such filings commencing for a Phase I Utility in 2020, and such filings commencing for a Phase II Utility in 2021, consisting of the schedules contained in the Commission's rules governing utility rate increase applications. Such filing shall encompass the three successive 12-month test periods ending December 31 immediately preceding the year in which such proceeding is conducted, except that the filing for a Phase II Utility in 2021 shall encompass the four successive 12-month test periods ending December 31, 2020, 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 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 triennial review proceedings. In a triennial filing under this subdivision that does not result in an overall rate change a utility may propose an adjustment to one or more tariffs that are revenue neutral to the utility.

4. (Expires December 31, 2023) 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; (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; and (iii) costs incurred by the utility to construct, operate, and maintain transmission lines and substations installed in order to provide service to a business park. 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, including costs incurred by the utility to construct, operate, and maintain transmission lines and substations installed in order to provide service to a business park; 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

182 recover these costs shall be designed using the appropriate billing determinants in the retail rate  
183 schedules.

184 *Notwithstanding any other provision of this subdivision, in any proceeding regarding petitions for a*  
185 *rate adjustment clause filed pursuant to this subdivision, the Commission may, as an alternative to a*  
186 *rate adjustment clause, authorize recovery of any proposed cost through the utility's rates for generation*  
187 *and distribution services, if the Commission, in its discretion, determines that such cost recovery better*  
188 *serves ratepayers while still providing the utility the opportunity to recover its costs and earn a fair rate*  
189 *of return.*

190 4. (Effective January 1, 2024) The following costs incurred by the utility shall be deemed reasonable  
191 and prudent: (i) costs for transmission services provided to the utility by the regional transmission entity  
192 of which the utility is a member, as determined under applicable rates, terms and conditions approved  
193 by the Federal Energy Regulatory Commission, and (ii) costs charged to the utility that are associated  
194 with demand response programs approved by the Federal Energy Regulatory Commission and  
195 administered by the regional transmission entity of which the utility is a member. Upon petition of a  
196 utility at any time after the expiration or termination of capped rates, but not more than once in any  
197 12-month period, the Commission shall approve a rate adjustment clause under which such costs,  
198 including, without limitation, costs for transmission service, charges for new and existing transmission  
199 facilities, administrative charges, and ancillary service charges designed to recover transmission costs,  
200 shall be recovered on a timely and current basis from customers. Retail rates to recover these costs shall  
201 be designed using the appropriate billing determinants in the retail rate schedules.

202 *Notwithstanding any other provision of this subdivision, in any proceeding regarding petitions for a*  
203 *rate adjustment clause filed pursuant to this subdivision, the Commission may, as an alternative to a*  
204 *rate adjustment clause, authorize recovery of any proposed cost through the utility's rates for generation*  
205 *and distribution services, if the Commission, in its discretion, determines that such cost recovery better*  
206 *serves ratepayers while still providing the utility the opportunity to recover its costs and earn a fair rate*  
207 *of return.*

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

211 a. Incremental costs described in clause (vi) of subsection B of § 56-582 incurred between July 1,  
212 2004, and the expiration or termination of capped rates, if such utility is, as of July 1, 2007, deferring  
213 such costs consistent with an order of the Commission entered under clause (vi) of subsection B of  
214 § 56-582. The Commission shall approve such a petition allowing the recovery of such costs that  
215 comply with the requirements of clause (vi) of subsection B of § 56-582;

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

220 c. Projected and actual costs for the utility to design, implement, and operate energy efficiency  
221 programs or pilot programs. Any such petition shall include a proposed budget for the design,  
222 implementation, and operation of the energy efficiency program, including anticipated savings from and  
223 spending on each program, and the Commission shall grant a final order on such petitions within eight  
224 months of initial filing. The Commission shall only approve such a petition if it finds that the program  
225 is in the public interest. If the Commission determines that an energy efficiency program or portfolio of  
226 programs is not in the public interest, its final order shall include all work product and analysis  
227 conducted by the Commission's staff in relation to that program that has bearing upon the Commission's  
228 determination. Such order shall adhere to existing protocols for extraordinarily sensitive information.

229 Energy efficiency pilot programs are in the public interest provided that the pilot program is (i) of  
230 limited scope, cost, and duration and (ii) intended to determine whether a new or substantially revised  
231 program would be cost-effective.

232 Prior to January 1, 2022, the Commission shall award a margin for recovery on operating expenses  
233 for energy efficiency programs and pilot programs, which margin shall be equal to the general rate of  
234 return on common equity determined as described in subdivision 2. Beginning January 1, 2022, and  
235 thereafter, if the Commission determines that the utility meets in any year the annual energy efficiency  
236 standards set forth in § 56-596.2, in the following year, the Commission shall award a margin on energy  
237 efficiency program operating expenses in that year, to be recovered through a rate adjustment clause,  
238 which margin shall be equal to the general rate of return on common equity determined as described in  
239 subdivision 2. If the Commission does not approve energy efficiency programs that, in the aggregate,  
240 can achieve the annual energy efficiency standards, the Commission shall award a margin on energy  
241 efficiency operating expenses in that year for any programs the Commission has approved, to be  
242 recovered through a rate adjustment clause under this subdivision, which margin shall equal the general  
243 rate of return on common equity determined as described in subdivision 2. Any margin awarded

pursuant to this subdivision shall be applied as part of the utility's next rate adjustment clause true-up proceeding. The Commission shall also award an additional 20 basis points for each additional incremental 0.1 percent in annual savings in any year achieved by the utility's energy efficiency programs approved by the Commission pursuant to this subdivision, beyond the annual requirements set forth in § 56-596.2, provided that the total performance incentive awarded in any year shall not exceed 10 percent of that utility's total energy efficiency program spending in that same year.

The Commission shall annually monitor and report to the General Assembly the performance of all programs approved pursuant to this subdivision, including each utility's compliance with the total annual savings required by § 56-596.2, as well as the annual and lifecycle net and gross energy and capacity savings, related emissions reductions, and other quantifiable benefits of each program; total customer bill savings that the programs produce; utility spending on each program, including any associated administrative costs; and each utility's avoided costs and cost-effectiveness results.

Notwithstanding any other provision of law, unless the Commission finds in its discretion and after consideration of all in-state and regional transmission entity resources that there is a threat to the reliability or security of electric service to the utility's customers, the Commission shall not approve construction of any new utility-owned generating facilities that emit carbon dioxide as a by-product of combusting fuel to generate electricity unless the utility has already met the energy savings goals identified in § 56-596.2 and the Commission finds that supply-side resources are more cost-effective than demand-side or energy storage resources.

As used in this subdivision, "large general service customer" means a customer that has a verifiable history of having used more than one megawatt of demand from a single site.

Large general service customers shall be exempt from requirements that they participate in energy efficiency programs if the Commission finds that 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 June 30, 2021, adopt rules or regulations (a) establishing the process for large general service customers to apply for such an exemption, (b) establishing the administrative procedures by which eligible customers will notify the utility, and (c) defining the standard criteria that shall be satisfied by an applicant in order to notify the utility, including means of evaluation measurement and verification and confidentiality requirements. At a minimum, such rules and regulations shall require that each exempted large general service customer certify to the utility and Commission that its implemented energy efficiency programs have delivered measured and verified savings within the prior five years. In adopting such rules or regulations, the Commission shall 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. Savings from large general service customers shall be accounted for in utility reporting in the standards in § 56-596.2.

The notice of nonparticipation by a large general service customer shall be for the duration of the service life of the customer's energy efficiency measures. The Commission may on its own motion initiate steps necessary to verify such nonparticipant's achievement of energy efficiency if the Commission has a body of evidence that the nonparticipant has knowingly misrepresented its energy efficiency achievement.

A utility shall not charge such large general service customer 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 compliance with renewable energy portfolio standard requirements pursuant to § 56-585.5 that are not recoverable under subdivision 6. The Commission shall approve such a petition allowing the recovery of such costs incurred as required by § 56-585.5, provided that the Commission does not otherwise find such costs were unreasonably or imprudently incurred;

e. Projected and actual costs of projects that the Commission finds to be necessary to mitigate impacts to marine life caused by construction of offshore wind generating facilities, as described in § 56-585.1:11, or to comply with state or federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations, including the costs of allowances purchased through a market-based trading program for carbon dioxide emissions. The Commission shall approve such a petition if it finds that such costs are necessary to comply with such environmental laws or regulations;

f. Projected and actual costs, not currently in rates, for the utility to design, implement, and operate programs approved by the Commission that accelerate the vegetation management of distribution

rights-of-way. No costs shall be allocated to or recovered from customers that are served within the large general service rate classes for a Phase II Utility or that are served at subtransmission or transmission voltage, or take delivery at a substation served from subtransmission or transmission voltage, for a Phase I Utility; and

g. Projected and actual costs, not currently in rates, for the utility to design, implement, and operate programs approved by the Commission to provide incentives to (i) low-income, elderly, and disabled individuals or (ii) organizations providing residential services to low-income, elderly, and disabled individuals for the installation of, or access to, equipment to generate electric energy derived from sunlight, provided the low-income, elderly, and disabled individuals, or organizations providing residential services to low-income, elderly, and disabled individuals, first participate in incentive programs for the installation of measures that reduce heating or cooling costs.

Any rate adjustment clause approved under subdivision 5 c by the Commission shall remain in effect until the utility exhausts the approved budget for the energy efficiency program. The Commission shall have the authority to determine the duration or amortization period for any other rate adjustment clause approved under this subdivision.

*Notwithstanding any other provision of this subdivision, in any proceeding regarding petitions for a rate adjustment clause filed pursuant to this subdivision, the Commission may, as an alternative to a rate adjustment clause, authorize recovery of any proposed cost through the utility's rates for generation and distribution services, if the Commission, in its discretion, determines that such cost recovery better serves ratepayers while still providing the utility the opportunity to recover its costs and earn a fair rate of return.*

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, including the costs of any system or equipment upgrade, system or equipment replacement, or other cost reasonably appropriate to extend the combined operating license for or the operating life of one or more generation facilities utilizing nuclear power, (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, (v) one or more pumped hydroelectricity generation and storage facilities that utilize on-site or off-site renewable energy resources as all or a portion of their power source and such facilities and associated resources are 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, or (vi) one or more electric distribution grid transformation projects; 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 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) or (vi), 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) or (vi), as applicable. As of December 1, 2028, any costs recovered by a utility pursuant to clause (iv) shall be limited to any remaining costs associated with conversions of overhead distribution facilities to underground facilities that have been previously approved or are pending approval by the Commission through a petition by the utility under this subdivision. 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 or makes modifications to any such facility, or purchases any facility consisting of at least one megawatt of generating capacity using energy derived from sunlight and located in the Commonwealth and that utilizes goods or services sourced, in whole or in part, from one or more Virginia businesses, 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 or acquisition 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 filing a petition for approval to construct or purchase a facility consisting of at least one megawatt of generating capacity using energy derived from sunlight and located in the Commonwealth and that utilizes goods or services sourced, in whole or in part, from one or more Virginia businesses may propose a rate adjustment clause based on a market index in lieu of a cost of service model for such facility. A utility seeking approval to construct or purchase a generating facility that emits carbon dioxide shall demonstrate that it has already met the energy savings goals identified in § 56-596.2 and that the identified need cannot be met more affordably through the deployment or utilization of demand-side resources or energy storage resources and that it has considered and weighed alternative options, including third-party market alternatives, in its selection process.

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 constructed by the utility and described in clause (i), (ii), (iii) or (v) begins commercial operation, the date the utility becomes the owner of a purchased generation facility consisting of at least one megawatt of generating capacity using energy derived from sunlight and located in the Commonwealth and that utilizes goods or services sourced, in whole or in part, from one or more Virginia businesses, or the date new underground facilities are classified by the utility as plant in service. In any application to construct a new generating facility, the utility shall include, and the Commission shall consider, the social cost of carbon, as determined by the Commission, as a benefit or cost, whichever is appropriate. The Commission shall ensure that the development of new, or expansion of existing, energy resources or facilities does not have a disproportionate adverse impact on historically economically disadvantaged communities. The Commission may adopt any rules it deems necessary to determine the social cost of carbon and shall use the best available science and technology, including the Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, published by the Interagency Working Group on Social Cost of Greenhouse Gases from the United States Government in August 2016, as guidance. The Commission shall include a system to adjust the costs established in this section with inflation.

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 constructed by the utility and described in clause (i), (ii), (iii) or (v) begins commercial operation, the date the utility becomes the owner of a purchased generation facility consisting of at least one megawatt of generating capacity using energy derived from sunlight and located in the Commonwealth and that utilizes goods or services sourced, in whole or in part, from one or more Virginia businesses, or the date new underground facilities or new electric distribution grid transformation projects 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) or (v) is in the public interest, and in determining whether to approve such facility, the Commission shall liberally construe the provisions of this title. The construction or purchase by a utility of one or more generation facilities with at least one megawatt of generating capacity, and with an aggregate rated capacity that does not exceed 16,100 megawatts, including rooftop solar installations with a capacity of not less than 50 kilowatts, and with an aggregate capacity of 100 megawatts, that use energy derived from sunlight or from onshore wind and are located in the Commonwealth or off the Commonwealth's Atlantic shoreline, regardless of whether any of such

428 facilities are located within or without the utility's service territory, is in the public interest, and in  
 429 determining whether to approve such facility, the Commission shall liberally construe the provisions of  
 430 this title. A utility may enter into short-term or long-term power purchase contracts for the power  
 431 derived from sunlight generated by such generation facility prior to purchasing the generation facility.  
 432 The replacement of any subset of a utility's existing overhead distribution tap lines that have, in the  
 433 aggregate, an average of nine or more total unplanned outage events-per-mile over a preceding 10-year  
 434 period with new underground facilities in order to improve electric service reliability is in the public  
 435 interest. In determining whether to approve petitions for rate adjustment clauses for such new  
 436 underground facilities that meet this criteria, and in determining the level of costs to be recovered  
 437 thereunder, the Commission shall liberally construe the provisions of this title.

438 The conversion of any such facilities on or after September 1, 2016, is deemed to provide local and  
 439 system-wide benefits and to be cost beneficial, and the costs associated with such new underground  
 440 facilities are deemed to be reasonably and prudently incurred and, notwithstanding the provisions of  
 441 subsection C or D, shall be approved for recovery by the Commission pursuant to this subdivision,  
 442 provided that the total costs associated with the replacement of any subset of existing overhead  
 443 distribution tap lines proposed by the utility with new underground facilities, exclusive of financing  
 444 costs, shall not exceed an average cost per customer of \$20,000, with such customers, including those  
 445 served directly by or downline of the tap lines proposed for conversion, and, further, such total costs  
 446 shall not exceed an average cost per mile of tap lines converted, exclusive of financing costs, of  
 447 \$750,000. A utility shall, without regard for whether it has petitioned for any rate adjustment clause  
 448 pursuant to clause (vi), petition the Commission, not more than once annually, for approval of a plan for  
 449 electric distribution grid transformation projects. Any plan for electric distribution grid transformation  
 450 projects shall include both measures to facilitate integration of distributed energy resources and measures  
 451 to enhance physical electric distribution grid reliability and security. In ruling upon such a petition, the  
 452 Commission shall consider whether the utility's plan for such projects, and the projected costs associated  
 453 therewith, are reasonable and prudent. Such petition shall be considered on a stand-alone basis without  
 454 regard to the other costs, revenues, investments, or earnings of the utility; without regard to whether the  
 455 costs associated with such projects will be recovered through a rate adjustment clause under this  
 456 subdivision or through the utility's rates for generation and distribution services; and without regard to  
 457 whether such costs will be the subject of a customer credit offset, as applicable, pursuant to subdivision  
 458 8 d. The Commission's final order regarding any such petition for approval of an electric distribution  
 459 grid transformation plan shall be entered by the Commission not more than six months after the date of  
 460 filing such petition. The Commission shall likewise enter its final order with respect to any petition by a  
 461 utility for a certificate to construct and operate a generating facility or facilities utilizing energy derived  
 462 from sunlight, pursuant to subsection D of § 56-580, within six months after the date of filing such  
 463 petition. The basis points to be added to the utility's general rate of return to calculate the enhanced rate  
 464 of return on common equity, and the first portion of that facility's service life to which such enhanced  
 465 rate of return shall be applied, shall vary by type of facility, as specified in the following table:

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

474 Only those facilities as to which a rate adjustment clause under this subdivision has been previously  
 475 approved by the Commission, or as to which a petition for approval of such rate adjustment clause was  
 476 filed with the Commission, on or before January 1, 2013, shall be entitled to the enhanced rate of return  
 477 on common equity as specified in the above table during the construction phase of the facility and the  
 478 approved first portion of its service life.

479 Thirty percent of all costs of such a facility utilizing nuclear power that the utility incurred between  
 480 July 1, 2007, and December 31, 2013, and all of such costs incurred after December 31, 2013, may be  
 481 deferred by the utility and recovered through a rate adjustment clause under this subdivision at such  
 482 time as the Commission provides in an order approving such a rate adjustment clause. The remaining 70  
 483 percent of all costs of such a facility that the utility incurred between July 1, 2007, and December 31,  
 484 2013, shall not be deferred for recovery through a rate adjustment clause under this subdivision;  
 485 however, such remaining 70 percent of all costs shall be recovered ratably through existing base rates as  
 486 determined by the Commission in the test periods under review in the utility's next review filed after  
 487 July 1, 2014. Thirty percent of all costs of a facility utilizing energy derived from offshore wind that the  
 488 utility incurred between July 1, 2007, and December 31, 2013, and all of such costs incurred after  
 489 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 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 utility-owned and utility-operated generating facility or facilities utilizing energy derived from sunlight or from onshore or offshore wind are in the public interest.

Notwithstanding any provision of Chapter 296 of the Acts of Assembly of 2018, construction, purchasing, or leasing activities for a new utility-owned and utility-operated generating facility or facilities utilizing energy derived from sunlight or from onshore wind with an aggregate capacity of 16,100 megawatts, including rooftop solar installations with a capacity of not less than 50 kilowatts, and with an aggregate capacity of 100 megawatts, together with a utility-owned and utility-operated generating facility or facilities utilizing energy derived from offshore wind with an aggregate capacity of not more than 3,000 megawatts, are in the public interest. Additionally, energy storage facilities with an aggregate capacity of 2,700 megawatts are in the public interest. To the extent that a utility elects to recover the costs of any such new generation or energy storage facility or facilities through its rates for generation and distribution services and does not petition and receive approval from the Commission for recovery of such costs through a rate adjustment clause described in clause (ii), the Commission shall, upon the request of the utility in a triennial review proceeding, provide for a customer credit reinvestment offset, as applicable, pursuant to subdivision 8 d with respect to all costs deemed reasonable and prudent by the Commission in a proceeding pursuant to subsection D of § 56-580 or in a triennial review proceeding.

Electric distribution grid transformation projects are in the public interest. To the extent that a utility elects to recover the costs of such electric distribution grid transformation projects through its rates for generation and distribution services, and does not petition and receive approval from the Commission for recovery of such costs through a rate adjustment clause described in clause (vi), the Commission shall, upon the request of the utility in a triennial review proceeding, provide for a customer credit reinvestment offset, as applicable, pursuant to subdivision 8 d with respect to all costs deemed reasonable and prudent by the Commission in a proceeding for approval of a plan for electric distribution grid transformation projects pursuant to subdivision 6 or in a triennial review proceeding.

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) "coalbed methane gas powered" if the facility is fired at least 50 percent by coalbed methane gas, as such term is defined in § 45.2-1600, produced from wells located in the Commonwealth, and (2) "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 for such utility pursuant to subdivision 2.

Notwithstanding any other provision of this subdivision, if the Commission finds during the triennial review conducted for a Phase II Utility in 2021 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

551 to no less than the general rate of return for such utility and may apply no less than the utility's general  
552 rate of return to any such facility for which the utility seeks approval in the future under this  
553 subdivision.

554 Notwithstanding any other provision of this subdivision, if a Phase II utility obtains approval from  
555 the Commission of a rate adjustment clause pursuant to subdivision 6 associated with a test or  
556 demonstration project involving a generation facility utilizing energy from offshore wind, and such  
557 utility has not, as of July 1, 2023, commenced construction as defined for federal income tax purposes  
558 of an offshore wind generation facility or facilities with a minimum aggregate capacity of 250  
559 megawatts, then the Commission, if it finds it in the public interest, may direct that the costs associated  
560 with any such rate adjustment clause involving said test or demonstration project shall thereafter no  
561 longer be recovered through a rate adjustment clause pursuant to subdivision 6 and shall instead be  
562 recovered through the utility's rates for generation and distribution services, with no change in such rates  
563 for generation and distribution services as a result of the combination of such costs with the other costs,  
564 revenues, and investments included in the utility's rates for generation and distribution services. Any  
565 such costs shall remain combined with the utility's other costs, revenues, and investments included in its  
566 rates for generation and distribution services until such costs are fully recovered.

567 *Notwithstanding any other provision of this subdivision, in any proceeding regarding petitions for a*  
568 *rate adjustment clause filed pursuant to this subdivision, the Commission may, as an alternative to a*  
569 *rate adjustment clause, authorize recovery of any proposed cost through the utility's rates for generation*  
570 *and distribution services, if the Commission, in its discretion, determines that such cost recovery better*  
571 *serves ratepayers while still providing the utility the opportunity to recover its costs and earn a fair rate*  
572 *of return.*

573 7. Any petition filed pursuant to subdivision 4, 5, or 6 shall be considered by the Commission on a  
574 stand-alone basis without regard to the other costs, revenues, investments, or earnings of the utility. Any  
575 costs incurred by a utility prior to the filing of such petition, or during the consideration thereof by the  
576 Commission, that are proposed for recovery in such petition and that are related to subdivision 5 a, or  
577 that are related to facilities and projects described in clause (i) of subdivision 6, or that are related to  
578 new underground facilities described in clause (iv) of subdivision 6, shall be deferred on the books and  
579 records of the utility until the Commission's final order in the matter, or until the implementation of any  
580 applicable approved rate adjustment clauses, whichever is later. Except as otherwise provided in  
581 subdivision 6, any costs prudently incurred on or after July 1, 2007, by a utility prior to the filing of  
582 such petition, or during the consideration thereof by the Commission, that are proposed for recovery in  
583 such petition and that are related to facilities and projects described in clause (ii) or clause (iii) of  
584 subdivision 6 that utilize nuclear power, or coal-fueled facilities and projects described in clause (ii) of  
585 subdivision 6 if such coal-fueled facilities will be built by a Phase I Utility, shall be deferred on the  
586 books and records of the utility until the Commission's final order in the matter, or until the  
587 implementation of any applicable approved rate adjustment clauses, whichever is later. Any costs  
588 prudently incurred after the expiration or termination of capped rates related to other matters described  
589 in subdivision 4, 5, or 6 shall be deferred beginning only upon the expiration or termination of capped  
590 rates, provided, however, that no provision of this act shall affect the rights of any parties with respect  
591 to the rulings of the Federal Energy Regulatory Commission in PJM Interconnection LLC and Virginia  
592 Electric and Power Company, 109 F.E.R.C. P 61,012 (2004). A utility shall establish a regulatory asset  
593 for regulatory accounting and ratemaking purposes under which it shall defer its operation and  
594 maintenance costs incurred in connection with (i) the refueling of any nuclear-powered generating plant  
595 and (ii) other work at such plant normally performed during a refueling outage. The utility shall  
596 amortize such deferred costs over the refueling cycle, but in no case more than 18 months, beginning  
597 with the month in which such plant resumes operation after such refueling. The refueling cycle shall be  
598 the applicable period of time between planned refueling outages for such plant. As of January 1, 2014,  
599 such amortized costs are a component of base rates, recoverable in base rates only ratably over the  
600 refueling cycle rather than when such outages occur, and are the only nuclear refueling costs recoverable  
601 in base rates. This provision shall apply to any nuclear-powered generating plant refueling outage  
602 commencing after December 31, 2013, and the Commission shall treat the deferred and amortized costs  
603 of such regulatory asset as part of the utility's costs for the purpose of proceedings conducted (a) with  
604 respect to triennial filings under subdivision 3 made on and after July 1, 2014, and (b) pursuant to  
605 § 56-245 or the Commission's rules governing utility rate increase applications as provided in subsection  
606 B. This provision shall not be deemed to change or reset base rates.

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

612 8. In any triennial review proceeding, for the purposes of reviewing earnings on the utility's rates for

generation and distribution services, 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 and deemed fully recovered in the period recorded: costs associated with asset impairments related to early retirement determinations made by the utility for utility generation facilities fueled by coal, natural gas, or oil or for automated meter reading electric distribution service meters; costs associated with projects necessary to comply with state or federal environmental laws, regulations, or judicial or administrative orders relating to coal combustion by-product management that the utility does not petition to recover through a rate adjustment clause pursuant to subdivision 5 e; 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 triennial 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 triennial 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 triennial review that:

a. Revenue reductions related to energy efficiency measures or programs approved and deployed since the utility's previous triennial review have caused the utility, as verified by the Commission, during the test period or periods under review, considered as a whole, to earn 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 for generation and distribution services necessary to recover such revenue reductions. If the Commission finds, for reasons other than revenue reductions related to energy efficiency measures, that 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, in the first triennial review proceeding conducted after January 1, 2021, for a Phase II Utility, the Commission may not order a rate increase, and in all triennial reviews of a Phase I or Phase II utility, 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; and provided that, solely

674 in connection with making its determination concerning the necessity for such a rate increase or the  
675 amount thereof, the Commission shall, in any triennial review proceeding conducted prior to July 1,  
676 2028, exclude from this most recently ended 12-month test period any remaining investment levels  
677 associated with a prior customer credit reinvestment offset pursuant to subdivision d.

678 b. The utility has, during the test period or test periods under review, considered as a whole, earned  
679 more than 50 basis points above a fair combined rate of return on its generation and distribution  
680 services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after  
681 December 31, 2013, for a Phase I Utility, more than 70 basis points above a fair combined rate of  
682 return on its generation and distribution services, as determined in subdivision 2, without regard to any  
683 return on common equity or other matters determined with respect to facilities described in subdivision  
684 6, the Commission shall, subject to the provisions of subdivisions 8 d and 9, direct that 60 percent of  
685 the amount of such earnings that were more than 50 basis points, or, for any test period commencing  
686 after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, that  
687 70 percent of the amount of such earnings that were more than 70 basis points, above such fair  
688 combined rate of return for the test period or periods under review, considered as a whole, shall be  
689 credited to customers' bills. Any such credits shall be amortized over a period of six to 12 months, as  
690 determined at the discretion of the Commission, following the effective date of the Commission's order,  
691 and shall be allocated among customer classes such that the relationship between the specific customer  
692 class rates of return to the overall target rate of return will have the same relationship as the last  
693 approved allocation of revenues used to design base rates; or

694 c. In any triennial review proceeding conducted after January 1, 2020, for a Phase I Utility or after  
695 January 1, 2021, for a Phase II Utility in which the utility has, during the test period or test periods  
696 under review, considered as a whole, earned more than 50 basis points above a fair combined rate of  
697 return on its generation and distribution services or, for any test period commencing after December 31,  
698 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis  
699 points above a fair combined rate of return on its generation and distribution services, as determined in  
700 subdivision 2, without regard to any return on common equity or other matter determined with respect  
701 to facilities described in subdivision 6, and the combined aggregate level of capital investment that the  
702 Commission has approved other than those capital investments that the Commission has approved for  
703 recovery pursuant to a rate adjustment clause pursuant to subdivision 6 made by the utility during the  
704 test periods under review in that triennial review proceeding in new utility-owned generation facilities  
705 utilizing energy derived from sunlight, or from wind, and in electric distribution grid transformation  
706 projects, as determined pursuant to subdivision 8 d, does not equal or exceed 100 percent of the  
707 earnings that are more than 70 basis points above the utility's fair combined rate of return on its  
708 generation and distribution services for the combined test periods under review in that triennial review  
709 proceeding, the Commission shall, subject to the provisions of subdivision 9 and in addition to the  
710 actions authorized in subdivision b, also order reductions to the utility's rates it finds appropriate.  
711 However, in the first triennial review proceeding conducted after January 1, 2021, for a Phase II Utility,  
712 any reduction to the utility's rates ordered by the Commission pursuant to this subdivision shall not  
713 exceed \$50 million in annual revenues, with any reduction allocated to the utility's rates for generation  
714 services, and in each triennial review of a Phase I or Phase II Utility, the Commission may not order  
715 such rate reduction unless it finds that the resulting rates will provide the utility with the opportunity to  
716 fully recover its costs of providing its services and to earn not less than a fair combined rate of return  
717 on its generation and distribution services, as determined in subdivision 2, without regard to any return  
718 on common equity or other matters determined with respect to facilities described in subdivision 6,  
719 using the most recently ended 12-month test period as the basis for determining the permissibility of any  
720 rate reduction under the standards of this sentence, and the amount thereof; and

721 d. (Expires July 1, 2028) In any triennial review proceeding conducted after December 31, 2017,  
722 upon the request of the utility, the Commission shall determine, prior to directing that 70 percent of  
723 earnings that are more than 70 basis points above the utility's fair combined rate of return on its  
724 generation and distribution services for the test period or periods under review be credited to customer  
725 bills pursuant to subdivision 8 b, the aggregate level of prior capital investment that the Commission has  
726 approved other than those capital investments that the Commission has approved for recovery pursuant  
727 to a rate adjustment clause pursuant to subdivision 6 made by the utility during the test period or  
728 periods under review in both (i) new utility-owned generation facilities utilizing energy derived from  
729 sunlight, or from onshore or offshore wind, and (ii) electric distribution grid transformation projects, as  
730 determined by the utility's plant in service and construction work in progress balances related to such  
731 investments as recorded per books by the utility for financial reporting purposes as of the end of the  
732 most recent test period under review. Any such combined capital investment amounts shall offset any  
733 customer bill credit amounts, on a dollar for dollar basis, up to the aggregate level of invested or  
734 committed capital under clauses (i) and (ii). The aggregate level of qualifying invested or committed  
735 capital under clauses (i) and (ii) is referred to in this subdivision as the customer credit reinvestment

offset, which offsets the customer bill credit amount that the utility has invested or will invest in new solar or wind generation facilities or electric distribution grid transformation projects for the benefit of customers, in amounts up to 100 percent of earnings that are more than 70 basis points above the utility's fair rate of return on its generation and distribution services, and thereby reduce or eliminate otherwise incremental rate adjustment clause charges and increases to customer bills, which is deemed to be in the public interest. If 100 percent of the amount of earnings that are more than 70 basis points above the utility's fair combined rate of return on its generation and distribution services, as determined in subdivision 2, exceeds the aggregate level of invested capital in new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, and electric distribution grid transformation projects, as provided in clauses (i) and (ii), during the test period or periods under review, then 70 percent of the amount of such excess shall be credited to customer bills as provided in subdivision 8 b in connection with the triennial review proceeding. The portion of any costs associated with new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, or electric distribution grid transformation projects that is the subject of any customer credit reinvestment offset pursuant to this subdivision shall not thereafter be recovered through the utility's rates for generation and distribution services over the service life of such facilities and shall not thereafter be included in the utility's costs, revenues, and investments in future triennial review proceedings conducted pursuant to subdivision 2 and shall not be the subject of a rate adjustment clause petition pursuant to subdivision 6. The portion of any costs associated with new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, or electric distribution grid transformation projects that is not the subject of any customer credit reinvestment offset pursuant to this subdivision may be recovered through the utility's rates for generation and distribution services over the service life of such facilities and shall be included in the utility's costs, revenues, and investments in future triennial review proceedings conducted pursuant to subdivision 2 until such costs are fully recovered, and if such costs are recovered through the utility's rates for generation and distribution services, they shall not be the subject of a rate adjustment clause petition pursuant to subdivision 6. Only the portion of such costs of new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, or electric distribution grid transformation projects that has not been included in any customer credit reinvestment offset pursuant to this subdivision, and not otherwise recovered through the utility's rates for generation and distribution services, may be the subject of a rate adjustment clause petition by the utility pursuant to subdivision 6.

The Commission's final order regarding such triennial 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 triennial review shall apply, for purposes of reviewing the utility's earnings on its rates for generation and distribution services, to the entire three successive 12-month test periods ending December 31 immediately preceding the year of the utility's subsequent triennial review filing under subdivision 3 and shall apply to applicable rate adjustment clauses under subdivisions 5 and 6 prospectively from the date the Commission's final order in the triennial review proceeding, utilizing rate adjustment clause true-up protocols as the Commission in its discretion may determine.

9. If, as a result of a triennial 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 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, provided that no credits shall be provided pursuant to this subdivision in connection with any triennial review unless such bill credits would be payable pursuant to the provisions of subdivision 8 d, and any credits under this subdivision shall be calculated net of any customer credit reinvestment offset amounts under subdivision 8 d. 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, excluding any debt associated with securitized bonds that are the obligation of non-Virginia jurisdictional customers, 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 Clean Energy Policy set forth in § 45.2-1706.1, and shall also consider whether the costs of such resources is likely to result in unreasonable increases in rates paid by customers.

E. Notwithstanding any other provision of law, the Commission shall determine the amortization period for recovery of any appropriate costs due to the early retirement of any electric generation facilities owned or operated by any Phase I Utility or Phase II Utility. In making such determination, the Commission shall (i) perform an independent analysis of the remaining undepreciated capital costs; (ii) establish a recovery period that best serves ratepayers; and (iii) allow for the recovery of any carrying costs that the Commission deems appropriate.

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

#### **§ 56-585.1:11. Development of offshore wind capacity.**

A. As used in this section:

"Advanced clean energy buyer" means a commercial or industrial customer of a Phase II Utility, irrespective of generation supplier, (i) with an aggregate load over 100 megawatts; (ii) with an aggregate amount of at least 200 megawatts of solar or wind energy supply under contract with a term of 10 years or more from facilities located within the Commonwealth by January 1, 2024; and (iii) that directly procures from the utility the electric supply and environmental attributes of the offshore wind facility associated with the lesser of 50 megawatts of nameplate capacity or 15 percent of the commercial or industrial customer's annual peak demand for a contract period of 15 years.

"Aggregate load" means the combined electrical load associated with selected accounts of an advanced clean energy buyer with the same legal entity name as, or in the names of affiliated entities that control, are controlled by, or are under common control of, such legal entity or are the names of affiliated entities under a common parent.

"Control" means the legal right, directly or indirectly, to direct or cause the direction of the management, actions, or policies of an affiliated entity, whether through the ability to exercise voting power, by contract, or otherwise. "Control" does not include control of an entity through a franchise or similar contractual agreement.

"Qualifying large general service customer" means a customer of a Phase II Utility, irrespective of general supplier, (i) whose peak demand during the most recent calendar year exceeded five megawatts and (ii) that contracts with the utility to directly procure electric supply and environmental attributes associated with the offshore wind facility in amounts commensurate with the customer's electric usage for a contract period of 15 years or more.

B. In order to meet the Commonwealth's clean energy goals, prior to December 31, 2034, the construction or purchase by a public utility of one or more offshore wind generation facilities located off the Commonwealth's Atlantic shoreline or in federal waters and interconnected directly into the Commonwealth, with an aggregate capacity of up to 5,200 megawatts, is in the public interest and the Commission shall so find, provided that *such construction or purchase is consistent with the provisions of subsection I of § 56-585.5 and that no customers of the utility shall be responsible for costs of any such facility in a proportion greater than the utility's share of the facility.*

C. 1. Pursuant to subsection B, construction by a Phase II Utility of one or more new utility-owned and utility-operated generating facilities utilizing energy derived from offshore wind and located off the Commonwealth's Atlantic shoreline, with an aggregate rated capacity of not less than 2,500 megawatts and not more than 3,000 megawatts, along with electrical transmission or distribution facilities associated therewith for interconnection is in the public interest. In acting upon any request for cost recovery by a Phase II Utility for costs associated with such a facility, the Commission shall determine the reasonableness and prudence of any such costs, provided that such costs shall be presumed to be reasonably and prudently incurred if the Commission determines that (i) the utility has complied with the competitive solicitation and procurement requirements pursuant to subsection E; (ii) the project's projected total levelized cost of energy, including any tax credit, on a cost per megawatt hour basis, inclusive of the costs of transmission and distribution facilities associated with the facility's interconnection, does not exceed 1.4 times the comparable cost, on an unweighted average basis, of a conventional simple cycle combustion turbine generating facility as estimated by the U.S. Energy Information Administration in its Annual Energy Outlook 2019; and (iii) the utility has commenced construction of such facilities for U.S. income taxation purposes prior to January 1, 2024, or has a plan for such facility or facilities to be in service prior to January 1, 2028. The Commission shall disallow costs, or any portion thereof, only if they are otherwise unreasonably and imprudently incurred. In its review, the Commission shall give due consideration to (a) the Commonwealth's renewable portfolio standards and carbon reduction requirements, (b) the promotion of new renewable generation resources, and (c) the economic development benefits of the project for the Commonwealth, including capital investments and job creation.

2. Notwithstanding the provisions of § 56-585.1, the Commission shall not grant an enhanced rate of return to a Phase II Utility for the construction of one or more new utility-owned and utility-operated generating facilities utilizing energy derived from offshore wind and located off the Commonwealth's Atlantic shoreline pursuant to this section.

3. Any such costs proposed for recovery through a rate adjustment clause pursuant to subdivision A 6 of § 56-585.1 shall be allocated to all customers of the utility in the Commonwealth as a non-bypassable charge, regardless of the generation supplier of any such customer, other than (i) PIPP eligible utility customers, (ii) advanced clean energy buyers, and (iii) qualifying large general service customers. No electric cooperative customer of the utility shall be assigned, nor shall the utility collect from any such cooperative, any of the costs of such facilities, including electrical transmission or distribution facilities associated therewith for interconnection. The Commission may promulgate such rules, regulations, or other directives necessary to administer the eligibility for these exemptions.

4. The Commission shall permit a portion of the nameplate capacity of any such facility, in the

920 aggregate, to be allocated to (i) advanced clean energy buyers or (ii) qualifying large general service  
921 customers, provided that no more than 10 percent of the offshore wind facility's capacity is allocated to  
922 qualifying large general service customers. A Phase II Utility shall petition the Commission for approval  
923 of a special contract with any advanced clean energy buyer, or any special rate applicable to qualifying  
924 large general service customers, pursuant to § 56-235.2, no later than 15 months prior to the projected  
925 commercial operation date of the facility, and all customer enrollments associated with such special  
926 contracts or rates shall be completed prior to commercial operation of the facility. Any such special  
927 contract or rate may include provisions for levelized rates of service over the duration of the customer's  
928 contracted agreement with the utility, and the Commission shall determine that such special contract or  
929 rate is designed to hold nonparticipating customers harmless over its term in connection with any  
930 petition for approval by the utility. The utility may petition for approval of such special contracts or  
931 rates in connection with any petition for approval of a rate adjustment clause pursuant to subdivision A  
932 6 of § 56-585.1 to recover the costs of the facility, and the Commission shall rule upon any such  
933 petitions in its final order in such proceeding within nine months from the date of filing.

934 D. In constructing any such facility contemplated in subsection B, the utility shall develop and  
935 submit a plan to the Commission for review that includes the following considerations: (i) options for  
936 utilizing local workers; (ii) the economic development benefits of the project for the Commonwealth,  
937 including capital investments and job creation; (iii) consultation with the Commonwealth's Chief  
938 Workforce Development Officer, the Chief Diversity, Equity, and Inclusion Officer, and the Virginia  
939 Economic Development Partnership on opportunities to advance the Commonwealth's workforce and  
940 economic development goals, including furtherance of apprenticeship and other workforce training  
941 programs; (iv) giving priority to the hiring, apprenticeship, and training of veterans, as that term is  
942 defined in § 2.2-2000.1, local workers, and workers from historically economically disadvantaged  
943 communities; and (v) procurement of equipment from Virginia-based or United States-based  
944 manufacturers using materials or product components made in Virginia or the United States, if  
945 reasonably available and competitively priced.

946 E. Any project constructed or purchased pursuant to subsection B shall (i) be subject to competitive  
947 procurement or solicitation for a substantial majority of the services and equipment, exclusive of  
948 interconnection costs, associated with the facility's construction; (ii) involve at least one experienced  
949 developer; and (iii) demonstrate the economic development benefits within the Commonwealth, including  
950 capital investments and job creation. A utility may give appropriate consideration to suppliers and  
951 developers that have demonstrated successful experience in offshore wind.

952 F. Any project shall include an environmental and fisheries mitigation plan submitted to the  
953 Commission for the construction and operation of such offshore wind facilities, provided that such plan  
954 includes an explicit description of the best management practices the bidder will employ that considers  
955 the latest science at the time the proposal is made to mitigate adverse impacts to wildlife, natural  
956 resources, ecosystems, and traditional or existing water-dependent uses. The plan shall include a  
957 summary of pre-construction assessment activities, consistent with federal requirements, to determine the  
958 spatial and temporal presence and abundance of marine mammals, sea turtles, birds, and bats in the  
959 offshore wind lease area.

960 **§ 56-585.5. Generation of electricity from renewable and zero carbon sources.**

961 A. As used in this section:

962 "Accelerated renewable energy buyer" means a commercial or industrial customer of a Phase I or  
963 Phase II Utility, irrespective of generation supplier, with an aggregate load over 25 megawatts in the  
964 prior calendar year, that enters into arrangements pursuant to subsection G, as certified by the  
965 Commission.

966 "Aggregate load" means the combined electrical load associated with selected accounts of an  
967 accelerated renewable energy buyer with the same legal entity name as, or in the names of affiliated  
968 entities that control, are controlled by, or are under common control of, such legal entity or are the  
969 names of affiliated entities under a common parent.

970 "Control" has the same meaning as provided in § 56-585.1:11.

971 "Falling water" means hydroelectric resources, including run-of-river generation from a combined  
972 pumped-storage and run-of-river facility. "Falling water" does not include electricity generated from  
973 pumped-storage facilities.

974 "Low-income qualifying projects" means a project that provides a minimum of 50 percent of the  
975 respective electric output to low-income utility customers as that term is defined in § 56-576.

976 "Phase I Utility" has the same meaning as provided in subdivision A 1 of § 56-585.1.

977 "Phase II Utility" has the same meaning as provided in subdivision A 1 of § 56-585.1.

978 "Previously developed project site" means any property, including related buffer areas, if any, that  
979 has been previously disturbed or developed for non-single-family residential, nonagricultural, or  
980 nonsilvicultural use, regardless of whether such property currently is being used for any purpose.

981 "Previously developed project site" includes a brownfield as defined in § 10.1-1230 or any parcel that



has been previously used (i) for a retail, commercial, or industrial purpose; (ii) as a parking lot; (iii) as the site of a parking lot canopy or structure; (iv) for mining, which is any lands affected by coal mining that took place before August 3, 1977, or any lands upon which extraction activities have been permitted by the Department of Energy under Title 45.2; (v) for quarrying; or (vi) as a landfill.

"Total electric energy" means total electric energy sold to retail customers in the Commonwealth service territory of a Phase I or Phase II Utility, other than accelerated renewable energy buyers, by the incumbent electric utility or other retail supplier of electric energy in the previous calendar year, excluding an amount equivalent to the annual percentages of the electric energy that was supplied to such customer from nuclear generating plants located within the Commonwealth in the previous calendar year, provided such nuclear units were operating by July 1, 2020, or from any zero-carbon electric generating facilities not otherwise RPS eligible sources and placed into service in the Commonwealth after July 1, 2030.

"Zero-carbon electricity" means electricity generated by any generating unit that does not emit carbon dioxide as a by-product of combusting fuel to generate electricity.

B. 1. By December 31, 2024, except for any coal-fired electric generating units (i) jointly owned with a cooperative utility or (ii) owned and operated by a Phase II Utility located in the coalfield region of the Commonwealth that co-fires with biomass, any Phase I and Phase II Utility shall retire all generating units principally fueled by oil with a rated capacity in excess of 500 megawatts and all coal-fired electric generating units operating in the Commonwealth.

2. By December 31, 2028, each Phase I and II Utility shall retire all biomass-fired electric generating units that do not co-fire with coal.

3. By December 31, 2045, each Phase I and II Utility shall retire all other electric generating units located in the Commonwealth that emit carbon as a by-product of combusting fuel to generate electricity.

4. A Phase I or Phase II Utility may petition the Commission for relief from the requirements of this subsection on the basis that the requirement would threaten the reliability or security of electric service to customers. The Commission shall consider in-state and regional transmission entity resources and shall evaluate the reliability of each proposed retirement on a case-by-case basis in ruling upon any such petition.

C. Each Phase I and Phase II Utility shall participate in a renewable energy portfolio standard program (RPS Program) that establishes annual goals for the sale of renewable energy to all retail customers in the utility's service territory, other than accelerated renewable energy buyers pursuant to subsection G, regardless of whether such customers purchase electric supply service from the utility or from suppliers other than the utility. To comply with the RPS Program, each Phase I and Phase II Utility shall procure and retire Renewable Energy Certificates (RECs) originating from renewable energy standard eligible sources (RPS eligible sources). For purposes of complying with the RPS Program from 2021 to 2024, a Phase I and Phase II Utility may use RECs from any renewable energy facility, as defined in § 56-576, provided that such facilities are located in the Commonwealth or are physically located within the PJM Interconnection, LLC (PJM) region. However, at no time during this period or thereafter may any Phase I or Phase II Utility use RECs from (i) renewable thermal energy, (ii) renewable thermal energy equivalent, (iii) biomass-fired facilities that are outside the Commonwealth, or (iv) biomass-fired facilities operating in the Commonwealth as of January 1, 2020, that supply 10 percent or more of their annual net electrical generation to the electric grid or more than 15 percent of their annual total useful energy to any entity other than the manufacturing facility to which the generating source is interconnected. From compliance year 2025 and all years after, each Phase I and Phase II Utility may only use RECs from RPS eligible sources for compliance with the RPS Program.

In order to qualify as RPS eligible sources, such sources must be (a) electric-generating resources that generate electric energy derived from solar or wind located in the Commonwealth or off the Commonwealth's Atlantic shoreline or in federal waters and interconnected directly into the Commonwealth or physically located within the PJM region; (b) falling water resources located in the Commonwealth or physically located within the PJM region that were in operation as of January 1, 2020, that are owned by a Phase I or Phase II Utility or for which a Phase I or Phase II Utility has entered into a contract prior to January 1, 2020, to purchase the energy, capacity, and renewable attributes of such falling water resources; (c) non-utility-owned resources from falling water that (1) are less than 65 megawatts, (2) began commercial operation after December 31, 1979, or (3) added incremental generation representing greater than 50 percent of the original nameplate capacity after December 31, 1979, provided that such resources are located in the Commonwealth or are physically located within the PJM region; (d) waste-to-energy or landfill gas-fired generating resources located in the Commonwealth and in operation as of January 1, 2020, provided that such resources do not use waste heat from fossil fuel combustion or forest or woody biomass as fuel; or (e) biomass-fired facilities in operation in the Commonwealth and in operation as of January 1, 2020, that supply no more than 10

1043 percent of their annual net electrical generation to the electric grid or no more than 15 percent of their  
 1044 annual total useful energy to any entity other than the manufacturing facility to which the generating  
 1045 source is interconnected. Regardless of any future maintenance, expansion, or refurbishment activities,  
 1046 the total amount of RECs that may be sold by any RPS eligible source using biomass in any year shall  
 1047 be no more than the number of megawatt hours of electricity produced by that facility in 2019;  
 1048 however, in no year may any RPS eligible source using biomass sell RECs in excess of the actual  
 1049 megawatt-hours of electricity generated by such facility that calendar year and shall be implemented in  
 1050 accordance with the following schedule:

1051	Year	RPS Program	Year	RPS Program
1052		Requirement		Requirement
1053	2021	6%	2021	14%
1054	2022	7%	2022	17%
1055	2023	8%	2023	20%
1056	2024	10%	2024	23%
1057	2025	14%	2025	26%
1058	2026	17%	2026	29%
1059	2027	20%	2027	32%
1060	2028	24%	2028	35%
1061	2029	27%	2029	38%
1062	2030	30%	2030	41%
1063	2031	33%	2031	45%
1064	2032	36%	2032	49%
1065	2033	39%	2033	52%
1066	2034	42%	2034	55%
1067	2035	45%	2035	59%
1068	2036	53%	2036	63%
1069	2037	53%	2037	67%
1070	2038	57%	2038	71%
1071	2039	61%	2039	75%
1072	2040	65%	2040	79%
1073	2041	68%	2041	83%
1074	2042	71%	2042	87%
1075	2043	74%	2043	91%
1076	2044	77%	2044	95%
1077	2045	80%	2045 and thereafter	100%
1078	2046	84%		
1079	2047	88%		
1080	2048	92%		
1081	2049	96%		
1082	2050 and thereafter	100%		

1083 A Phase II Utility shall meet one percent of the RPS Program requirements in any given compliance  
 1084 year with solar, wind, or anaerobic digestion resources of one megawatt or less located in the  
 1085 Commonwealth, with not more than 3,000 kilowatts at any single location or at contiguous locations  
 1086 owned by the same entity or affiliated entities and, to the extent that low-income qualifying projects are  
 1087 available, then no less than 25 percent of such one percent shall be composed of low-income qualifying  
 1088 projects.

1089 Beginning with the 2025 compliance year and thereafter, at least 75 percent of all RECs used by a  
 1090 Phase II Utility in a compliance period shall come from RPS eligible resources located in the  
 1091 Commonwealth.

1092 Any Phase I or Phase II Utility may apply renewable energy sales achieved or RECs acquired in  
 1093 excess of the sales requirement for that RPS Program to the sales requirements for RPS Program  
 1094 requirements in the year in which it was generated and the five calendar years after the renewable  
 1095 energy was generated or the RECs were created. To the extent that a Phase I or Phase II Utility  
 1096 procures RECs for RPS Program compliance from resources the utility does not own, the utility shall be  
 1097 entitled to recover the costs of such certificates at its election pursuant to § 56-249.6 or subdivision A 5  
 1098 d of § 56-585.1.

1099 D. Each Phase I or Phase II Utility shall petition the Commission for necessary approvals to procure  
 1100 zero-carbon electricity generating capacity as set forth in this subsection and energy storage resources as  
 1101 set forth in subsection E. To the extent that a Phase I or Phase II Utility constructs or acquires new  
 1102 zero-carbon generating facilities or energy storage resources, the utility shall petition the Commission for  
 1103 the recovery of the costs of such facilities, at the utility's election, either through its rates for generation  
 1104 and distribution services or through a rate adjustment clause pursuant to subdivision A 6 of § 56-585.1.  
 1105 All costs not sought for recovery through a rate adjustment clause pursuant to subdivision A 6 of  
 1106 § 56-585.1 associated with generating facilities provided by sunlight or onshore or offshore wind are  
 1107 also eligible to be applied by the utility as a customer credit reinvestment offset as provided in

subdivision A 8 of § 56-585.1. Costs associated with the purchase of energy, capacity, or environmental attributes from facilities owned by the persons other than the utility required by this subsection shall be recovered by the utility either through its rates for generation and distribution services or pursuant to § 56-249.6.

1. Each Phase I Utility shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of 600 megawatts of generating capacity using energy derived from sunlight or onshore wind.

a. By December 31, 2023, each Phase I Utility shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of at least 200 megawatts of generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by such Phase I Utility.

b. By December 31, 2027, each Phase I Utility shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of at least 200 megawatts of additional generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by such Phase I Utility.

c. By December 31, 2030, each Phase I Utility shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of at least 200 megawatts of additional generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by such Phase I Utility.

d. Nothing in this subdivision 1 shall prohibit such Phase I Utility from constructing, acquiring, or entering into agreements to purchase the energy, capacity, and environmental attributes of more than 600 megawatts of generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, provided the utility receives approval from the Commission pursuant to §§ 56-580 and 56-585.1.

2. By December 31, 2035, each Phase II Utility shall petition the Commission for necessary approvals to (i) construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of 16,100 megawatts of generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, which shall include 1,100 megawatts of solar generation of a nameplate capacity not to exceed three megawatts per individual project and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar facilities owned by persons other than a utility, including utility affiliates and deregulated affiliates and (ii) pursuant to § 56-585.1:11, construct or purchase one or more offshore wind generation facilities located off the Commonwealth's Atlantic shoreline or in federal waters and interconnected directly into the Commonwealth with an aggregate capacity of up to 5,200 megawatts. At least 200 megawatts of the 16,100 megawatts shall be placed on previously developed project sites.

a. By December 31, 2024, each Phase II Utility shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of at least 3,000 megawatts of generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by such Phase II Utility.

b. By December 31, 2027, each Phase II Utility shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of at least 3,000 megawatts of additional generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by such Phase II Utility.

c. By December 31, 2030, each Phase II Utility shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of at least 4,000 megawatts of additional generating capacity located in the

Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by such Phase II Utility.

d. By December 31, 2035, each Phase II Utility shall petition the Commission for necessary approvals to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of at least 6,100 megawatts of additional generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, and 35 percent of such generating capacity procured shall be from the purchase of energy, capacity, and environmental attributes from solar or onshore wind facilities owned by persons other than the utility, with the remainder, in the aggregate, being from construction or acquisition by such Phase II Utility.

e. Nothing in this subdivision 2 shall prohibit such Phase II Utility from constructing, acquiring, or entering into agreements to purchase the energy, capacity, and environmental attributes of more than 16,100 megawatts of generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind, provided the utility receives approval from the Commission pursuant to §§ 56-580 and 56-585.1.

3. Nothing in this section shall prohibit a utility from petitioning the Commission to construct or acquire zero-carbon electricity or from entering into contracts to procure the energy, capacity, and environmental attributes of zero-carbon electricity generating resources in excess of the requirements in subsection B. The Commission shall determine whether to approve such petitions on a stand-alone basis pursuant to §§ 56-580 and 56-585.1, provided that the Commission's review shall also consider whether the proposed generating capacity (i) is necessary to meet the utility's native load, (ii) is likely to lower customer fuel costs, (iii) will provide economic development opportunities in the Commonwealth, and (iv) serves a need that cannot be more affordably met with demand-side or energy storage resources.

Each Phase I and Phase II Utility shall, at least once every year, conduct a request for proposals for new solar and wind resources. Such requests shall quantify and describe the utility's need for energy, capacity, or renewable energy certificates. The requests for proposals shall be publicly announced and made available for public review on the utility's website at least 45 days prior to the closing of such request for proposals. The requests for proposals shall provide, at a minimum, the following information: (a) the size, type, and timing of resources for which the utility anticipates contracting; (b) any minimum thresholds that must be met by respondents; (c) major assumptions to be used by the utility in the bid evaluation process, including environmental emission standards; (d) detailed instructions for preparing bids so that bids can be evaluated on a consistent basis; (e) the preferred general location of additional capacity; and (f) specific information concerning the factors involved in determining the price and non-price criteria used for selecting winning bids. A utility may evaluate responses to requests for proposals based on any criteria that it deems reasonable but shall at a minimum consider the following in its selection process: (1) the status of a particular project's development; (2) the age of existing generation facilities; (3) the demonstrated financial viability of a project and the developer; (4) a developer's prior experience in the field; (5) the location and effect on the transmission grid of a generation facility; (6) benefits to the Commonwealth that are associated with particular projects, including regional economic development and the use of goods and services from Virginia businesses; and (7) the environmental impacts of particular resources, including impacts on air quality within the Commonwealth and the carbon intensity of the utility's generation portfolio.

4. In connection with the requirements of this subsection, each Phase I and Phase II Utility shall, commencing in 2020 and concluding in 2035, submit annually a plan and petition for approval for the development of new solar and onshore wind generation capacity. Such plan shall reflect, in the aggregate and over its duration, the requirements of subsection D concerning the allocation percentages for construction or purchase of such capacity. Such petition shall contain any request for approval to construct such facilities pursuant to subsection D of § 56-580 and a request for approval or update of a rate adjustment clause pursuant to subdivision A 6 of § 56-585.1 to recover the costs of such facilities. Such plan shall also include the utility's plan to meet the energy storage project targets of subsection E, including the goal of installing at least 10 percent of such energy storage projects behind the meter. In determining whether to approve the utility's plan and any associated petition requests, the Commission shall determine whether they are reasonable and prudent and shall give due consideration to (i) the RPS and carbon dioxide reduction requirements in this section, (ii) the promotion of new renewable generation and energy storage resources within the Commonwealth, and associated economic development, and (iii) fuel savings projected to be achieved by the plan. Notwithstanding any other provision of this title, the Commission's final order regarding any such petition and associated requests shall be entered by the Commission not more than six months after the date of the filing of such petition.

5. If, in any year, a Phase I or Phase II Utility is unable to meet the compliance obligation of the RPS Program requirements or if the cost of RECs necessary to comply with RPS Program requirements

exceeds \$45 per megawatt hour, such supplier shall be obligated to make a deficiency payment equal to \$45 for each megawatt-hour shortfall for the year of noncompliance, except that the deficiency payment for any shortfall in procuring RECs for solar, wind, or anaerobic digesters located in the Commonwealth shall be \$75 per megawatts hour for resources one megawatt and lower. The amount of any deficiency payment shall increase by one percent annually after 2021. A Phase I or Phase II Utility shall be entitled to recover the costs of such payments as a cost of compliance with the requirements of this subsection pursuant to subdivision A 5 d of § 56-585.1. All proceeds from the deficiency payments shall be deposited into an interest-bearing account administered by the Department of Energy. In administering this account, the Department of Energy shall manage the account as follows: (i) 50 percent of total revenue shall be directed to job training programs in historically economically disadvantaged communities; (ii) 16 percent of total revenue shall be directed to energy efficiency measures for public facilities; (iii) 30 percent of total revenue shall be directed to renewable energy programs located in historically economically disadvantaged communities; and (iv) four percent of total revenue shall be directed to administrative costs.

For any project constructed pursuant to this subsection or subsection E, a utility shall, subject to a competitive procurement process, procure equipment from a Virginia-based or United States-based manufacturer using materials or product components made in Virginia or the United States, if reasonably available and competitively priced.

E. To enhance reliability and performance of the utility's generation and distribution system, each Phase I and Phase II Utility shall petition the Commission for necessary approvals to construct or acquire new, utility-owned energy storage resources.

1. By December 31, 2035, each Phase I Utility shall petition the Commission for necessary approvals to construct or acquire 400 megawatts of energy storage capacity. Nothing in this subdivision shall prohibit a Phase I Utility from constructing or acquiring more than 400 megawatts of energy storage, provided that the utility receives approval from the Commission pursuant to §§ 56-580 and 56-585.1.

2. By December 31, 2035, each Phase II Utility shall petition the Commission for necessary approvals to construct or acquire 2,700 megawatts of energy storage capacity. Nothing in this subdivision shall prohibit a Phase II Utility from constructing or acquiring more than 2,700 megawatts of energy storage, provided that the utility receives approval from the Commission pursuant to §§ 56-580 and 56-585.1.

3. No single energy storage project shall exceed 500 megawatts in size, except that a Phase II Utility may procure a single energy storage project up to 800 megawatts.

4. All energy storage projects procured pursuant to this subsection shall meet the competitive procurement protocols established in subdivision D 3.

5. After July 1, 2020, at least 35 percent of the energy storage facilities placed into service shall be (i) purchased by the public utility from a party other than the public utility or (ii) owned by a party other than a public utility, with the capacity from such facilities sold to the public utility. By January 1, 2021, the Commission shall adopt regulations to achieve the deployment of energy storage for the Commonwealth required in subdivisions 1 and 2, including regulations that set interim targets and update existing utility planning and procurement rules. The regulations shall include programs and mechanisms to deploy energy storage, including competitive solicitations, behind-the-meter incentives, non-wires alternatives programs, and peak demand reduction programs.

F. All costs incurred by a Phase I or Phase II Utility related to compliance with the requirements of this section or pursuant to § 56-585.1:11, including (i) costs of generation facilities powered by sunlight or onshore or offshore wind, or energy storage facilities, that are constructed or acquired by a Phase I or Phase II Utility after July 1, 2020, (ii) costs of capacity, energy, or environmental attributes from generation facilities powered by sunlight or onshore or offshore wind, or falling water, or energy storage facilities purchased by the utility from persons other than the utility through agreements after July 1, 2020, and (iii) all other costs of compliance, including costs associated with the purchase of RECs associated with RPS Program requirements pursuant to this section shall be recovered from all retail customers in the service territory of a Phase I or Phase II Utility as a non-bypassable charge, irrespective of the generation supplier of such customer, except (a) as provided in subsection G for an accelerated renewable energy buyer or (b) as provided in subdivision C 3 of § 56-585.1:11, with respect to the costs of an offshore wind generation facility, for a PIPP eligible utility customer or an advanced clean energy buyer or qualifying large general service customer, as those terms are defined in § 56-585.1:11. If a Phase I or Phase II Utility serves customers in more than one jurisdiction, such utility shall recover all of the costs of compliance with the RPS Program requirements from its Virginia customers through the applicable cost recovery mechanism, and all associated energy, capacity, and environmental attributes shall be assigned to Virginia to the extent that such costs are requested but not recovered from any system customers outside the Commonwealth.

By September 1, 2020, the Commission shall direct the initiation of a proceeding for each Phase I

and Phase II Utility to review and determine the amount of such costs, net of benefits, that should be allocated to retail customers within the utility's service territory which have elected to receive electric supply service from a supplier of electric energy other than the utility, and shall direct that tariff provisions be implemented to recover those costs from such customers beginning no later than January 1, 2021. Thereafter, such charges and tariff provisions shall be updated and trued up by the utility on an annual basis, subject to continuing review and approval by the Commission.

G. 1. An accelerated renewable energy buyer may contract with a Phase I or Phase II Utility, or a person other than a Phase I or Phase II Utility, to obtain (i) RECs from RPS eligible resources or (ii) bundled capacity, energy, and RECs from solar or wind generation resources located within the PJM region and initially placed in commercial operation after January 1, 2015, including any contract with a utility for such generation resources that does not allocate to or recover from any other customer of the utility the cost of such resources. Such an accelerated renewable energy buyer may offset all or a portion of its electric load for purposes of RPS compliance through such arrangements. An accelerated renewable energy buyer shall be exempt from the assignment of non-bypassable RPS compliance costs pursuant to subsection F, with the exception of the costs of an offshore wind generating facility pursuant to § 56-585.1:11, based on the amount of RECs obtained pursuant to this subsection in proportion to the customer's total electric energy consumption, on an annual basis. An accelerated renewable energy buyer obtaining RECs only shall not be exempt from costs related to procurement of new solar or onshore wind generation capacity, energy, or environmental attributes, or energy storage facilities, by the utility pursuant to subsections D and E, however, an accelerated renewable energy buyer that is a customer of a Phase II Utility and was subscribed, as of March 1, 2020, to a voluntary companion experimental tariff offering of the utility for the purchase of renewable attributes from renewable energy facilities that requires a renewable facilities agreement and the purchase of a minimum of 2,000 renewable attributes annually, shall be exempt from allocation of the net costs related to procurement of new solar or onshore wind generation capacity, energy, or environmental attributes, or energy storage facilities, by the utility pursuant to subsections D and E, based on the amount of RECs associated with the customer's renewable facilities agreements associated with such tariff offering as of that date in proportion to the customer's total electric energy consumption, on an annual basis. To the extent that an accelerated renewable energy buyer contracts for the capacity of new solar or wind generation resources pursuant to this subsection, the aggregate amount of such nameplate capacity shall be offset from the utility's procurement requirements pursuant to subsection D. All RECs associated with contracts entered into by an accelerated renewable energy buyer with the utility, or a person other than the utility, for an RPS Program shall not be credited to the utility's compliance with its RPS requirements, and the calculation of the utility's RPS Program requirements shall not include the electric load covered by customers certified as accelerated renewable energy buyers.

2. Each Phase I or Phase II Utility shall certify, and verify as necessary, to the Commission that the accelerated renewable energy buyer has satisfied the exemption requirements of this subsection for each year, or an accelerated renewable energy buyer may choose to certify satisfaction of this exemption by reporting to the Commission individually. The Commission may promulgate such rules and regulations as may be necessary to implement the provisions of this subsection.

3. Provided that no incremental costs associated with any contract between a Phase I or Phase II Utility and an accelerated renewable energy buyer is allocated to or recovered from any other customer of the utility, any such contract with an accelerated renewable energy buyer that is a jurisdictional customer of the utility shall not be deemed a special rate or contract requiring Commission approval pursuant to § 56-235.2.

H. No customer of a Phase II Utility with a peak demand in excess of 100 megawatts in 2019 that elected pursuant to subdivision A 3 of § 56-577 to purchase electric energy from a competitive service provider prior to April 1, 2019, shall be allocated any non-bypassable charges pursuant to subsection F for such period that the customer is not purchasing electric energy from the utility, and such customer's electric load shall not be included in the utility's RPS Program requirements. No customer of a Phase I Utility that elected pursuant to subdivision A 3 of § 56-577 to purchase electric energy from a competitive service provider prior to February 1, 2019, shall be allocated any non-bypassable charges pursuant to subsection F for such period that the customer is not purchasing electric energy from the utility, and such customer's electric load shall not be included in the utility's RPS Program requirements.

I. *The Commission shall not approve the recovery of costs related to the construction or acquisition of generation facilities powered by sunlight or onshore or offshore wind, or energy storage facilities, that are constructed or acquired by a Phase I or Phase II Utility after July 1, 2022, in compliance with the requirements of this section or pursuant to § 56-585.1:11, unless the Commission determines that the construction or acquisition of such facilities is (i) necessary to maintain the reliability or security of electric service to customers or meet the RPS program requirements established in this section and (ii) is the lowest-cost option to maintain the reliability or security of electric service to customers or meet the RPS program requirements.*

**1354**        *J.* Nothing in this section shall apply to any entity organized under Chapter 9.1 (§ 56-231.15 et seq.).  
**1355**        ~~*J.*~~ *K.* The Commission shall adopt such rules and regulations as may be necessary to implement the  
**1356** provisions of this section, including a requirement that participants verify whether the RPS Program  
**1357** requirements are met in accordance with this section.

**INTRODUCED**

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