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SENATE BILL NO. 1265

AMENDMENT IN THE NATURE OF A SUBSTITUTE

(Proposed by the Senate Committee on Commerce and Labor on January 30, 2023)

(Patron Prior to Substitute—Senator Saslaw)

A BILL to amend and reenact §§ 56-581, 56-585.1, 56-585.1:4, and 56-599 of the Code of Virginia and to amend the Code of Virginia by adding a section numbered 56-249.6:1, relating to Virginia Electric Utility Regulation Act; financing for certain deferred fuel costs; review proceedings; rates; return on common equity; rate adjustment clauses; capitalization ratio for certain projects; generation facility retirements subject to approval.

Be it enacted by the General Assembly of Virginia:

1. That §§ 56-581, 56-585.1, 56-585.1:4, and 56-599 of the Code of Virginia are amended and reenacted and that the Code of Virginia is amended by adding a section numbered 56-249.6:1 as follows:

§ 56-249.6:1. Financing for certain deferred fuel costs.

A. Notwithstanding the provisions of § 56-249.6 or Chapter 3 (§ 56-55 et seq.), an electric utility may petition the Commission for a financing order and the Commission shall either issue (i) such financing order or (ii) an order rejecting the petition no more than four months from the date of filing such petition and in accordance with the requirements of subdivision 2.

1. The petition shall include: (i) an estimate of the total amount of deferred fuel costs that the electric utility has incurred over the time period noted in the petition; (ii) an indication of whether the electric utility proposes to finance all or a portion of the deferred fuel costs using one or more series or tranches of deferred fuel cost bonds; (iii) an estimate and details of the financing costs related to the deferred fuel costs to be financed through the deferred fuel cost bonds; (iv) an estimate of the deferred fuel cost charges necessary to recover the deferred fuel costs and all financing costs and the proposed period for recovery of such costs; (v) a description of any benefits expected to result from the issuance of deferred fuel cost bonds including the avoidance of or significant mitigation of abrupt and significant increases in rates to the electric utility's customers for the applicable time period; and (vi) direct testimony and exhibits supporting the petition. If the electric utility proposes to finance a portion of the deferred fuel costs, the electric utility shall identify in the petition the specific amount of deferred fuel costs for the applicable time period to be financed using deferred fuel cost bonds. By electing not to finance a portion of deferred fuel costs for an applicable time period using deferred fuel cost bonds, an electric utility shall not be deemed to waive its right to recover such costs pursuant to a separate proceeding with the Commission.

2. a. If an electric utility petitions the Commission for a financing order pursuant to this section, following notice and an opportunity for hearing, the Commission shall either issue (i) a financing order or (ii) an order rejecting the petition, not more than four months from the date of filing such petition.

b. A financing order issued by the Commission pursuant to this section shall include:

(1) The amount of deferred fuel cost costs to be financed using deferred fuel cost bonds. The Commission shall describe and estimate the amount of financing costs that may be recovered through deferred fuel cost charges. The financing order shall also specify the period over which deferred fuel cost costs and financing costs may be recovered and whether the deferred fuel cost bonds may be offered and issued in one or more series or tranches during a fixed period not to exceed one year after the date of the financing order;

(2) A finding that the proposed issuance of deferred fuel cost bonds is in the public interest and the associated deferred fuel cost charges are just and reasonable;

(3) A finding that the structuring and pricing of the deferred fuel cost bonds are reasonably expected to result in reasonable deferred fuel cost charges consistent with market conditions at the time the deferred fuel cost bonds are priced and the terms set forth in such financing order;

(4) A requirement that, for so long as the deferred fuel cost bonds are outstanding and until all financing costs have been paid in full, the imposition and collection of deferred fuel cost charges authorized under a financing order shall be non-bypassable and paid by all retail customers of the electric utility, irrespective of the generation supplier of such customer, except for an exempt retail access customer;

(5) A formula-based true-up mechanism for making annual adjustments to the deferred fuel cost charges that customers are required to pay pursuant to the financing order and for making any adjustments that are necessary to correct for any overcollection or undercollection of the charges or to otherwise ensure the timely payment of deferred fuel cost bonds and financing costs and other required amounts and charges payable in connection with the deferred fuel cost bonds;

(6) The deferred fuel cost property that is, or shall be, created in favor of an electric utility or its successors or assignees and that shall be used to pay or secure deferred fuel cost bonds and all financing costs;

(7) The authority of the electric utility to establish the terms and conditions of the deferred fuel cost bonds, including repayment schedules, expected interest rates, the issuance in one or more series or tranches with different maturity dates, and other financing costs;

(8) A finding that the deferred fuel cost charges shall be allocated among customer classes in accordance with the methodology approved in the electric utility's last fuel factor proceeding;

(9) A requirement that after the final terms of an issuance of deferred fuel cost bonds have been established and before the issuance of deferred fuel cost bonds, the electric utility determines the resulting initial deferred fuel cost charge in accordance with the financing order and that such initial deferred fuel cost charge be final and effective upon the issuance of such deferred fuel cost bonds without further Commission action so long as such initial deferred fuel cost charge is consistent with the financing order;

(10) A method of tracing funds collected as deferred fuel cost charges, or other proceeds of deferred fuel cost property, and a requirement that such method be the method of tracing such funds and determining the identifiable cash proceeds of any deferred fuel cost property subject to the financing order under applicable law; and

(11) Any other conditions not otherwise inconsistent with this section that the Commission determines are appropriate.

c. A financing order issued to an electric utility may provide that creation of the electric utility's deferred fuel cost property is conditioned upon, and simultaneous with, the sale or other transfer for the deferred fuel cost property to an assignee and the pledge of the deferred fuel cost property to secure deferred fuel cost bonds.

d. If the Commission issues a financing order, the Commission shall establish a protocol for the electric utility to annually file a petition or, in the Commission's discretion, a letter setting out application of the formula-based mechanism and, based on estimates of consumption for each rate class and other mathematical factors, requesting administrative approval to make applicable adjustments. The review of the filing shall be limited to determining whether there are any mathematical or clerical errors in the application of the formula-based mechanism relating to the appropriate amount of any overcollection or undercollection of deferred fuel cost charges and the amount of an adjustment. The adjustments shall ensure the recovery of revenues sufficient to provide for the payment of principal, interest, acquisition, defeasance, financing costs, or redemption premium and other fees, costs, and charges in respect of deferred fuel cost bonds approved under the financing order. Within 30 days after receiving an electric utility's request pursuant to this subdivision d, the Commission shall either approve the request or inform the electric utility of mathematical or clerical errors in its calculation. If the Commission informs the electric utility of mathematical or clerical errors in its calculation, the electric utility may correct its error and refile its request. The time frames previously described in this subdivision d shall apply to a refiled request.

e. Subsequent to the transfer of deferred fuel cost property to an assignee or the issuance of deferred fuel cost bonds authorized thereby, whichever is earlier, a financing order shall be irrevocable and, except for changes made pursuant to the formula-based mechanism authorized in this section, the Commission shall not amend, modify, or terminate the financing order by any subsequent action or reduce, impair, postpone, terminate, or otherwise adjust deferred fuel cost charges approved in the financing order. After the issuance of a financing order, the electric utility shall retain sole discretion regarding whether to assign, sell, or otherwise transfer deferred fuel cost property or to cause deferred fuel cost bonds to be issued, including the right to defer or postpone such assignment, sale, transfer, or issuance.

3. At the request of an electric utility, the Commission may commence a proceeding and issue a subsequent financing order that provides for refinancing, retiring, or refunding deferred fuel cost bonds issued pursuant to the original financing order if the Commission finds that the subsequent financing order satisfies all of the criteria specified in this section for a financing order. Effective upon retirement of the refunded deferred fuel cost bonds and the issuance of new deferred fuel cost bonds, the Commission shall adjust the related deferred fuel cost charges accordingly.

4. a. A financing order shall remain in effect and deferred fuel cost property under the financing order shall continue to exist until deferred fuel cost bonds issued pursuant to the financing order have been paid in full or defeased and, in each case, all Commission-approved financing costs of such deferred fuel cost bonds have been recovered in full.

b. A financing order issued to an electric utility shall remain in effect and unabated notwithstanding the reorganization, bankruptcy or other insolvency proceedings, merger, or sale of the electric utility or its successors or assignees.

B. 1. The Commission shall not, in exercising its powers and carrying out its duties regarding any *matter within its authority pursuant to this chapter, and notwithstanding any other provision of law, consider the deferred fuel cost bonds issued pursuant to a financing order to be the debt of the electric utility other than for federal income tax purposes, consider the deferred fuel cost charges paid under the financing order to be the revenue of the electric utility for any purpose, or consider the deferred fuel costs or financing costs specified in the financing order to be the costs of the electric utility, nor shall the Commission determine any action taken by an electric utility which is consistent with the financing order to be unjust or unreasonable.*

2. The Commission shall not order or otherwise directly or indirectly require an electric utility to use deferred fuel cost bonds to finance any project, addition, plant, facility, extension, capital improvement, equipment, or any other expenditure. After the issuance of a financing order, the electric utility shall retain sole discretion regarding whether to cause the deferred fuel cost bonds to be issued, including the right to defer or postpone such sale, assignment, transfer, or issuance. Nothing shall prevent the electric utility from abandoning the issuance of deferred fuel cost bonds under the financing order by filing with the Commission a statement of abandonment and the reasons therefor. The Commission shall not deny an electric utility its right to recover deferred fuel costs as otherwise provided in this section, or refuse or condition authorization or approval of the issuance and sale by an electric utility of securities or the assumption by the electric utility of liabilities or obligations, solely because of the potential availability of deferred fuel cost bond financing.

C. The electric bills of an electric utility that has obtained a financing order and caused deferred fuel cost bonds to be issued shall comply with the provisions of this subsection; however, the failure of an electric utility to comply with this subsection does not invalidate, impair, or affect any financing order, deferred fuel cost property, deferred fuel cost charge, or deferred fuel cost bonds. The electric utility shall:

1. Explicitly reflect that a portion of the charges on any electric bill represents deferred fuel cost charges approved in a financing order issued to the electric utility and, if the deferred fuel cost property has been transferred to an assignee, such bill shall include a statement to the effect that the assignee is the owner of the rights to deferred fuel cost charges and that the electric utility or another entity, if applicable, is acting as a collection agent or servicer for the assignee. The tariff applicable to customers must indicate the deferred fuel cost charge and the ownership of the charge; and

2. Include the deferred fuel cost charge on each customer's bill as a separate line item and include both the rate and the amount of the charge on each bill.

D. 1. The following provisions shall be applicable to deferred fuel cost property:

a. All deferred fuel cost property that is specified in a financing order shall constitute an existing, present intangible property right or interest therein, notwithstanding that the imposition and collection of deferred fuel cost charges depends on the electric utility, to which the financing order is issued, performing its servicing functions relating to the collection of deferred fuel cost charges and on future electricity consumption. The deferred fuel cost property shall exist (i) regardless of whether or not the revenues or proceeds arising from the deferred fuel cost property have been billed, have accrued, or have been collected and (ii) notwithstanding the fact that the value or amount of the deferred fuel cost property is dependent on the future provision of service to customers by the electric utility or its successors or assignees and the future consumption of electricity by customers;

b. Deferred fuel cost property specified in a financing order shall exist until deferred fuel cost bonds issued pursuant to the financing order are paid in full and all financing costs and other costs of such deferred fuel cost bonds have been recovered in full;

c. All or any portion of deferred fuel cost property specified in a financing order issued to an electric utility may be transferred, sold, conveyed, or assigned to a successor or assignee that is wholly owned, directly or indirectly, by the electric utility and created for the limited purpose of acquiring, owning, or administering deferred fuel cost property or issuing deferred fuel cost bonds under the financing order. All or any portion of deferred fuel cost property may be pledged to secure deferred fuel cost bonds issued pursuant to the financing order, amounts payable to financing parties and to counterparties under any ancillary agreements, and other financing costs. Any transfer, sale, conveyance, assignment, grant of a security interest in or pledge of deferred fuel cost property by an electric utility, or an affiliate of the electric utility, to an assignee, to the extent previously authorized in a financing order, shall not require the prior consent and approval of the Commission;

d. If an electric utility defaults on any required payment of charges arising from deferred fuel cost property specified in a financing order, a court, upon application by an interested party, and without limiting any other remedies available to the applying party, shall order the sequestration and payment of the revenues arising from the deferred fuel cost property to the financing parties or their assignees. Any such financing order shall remain in full force and effect notwithstanding any reorganization, bankruptcy, or other insolvency proceedings with respect to the electric utility or its successors or assignees;

e. The interest of a transferee, purchaser, acquirer, assignee, or pledgee in deferred fuel cost property specified in a financing order issued to an electric utility, and in the revenue and collections arising from that property, shall not be subject to setoff, counterclaim, surcharge, or defense by the electric utility or any other person or in connection with the reorganization, bankruptcy, or other insolvency of the electric utility or any other entity;

f. Any successor to an electric utility, whether pursuant to any reorganization, bankruptcy, or other insolvency proceeding or whether pursuant to any merger or acquisition, sale, or other business combination, or transfer by operation of law, as a result of electric utility restructuring or otherwise, shall perform and satisfy all obligations of, and have the same rights under a financing order as, the electric utility under the financing order in the same manner and to the same extent as the electric utility, including collecting and paying to the person entitled to receive the revenues, collections, payments, or proceeds of the deferred fuel cost property. Nothing in this subdivision f is intended to limit or impair any authority of the Commission concerning the transfer or succession of interests of public utilities; and

g. Deferred fuel cost bonds shall be nonrecourse to the credit or any assets of the electric utility other than the deferred fuel cost property as specified in the financing order and any rights under any ancillary agreement.

2. The following provisions shall be applicable to security interests:

a. The creation, perfection, and enforcement of any security interest in deferred fuel cost property to secure the repayment of the principal and interest and other amounts payable in respect of deferred fuel cost bonds; amounts payable under any indenture, ancillary agreement, or other financing documents in respect of the deferred fuel costs; and other financing costs shall be governed by this subsection and not by the provisions of the Uniform Commercial Code (Titles 8.1A through 8.9A);

b. A security interest in deferred fuel cost property shall be created and enforceable when all of the following have occurred: (i) a financing order is issued, (ii) value is received by the debtor or seller for such deferred fuel cost property, (iii) the debtor or seller has rights in such deferred fuel cost property or the power to transfer rights in such deferred fuel cost property, and (iv) a security agreement granting such security interest is executed and delivered by the debtor or seller. The description of deferred fuel cost property in a security agreement shall be sufficient if the description refers to this section and the financing order creating the deferred fuel cost property;

c. A security interest shall attach without any physical delivery of collateral or other act and, upon the filing of a financing statement with the Commission, the lien of the security interest shall be valid, binding, and perfected against all parties having claims of any kind in tort, contract, or otherwise against the person granting the security interest, regardless of whether the parties have notice of the lien. Also upon this filing, a transfer of an interest in the deferred fuel cost property shall be perfected against all parties having claims of any kind, including any judicial lien or other lien creditors or any claims of the transferor or creditors of the transferor, and shall have priority over all competing claims other than any prior security interest, ownership interest, or assignment in the property previously perfected in accordance with this section;

d. The Commission shall maintain any financing statement filed to perfect any security interest under this section in the same manner that the Commission maintains financing statements filed by transmitting utilities under the Uniform Commercial Code (Titles 8.1A through 8.9A). The filing of a financing statement under this section shall be governed by the provisions regarding the filing of financing statements in the Uniform Commercial Code (Titles 8.1A through 8.9A);

e. The priority of a security interest in deferred fuel cost property shall not be affected by the commingling of deferred fuel cost charges with other amounts. Any pledgee or secured party shall have a perfected security interest in the amount of all deferred fuel cost charges that are deposited in any cash or deposit account of the qualifying utility in which deferred fuel cost charges have been commingled with other funds and any other security interest that may apply to those funds shall be terminated when they are transferred to a segregated account for the assignee or a financing party;

f. No application of the formula-based adjustment mechanism as provided in this section shall affect the validity, perfection, or priority of a security interest in or transfer of deferred fuel cost property; and

g. If a default or termination occurs under the deferred fuel cost bonds, the financing parties or their representatives may foreclose on or otherwise enforce their lien and security interest in any deferred fuel cost property as if they were secured parties with a perfected and prior lien under the Uniform Commercial Code (Titles 8.1A through 8.9A), and the Commission may order that amounts arising from deferred fuel cost charges be transferred to a separate account for the financing parties' benefit, to which their lien and security interest shall apply. On application by or on behalf of the financing parties, the Commission shall order the sequestration and payment to them of revenues arising from the deferred fuel cost charges.

3. a. Any sale, assignment, or other transfer of deferred fuel cost property shall be an absolute transfer and true sale of and not a pledge of, or secured transaction relating to, the transferor's right, title, and interest in, to, and under the deferred fuel cost property if the documents governing the transaction expressly state that the transaction is a sale or other absolute transfer other than for federal and state income tax purposes. For all purposes other than federal and state income tax purposes, the parties' characterization of a transaction as a sale of an interest in deferred fuel cost property shall be conclusive that the transaction is a true sale and that ownership has passed to the party characterized as the purchaser, regardless of any fact or circumstance that might support characterization of the transfer as a secured transaction. A transfer of an interest in deferred fuel cost property shall occur only when all of the following have occurred: (i) the financing order creating the deferred fuel cost property has become effective, (ii) the documents evidencing the transfer of deferred fuel cost property have been executed by the transferor and delivered to the assignee, and (iii) value is received by the transferor for the deferred fuel cost property. After such a transaction, the deferred fuel cost property shall not be subject to any claims of the transferor or the transferor's creditors, other than creditors holding a prior security interest in the deferred fuel cost property perfected in accordance with subdivision 2.

b. The characterization of the sale, assignment, or other transfer as an absolute transfer and true sale and the corresponding characterization of the interest of the assignee as an ownership interest, shall not be affected or impaired by the occurrence of any of the following factors:

(1) Commingling of deferred fuel cost charges with other amounts;

(2) The retention by the seller of (i) a partial or residual interest, including an equity interest, in the deferred fuel cost property, whether direct or indirect, or whether subordinate or otherwise, or (ii) the right to recover costs associated with taxes, franchise fees, or license fees imposed on the collection of deferred fuel cost charges;

(3) Any recourse that the assignee may have against the seller;

(4) Any right or obligation that the seller may have to repurchase the deferred fuel cost charges;

(5) Any indemnification obligations of the seller;

(6) The obligation of the seller to collect deferred fuel cost charges on behalf of the assignee;

(7) The transferor acting as the servicer of the deferred fuel cost charges or the existence of any contract that authorizes or requires the electric utility, to the extent that any interest in deferred fuel cost property is sold or assigned, to agree with the assignee or any financing party that it will continue to operate its system to provide service to its customers, will collect amounts in respect of the deferred fuel cost charges for the benefit and account of such assignee or financing party, and will account for and remit such amounts to or for the account of such assignee or financing party;

(8) The treatment of the sale, conveyance, assignment, or other transfer for tax, financial reporting, or other purposes;

(9) The granting or providing to bondholders of a preferred right to the deferred fuel cost property or credit enhancement by the electric utility or its affiliates with respect to the deferred fuel cost bonds; or

(10) Any application of the formula-based adjustment mechanism as provided in this section.

c. Any right that an electric utility has in the deferred fuel cost property before its pledge, sale, or transfer or any other right created under this section or created in the financing order and assignable under this section or assignable pursuant to a financing order shall be property in the form of a contract right or a chose in action. Transfer of an interest in deferred fuel cost property to an assignee shall be enforceable only when all of the following have occurred: (i) a financing order is issued, (ii) value is received by the transferor for such deferred fuel cost property, (iii) the transferor has rights in such deferred fuel cost property or the power to transfer rights in such deferred fuel cost property, and (iv) transfer documents in connection with the issuance of deferred fuel cost bonds are executed and delivered by the transferor. An enforceable transfer of an interest in deferred fuel cost property to an assignee shall be perfected against all third parties, including subsequent judicial or other lien creditors, when a notice of that transfer has been given by the filing of a financing statement in accordance with subdivision 2 c. The transfer shall be perfected against third parties as of the date of filing.

d. The Commission shall maintain any financing statement filed to perfect any sale, assignment, or transfer of deferred fuel cost property under this section in the same manner that the Commission maintains financing statements filed by transmitting utilities under the Uniform Commercial Code (Titles 8.1A through 8.9A). The filing of any financing statement under this section shall be governed by the provisions regarding the filing of financing statements in the Uniform Commercial Code (Titles 8.1A through 8.9A). The filing of such a financing statement shall be the only method of perfecting a transfer of deferred fuel cost property.

e. The priority of a transfer perfected under this section shall not be impaired by any later modification of the financing order or deferred fuel cost property or by the commingling of funds arising from deferred fuel cost property with other funds. Any other security interest that may apply to *those funds, other than a security interest perfected under subdivision 2, shall be terminated when they are transferred to a segregated account for the assignee or a financing party. If deferred fuel cost property has been transferred to an assignee or financing party, any proceeds of that property shall be held in trust for the assignee or financing party.*

f. The priority of the conflicting interests of assignees in the same interest or rights in any deferred fuel cost property shall be determined as follows:

(1) Conflicting perfected interests or rights of assignees shall rank according to priority in time of perfection. Priority shall date from the time a filing covering the transfer is made in accordance with subdivision 2 c;

(2) A perfected interest or right of an assignee shall have priority over a conflicting unperfected interest or right of an assignee; and

(3) A perfected interest or right of an assignee shall have priority over a person who becomes a lien creditor after the perfection of such assignee's interest or right.

E. The description of deferred fuel cost property being transferred to an assignee in any sale agreement, purchase agreement, or other transfer agreement, granted or pledged to a pledgee in any security agreement, pledge agreement, or other security document, or indicated in any financing statement, shall only be sufficient if such description or indication refers to the financing order that created the deferred fuel cost property and states that the agreement or financing statement covers all or part of the property described in the financing order. This section shall apply to all purported transfers of, and all purported grants or liens or security interests in, deferred fuel cost property, regardless of whether the related sale agreement, purchase agreement, other transfer agreement, security agreement, pledge agreement, or other security document was entered into, or any financing statement was filed.

F. All financing statements referenced in this section shall be subject to Part 5 of Title 8.9A (§ 8.9A-501 et seq.) of the Uniform Commercial Code, except that the requirement as to continuation statements shall not apply.

G. The laws of the Commonwealth shall govern the validity, enforceability, attachment, perfection, priority, and exercise of remedies with respect to the transfer of an interest or right or the pledge or creation of a security interest in any deferred fuel cost property.

H. Neither the Commonwealth nor its political subdivisions shall be liable on any deferred fuel cost bonds, and the bonds shall not be a debt or a general obligation of the Commonwealth or any of its political subdivisions, agencies, or instrumentalities, nor shall they be special obligations or indebtedness of the Commonwealth or any of its agencies or political subdivisions. An issue of deferred fuel cost bonds shall not, directly, indirectly, or contingently, obligate the Commonwealth or any agency, political subdivision, or instrumentality of the Commonwealth to levy any tax or make any appropriation for payment of the deferred fuel cost bonds, other than in their capacity as consumers of electricity. All deferred fuel cost bonds shall contain on the face thereof a statement to the following effect: "NEITHER THE FULL FAITH AND CREDIT NOR THE TAXING POWER OF THE COMMONWEALTH IS PLEDGED TO THE PAYMENT OF THE PRINCIPAL OF, OR INTEREST ON, THIS BOND."

I. All of the following entities may legally invest any sinking funds, moneys, or other funds in deferred fuel cost bonds:

1. Subject to applicable statutory restrictions on state or local investment authority, the Commonwealth, units of local government, political subdivisions, public bodies, and public officers, except for members of the Commission;

2. Banks and bankers, savings and loan associations, credit unions, trust companies, savings banks and institutions, investment companies, insurance companies, insurance associations, and other persons carrying on a banking or insurance business;

3. Personal representatives, guardians, trustees, and other fiduciaries; and

4. All other persons authorized to invest in bonds or other obligations of a similar nature.

J. 1. The Commonwealth and its agencies, including the Commission, pledge and agree with bondholders, the owners of the deferred fuel cost property, and other financing parties that the Commonwealth and its agencies shall not take any action listed in this subdivision. This subsection does not preclude limitation or alteration if full compensation is made by law for the full protection of the deferred fuel cost charges collected pursuant to a financing order and of the bondholders and any assignee or financing party entering into a contract with the electric utility. The Commonwealth and its agencies, including the Commission, shall not:

a. Alter the provisions of this section that authorize the Commission to create an irrevocable contract right or chose in action by the issuance of a financing order, to create deferred fuel cost property, and to make the deferred fuel cost charges imposed by a financing order irrevocable, binding, or nonbypassable charges;

b. Take or permit any action that impairs or would impair the value of deferred fuel cost property or *the security for the deferred fuel cost bonds or revises the deferred fuel costs for which recovery is authorized;*

c. In any way impair the rights and remedies of the bondholders, assignees, and other financing parties; or

d. Except for changes made pursuant to the formula-based adjustment mechanism authorized under this section, reduce, alter, or impair deferred fuel cost charges that are to be imposed, billed, charged, collected, and remitted for the benefit of the bondholders, any assignee, and any other financing parties until any and all principal, interest, premium, financing costs and other fees, expenses, or charges incurred, and any contracts to be performed, in connection with the related deferred fuel cost bonds have been paid and performed in full.

2. Any person that issues deferred fuel cost bonds may include the language specified in subdivision 1 in the deferred fuel cost bonds and related documentation.

K. An assignee or financing party shall not be considered an electric utility or person providing electric service by virtue of engaging in the transactions described in this section.

L. If there is a conflict between this section and any other law regarding the attachment, assignment, or perfection, or the effect of perfection, or priority of, assignment or transfer of, or security interest in deferred fuel cost property, this section shall govern.

M. In making determinations under this section, the Commission may engage an outside consultant and counsel.

N. If any provision of this section is held invalid or is invalidated, superseded, replaced, repealed, or expires for any reason, that occurrence shall not affect the validity of any action allowed under this section which is taken by an electric utility, an assignee, a financing party, a collection agent, or a party to an ancillary agreement, and any such action shall remain in full force and effect with respect to all deferred fuel cost bonds issued or authorized in a financing order issued under this section before the date that such provision is held invalid or is invalidated, superseded, replaced, or repealed, or expires for any reason.

O. As used in this section:

"Ancillary agreement" means a bond, insurance policy, letter of credit, reserve account, surety bond, interest rate lock or swap arrangement, hedging arrangement, liquidity or credit support arrangement, or other financial arrangement entered into in connection with deferred fuel cost bonds.

"Assignee" means a legally recognized entity to which an electric utility assigns, sells, or transfers, other than as a security, all or a portion of its interest in or right to deferred fuel cost property. "Assignee" includes a corporation, limited liability company, general partnership or limited partnership, public authority trust, financing entity, or other entity to which an assignee assigns, sells, or transfers, other than as a security, all or a portion of its interest in or right to deferred fuel cost property.

"Bondholder" means a person who holds a deferred fuel cost bond.

"Deferred fuel cost bonds" means bonds debentures, notes, certificates of participation, certificates of beneficial interest, certificates of ownership, or other evidences of indebtedness or ownership that are issued in one or more series or tranches by an electric utility or its assignee pursuant to a financing order, the proceeds of which are used directly or indirectly to recover, finance, or refinance Commission-approved deferred fuel costs and financing costs, and that are secured by or payable from deferred fuel cost property. If certificates of participation or ownership are issued, references in this section to principal, interest, or premium shall be construed to refer to comparable amounts under those certificates.

"Deferred fuel cost charge" means the nonbypassable charges authorized by the Commission to repay, finance, or refinance deferred fuel costs and financing costs (i) imposed on and part of all retail customer bills, except those of exempt retail access customers, (ii) collected by an electric utility or its successor or assignees, or a collection agent, in full, seperate and apart from the electric utility's base rates, and (iii) paid by all retail customers of the electric utility, irrespective of the generation supplier of such customer, except for an exempt retail access customer.

"Deferred fuel cost property" includes:

1. All rights and interests of an electric utility or successor or assignee of the electric utility under a financing order, including the right to impose, bill, charge, collect, and receive deferred fuel cost charges authorized under the financing order and to obtain periodic adjustments to such charges as provided in the financing order; and

2. All revenues, collections, claims, rights to payments, payments, money, or proceeds arising from the rights and interests specified in the financing order, regardless of whether such revenues, collections, claims, rights to payment, payments, money, or proceeds are imposed, billed, received, collected, or maintained together with or commingled with other revenues, collections, rights to payment, payments, money, or proceeds.

"Deferred fuel costs" means the unrecovered amounts of previously incurred costs of fuel used to

generate electricity, including the costs of purchased power, that have been deferred by an electric utility for future recovery from the utility's customers, along with financing costs on the utility's fuel deferral balance.

"Electric utility" means a Phase II Utility.

"Exempt retail access customer" means a retail customer of an electric utility that, pursuant to the provisions of § 56-577 or 56-577.1, purchased electric energy exclusively from a supplier of electric energy licensed to sell retail electric energy exclusively within the Commonwealth other than the electric utility for the entire period between July 1, 2021, and June 30, 2023.

"Financing costs" means:

1. Interest and any premium, including any acquisition, defeasance, or redemption premium, payable on deferred fuel cost bonds;

2. Any payment required under any indenture, ancillary agreement, or other financing documents pertaining to deferred fuel cost bonds and any amount required to fund or replenish a reserve account or other accounts established under the terms of any indenture, ancillary agreement, or other financing documents pertaining to deferred fuel cost bonds;

3. Any other costs related to structuring, offering, issuing, supporting, repaying, refunding, servicing, and complying with deferred fuel cost bonds, including service fees, accounting and auditing fees, trustee fees, legal fees, consulting fees, structuring adviser fees, administrative fees, placement and underwriting fees, independent director and manager fees, capitalized interest, rating agency fees, stock exchange listing and compliance fees, security registration fees, filing fees, information technology programming costs, and any other costs necessary to otherwise ensure the timely payment of deferred fuel cost bonds or other amounts or charges payable in connection with the bonds, including costs related to obtaining the financing order;

4. Any taxes and license fees or other fees imposed on the revenues generated from the collection of deferred fuel cost charges or otherwise resulting from the collection of deferred fuel cost charges, in any such case whether paid, payable, or accrued;

5. Any state and local taxes, franchise, gross receipts, and other taxes or similar charges including regulatory assessment fees, whether paid, payable, or accrued;

6. Any costs incurred by the Commission for any outside consultants or counsel retained in connection with the securitization of deferred fuel costs; and

7. Any financing costs on the utility's fuel deferral balance prior to issuance of any fuel cost bonds, calculated at the utility's approved weighted average cost of capital.

"Financing order" means an order that authorizes the issuance of deferred fuel cost bonds; the imposition, collection, and periodic adjustments of a deferred fuel cost charge; the creation of deferred fuel cost property; the sale, assignment, or transfer of deferred fuel cost property to an assignee and any other actions necessary or advisable to take actions described in the financing order.

"Financing party" means bondholders and trustees, collateral agents, any party under an ancillary agreement, or any other person acting for the benefit of bondholders.

"Financing statement" has the same meaning as provided in § 8.9A-102 of the Uniform Commercial Code.

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

"Pledgee" means a financing party to which an electric utility or its successors or assignees mortgages, negotiates, pledges, or creates a security interest or lien on all or any portion of its interest in or right to deferred fuel cost property.

§ 56-581. Regulation of rates subject to Commission's jurisdiction.

A. ~~After the expiration or termination of capped rates except as provided in § 56-585.1, the~~ *The* Commission shall regulate the rates of investor-owned incumbent electric utilities for the transmission of electric energy, to the extent not prohibited by federal law, and for the generation of electric energy and the distribution of electric energy to retail customers pursuant to *this section and* § 56-585.1.

B. In any proceeding to review base rates for a Phase I Utility that commences after July 1, 2023, if the Commission determines in its sole discretion that the utility's existing base rates will, on a going-forward basis, either produce (i) revenues in excess of the utility's authorized rate of return or (ii) revenues below the utility's authorized rate of return, then, notwithstanding any provision of law governing rate proceedings, the Commission shall order any reductions or increases, as applicable and necessary, to such base rates that it deems appropriate to ensure the resulting base rates (a) are just and reasonable and (b) provide the utility an opportunity to recover its costs of providing services over the rate period ending on December 31 of the year of the utility's succeeding review and earn a fair rate of return authorized pursuant to the provisions governing such review proceeding. Such determination shall be limited to the Phase I Utility's base rates and shall not consider the costs or revenues recovered in any rate adjustment clause authorized pursuant to this chapter.

C. In any proceeding to review base rates for a Phase II Utility that commences after July 1, 2023, if the Commission determines in its sole discretion that the utility's existing base rates will, on a *going-forward basis, either produce (i) revenues in excess of the utility's authorized rate of return or (ii) revenues below the utility's authorized rate of return, then, notwithstanding any provision of subdivision A 8 of § 56-585.1, the Commission shall order any reductions or increases, as applicable and necessary, to such base rates that it deems appropriate to ensure the resulting base rates (a) are just and reasonable and (b) provide the utility an opportunity to recover its costs of providing services over the rate period ending on December 31 of the year of the utility's succeeding review and earn a fair rate of return authorized pursuant to the provisions governing such review proceeding. Such determination shall be limited to the Phase II Utility's base rates and shall not consider the costs or revenues recovered in any rate adjustment clause authorized pursuant to subdivision A 6 of § 56-585.1 that has not been combined with the utility's base rates. The Commission shall use the most recently ended 12-month test period, along with normalization of nonrecurring test period costs and annualized adjustments for future costs, as the basis for determining the appropriateness of any rate adjustment. In any such filing to review base rates, a Phase II Utility shall separately project future costs over each 12-month period ending on December 31 of the year of the utility's succeeding review period. The Commission may, to the extent it finds such action aligns with the utility's projected cost of service, direct that any reduction or increase to the utility's rates for generation and distribution services be implemented on a staggered basis at the commencement and midpoint of the succeeding rate period.*

~~B.~~ *D.* Beginning July 1, 1999, and thereafter, no cooperative that was a member of a power supply cooperative on January 1, 1999, shall be obligated to file any rate rider as a consequence of an increase or decrease in the rates, other than fuel costs, of its wholesale supplier, nor must any adjustment be made to such cooperative's rates as a consequence thereof.

~~C.~~ *E.* Except for the provision of default services under § 56-585 or emergency services in § 56-586, nothing in this chapter shall authorize the Commission to regulate the rates or charges for electric service to the Commonwealth and its municipalities.

F. As used in this section:

"Base rates" means rates for generation and distribution services.

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

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

§ 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

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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 conduct a review for a Phase II Utility in 2021, utilizing the four successive 12-month test periods beginning January 1, 2017, and ending December 31, 2020, with subsequent reviews on a ~~triennial~~ *biennial* basis *commencing in 2023, with such proceedings* utilizing the ~~three~~ *two* successive 12-month test periods ending December 31 immediately preceding the year in which such review proceeding is conducted. ~~All such reviews occurring after December 31, 2017, shall be referred to as triennial reviews.~~ For purposes of this section, a Phase I Utility is an investor-owned incumbent electric utility that was, as of July 1, 1999, not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002, and a Phase II Utility is an investor-owned incumbent electric utility that was bound by such a settlement.

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

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

For a Phase II Utility, the Commission may use any methodology to determine such return it finds consistent with the public interest, but for applications received by the Commission on or after July 1, 2023, such return shall not be set lower than the average of the most recently authorized returns on common equity set by the applicable regulatory commissions for all investor-owned electric utilities in the peer group of the utility subject to such review, nor shall the Commission set such return more than 150 basis points higher than such average. In the case of a peer utility having an authorized weighted cost of equity, an authorized return on equity shall be imputed utilizing the utility's actual capital structure as most recently reported to the Securities and Exchange Commission. In the case of a peer utility having an authorized return on equity or weighted cost of equity range or band, the mid-point of the range or band shall be utilized.

b. ~~In~~ *For a Phase I Utility, in* selecting such majority of peer group investor-owned electric utilities for applications received by the Commission on or after January 1, 2020, the Commission shall first remove from such group the two utilities within such group that have the lowest reported or authorized, as applicable, returns of the group, as well as the two utilities within such group that have the highest reported or authorized, as applicable, returns of the group, and the Commission shall then select a majority of the utilities remaining in such peer group. In its final order regarding such triennial review, the Commission shall identify the utilities in such peer group it selected for the calculation of such limitation. ~~For~~ *With respect to both Phase I and Phase II Utilities, for* purposes of this subdivision *2*, an investor-owned electric utility shall be deemed part of such peer group if (i) its principal operations are conducted in the southeastern United States east of the Mississippi River in either the states of West Virginia or Kentucky or in those states south of Virginia, excluding the state of Tennessee, (ii) it is a vertically-integrated electric utility providing generation, transmission, and distribution services whose facilities and operations are subject to state public utility regulation in the state where its principal operations are conducted, (iii) it had a long-term bond rating assigned by Moody's Investors Service of at least Baa at the end of the most recent test period subject to such ~~triennial~~ review, and (iv) it is not an affiliate of the utility subject to such ~~triennial~~ review *or a utility whose fair rate of return on common equity is determined by the Commission. Additionally, for reviews filed by a Phase II Utility, an investor-owned electric utility shall be deemed part of such peer group only if it meets the requirements* *in this subdivision and is a vertically-integrated electric utility providing generation, transmission, and distribution services to at least 200,000 retail electric customers.*

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

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

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

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

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

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

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

g. If the combined rate of return on common equity earned by the generation and distribution services is no more than 50 basis points above or below the return as so determined or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, such return is no more than 70 basis points above or below the return as so determined, such combined return shall not be considered either excessive or insufficient, respectively. However, for any test period commencing after December 31, 2012, for a Phase II Utility, and after December 31, 2013, for a Phase I Utility, if the utility has, during the test period or periods under review, earned below the return as so determined, whether or not such combined return is within 70 basis points of the return as so determined, the utility may petition the Commission for approval of an increase in rates in accordance with the provisions of subdivision 8 a as if it had earned more than 70 basis points below a fair combined rate of return, and such proceeding shall otherwise be conducted in accordance with the provisions of this section. 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~~ *and terminating thereafter*. 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. *After 2021, each Phase II Utility shall make a biennial filing by March 31 of every second year, except that the 2023 filing for a Phase II Utility shall be made on or after July 1, 2023. All biennial filings shall encompass the two successive 12-month test periods ending December 31 immediately preceding the year in which such review proceeding is conducted. All such filings shall consist of the schedules contained in the Commission's rules governing utility rate increase applications,* 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. *In a 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.*

If the Commission determines that rates should be revised or credits be applied to customers' bills pursuant to subdivision 8 or ~~9~~ *10*, 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 *in this paragraph*, 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.~~

As of July 1, 2023, a Phase II Utility shall select a subset of rate adjustment clauses previously implemented pursuant to subdivision 5 or 6 having a combined annual revenue requirement, as of July 1, 2023, of at least $350 million and combine such rate adjustment clauses with the utility's costs, revenues, and investments for generation and distribution services. After such rate adjustment clauses are combined as specified in this paragraph, such rate adjustment clauses shall be considered part of the utility's costs, revenues, and investments for the purposes of future biennial review proceedings, and the combination of such rate adjustment clauses shall be specifically subject to audit by the Commission in the utility's 2023 biennial review filing.

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

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

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

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

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

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

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

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

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

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

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

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

Thirty percent of all costs of such a facility utilizing nuclear power that the utility incurred between July 1, 2007, and December 31, 2013, and all of such costs incurred after December 31, 2013, may be deferred by the utility and recovered through a rate adjustment clause under this subdivision at such time as the Commission provides in an order approving such a rate adjustment clause. The remaining 70 percent of all costs of such a facility that the utility incurred between July 1, 2007, and December 31, 2013, shall not be deferred for recovery through a rate adjustment clause under this subdivision; however, such remaining 70 percent of all costs shall be recovered ratably through existing base rates as determined by the Commission in the test periods under review in the utility's next review filed after July 1, 2014. Thirty percent of all costs of a facility utilizing energy derived from offshore wind that the utility incurred between July 1, 2007, and December 31, 2013, and all of such costs incurred after December 31, 2013, may be deferred by the utility and recovered through a rate adjustment clause under this subdivision at such time as the Commission provides in an order approving such a rate adjustment clause. The remaining 70 percent of all costs of such a facility that the utility incurred between July 1, 2007, and December 31, 2013, shall not be deferred for recovery through a rate adjustment clause under this subdivision; however, such remaining 70 percent of all costs shall be recovered ratably through existing base rates as determined by the Commission in the test periods under review in the utility's next 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

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

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

7. Any petition filed pursuant to subdivision 4, 5, or 6 shall be considered by the Commission on a stand-alone basis without regard to the other costs, revenues, investments, or earnings of the utility. Any costs incurred by a utility prior to the filing of such petition, or during the consideration thereof by the Commission, that are proposed for recovery in such petition and that are related to subdivision 5 a, or that are related to facilities and projects described in clause (i) of subdivision 6, or that are related to new underground facilities described in clause (iv) of subdivision 6, shall be deferred on the books and records of the utility until the Commission's final order in the matter, or until the implementation of any applicable approved rate adjustment clauses, whichever is later. Except as otherwise provided in subdivision 6, any costs prudently incurred on or after July 1, 2007, by a utility prior to the filing of such petition, or during the consideration thereof by the Commission, that are proposed for recovery in such petition and that are related to facilities and projects described in clause (ii) or clause (iii) of subdivision 6 that utilize nuclear power, or coal-fueled facilities and projects described in clause (ii) of subdivision 6 if such coal-fueled facilities will be built by a Phase I Utility, shall be deferred on the books and records of the utility until the Commission's final order in the matter, or until the implementation of any applicable approved rate adjustment clauses, whichever is later. Any costs prudently incurred after the expiration or termination of capped rates related to other matters described in subdivision 4, 5, or 6 shall be deferred beginning only upon the expiration or termination of capped rates, provided, however, that no provision of this act shall affect the rights of any parties with respect to the rulings of the Federal Energy Regulatory Commission in PJM Interconnection LLC and Virginia

Electric and Power Company, 109 F.E.R.C. P 61,012 (2004). A utility shall establish a regulatory asset for regulatory accounting and ratemaking purposes under which it shall defer its operation and maintenance costs incurred in connection with (i) the refueling of any nuclear-powered generating plant and (ii) other work at such plant normally performed during a refueling outage. The utility shall amortize such deferred costs over the refueling cycle, but in no case more than 18 months, beginning with the month in which such plant resumes operation after such refueling. The refueling cycle shall be the applicable period of time between planned refueling outages for such plant. As of January 1, 2014, such amortized costs are a component of base rates, recoverable in base rates only ratably over the refueling cycle rather than when such outages occur, and are the only nuclear refueling costs recoverable in base rates. This provision shall apply to any nuclear-powered generating plant refueling outage commencing after December 31, 2013, and the Commission shall treat the deferred and amortized costs of such regulatory asset as part of the utility's costs for the purpose of proceedings conducted (a) with respect to ~~triennial~~ filings under subdivision 3 made on and after July 1, 2014, and (b) pursuant to § 56-245 or the Commission's rules governing utility rate increase applications as provided in subsection B. This provision shall not be deemed to change or reset base rates.

The Commission's final order regarding any petition filed pursuant to subdivision 4, 5, or 6 shall be entered not more than three months, eight months, and nine months, respectively, after the date of filing of such petition. If such petition is approved, the order shall direct that the applicable rate adjustment clause be applied to customers' bills not more than 60 days after the date of the order, or upon the expiration or termination of capped rates, whichever is later. *At any time, the Commission may, in its discretion, for a Phase II Utility, upon petition by a such a utility or upon its own initiated proceeding, direct the consolidation of any one or more subsets of rate adjustment clauses previously implemented pursuant to subdivision 5 or 6 in the interest of judicial economy, customer transparency, or other factors the Commission determines to be appropriate. Any subset of rate adjustment clauses so consolidated shall continue to be considered by the Commission without regard to the other costs, revenues, investments, or earnings of the utility and remain as a cost recovery mechanism independent from the utility's rates for generation and distribution services pursuant to this subdivision and subdivisions 5 and 6, but will be combined as a single rate adjustment clause for cost recovery and review purposes.*

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~~ *any* triennial review *initiated prior to July 1, 2023, by a Phase II Utility or at any time by a Phase I Utility, or, for subdivision d, as a result of any triennial or biennial review initiated prior to January 1, 2024, by a Phase II Utility or at any time by a Phase I Utility,* 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 in connection with making its determination concerning the necessity for such a rate increase or the amount thereof, the Commission shall, in any triennial review proceeding conducted prior to July 1, 2028, exclude from this most recently ended 12-month test period any remaining investment levels associated with a prior customer credit reinvestment offset pursuant to subdivision d.

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

c. ~~In any triennial review proceeding conducted after January 1, 2020, for a Phase I Utility or after January 1, 2021, for a Phase II Utility in which the~~ *The* utility has, during the test period or test periods under review, considered as a whole, earned more than 50 basis points above a fair combined rate of return on its generation and distribution services or, for any test period commencing after December 31, 2012, for a Phase II Utility and after December 31, 2013, for a Phase I Utility, more than 70 basis points above a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matter determined with respect to facilities described in subdivision 6, and the combined aggregate level of capital investment that the Commission has approved other than those capital investments that the Commission has approved for recovery pursuant to a rate adjustment clause pursuant to subdivision 6 made by the utility during the test periods under review in that triennial review proceeding in new utility-owned generation facilities utilizing energy derived from sunlight, or from wind, and in electric distribution grid transformation projects, as determined pursuant to subdivision 8 d, does not equal or exceed 100 percent of the earnings that are more than 70 basis points above the utility's fair combined rate of return on its generation and distribution services for the combined test periods under review in that triennial review proceeding, the Commission shall, subject to the provisions of subdivision ~~9~~ *10* and in addition to the actions authorized in subdivision b, also order reductions to the utility's rates it finds appropriate. However, in the first triennial review proceeding conducted after January 1, 2021, for a Phase II Utility, any reduction to the utility's rates ordered by the Commission pursuant to this subdivision shall not exceed $50 million in annual revenues, with any reduction allocated to the utility's rates for generation services, and in each triennial review of a Phase I or Phase II Utility, the Commission may not order such rate reduction unless it finds that the resulting rates will provide the utility with the opportunity to fully recover its costs of providing its services and to earn not less than a fair combined rate of return on its generation and distribution services, as determined in subdivision 2, without regard to any return on common equity or other matters determined with respect to facilities described in subdivision 6, using the most recently ended 12-month test period as the basis for determining the permissibility of any rate reduction under the standards of this sentence, and the amount thereof; and

d. (Expires July 1, 2028) In any ~~triennial~~ review proceeding conducted after December 31, 2017, upon the request of the utility, the Commission shall determine, prior to directing that 70 percent of earnings that are more than 70 basis points above the utility's fair combined rate of return on its generation and distribution services for the test period or periods under review be credited to customer bills pursuant to subdivision 8 b, the aggregate level of prior capital investment that the Commission has approved other than those capital investments that the Commission has approved for recovery pursuant to a rate adjustment clause pursuant to subdivision 6 made by the utility during the test period or periods under review in both (i) new utility-owned generation facilities utilizing energy derived from sunlight, or from onshore or offshore wind, and (ii) electric distribution grid transformation projects, as determined by the utility's plant in service and construction work in progress balances related to such investments as recorded per books by the utility for financial reporting purposes as of the end of the most recent test period under review. Any such combined capital investment amounts shall offset any customer bill credit amounts, on a dollar for dollar basis, up to the aggregate level of invested or committed capital under clauses (i) and (ii). The aggregate level of qualifying invested or committed 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 *two or* three, *as applicable,* 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. *In any biennial review, if the Commission determines that the utility has during the test period or test periods under review, considered as a whole, earned more than 70 basis points above a fair combined rate of return on its generation and distribution services previously authorized by the Commission, 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, which have not been combined with the utility's costs, revenues, and investments for generation and distribution services, the Commission shall, subject to the provisions of subdivision 8 d, direct that 85 percent of the amount of such earnings that were more than 70 basis points above such fair combined rate of return for the test period or periods under review, considered as a whole, be credited to customers' bills. Any such credits shall be amortized over a period of six to 12 months, as determined at the discretion of the Commission, following the effective date of the Commission's order, and shall be allocated among customer classes such that the relationship between the specific customer class rates of return to the overall target rate of return will have the same relationship as the last approved allocation of revenues used to design base rates.*

10. 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.~~ *11.* 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.

Throughout the duration of the construction period for any project constructed by a Phase II Utility pursuant to § 56-585.1:11, such utility shall undertake reasonable efforts to maintain, subject to audit by the Commission, its common equity capitalization to total capitalization ratio at a level at least equal to the average of such ratio for all utilities in the applicable Phase II Utility's peer group investor-owned utilities, as determined according to subdivision A 2 b, and as authorized by such utilities' regulatory commission in their most recent governing rate proceeding.

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.

§ 56-585.1:4. Development of solar and wind generation and energy storage capacity in the Commonwealth.

A. Prior to January 1, 2024, (i) the construction or purchase by a public utility of one or more solar or wind generation facilities located in the Commonwealth or off the Commonwealth's Atlantic shoreline, each having a rated capacity of at least one megawatt and having in the aggregate a rated capacity that does not exceed 5,000 megawatts, or (ii) the purchase by a public utility of energy, capacity, and environmental attributes from solar facilities described in clause (i) owned by persons other than a public utility is in the public interest, and the Commission shall so find if required to make a finding regarding whether such construction or purchase is in the public interest.

B. Prior to January 1, 2024, (i) the construction or purchase by a public utility of one or more solar or wind generation facilities located in the Commonwealth or off the Commonwealth's Atlantic shoreline, each having a rated capacity of less than one megawatt, including rooftop solar installations with a capacity of not less than 50 kilowatts, and having in the aggregate a rated capacity that does not exceed 500 megawatts, or (ii) the purchase by a public utility of energy, capacity, and environmental attributes from solar facilities described in clause (i) owned by persons other than a public utility is in the public interest, and the Commission shall so find if required to make a finding regarding whether such construction or purchase is in the public interest.

C. The aggregate cap of 5,000 megawatts of rated capacity described in clause (i) of subsection A, the aggregate cap of 500 megawatts of rated capacity described in clause (i) of subsection B, and the aggregate cap of 200 megawatts of rated capacity described in subsection I are separate and independent from each other. The capacity of facilities in subsection B shall not be counted in determining the capacity of facilities in subsection A or I; the capacity of facilities in subsection A shall not be counted in determining the capacity of facilities in subsection B or I; and the capacity of facilities in subsection I shall not be counted in determining the capacity of facilities in subsection A or B.

D. Twenty-five percent of the solar generation capacity placed in service on or after July 1, 2018, located in the Commonwealth, and found to be in the public interest pursuant to subsection A or B shall be from the purchase by a public utility of energy, capacity, and environmental attributes from solar facilities owned by persons other than a public utility. The remainder shall be construction or purchase by a public utility of one or more solar generation facilities located in the Commonwealth. All of the solar generation capacity located in the Commonwealth and found to be in the public interest pursuant to subsection A or B shall be subject to competitive procurement, provided that a public utility may select solar generation capacity without regard to whether such selection satisfies price criteria if the selection of the solar generating capacity materially advances non-price criteria, including favoring geographic distribution of generating capacity, areas of higher employment, or regional economic development, if such non-price solar generating capacity selected does not exceed 25 percent of the utility's solar generating capacity.

E. Construction, purchasing, or leasing activities for a test or demonstration project for a new utility-owned and utility-operated generating facility or facilities utilizing energy derived from offshore wind with an aggregate capacity of not more than 16 megawatts are in the public interest.

F. Prior to January 1, 2035, (i) the construction by a public utility of one or more energy storage facilities located in the Commonwealth, having in the aggregate a rated capacity that does not exceed 2,700 megawatts, or (ii) the purchase by a public utility of energy storage facilities described in clause (i) owned by persons other than a public utility or the capacity from such facilities is in the public interest, and the Commission shall so find if required to make a finding regarding whether such construction or purchase is in the public interest.

G. At least 35 percent of the energy storage capacity placed in service on or after July 1, 2020, located in the Commonwealth and found to be in the public interest pursuant to subsection F shall be from the purchase by a public utility of energy storage facilities owned by persons other than a public utility or the capacity from such facilities. All of the energy storage facilities located in the Commonwealth and found to be in the public interest pursuant to subsection F shall be subject to competitive procurement, provided that a public utility may select energy storage facilities without regard to whether such selection satisfies price criteria if the selection of the energy storage facilities materially advances non-price criteria, including favoring geographic distribution of generating facilities, areas of higher employment, or regional economic development, if such energy storage facilities selected for the advancement of non-price criteria do not exceed 25 percent of the utility's energy storage capacity.

H. A utility may elect to petition the Commission, outside of a triennial *or biennial* review proceeding conducted pursuant to § 56-585.1, at any time for a prudency determination with respect to the construction or purchase by the utility of one or more solar or wind generation facilities located in the Commonwealth or off the Commonwealth's Atlantic Shoreline or the purchase by the utility of energy, capacity, and environmental attributes from solar or wind facilities owned by persons other than the utility. The Commission's final order regarding any such petition shall be entered by the Commission not more than three months after the date of the filing of such petition.

I. Prior to January 1, 2024, (i) the construction or purchase by a public utility of one or more solar or wind generation facilities located on a previously developed project site in the Commonwealth having in the aggregate a rated capacity that does not exceed 200 megawatts or (ii) the purchase by a public utility of energy, capacity, and environmental attributes from solar facilities described in clause (i) owned by persons other than a public utility, is in the public interest.

§ 56-599. Integrated resource plan required.

A. Each electric utility shall file an updated integrated resource plan by July 1, 2015. Thereafter, each electric utility shall file an updated integrated resource plan by May 1, in each year immediately preceding the year the utility is subject to a triennial *or biennial* review filing. A copy of each integrated resource plan shall be provided to the Chairman of the House Committee on Labor and Commerce, the Chairman of the Senate Committee on Commerce and Labor, and to the Chairman of the Commission on Electric Utility Regulation. All updated integrated resource plans shall comply with the provisions of any relevant order of the Commission establishing guidelines for the format and contents of updated and revised integrated resource plans. Each integrated resource plan shall consider options for maintaining and enhancing rate stability, energy independence, economic development including retention and expansion of energy-intensive industries, and service reliability.

B. In preparing an integrated resource plan, each electric utility shall systematically evaluate and may propose:

1. Entering into short-term and long-term electric power purchase contracts;

2. Owning and operating electric power generation facilities;

3. Building new generation facilities;

4. Relying on purchases from the short term or spot markets;

5. Making investments in demand-side resources, including energy efficiency and demand-side management services;

6. Taking such other actions, as the Commission may approve, to diversify its generation supply portfolio and ensure that the electric utility is able to implement an approved plan;

7. The methods by which the electric utility proposes to acquire the supply and demand resources identified in its proposed integrated resource plan;

8. The effect of current and pending state and federal environmental regulations upon the continued operation of existing electric generation facilities or options for construction of new electric generation facilities;

9. The most cost effective means of complying with current and pending state and federal environmental regulations, including compliance options to minimize effects on customer rates of such regulations;

10. Long-term electric distribution grid planning and proposed electric distribution grid transformation projects;

11. Developing a long-term plan for energy efficiency measures to accomplish policy goals of reduction in customer bills, particularly for low-income, elderly, and disabled customers; reduction in emissions; and reduction in carbon intensity; and

12. Developing a long-term plan to integrate new energy storage facilities into existing generation and distribution assets to assist with grid transformation.

C. As part of preparing any integrated resource plan pursuant to this section, each utility shall conduct a facility retirement study for owned facilities located in the Commonwealth that emit carbon dioxide as a byproduct of combusting fuel and shall include the study results in its integrated resource plan. Upon filing the integrated resource plan with the Commission, the utility shall contemporaneously disclose the study results to each planning district commission, county board of supervisors, and city and town council where such electric generation unit is located, the Department of Energy, the Department of Housing and Community Development, the Virginia Employment Commission, and the Virginia Council on Environmental Justice. The disclosure shall include (i) the driving factors of the decision to retire and (ii) the anticipated retirement year of any electric generation unit included in the plan. Any electric generating facility with an anticipated retirement date that meets the criteria of § 45.2-1701.1 shall comply with the public disclosure requirements therein.

D. The Commission shall analyze and review an integrated resource plan and, after giving notice and opportunity to be heard, the Commission shall make a determination within nine months after the date of filing as to whether such an integrated resource plan is reasonable and is in the public interest.