Attachment 1

Model Rule
Part XX CO_2 Budget Trading Program
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Subpart XX-1 CO_2 Budget Trading Program General Provisions

XX-1.1 Purpose.

This Part establishes the NAME OF RELEVANT RGGI STATE component of the CO_2 Budget Trading Program, which is designed to reduce anthropogenic emissions of CO_2, a greenhouse gas, from CO_2 budget sources in an economically efficient manner.

XX-1.2 Definitions.

Account Number. The identification number given by the REGULATORY AGENCY or its agent to each CO_2 Allowance Tracking System account.

Acid rain emissions limitation. As defined in 40 CFR 72.2, a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program under title IV of the Clean Air Act.

Acid Rain Program. Acid Rain Program means a multi-state sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the Administrator under title IV of the CAA and 40 CFR Parts 72 through 78.

Administrator. Administrator means the Administrator of the United States Environmental Protection Agency or the administrator's authorized representative.

Allocate or allocation. The determination by the REGULATORY AGENCY of the number of CO_2 allowances to be recorded in the compliance account of a CO_2 budget unit, an allocation set-aside account, the consumer benefit or strategic energy purpose account, or the general account of the sponsor of an approved CO_2 emissions offset project.

[The reference to the consumer benefit or strategic energy purpose account illustrates how this account could be labeled and does not necessarily represent what an individual RGGI State will propose.]

Allocation year. A calendar year for which the REGULATORY AGENCY allocates or awards CO_2 allowances pursuant to Subparts XX-5 and XX-10. The allocation year of each CO_2 allowance is reflected in the unique identification number given to the allowance pursuant to subdivision XX-6.4(c).

Allowance auction or auction. An auction in which the REGULATORY AGENCY or its agent offers CO_2 allowances for sale.

Attribute. A characteristic associated with electricity generated using a particular renewable fuel, such as its generation date, facility geographic location, unit vintage, emissions output, fuel, state program eligibility, or other characteristic that can be identified, accounted for, and tracked.

Attribute credit. An attribute credit represents the attributes related to one megawatt-hour of electricity generation.

Automated Data Acquisition and Handling System (DAHS). That component of the continuous emissions monitoring system, or other emissions monitoring system approved for use under Subpart XX-8, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by Subpart XX-8.

Award. The determination by the REGULATORY AGENCY of the number of CO_2 offset allowances to be recorded in the general account of a project sponsor pursuant to XX-10.7. Award is a type of allocation.

Billing Meter. To qualify as a billing meter, the measurement device must be used to measure electric or thermal output for commercial billing under a contract. The facility selling the electric or thermal output must have different owners from the owners of the party purchasing the electric or thermal output.

Boiler. An enclosed fossil or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

CO_2 allowance. A limited authorization by the REGULATORY AGENCY or a participating state under the CO_2 Budget Trading Program to emit up to one ton of CO_2, subject to all applicable limitations contained in this Part.

CO_2 allowance deduction or deduct CO_2 allowances. The permanent withdrawal of CO_2 allowances by the REGULATORY AGENCY or its agent from a CO_2 Allowance Tracking System compliance account to account for the number of tons of CO_2 emitted from a CO_2 budget source for a control period or an interim control period, determined in accordance with Subpart XX-8, or for the forfeit or retirement of CO_2 allowances as provided by this Part.

CO_2 allowances held or hold CO_2 allowances. The CO_2 allowances recorded by the REGULATORY AGENCY or its agent, or submitted to the REGULATORY AGENCY or its agent for recordation, in accordance with Subparts XX-6 and XX-7, in a CO_2 Allowance Tracking System account.

CO_2 Allowance Tracking System (COATS). A system by which the REGULATORY AGENCY or its agent records allocations, deductions, and transfers of CO_2 allowances under the CO_2 Budget Trading Program. The tracking system may also be used to track CO_2 emissions offset projects, CO_2 allowance prices and emissions from affected sources.

CO_2 Allowance Tracking System account. An account in the CO_2 Allowance Tracking System established by the REGULATORY AGENCY or its agent for purposes of recording the allocation, holding, transferring, or deducting of CO_2 allowances.

CO_2 allowance transfer deadline. Midnight of the March 1 occurring after the end of the relevant control period and each relevant interim control period or, if that March 1 is not

a business day, midnight of the first business day thereafter and is the deadline by which CO_2 allowances must be submitted for recordation in a CO_2 budget source's compliance account in order for the source to meet the CO_2 requirements of XX-1.5(c) for the control period and each interim control period immediately preceding such deadline.

CO_2 authorized account representative. For a CO_2 budget source and each CO_2 budget unit at the source, the natural person who is authorized by the owners and operators of the source and all CO_2 budget units at the source, in accordance with Subpart XX-2, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Budget Trading Program or, for a general account, the natural person who is authorized, under Subpart XX-6, to transfer or otherwise dispose of CO_2 allowances held in the general account. If the CO_2 budget source is also subject to the Acid Rain Program, CSAPR NO_x Annual Trading Program, CSAPR NO_x Ozone Season Trading Program, CSAPR SO_2 Group 1 Trading Program or CSAPR SO_2 Group 2 Trading Program then, for a CO_2 Budget Trading Program compliance account, this natural person shall be the same person as the designated representative as defined in the respective program.

CO_2 authorized alternate account representative. For a CO_2 budget source and each CO_2 budget unit at the source, the alternate natural person who is authorized by the owners and operators of the source and all CO_2 budget units at the source, in accordance with Subpart XX-2, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Budget Trading Program or, for a general account, the alternate natural person who is authorized, under Subpart XX-6, to transfer or otherwise dispose of CO_2 allowances held in the general account. If the CO_2 budget source is also subject to the Acid Rain Program, CSAPR NO_x Annual Trading Program, CSAPR NO_x Ozone Season Trading Program, CSAPR SO_2 Group 1 Trading Program or CSAPR SO_2 Group 2 Trading Program then, for a CO_2 Budget Trading Program

compliance account, this alternate natural person shall be the same person as the alternate designated representative as defined in the respective program.

CO_2 budget emissions limitation. For a CO_2 budget source, the tonnage equivalent, in CO_2 emissions in a control period or an interim control period, of the CO_2 allowances available for compliance deduction for the source for a control period or an interim control period.

CO_2 budget permit. The portion of the legally binding permit issued by the REGULATORY AGENCY pursuant to **[Insert Reference to State's Permitting Regulation(s)]** to a CO_2 budget source or CO_2 budget unit which specifies the CO_2 Budget Trading Program requirements applicable to the CO_2 budget source, to each CO_2 budget unit at the CO_2 budget source, and to the owners and operators and the CO_2 authorized account representative of the CO_2 budget source and each CO_2 budget unit.

CO_2 budget source. A source that includes one or more CO_2 budget units.

CO_2 Budget Trading Program. A multi-state CO_2 air pollution control and emissions reduction program established pursuant to this Part and corresponding regulations in other states as a means of reducing emissions of CO_2 from CO_2 budget sources.

CO_2 budget unit. A unit that is subject to the CO_2 Budget Trading Program requirements under section XX-1.4.

CO_2 cost containment reserve allowance or CO_2 CCR allowance. A CO_2 allowance that is offered for sale at an auction by the REGULATORY AGENCY for the purpose of containing the cost of CO_2 Allowances. CO_2 CCR allowances offered for sale at an auction are separate from and additional to CO_2 allowances allocated from the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base and adjusted

budgets. CO_2 CCR allowances are subject to all applicable limitations contained in this Part.

CO_2 cost containment reserve trigger price, or CCR trigger price. The CCR trigger price is the minimum price at which CO_2 CCR allowances are offered for sale by the REGULATORY AGENCY or its agent at an auction. The CCR trigger price shall be $10.00 per CO_2 allowance in calendar year 2017. Each calendar year thereafter through 2020, the CCR trigger price shall be 1.025 multiplied by the CCR trigger price from the previous calendar year, rounded to the nearest whole cent. The CCR trigger price in calendar year 2021 shall be $13.00. Each calendar year thereafter, the CCR trigger price shall be 1.07 multiplied by the CCR trigger price from the previous calendar year, rounded to the nearest whole cent, as shown in Table 1.

Table 1. CO_2 CCR Trigger Price

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$10.25	$10.51	$10.77	$13.00	$13.91	$14.88	$15.92	$17.03	$18.22	$19.50	$20.87	$22.33	$23.89

CO_2 emissions containment reserve allowance or CO_2 ECR allowance. A CO_2 allowance that is withheld from sale at an auction by the REGULATORY AGENCY for the purpose of additional emission reduction in the event of lower than anticipated emission reduction costs.

CO_2 emissions containment reserve trigger price, or ECR trigger price. The ECR trigger price is the price below which CO_2 allowances will be withheld from sale by the REGULATORY AGENCY or its agent at an auction. The ECR trigger price in calendar year 2021 shall be $6.00. Each calendar year thereafter, the ECR trigger price shall be 1.07 multiplied by the ECR trigger price from the previous calendar year, rounded to the nearest whole cent, as shown in Table 2.

Table 2. CO_2 ECR Trigger Price

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$ 6.00	$ 6.42	$ 6.87	$ 7.35	$ 7.86	$ 8.41	$ 9.00	$ 9.63	$10.30	$11.02

CO_2 equivalent. The quantity of a given greenhouse gas multiplied by its global warming potential (GWP).

CO_2 offset allowance. A CO_2 allowance that is awarded to the sponsor of a CO_2 emissions offset project pursuant to section XX-10.7 and is subject to the relevant compliance deduction limitations of section XX-6.5(a)(3).

Combined cycle system. A system comprised of one or more combustion turbines, heat recovery steam generators, and steam turbines configured to improve overall efficiency of electricity generation or steam production.

[This definition of CHP unit illustrates how this could be defined and does not necessarily represent what an individual RGGI State will propose]

Combined heat and power unit or CHP unit, (also known as "cogeneration"). An electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy facility.

Combustion turbine. An enclosed fossil or other fuel-fired device that is comprised of a compressor (if applicable), a combustor, and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine.

Commence commercial operation. With regard to a unit that serves a generator, to have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation. For a unit that is a CO_2 budget unit under

section XX-1.4 on the date the unit commences commercial operation, such date shall remain the unit's date of commencement of commercial operation even if the unit is subsequently modified, reconstructed, or repowered. For a unit that is not a CO_2 budget unit under section XX-1.4 on the date the unit commences commercial operation, the date the unit becomes a CO_2 budget unit under section XX-1.4 shall be the unit's date of commencement of commercial operation.

Commence operation. To begin any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber. For a unit that is a CO_2 budget unit under section XX-1.4 on the date of commencement of operation, such date shall remain the unit's date of commencement of operation even if the unit is subsequently modified, reconstructed, or repowered. For a unit that is not a CO_2 budget unit under section XX-1.4 on the date of commencement of operation, the date the unit becomes a CO_2 budget unit under section XX-1.4 shall be the unit's date of commencement of operation.

Compliance account. A CO_2 Allowance Tracking System account, established by the REGULATORY AGENCY or its agent for a CO_2 budget source under Subpart XX-6, in which are held CO_2 allowances available for use by the source for a control period and each interim control period for the purpose of meeting the CO_2 requirements of XX-1.5(c).

[This definition for the consumer benefit or strategic energy purpose account illustrates how this account could be defined and does not necessarily represent what an individual RGGI State will propose.]

Consumer benefit or strategic energy purpose account. A general account established by the Regulatory Agency or its agent from which allowances will be sold or distributed in order to provide funds to encourage and foster the following: promotion of energy efficiency measures, direct mitigation of electricity ratepayer impacts attributable to the

implementation of the CO_2 Budget Trading Program, promotion of renewable or non-carbon-emitting energy technologies, stimulation or reward of investment in the development of innovative carbon emissions abatement technologies with significant carbon reduction potential, and/or the administration of NAME OF RELEVANT RGGI STATE component of the CO_2 Budget Trading Program.

Continuous Emissions Monitoring System (CEMS). The equipment required under Subpart XX-8 to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated DAHS), a permanent record of stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with 40 CFR Part 75 and Subpart XX-8. The following systems are types of continuous emissions monitoring systems required under Subpart XX-8.

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A nitrogen oxides emissions rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X concentration, in parts per million (ppm), diluent gas concentration, in percent CO_2 or O_2; and NO_X emissions rate, in pounds per million British thermal units (lb/MMBtu);

(3) A moisture monitoring system, as defined in 40 CFR 75.11(b)(2) and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(4) A carbon dioxide monitoring system, consisting of a CO_2 pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated

data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(5) An oxygen monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period. The control period is a three-calendar-year time period. The first control period is from January 1, 2009 to December 31, 2011, inclusive. Each subsequent sequential three-calendar-year period is a separate control period. The first two calendar years of each control period are each defined as an interim control period, beginning on January 1, 2015.

Cross State Air Pollution Rule (CSAPR) NO_X Annual Trading Program. A multi-state NO_X air pollution control and emission reduction program established in accordance with subpart AAAAA of 40 CFR Part 97 and 40 CFR 52.38(a) (including such a program that is revised in a SIP revision approved by the Administrator under 40 CFR 52.38(a)(3) or (4) or that is established in a SIP revision approved by the Administrator under 40 CFR 52.38(a)(5)), as a means of mitigating interstate transport of fine particulates and NO_X.

Cross State Air Pollution Rule (CSAPR) NO_X Ozone Season Trading Program. A multi-state NO_X air pollution control and emission reduction program established in accordance with subpart BBBBB of 40 CFR Part 97 and 40 CFR 52.38(b) (including such a program that is revised in a SIP revision approved by the Administrator under 40 CFR 52.38(b)(3) or (4) or that is established in a SIP revision approved by the Administrator under 40 CFR 52.38(b)(5)), as a means of mitigating interstate transport of ozone and NO_X.

Cross State Air Pollution Rule (CSAPR) SO_2 Group 1 Trading Program. A multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart CCCCC of 40 CFR Part 97 and 40 CFR 52.39(a), (b), (d) through (f), (j), and (k)

(including such a program that is revised in a SIP revision approved by the Administrator under 40 CFR 52.39(d) or (e) or that is established in a SIP revision approved by the Administrator under 40 CFR 52.39(f)), as a means of mitigating interstate transport of fine particulates and SO_2.

Cross State Air Pollution Rule (CSAPR) SO_2 Group 2 Trading Program. A multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart DDDDD of 40 CFR Part 97 and 40 CFR 52.39(a), (c), and (g) through (k) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under 40 CFR 52.39(g) or (h) of this chapter or that is established in a SIP revision approved by the Administrator under 40 CFR 52.39(i) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

Eligible biomass. Eligible biomass includes sustainably harvested woody and herbaceous fuel sources that are available on a renewable or recurring basis (excluding old-growth timber), including dedicated energy crops and trees, agricultural food and feed crop residues, aquatic plants, unadulterated wood and wood residues, animal wastes, other clean organic wastes not mixed with other solid wastes, biogas, and other neat liquid biofuels derived from such fuel sources. Sustainably harvested will be determined by the REGULATORY AGENCY.

Excess emissions. Any tonnage of CO_2 emitted by a CO_2 budget source during a control period that exceeds the CO_2 budget emissions limitation for the source.

Excess interim emissions. Any tonnage of CO_2 emitted by a CO_2 budget source during an interim control period multiplied by 0.50 that exceeds the CO_2 budget emissions limitation for the source.

First control period adjustment for banked allowances. An adjustment applied to the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget for allocation years 2014 through 2020 to address the surplus allocation year 2009, 2010,

and 2011 allowances held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program, but not including accounts opened by participating states.

Fossil fuel. Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil fuel-fired.

(1) With regard to a unit that commenced operation prior to January 1, 2005, the combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel combusted comprises, or is projected to comprise, more than 50 percent of the annual heat input on a Btu basis during any year.

(2) With regard to a unit that commenced or commences operation on or after January 1, 2005, the combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel combusted comprises, or is projected to comprise, more than 5 percent of the annual heat input on a Btu basis during any year.

General account. A CO_2 Allowance Tracking System account, established under Subpart XX-6, that is not a compliance account.

Global Warming Potential (GWP). A measure of the radiative efficiency (heat-absorbing ability) of a particular gas relative to that of carbon dioxide (CO_2) after taking into account the decay rate of each gas (the amount removed from the atmosphere over a given number of years) relative to that of CO_2. Global warming potentials used in this Part are consistent with the values used in the Intergovernmental Panel on Climate Change, Fifth Assessment Report.

Gross generation. The electrical output (in MWe) at the terminals of the generator.

Interim control period. An interim control period is a one-calendar-year time period, during each of the first and second calendar years of each three year control period. The first interim control period starts on January 1, 2015 and ends on December 31, 2015, inclusive. The second interim control period starts on January 1, 2016 and ends on December 31, 2016, inclusive. Each successive three year control period will have two interim control periods, comprised of each of the first two calendar years of that control period.

Life-of-the-unit contractual arrangement. A unit participation power sales agreement under which a customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and/or associated energy from any specified unit pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period equal to or greater than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum potential hourly heat input. An hourly heat input used for reporting purposes when a unit lacks certified monitors to report heat input. If the unit intends to use appendix D of 40 CFR Part 75 to report heat input, this value should be calculated, in accordance with 40 CFR Part 75, using the maximum fuel flow rate and the maximum gross calorific value. If the unit intends to use a flow monitor and a diluent gas monitor, this value should be reported, in accordance with 40 CFR Part 75, using the maximum potential flow rate and either the maximum carbon dioxide concentration (in percent CO_2) or the minimum oxygen concentration (in percent O_2).

Minimum reserve price. The minimum reserve price in calendar year 2014 shall be $2.00. Each calendar year thereafter, the minimum reserve price shall be 1.025 multiplied by the minimum reserve price from the previous calendar year, rounded to the nearest whole cent.

Monitoring system. Any monitoring system that meets the requirements of Subpart XX-8, including a continuous emissions monitoring system, an excepted monitoring system, or an alternative monitoring system.

NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program adjusted budget. The NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program adjusted budget is determined in accordance with section XX-5.3 and is the annual amount of CO_2 tons available in NAME OF RELEVANT RGGI STATE for allocation in a given allocation year, in accordance with the CO_2 Budget Trading Program. CO_2 offset allowances allocated to project sponsors and CO_2 CCR allowances offered for sale at an auction are separate from and additional to CO_2 allowances allocated from the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program adjusted budget.

NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program Base Budget. The NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is specified in section XX-5.1. CO_2 offset allowances allocated to project sponsors and CO_2 CCR allowances offered for sale at an auction are separate from and additional to CO_2 allowances allocated from the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program Base Budget.

Nameplate capacity. The maximum electrical output (in MWe) that a generator can sustain over a specified period of time when not restricted by seasonal or other de-ratings as measured in accordance with the United States Department of Energy standards.

[This definition for Net-Electric Output illustrates how this could be defined and does not necessarily represent what an individual RGGI State will propose.]

Net-electric output. The amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (i.e., auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

Non-CO_2 budget unit. A unit that does not meet the applicability criteria of Section XX-1.4 of this Part.

Operator. Any person who operates, controls, or supervises a CO_2 budget unit or a CO_2 budget source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner. Any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a CO_2 budget unit; or

(2) Any holder of a leasehold interest in a CO_2 budget unit, other than a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the CO_2 budget unit; or

(3) Any purchaser of power from a CO_2 budget unit under a life-of-the-unit contractual arrangement in which the purchaser controls the dispatch of the unit; or

(4) With respect to any general account, any person who has an ownership interest with respect to the CO_2 allowances held in the general account and who is subject to the binding agreement for the CO_2 authorized

account representative to represent that person's ownership interest with respect to the CO_2 allowances.

Participating state. A state that has established a corresponding regulation as part of the CO_2 Budget Trading Program.

Receive or *receipt of*. When referring to the REGULATORY AGENCY or its agent, to come into possession of a document, information, or correspondence (whether sent in writing or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence, by the REGULATORY AGENCY or its agent in the regular course of business.

Recordation, record, or *recorded*. With regard to CO_2 allowances, the movement of CO_2 allowances by the REGULATORY AGENCY or its agent from one CO_2 Allowance Tracking System account to another, for purposes of allocation, transfer, or deduction.

Reserve price. The minimum acceptable price for each CO_2 allowance in a specific auction. The reserve price at an auction is either the minimum reserve price or the CCR trigger price, as specified in Subpart XX-9.

Second control period adjustment for banked allowances. An adjustment applied to the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget for allocation years 2015 through 2020 to address the allocation year 2012 and 2013 allowances held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program, but not including accounts opened by participating states, that are in addition to the aggregate quantity of 2012 and 2013 emissions from all CO_2 budget sources in all of the participating states.

Serial number. When referring to CO_2 allowances, the unique identification number assigned to each CO_2 allowance by the REGULATORY AGENCY or its agent under

section XX-6.4(c).

Source. Any governmental, institutional, commercial, or industrial structure, installation, plant, building, or facility that emits or has the potential to emit any air pollutant. A source, including a source with multiple units, shall be considered a single facility.

State. A State, the District of Columbia, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, and American Samoa and includes the Commonwealth of the Northern Mariana Islands.

Submit or *serve*. To send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service;

(3) By other means of dispatch or transmission and delivery.

Compliance with any "submission," "service," or "mailing" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Third adjustment for banked allowances. An adjustment applied to the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget for allocation years 2021 through 2025 to address allowances held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program, but not including accounts opened by participating states, that are in addition to the aggregate quantity of emissions from all CO_2 budget sources in all of the participating states at the end of the fourth control period in 2020 and as reflected in the CO_2 Allowance Tracking System on March 15, 2021.

Ton or *tonnage.* Any "short ton", or 2,000 pounds. For the purpose of determining compliance with the CO_2 requirements of XX-1.5(c), total tons for a control period and each interim control period shall be calculated as the sum of all recorded hourly emissions (or the tonnage equivalent of the recorded hourly emissions rates) in

accordance with Subpart XX-8, with any remaining fraction of a ton equal to or greater than 0.50 ton deemed to equal one ton and any fraction of a ton less than 0.50 ton deemed to equal zero tons. A short ton is equal to 0.9072 metric tons.

Undistributed CO_2 allowances. CO_2 allowances originally allocated to a set aside account as pursuant to XX-5.3 that were not distributed.

Unit. A fossil fuel-fired stationary boiler, combustion turbine, or combined cycle system.

Unit operating day. A calendar day in which a unit combusts any fuel.

Unsold CO_2 allowances. CO_2 allowances that have been made available for sale in an auction conducted by the REGULATORY AGENCY or its agent, but not sold.

Voluntary renewable energy purchase. A purchase of electricity from renewable energy generation or renewable energy attribute credits by a retail electricity customer on a voluntary basis. Renewable energy includes electricity generated from biomass, wind, solar thermal, photovoltaic, geothermal, hydroelectric facilities certified by the Low Impact Hydropower Institute, wave and tidal action, and fuel cells powered by renewable fuels. The renewable energy generation or renewable energy attribute credits related to such purchases may not be used by the generator or purchaser to meet any regulatory mandate, such as a renewable portfolio standard.

[The above subdivision is an optional definition that complements the optional voluntary renewable energy market set-aside provision at XX-5.3(d).]

XX-1.3 Measurements, abbreviations and acronyms.

Measurements, abbreviations, and acronyms used in this Part are defined as follows:

(1) CO_2: carbon dioxide.

(2) hr: hour.

(3) lb: pounds.

(4) MMBtu: one million British thermal units

(5) MW: megawatt

(6) MWe: megawatt electrical.

(7) MWh: megawatt hours

XX-1.4 Applicability.

(a) *Units.* Any unit that, at any time on or after January 1, 2005, serves an electricity generator with a nameplate capacity equal to or greater than 25 MWe shall be a CO_2 budget unit, and any source that includes one or more such units shall be a CO_2 budget source, subject to the requirements of this Part.

[The following subdivision is optional. The text of this subdivision illustrates how a participating state might provide for an exemption for units with electrical output to the electric grid restricted by permit conditions. Upon exemption, the tons attributable to sources in a state's initial inventory shall be removed the state's budget under Section XX-5.3.]

(b) *Limited exemption for units with electrical output to the electric grid restricted by permit conditions*.

(1) *Applicability*. Notwithstanding subdivision (a) of this section, a unit under subdivision (a) of this section that has a permit containing a condition restricting the supply of the unit's annual electrical output to the electric grid to less than or equal to 10 percent of the annual gross generation of the unit, and which complies with the provisions in paragraph (b)(3) of this section, shall be exempt from the requirements of this Part, except for the provisions of this section, section XX-1.2, section XX-1.3, section XX-1.6 and, if applicable because of the allocation of CO_2 allowances during the pre-exemption time period, Subparts XX-5, XX-6 and XX-7.

(2) *Effective date*. The exemption under paragraph (b)(1) of this section shall

become effective as of the January 1 that is on or after the date on which the restriction on the percentage of annual gross generation that may be supplied to the electric grid and the provisions in the permit required under paragraph (b)(1) of this section become final.

(3) *Compliance.*

(i) A unit exempt under paragraph (b)(1) of this section shall comply with the restriction on percentage of annual gross generation that may be supplied to the electric grid described in paragraph (b)(1) of this section.

(ii) A unit exempt under paragraph (b)(1) shall report to the REGULATORY AGENCY the amount of annual gross generation and the amount of annual gross generation supplied to the electric grid during the year by the following February 1.

(iii) For a period of 10 years from the date the records are created, the owners and operators of a unit exempt under paragraph (b)(1) of this section shall retain, at the source that includes the unit, records demonstrating that the conditions of the permit under paragraph (b)(1) of this section were met. The 10-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the REGULATORY AGENCY. The owners and operators bear the burden of proof that the unit met the restriction on the percentage of annual gross generation that may be supplied to the electric grid.

(iv) The owners and operators and, to the extent applicable, the CO_2 authorized account representative of a unit exempt under paragraph (b)(1) of this section shall comply with all the requirements of this Part concerning all time periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(v) On the earlier of the following dates, a unit exempt under paragraph (b)(1) of this section shall lose its exemption:

(a) The date on which the restriction on the percentage of annual gross generation that may be supplied to the electric grid described in paragraph (b)(1) of this section is removed from the unit's permit or otherwise becomes no longer applicable in any year that commences on or after January 1, 2009; or

(b) The first date on which the unit fails to comply, or on which the owners and operators fail to meet their burden of proving that the unit is complying, with the restriction on the percentage of annual gross generation that may be supplied to the electric grid described in paragraph (b)(1) of this section during any year that commences on or after January 1, 2009.

(vi) A unit that loses its exemption in accordance with subparagraph (b)(3)(v) of this section shall be subject to the requirements of this Part. For the purpose of applying permitting requirements under Subpart XX-3, allocating allowances under Subpart XX-5, and applying monitoring requirements under Subpart XX-8, the unit shall be treated as commencing operation on the date the unit loses its exemption.

(4) *Deduction of tons from NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program limited industrial exemption set-aside account*. In the event that the REGULATORY AGENCY grants an exemption under this subdivision to a CO_2 source, with one or more units that on January 1, 2005, serves an electricity generator with a nameplate capacity equal to or greater than 25 MWe, the REGULATORY AGENCY shall retire for each subsequent allocation year the number of CO_2 tons equal to the exempt

source's average annual emissions over the most recent three calendar years for which data are available. The retired tons shall be taken from the set-aside established for such purpose under section XX-5.3.

XX-1.5 Standard requirements.

(a) *Permit requirements*. **[Each state's text for this subdivision will likely be different because the states have unique permitting requirements. The text below illustrates how this subdivision could be drafted and does not necessarily represent what an individual RGGI state will propose.]**

(1) The CO_2 authorized account representative of each CO_2 budget source required to have an operating permit pursuant to **[Insert Reference to state's Permitting Regulation(s)]** of this Title and each CO_2 budget unit required to have an operating permit pursuant to **[Insert Reference to state's Permitting Regulation(s)]** of this Title shall:

(i) Submit to the REGULATORY AGENCY a complete CO_2 budget permit application under section XX-3.3 in accordance with the deadlines specified in section XX-3.2; and

(ii) Submit in a timely manner any supplemental information that the REGULATORY AGENCY determines is necessary in order to review the CO_2 budget permit application and issue or deny a CO_2 budget permit.

(2) The owners and operators of each CO_2 budget source required to have an operating permit pursuant to **[Insert Reference to state's Permitting Regulation(s)]** of this Title and each CO_2 budget unit required to have an operating permit pursuant to **[Insert Reference to state's Permitting Regulation(s)]** of this Title for the source shall have a CO_2 budget permit and operate the CO_2 budget source and the CO_2 budget unit at the source in compliance with such CO_2 budget permit.

(b) *Monitoring requirements*.

(1) The owners and operators and, to the extent applicable, the CO_2 authorized account representative of each CO_2 budget source and each CO_2 budget unit at the source shall comply with the monitoring requirements of Subpart XX-8.

(2) The emissions measurements recorded and reported in accordance with Subpart XX-8 shall be used to determine compliance by the unit with the CO_2 requirements under subdivision (c) of this section.

(c) *CO_2 requirements*.

(1) The owners and operators of each CO_2 budget source and each CO_2 budget unit at the source shall hold CO_2 allowances available for compliance deductions under section XX-6.5, as of the CO_2 allowance transfer deadline, in the source's compliance account in an amount not less than the total CO_2 emissions for the control period from all CO_2 budget units at the source, less the CO_2 allowances deducted to meet the requirements of paragraph XX-1.5(c)(2), with respect to the previous two interim control periods, as determined in accordance with Subparts XX-6 and XX-8.

(2) The owners and operators of each CO_2 budget source and each CO_2 budget unit at the source shall hold CO_2 allowances available for compliance deductions under section XX-6.5, as of the CO_2 allowance transfer deadline, in the source's compliance account in an amount not less than the total CO_2 emissions for the interim control period from all CO_2 budget units at the source multiplied by 0.50, as determined in accordance with Subparts XX-6 and XX-8.

(3) Each ton of CO_2 emitted in excess of the CO_2 budget emissions limitation for a control period shall constitute a separate violation of this Part and applicable federal and state law.

(4) Each ton of excess interim emissions shall constitute a separate violation of this Part and applicable state law.

(5) A CO_2 budget unit shall be subject to the requirements under paragraph (c)(1) of this section starting on the later, of January 1, 2009 or the date on which the unit commences operation.

(6) CO_2 allowances shall be held in, deducted from, or transferred among CO_2 Allowance Tracking System accounts in accordance with Subparts XX-5, XX-6, and XX-7, and section XX-10.7.

(7) A CO_2 allowance shall not be deducted, in order to comply with the requirements under paragraph (c)(1) or (2) of this section, for a control period or interim control period that ends prior to the year for which the CO_2 allowance was allocated. A CO_2 offset allowance shall not be deducted, in order to comply with the requirements under paragraph (c)(1) or (2) of this section, beyond the applicable percent limitations set out in paragraph XX-6.5(a)(3).

(8) A CO_2 allowance under the CO_2 Budget Trading Program is a limited authorization by the REGULATORY AGENCY or a participating state to emit one ton of CO_2 in accordance with the CO_2 Budget Trading Program. No provision of the CO_2 Budget Trading Program, the CO_2 budget permit application, or the CO_2 budget permit or any provision of law shall be construed to limit the authority of the REGULATORY AGENCY or a participating state to terminate or limit such authorization.

(9) A CO_2 allowance under the CO_2 Budget Trading Program does not constitute a property right.

(d) *Excess emissions requirements*. The owners and operators of a CO_2 budget source that has excess emissions in any control period, or excess interim emissions for any interim control period, shall:

(1) Forfeit the CO_2 allowances required for deduction under paragraph XX-

6.5(d)(1), provided CO_2 offset allowances may not be used to cover any part of such excess emissions; and

(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed under paragraph XX-6.5(d)(2).

(e) *Recordkeeping and reporting requirements.*

(1) Unless otherwise provided, the owners and operators of the CO_2 budget source and each CO_2 budget unit at the source shall keep on site at the source each of the following documents for a period of 10 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 10 years, in writing by the REGULATORY AGENCY.

(i) The account certificate of representation for the CO_2 authorized account representative for the source and each CO_2 budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with section XX-2.4, provided that the certificate and documents shall be retained on site at the source beyond such 10-year period until such documents are superseded because of the submission of a new account certificate of representation changing the CO_2 authorized account representative.

(ii) All emissions monitoring information, in accordance with Subpart XX-8 and 40 CFR 75.57.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CO_2 Budget Trading Program.

(iv) Copies of all documents used to complete a CO_2 budget permit application and any other submission under the CO_2 Budget Trading Program or to demonstrate compliance with the

requirements of the CO_2 Budget Trading Program.

(2) The CO_2 authorized account representative of a CO_2 budget source and each CO_2 budget unit at the source shall submit the reports and compliance certifications required under the CO_2 Budget Trading Program, including those under Subpart XX-4.

(f) *Liability*.

(1) No permit revision shall excuse any violation of the requirements of the CO_2 Budget Trading Program that occurs prior to the date that the revision takes effect.

(2) Any provision of the CO_2 Budget Trading Program that applies to a CO_2 budget source (including a provision applicable to the CO_2 authorized account representative of a CO_2 budget source) shall also apply to the owners and operators of such source and of the CO_2 budget units at the source.

(3) Any provision of the CO_2 Budget Trading Program that applies to a CO_2 budget unit (including a provision applicable to the CO_2 authorized account representative of a CO_2 budget unit) shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities*. No provision of the CO_2 Budget Trading Program, a CO_2 budget permit application, or a CO_2 budget permit, shall be construed as exempting or excluding the owners and operators and, to the extent applicable, the CO_2 authorized account representative of the CO_2 budget source or CO_2 budget unit from compliance with any other provisions of applicable State and federal law regulations.

XX-1.6 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the CO_2 Budget Trading Program, to begin on the occurrence of an act or event shall begin on the day

the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CO_2 Budget Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CO_2 Budget Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

XX-1.7 Severability.

If any provision of this Part, or its application to any particular person or circumstances, is held invalid, the remainder of this Part, and the application thereof to other persons or circumstances, shall not be affected thereby.

Subpart XX-2 CO_2 Authorized Account Representative for CO_2 Budget Sources

XX-2.1 Authorization and responsibilities of the CO_2 authorized account representative.

(a) Except as provided under section XX-2.2, each CO_2 budget source, including all CO_2 budget units at the source, shall have one and only one CO_2 authorized account representative, with regard to all matters under the CO_2 Budget Trading Program concerning the source or any CO_2 budget unit at the source.

(b) The CO_2 authorized account representative of the CO_2 budget source shall be selected by an agreement binding on the owners and operators of the source and all CO_2 budget units at the source and must act in accordance with the certificate of representation under section XX-2.4.

(c) Upon receipt by the REGULATORY AGENCY or its agent of a complete account certificate of representation under section XX-2.4, the CO_2 authorized account representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the CO_2 budget source represented and each CO_2 budget unit at the source in all matters pertaining to the CO_2 Budget Trading Program, notwithstanding any agreement between the CO_2 authorized account representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the CO_2 authorized account representative by the REGULATORY AGENCY or a court regarding the source or unit.

(d) No CO_2 budget permit shall be issued, and no CO_2 Allowance Tracking System account shall be established for a CO_2 budget source, until the REGULATORY AGENCY or its agent has received a complete account certificate of representation under section XX-2.4 for a CO_2 authorized account representative of the source and the CO_2 budget units at the source. Each submission under the CO_2 Budget Trading Program shall be submitted, signed, and certified by the CO_2 authorized account representative for each CO_2 budget source on behalf of which the submission is made.

(e) Each such submission shall include the following certification statement by the CO_2 authorized account representative:
"I am authorized to make this submission on behalf of the owners and Operators of the CO_2 budget sources or CO_2 budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(f) The REGULATORY AGENCY or its agent will accept or act on a submission made on behalf of owners or operators of a CO_2 budget source or a CO_2 budget unit only if the submission has been made, signed, and certified in accordance with subdivision (e) of this section.

XX-2.2 CO_2 authorized alternate account representative.

(a) An account certificate of representation may designate one and only one CO_2 authorized alternate account representative who may act on behalf of the CO_2 authorized account representative. The agreement by which the CO_2 authorized alternate account representative is selected shall include a procedure for authorizing the CO_2 authorized alternate account representative to act in lieu of the CO_2 authorized account representative.

(b) Upon receipt by the REGULATORY AGENCY or its agent of a complete account certificate of representation under section XX-2.4, any representation, action, inaction, or submission by the CO_2 authorized alternate account representative shall be deemed to be a representation, action, inaction, or submission by the CO_2 authorized account representative.

(c) Except in this section and subdivision XX-2.1(a), section XX-2.3, section XX-2.4, and section XX-6.2, whenever the term "CO_2 authorized account representative" is used in this Part, the term shall be construed to include the CO_2 authorized alternate account representative.

XX-2.3 Changing the CO_2 authorized account representatives and the CO_2 authorized alternate account representative; changes in the owner and operators.

(a) *Changing the CO_2 authorized account representative*. The CO_2 authorized account representative may be changed at any time upon receipt by the REGULATORY AGENCY or its agent of a superseding complete account certificate of representation

under section XX-2.4. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative or CO_2 authorized alternate account representative prior to the time and date when the REGULATORY AGENCY or its agent receives the superseding account certificate of representation shall be binding on the new CO_2 authorized account representative and the owners and operators of the CO_2 budget source and the CO_2 budget units at the source.

(b) *Changing the CO_2 authorized alternate account representative*. The CO_2 authorized alternate account representative may be changed at any time upon receipt by the REGULATORY AGENCY or its agent of a superseding complete account certificate of representation under section XX-2.4. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous or CO_2 authorized alternate account representative or CO_2 authorized alternate account representative prior to the time and date when the REGULATORY AGENCY or its agent receives the superseding account certificate of representation shall be binding on the new CO_2 authorized alternate account representative and the owners and operators of the CO_2 budget source and the CO_2 budget units at the source.

(c) *Changes in the owners and operators*.

(1) In the event a new owner or operator of a CO_2 budget source or a CO_2 budget unit is not included in the list of owners and operators submitted in the account certificate of representation, such new owner or operator shall be deemed to be subject to and bound by the account certificate of representation, the representations, actions, inactions, and submissions of the CO_2 authorized account representative and any CO_2 authorized alternate account representative of the source or unit, and the decisions, orders, actions, and inactions of the REGULATORY AGENCY, as if the new owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a CO_2 budget source or a CO_2 budget unit, including the addition of a new owner or operator, the CO_2 authorized account representative or CO_2 authorized alternate account representative shall submit a revision to the account certificate of representation amending the list of owners and operators to include the change.

XX-2.4 Account certificate of representation.

(a) A complete account certificate of representation for a CO_2 authorized account representative or a CO_2 authorized alternate account representative shall include the following elements in a format prescribed by the REGULATORY AGENCY or its agent:

(1) Identification of the CO_2 budget source and each CO_2 budget unit at the source for which the account certificate of representation is submitted;

(2) The name, address, e-mail address, and telephone number of the CO_2 authorized account representative and any CO_2 authorized alternate account representative;

(3) A list of the owners and operators of the CO_2 budget source and of each CO_2 budget unit at the source;

(4) The following certification statement by the CO_2 authorized account representative and any CO_2 authorized alternate account representative: *"I certify that I was selected as the CO_2 authorized account representative or CO_2 authorized alternate account representative, as applicable, by an agreement binding on the owners and operators of the CO_2 budget source and each CO_2 budget unit at the source. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Budget Trading Program on behalf of the owners and operators of the CO_2 budget source and of each CO_2 budget unit at the source and that each such owner and operator shall be fully bound by my representations,*

actions, inactions, or submissions and by any decision or order issued to me by the REGULATORY AGENCY or a court regarding the source or unit."; and

(5) The signature of the CO_2 authorized account representative and any CO_2 authorized alternate account representative and the dates signed.

(b) Unless otherwise required by the REGULATORY AGENCY or its agent, documents of agreement referred to in the account certificate of representation shall not be submitted to the REGULATORY AGENCY or its agent. Neither the REGULATORY AGENCY nor its agent shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

XX-2.5 Objections concerning the CO_2 authorized account representative.

(a) Once a complete account certificate of representation under section XX-2.4 has been submitted and received, the REGULATORY AGENCY and its agent will rely on the account certificate of representation unless and until the REGULATORY AGENCY or its agent receives a superseding complete account certificate of representation under section XX-2.4.

(b) Except as provided in subdivision XX-2.3(a) or (b), no objection or other communication submitted to the REGULATORY AGENCY or its agent concerning the authorization, or any representation, action, inaction, or submission of the CO_2 authorized account representative shall affect any representation, action, inaction, or submission of the CO_2 authorized account representative or the finality of any decision or order by the REGULATORY AGENCY or its agent under the CO_2 Budget Trading Program.

(c) Neither the REGULATORY AGENCY nor its agent will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any CO_2 authorized account representative, including private legal

disputes concerning the proceeds of CO_2 allowance transfers.

XX-2.6 Delegation by CO_2 authorized account representative and CO_2 authorized alternate account representative.

(a) A CO_2 authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the REGULATORY AGENCY or its agent under this Part.

(b) A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the REGULATORY AGENCY or its agent under this part.

(c) In order to delegate authority to make an electronic submission to the REGULATORY AGENCY or its agent in accordance with subdivision (a) and (b) of this section, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, must submit to the REGULATORY AGENCY or its agent a notice of delegation, in a format prescribed by the REGULATORY AGENCY that includes the following elements:

(1) The name, address, e-mail address, and telephone number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;

(2) The name, address, e-mail address, and telephone number of each such natural person, herein referred to as the “electronic submission agent”;

(3) For each such natural person, a list of the type of electronic submissions under subdivision (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such CO_2 authorized account representative or CO_2 authorized alternate account representative:

(i) *“I agree that any electronic submission to the REGULATORY AGENCY or its agent that is by a natural person identified in this*

notice of delegation and of a type listed for such electronic submission agent in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under subdivision XX-2.6(d) shall be deemed to be an electronic submission by me."

(ii) "*Until this notice of delegation is superseded by another notice of delegation under subdivision XX-2.6(d), I agree to maintain an e-mail account and to notify the REGULATORY AGENCY or its agent immediately of any change in my e-mail address unless all delegation authority by me under section XX-2.6 is terminated."*

(d) A notice of delegation submitted under subdivision (c) of this section shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the REGULATORY AGENCY or its agent and until receipt by the REGULATORY AGENCY or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of delegation may replace any previously identified electronic submission agent, add a new electronic submission agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in subparagraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under subdivision (d) of this section shall be deemed to be an electronic submission by the CO_2 authorized account representative or CO_2 authorized alternate account representative submitting such notice of delegation.

(f) A CO_2 authorized account representative may delegate, to one or more natural

persons, his or her authority to review information in the CO_2 allowance tracking system under this part.

(g) A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his or her authority to review information in the CO_2 allowance tracking system under this part.

(h) In order to delegate authority to review information in the CO_2 allowance tracking system in accordance with subdivision (f) and (g) of this section, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, must submit to the REGULATORY AGENCY or its agent a notice of delegation, in a format prescribed by the REGULATORY AGENCY that includes the following elements:

(1) The name, address, e-mail address, and telephone number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;

(2) The name, address, e-mail address, and telephone number of each such natural person, herein referred to as the "reviewer";

(3) For each such natural person, a list of the type of information under subdivision (f) or (g) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such CO_2 authorized account representative or CO_2 authorized alternate account representative:

(i) *"I agree that any information that is reviewed by a natural person identified in this notice of delegation and of a type listed for such information accessible by the reviewer in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under subdivision XX-2.6(i) shall be*

deemed to be a reviewer by me."

(ii) "*Until this notice of delegation is superseded by another notice of delegation under subdivision XX-2.6(i), I agree to maintain an e-mail account and to notify the REGULATORY AGENCY or its agent immediately of any change in my e-mail address unless all delegation authority by me under section XX-2.6 is terminated."*

(i) A notice of delegation submitted under subdivision (h) of this section shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the REGULATORY AGENCY or its agent and until receipt by the REGULATORY AGENCY or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of delegation may replace any previously identified reviewer, add a new reviewer, or eliminate entirely any delegation of authority.

Subpart XX-3 Permits

[Each state's text for this Subpart will likely be different because states have unique permitting requirements. The text below illustrates how this Subpart could be drafted and does not necessarily represent what an individual RGGI state will propose.]

XX-3.1 CO_2 budget permit requirements.

(a) Each CO_2 budget source must have a permit issued by the REGULATORY AGENCY pursuant to **[Insert Reference to State's Permitting Regulation(s)]** of this Title.

(b) Each CO_2 budget permit shall contain all applicable CO_2 Budget Trading Program requirements and shall be a complete and distinguishable portion of the permit

under subdivision (a) of this section.

XX-3.2 Submission of CO_2 budget permit applications.

For any CO_2 budget source, the CO_2 authorized account representative shall submit a complete CO_2 budget permit application under section XX-3.3 covering such CO_2 budget source to the REGULATORY AGENCY by the later of January 1, 2009 or 12 months before the date on which the CO_2 budget source, or a new unit at the source, commences operation.

XX-3.3 Information requirements for CO_2 budget permit applications.

(a) A complete CO_2 budget permit application shall include the following elements concerning the CO_2 budget source for which the application is submitted, in a format prescribed by the REGULATORY AGENCY:

(1) Identification of the CO_2 budget source, including plant name and the ORIS (Office of Regulatory Information Systems) or facility code assigned to the source by the Energy Information Administration of the United States Department of Energy, if applicable;

(2) Identification of each CO_2 budget unit at the CO_2 budget source; and

(3) The standard requirements under section XX-1.5.

Subpart XX-4 Compliance Certification

XX-4.1 Compliance certification report.

(a) *Applicability and deadline*. For each control period in which a CO_2 budget source is subject to the CO_2 requirements of XX-1.5(c), the CO_2 authorized account representative of the source shall submit to the REGULATORY AGENCY by the March 1 following the relevant control period, a compliance certification report. A compliance certification report is not required as part of the compliance obligation during an interim

control period.

(b) *Contents of report*. The CO_2 authorized account representative shall include in the compliance certification report under subdivision (a) of this section the following elements, in a format prescribed by the REGULATORY AGENCY:

(1) Identification of the source and each CO_2 budget unit at the source;

(2) At the CO_2 authorized account representative's option, the serial numbers of the CO_2 allowances that are to be deducted from the source's compliance account under section XX-6.5 for the control period, including the serial numbers of any CO_2 offset allowances that are to be deducted subject to the limitations of paragraph XX-6.5(a)(3); and

(3) The compliance certification under subdivision (c) of this section.

(c) *Compliance certification*. In the compliance certification report under subdivision (a) of this section, the CO_2 authorized account representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the source and the CO_2 budget units at the source in compliance with the CO_2 Budget Trading Program, whether the source and each CO_2 budget unit at the source for which the compliance certification is submitted was operated during the calendar years covered by the report in compliance with the requirements of the CO_2 Budget Trading Program , including:

(1) Whether the source was operated in compliance with the CO_2 requirements of XX-1.5(c);

(2) Whether the monitoring plan applicable to each unit at the source has been maintained to reflect the actual operation and monitoring of the unit, and contains all information necessary to attribute CO_2 emissions to the unit, in accordance with Subpart XX-8;

(3) Whether all the CO_2 emissions from the units at the source were monitored or accounted for through the missing data procedures and

reported in the quarterly monitoring reports, including whether conditional data were reported in the quarterly reports in accordance with Subpart XX-8. If conditional data were reported, the owner or operator shall indicate whether the status of all conditional data has been resolved and all necessary quarterly report resubmissions have been made;

(4) Whether the facts that form the basis for certification under Subpart XX-8 of each monitor at each unit at the source, or for using an excepted monitoring method or alternative monitoring method approved under Subpart XX-8, if any, have changed; and

(5) If a change is required to be reported under paragraph (c)(4) of this section, specify the nature of the change, the reason for the change, when the change occurred, and how the unit's compliance status was determined subsequent to the change, including what method was used to determine emissions when a change mandated the need for monitor recertification.

XX-4.2 REGULATORY AGENCY's action on compliance certifications.

(a) The REGULATORY AGENCY or its agent may review and conduct independent audits concerning any compliance certification or any other submission under the CO_2 Budget Trading Program and make appropriate adjustments of the information in the compliance certifications or other submissions.

(b) The REGULATORY AGENCY or its agent may deduct CO_2 allowances from or transfer CO_2 allowances to a source's compliance account based on the information in the compliance certifications or other submissions, as adjusted under subdivision (a) of this section.

Subpart XX-5 CO_2 Allowance Allocations

XX-5.1 NAME OF RELEVANT RGGI STATE CO_2 trading program base budget.

(a) For 2018, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(b) For 2019, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(c) For 2020, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(d) For 2021, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(e) For 2022, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(f) For 2023, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(g) For 2024, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(h) For 2025, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(i) For 2026, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(j) For 2027, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading

Program base budget is___tons.

(k) For 2028, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(l) For 2029, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

(m) For 2030 and each succeeding calendar year, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget is___tons.

[…or as established in a future program adjustment.]

XX-5.2 Undistributed and unsold CO_2 allowances

(a) REGULATORY AGENCY may retire undistributed CO_2 allowances at the end of each control period.

(b) REGULATORY AGENCY may retire unsold CO_2 allowances at the end of each control period.

XX-5.3 CO_2 allowance allocations.

(a) *General allocations*. **[Allocation provisions will vary from state to state, provided at least 25% of the allocations will go to a consumer benefit or strategic energy purpose.]**

(b) *Consumer benefit or strategic energy purpose allocation.* The REGULATORY AGENCY will allocate a minimum of twenty-five percent of the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget to the consumer benefit or strategic energy purpose set-aside account.

[The reference to the consumer benefit or strategic energy purpose account

illustrates how this account could be labeled and does not necessarily represent what an individual RGGI state will propose.]

(c) *CO_2 Allowances available for allocation*. For the allocation year 2018 and each succeeding calendar year, the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program adjusted budget shall be the maximum number of allowances available for allocation in a given allocation year, except for CO_2 offset allowances and CO_2 CCR allowances. In any year in which there is no adjusted budget, the adjusted budget shall equal the base budget.

(d) *Cost Containment Reserve (CCR) allocation*. The REGULATORY AGENCY shall allocate CO_2 CCR allowances, separate from and additional to the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget set forth in section XX-5.1, to the RELEVANT STATE AUCTION ACCOUNT. The CCR allocation is for the purpose of containing the cost of CO_2 allowances. The REGULATORY AGENCY shall allocate CO_2 CCR allowances in the following manner:

(1) The REGULATORY AGENCY shall initially allocate___CO_2 CCR allowances for calendar year 2014.

(2) On or before January 1, 2015 and each calendar year thereafter through 2020, the REGULATORY AGENCY shall allocate CO_2 CCR allowances in an amount equal to _____, minus the number of CO_2 CCR allowances that remain in the RELEVANT STATE AUCTION ACCOUNT at the end of the prior calendar year.

(3) On or before January 1, 2021 and each year thereafter, the REGULATORY AGENCY shall allocate current vintage year CCR allowances equal to the quantity in Table 3, and withdraw the number of CO_2 CCR allowances that remain in the RELEVANT STATE AUCTION ACCOUNT at the end of the prior calendar year:

Table 3. CCR allowances from 2021 forward

2021	2022	2023	2024	2024	2025	2026	2027	2028	2029	2030 and each year thereafter
TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD

(e) *Emissions Containment Reserve (ECR) Withholding*. The REGULATORY AGENCY shall convert and transfer any CO_2 allowances that have been withheld from any auction(s) into the RELEVANT STATE ECR ACCOUNT. The ECR withholding is for the purpose of additional emissions reductions in the event of lower than anticipated emissions reduction costs. The REGULATORY AGENCY shall withhold CO_2 ECR allowances in the following manner.

(1) If the condition in paragraph 9.2 (d)(1) is met at an auction, then the maximum number of CO_2 ECR allowances that will be withheld from that auction will be equal to the quantity shown in Table 4 minus the total quantity of CO_2 ECR allowances that have been withheld from any prior auction(s) in that calendar year. Any CO_2 ECR allowances withheld from an auction will be transferred into the RELEVANT STATE ECR ACCOUNT.

Table 4. ECR allowances from 2021 forward

2021	2022	2023	2024	2024	2025	2026	2027	2028	2029	2030 and each year thereafter
TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD

(2) Allowances that have been transferred into the RELEVANT STATE ECR ACCOUNT shall not be withdrawn.

(f) *First control period adjustment for banked allowances.* By January 15, 2014, the REGULATORY AGENCY shall establish the first control period adjustment for banked allowances quantity for allocation years 2014 through 2020:

Table 5. First control period adjustment for banked allowances

2014	2015	2016	2017	2018	2019	2020
Insert amount						

(g) *Second control period adjustment for banked allowances.* On March 17, 2014, the REGULATORY AGENCY shall establish the second control period adjustment for banked allowances quantity the allocation years 2015 through 2020:

Table 6. Second control period adjustment for banked allowances

2015	2016	2017	2018	2019	2020
Insert amount					

(h) *Third adjustment for banked allowances.* On March 15, 2021, the REGULATORY AGENCY shall determine the third adjustment for banked allowances quantity for allocation years 2021 through 2025 through the application of the following formula:

$$TABA = \frac{TA - TAE}{5} \times RS\%$$

Where:

TABA is the third adjustment for banked allowances quantity in tons.

TA, third adjustment, is the total quantity of allowances of vintage years prior to 2021 held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program, but not including accounts opened by participating states, as reflected in the CO_2 Allowance

Tracking System on March 15, 2021.

TAE, third adjustment emissions, is the total quantity of 2018, 2019 and 2020 emissions from all CO_2 budget sources in all participating states, reported pursuant to CO_2 Budget Trading Program as reflected in the CO_2 Allowance Tracking System on March 15, 2021.

RS% is RELEVANT RGGI STATE'S 2021 budget divided by the 2021 regional budget.

(i) *CO_2 Budget Trading Program adjusted budgets for 2018 through 2020.* On April 15, 2014 the REGULATORY AGENCY shall establish the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program adjusted budgets for the 2018 through 2020 allocation years in the following table:

Table 7. CO_2 Budget Trading Program adjusted budgets

2018	2019	2020
Insert amount		

(j) *CO_2 Budget Trading Program adjusted budgets for 2021 through 2025.* On or before April 15, 2021, the REGULATORY AGENCY shall establish the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program adjusted budgets for the 2021 through 2025 allocation years by the following formula:

AB = BB – TABA

Where:

AB is the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program adjusted budget.

BB is the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program

base budget.

TABA is the third adjustment for banked allowances quantity in tons.

(k) After making the determinations in XX-5.3 (j), the REGULATORY AGENCY or its Agent will publish the CO_2 trading program adjusted budgets for the 2021 through 2025 allocation years.

[The following subdivision is an optional voluntary renewable energy market set-aside provision. It represents one way a state could implement such a set-aside.]

(l) *Voluntary renewable energy market set-aside allocation*. For each control period, the REGULATORY AGENCY shall allocate to the voluntary renewable energy market set-aside account a certain number of tons, calculated as set forth in this subdivision, from the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget set forth in section XX-5.1, as applicable. The REGULATORY AGENCY shall administer the voluntary renewable energy set-aside in accordance with this subdivision.

(1) The REGULATORY AGENCY will open and manage a general account for the voluntary renewable energy market set-aside for each control period.

(2) The number of tons that will be allocated to the voluntary renewable energy market set-aside account in a specific control period will be determined as set out in this paragraph.

(i) Any person may submit data to the REGULATORY AGENCY documenting purchases of voluntary renewable energy that meet the requirements of this subdivision by no later than the July 30 prior to the beginning of a control period. Such data must be from reputable sources, which may include retail electricity providers, organizations that certify renewable energy products, and other parties as determined by the REGULATORY AGENCY. To be considered, data must be verifiable and document the following for voluntary renewable energy purchases.

(a) Documentation of voluntary renewable energy or renewable energy attribute credit purchases by retail customers, by customer class, in the State during the most recent three-year period for which data are available.

(b) Documentation that the renewable energy or renewable energy attributes related to voluntary renewable energy or renewable energy attribute credit sales was procured by the retail provider.

(c) Time period when the retail purchase(s) was made.

(d) State where the electricity was generated or the renewable energy attribute credit was created, including documentation of facility name, unique generator identification number, and fuel type.

(e) Time period when the electricity was generated or the renewable energy attribute credit was created.

(ii) Subject to the timely receipt of adequate data pursuant to subparagraph (i) of this paragraph, and based on such data, the REGULATORY AGENCY shall project the voluntary renewable energy purchases in the State during a control period that represents renewable energy generation in one or more participating states. The megawatt-hours (MWh) of projected voluntary renewable energy purchases in a control period shall be multiplied by the marginal CO_2 emissions rate (lbs. CO_2/MWh) in the control area where the generation occurred, as determined by the REGULATORY AGENCY. If data to determine the marginal emissions rate is unavailable, the average emissions rate shall be used, as determined by the REGULATORY AGENCY.

(iii) The CO_2 tons to be allocated to the voluntary renewable energy set-aside account shall be calculated as follows:

CO_2 tons = MP x EF

Where:

CO_2 tons, rounded down to the nearest whole ton, is the number of allowances to be placed in the reserve account;

MP is the projected MWh of voluntary renewable energy purchases in the State during the future control period that meets the requirements of this subdivision; and

EF is the CO_2 emissions factor for the control area where the electricity represented by the sale was generated.

(iv) If following the end of a control period, the number of CO_2 allowances allocated to the voluntary renewable energy set-aside account is less than the number of CO_2 tons represented by the actual MWh of voluntary renewable energy purchases during the control period, the REGULATORY AGENCY will add the difference between CO_2 tons represented by actual purchases, as calculated in accordance with subparagraph (iii) of this paragraph, and CO_2 allowances held in the set-aside account to the projection for the following control period, pursuant to paragraph (2) of this subdivision. If following the end of a control period, the number of CO_2 allowances allocated to the voluntary renewable energy set-aside account is greater than the number of CO_2 tons represented by the actual MWh of voluntary renewable energy purchases during the control period, the REGULATORY AGENCY will subtract the difference between CO_2 tons represented by actual purchases, as calculated in accordance with subparagraph (iii) of this paragraph, and CO_2 allowances held in the set-aside account from the

projection for the following control period, pursuant to paragraph (2) of this subdivision. In no event shall the size of the voluntary renewable set-aside exceed_____tons.

(3) As of the December 31 that is after the end of a control period for which an allocation has been made to the voluntary renewable energy set-aside account, the REGULATORY AGENCY shall determine the actual MWh of voluntary renewable energy purchases that occurred during the control period. The REGULATORY AGENCY shall retire CO_2 allowances in the voluntary renewable energy set-aside account in an amount up to the number of tons of CO_2 represented by actual voluntary renewable energy purchases, based on actual MWh purchases and the emissions factor determined pursuant to paragraph (2) of this subdivision.

[The following subdivision is an optional limited industrial exemptions set-aside allocation provision. It represents one way a state could implement such a set-aside.]

(m) *Limited industrial exemption set-aside allocation.* The limited industrial exemption set-aside allocation will consist of_tons from the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget set forth in section XX-5.1, as applicable. For each control period, the AGENCY will determine CO_2 allowance allocations in accordance with the following procedures.

(1) The REGULATORY AGENCY will open and manage a general account for the limited exemption set-aside for each control period.

(2) As of the January 1 that is after the date that an exemption under subdivision XX-1.4(b) has been granted, for each allocation year the REGULATORY AGENCY will retire CO_2 allowances in the limited industrial exemption set-aside general account as determined pursuant to paragraph XX-1.4(b)(4).

(3) After retirement of allowances pursuant to paragraph (2) of this subdivision,

the REGULATORY AGENCY will determine whether any CO_2 allowances remain in the limited industrial exemption set-aside general account for the control period. The REGULATORY AGENCY will transfer any such remaining CO_2 allowances from the limited industrial exemption set-aside allocation general account to the compliance account of each CO_2 budget source that was allocated allowances pursuant to subdivision (a) of this section using the following methodology:

Existing CO_2 budget unit's share of the CO_2 allowances remaining in the limited industrial exemption set-aside general account = Total CO_2 allowances remaining in the limited industrial exemption set-aside general account x (The individual CO_2 budget unit's CO_2 allowance allocation determined in accordance with subdivision (a) of this section ÷ The NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program annual base budget, as applicable)

Where:

"Total CO_2 allowances remaining in the limited industrial exemption set-aside allocation general account" is the total number of CO_2 allowances remaining in the limited industrial exemption set-aside allocation general account (established under paragraph (e)(1) of this section) for the particular control period to which the limited industrial exemption set-aside allocation applies; and

"The individual CO_2 budget unit's CO_2 allowance allocation" is the number of CO_2 allowances allocated under subdivision (a) of this section to the individual CO_2 budget unit for the control period to which the limited industrial exemption set- aside allocation applies.

The REGULATORY AGENCY will only transfer CO_2 allowances in whole

ton increments. The REGULATORY AGENCY will continue to hold any fractional shares of CO_2 allowances in the name of the CO_2 budget unit as banked CO_2 allowances until they may be combined with other fractional shares of CO_2 allowances in future years and then transferred as whole ton increments.

Subpart XX-6 CO_2 Allowance Tracking System

XX-6.1 CO_2 Allowance Tracking System accounts.

(a) *Nature and function of compliance accounts*. Consistent with subdivision XX-6.2(a), the REGULATORY AGENCY or its agent will establish one compliance account for each CO_2 budget source. Allocations of CO_2 allowances pursuant to Subpart XX-5 and deductions or transfers of CO_2 allowances pursuant to sections XX-4.2, XX-6.5, XX-6.7, or Subpart XX-7 will be recorded in the compliance accounts in accordance with this Subpart.

(b) *Nature and function of general accounts*. Consistent with subdivision XX- 6.2(b), the REGULATORY AGENCY or its agent will establish, upon request, a general account for any person. Transfers of CO_2 allowances pursuant to Subpart XX-7 will be recorded in the general account in accordance with this Subpart.

XX-6.2 Establishment of accounts.

(a) *Compliance accounts*. Upon receipt of a complete account certificate of representation under section XX-2.4, the REGULATORY AGENCY or its agent will establish a compliance account for each CO_2 budget source for which the account certificate of representation was submitted.

(b) *General accounts*.

(1) *Application for general account.* Any person may apply to open a general

account for the purpose of holding and transferring CO_2 allowances. An application for a general account may designate one and only one CO_2 authorized account representative and one and only one CO_2 authorized alternate account representative who may act on behalf of the CO_2 authorized account representative. The agreement by which the CO_2 authorized alternate account representative is selected shall include a procedure for authorizing the CO_2 authorized alternate account representative to act in lieu of the CO_2 authorized account representative. A complete application for a general account shall be submitted to the REGULATORY AGENCY or its agent and shall include the following elements in a format prescribed by the REGULATORY AGENCY or its agent:

(i) Name, address, e-mail address, and telephone number of the CO_2 authorized account representative and any CO_2 authorized alternate account representative;

(ii) At the option of the CO_2 authorized account representative, organization name and type of organization;

(iii) A list of all persons subject to a binding agreement for the CO_2 authorized account representative or any CO_2 authorized alternate account representative to represent their ownership interest with respect to the CO_2 allowances held in the general account;

(iv) The following certification statement by the CO_2 authorized account representative and any CO_2 authorized alternate account representative: “I certify that I was selected as the CO_2 authorized account representative or the CO_2 authorized alternate account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CO_2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under

the CO_2 Budget Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the REGULATORY AGENCY or its agent or a court regarding the general account.";

(v) The signature of the CO_2 authorized account representative and any CO_2 authorized alternate account representative and the dates signed; and

(vi) Unless otherwise required by the REGULATORY AGENCY or its agent, documents of agreement referred to in the application for a general account shall not be submitted to the REGULATORY AGENCY or its agent. Neither the REGULATORY AGENCY nor its agent shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) *Authorization of CO_2 authorized account representative*.

(i) Upon receipt by the REGULATORY AGENCY or its agent of a complete application for a general account under paragraph (b)(1) of this section:

(a) The REGULATORY AGENCY or its agent will establish a general account for the person or persons for whom the application is submitted.

(b) The CO_2 authorized account representative and any CO_2 authorized alternate account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CO_2 allowances held in the general account in all matters pertaining to the CO_2 Budget Trading Program, notwithstanding any agreement between the CO_2 authorized

account representative or any CO_2 authorized alternate account representative and such person. Any such person shall be bound by any order or decision issued to the CO_2 authorized account representative or any CO_2 authorized alternate account representative by the REGULATORY AGENCY or its agent or a court regarding the general account.

(c) Any representation, action, inaction, or submission by any CO_2 authorized alternate account representative shall be deemed to be a representation, action, inaction, or submission by the CO_2 authorized account representative.

(ii) Each submission concerning the general account shall be submitted, signed, and certified by the CO_2 authorized account representative or any CO_2 authorized alternate account representative for the persons having an ownership interest with respect to CO_2 allowances held in the general account. Each such submission shall include the following certification statement by the CO_2 authorized account representative or any CO_2 authorized alternate account representative:

"I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CO_2 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting

required statements and information, including the possibility of fine or imprisonment."

(iii) The REGULATORY AGENCY or its agent will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with subparagraph (b)(2)(ii) of this section.

(3) *Changing CO_2 authorized account representative and CO_2 authorized alternate account representative; changes in persons with ownership interest*.

(i) The CO_2 authorized account representative for a general account may be changed at any time upon receipt by the REGULATORY AGENCY or its agent of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative, or the previous CO_2 authorized alternate account representative, prior to the time and date when the REGULATORY AGENCY or its agent receives the superseding application for a general account shall be binding on the new CO_2 authorized account representative and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

(ii) The CO_2 authorized alternate account representative for a general account may be changed at any time upon receipt by the REGULATORY AGENCY or its agent of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative, or the previous CO_2 authorized alternate account representative, prior to the time and date when the

REGULATORY AGENCY or its agent receives the superseding application for a general account shall be binding on the new CO_2 authorized alternate account representative and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

(iii) In the event a new person having an ownership interest with respect to CO_2 allowances in the general account is not included in the list of such persons in the application for a general account, such new person shall be deemed to be subject to and bound by the application for a general account, the representations, actions, inactions, and submissions of the CO_2 authorized account representative and any CO_2 authorized alternate account representative, and the decisions, orders, actions, and inactions of the REGULATORY AGENCY or its agent, as if the new person were included in such list.

(iv) Within 30 days following any change in the persons having an ownership interest with respect to CO_2 allowances in the general account, including the addition or deletion of persons, the CO_2 authorized account representative or any CO_2 authorized alternate account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CO_2 allowances in the general account to include the change.

(4) *Objections concerning CO_2 authorized account representative*.

(i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the REGULATORY AGENCY or its agent will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the

REGULATORY AGENCY or its agent.

(ii) Except as provided in subparagraphs (b)(3)(i) and (ii) of this section, no objection or other communication submitted to the REGULATORY AGENCY or its agent concerning the authorization, or any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative for a general account shall affect any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative or the finality of any decision or order by the REGULATORY AGENCY or its agent under the CO_2 Budget Trading Program.

(iii) Neither the REGULATORY AGENCY nor its agent will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative for a general account, including private legal disputes concerning the proceeds of CO_2 allowance transfers.

(5) *Delegation by CO_2 authorized account representative and CO_2 authorized alternate account representative.*

(i) A CO_2 authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the REGULATORY AGENCY or its agent provided for under Subparts XX-6 and XX-7.

(ii) A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the REGULATORY AGENCY or its agent provided for under Subparts XX-6 and XX-7.

(iii) In order to delegate authority to make an electronic submission to

the REGULATORY AGENCY or its agent in accordance with subparagraphs (i) and (ii) of this paragraph, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, must submit to the REGULATORY AGENCY or its agent a notice of delegation, in a format prescribed by the REGULATORY AGENCY that includes the following elements:

(a) The name, address, e-mail address, and telephone number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;

(b) The name, address, e-mail address, and telephone number of each such natural person, herein referred to as "electronic submission agent";

(c) For each such natural person, a list of the type of electronic submissions under subdivision (a) or (b) of this section for which authority is delegated to him or her; and

(d) The following certification statements by such CO_2 authorized account representative or CO_2 authorized alternate account representative:

(1) "I agree that any electronic submission to the REGULATORY AGENCY or its agent that is by a natural person identified in this notice of delegation and of a type listed for such electronic submission agent in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under subparagraph XX- 6.2(b)(5)(iv) shall be deemed to be

an electronic submission by me."

(2) "Until this notice of delegation is superseded by another notice of delegation under subparagraph XX-6.2(b)(5)(iv), I agree to maintain an e-mail account and to notify the REGULATORY AGENCY or its agent immediately of any change in my e-mail address unless all delegation authority by me under paragraph XX-6.2(b)(5) is terminated."

(iv) A notice of delegation submitted under subparagraph (iii) of this paragraph shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the REGULATORY AGENCY or its agent and until receipt by the REGULATORY AGENCY or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of delegation may replace any previously identified electronic submission agent, add a new electronic submission agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in sub-clause (iii)*(d)(1)* of this paragraph and made in accordance with a notice of delegation effective under subparagraph (iv) of this paragraph shall be deemed to be an electronic submission by the CO_2 authorized account representative or CO_2 authorized alternate account representative submitting such notice of delegation.

(c) *Account identification*. The REGULATORY AGENCY or its agent will assign a unique identifying number to each account established under subdivisions (a) or (b) of this section.

XX-6.3 CO_2 Allowance Tracking System responsibilities of CO_2 authorized account representative.

Following the establishment of a CO_2 Allowance Tracking System account, all submissions to the REGULATORY AGENCY or its agent pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CO_2 allowances in the account, shall be made only by the CO_2 authorized account representative for the account.

XX-6.4 Recordation of CO_2 allowance allocations.

(a) By January 1 of each calendar year, the REGULATORY AGENCY or its agent will record in the following accounts:

(1) In each CO_2 budget source's compliance account, the CO_2 allowances allocated for CO_2 budget units at the source (if any) under subdivision XX-5.3(a); and

(2) The CO_2 allowances allocated for the consumer benefit or strategic energy purpose account under subdivision XX-5.3(b).

[Should states wish to establish other set-aside allocations (for new sources, for example), they would be referred to (at least generically) in the above subdivision.]

(b) Each year the REGULATORY AGENCY or its agent will record CO_2 allowances, as allocated to the unit under Subpart XX-5, in the compliance account for the year after the last year for which CO_2 allowances were previously allocated to the compliance account. Each year, the REGULATORY AGENCY or its agent will also record CO_2 allowances, as allocated under Subpart XX-5, in an allocation set-aside for the year after the last year for which CO_2 allowances were previously allocated to an allocation set-aside.

(c) *Serial numbers for allocated CO_2 allowances*. When allocating CO_2 allowances

to and recording them in an account, the REGULATORY AGENCY or its agent will assign each CO_2 allowance a unique identification number that will include digits identifying the year for which the CO_2 allowance is allocated.

XX-6.5 Compliance.

(a) *Allowances available for compliance deduction.* CO_2 allowances that meet the following criteria are available to be deducted in order for a CO_2 budget source to comply with the CO_2 requirements of XX-1.5(c) for a control period or an interim control period.

(1) The CO_2 allowances, other than CO_2 offset allowances, are of allocation years that fall within a prior control period, the same control period, or the same interim control period for which the allowances will be deducted.

(2) The CO_2 allowances are held in the CO_2 budget source's compliance account as of the CO_2 allowance transfer deadline for that control period or interim control period or are transferred into the compliance account by a CO_2 allowance transfer correctly submitted for recordation under section XX-7.1 by the CO_2 allowance transfer deadline for that control period or interim control period.

(3) For CO_2 offset allowances, the number of CO_2 offset allowances that are available to be deducted in order for a CO_2 budget source to comply with the CO_2 requirements of XX-1.5(c) for a control period or an interim control period may not exceed 3.3 percent of the CO_2 budget source's CO_2 emissions for that control period, or 3.3 percent of 0.50 times the CO_2 budget source's CO_2 emissions for an interim control period, as determined in accordance with Subparts XX-6 and XX-8.

(4) The CO_2 allowances are not necessary for deductions for excess emissions for a prior control period under subdivision (d) of this section.

(b) *Deductions for compliance*. Following the recordation, in accordance with section

XX-7.2, of CO_2 allowance transfers submitted for recordation in the CO_2 budget source's compliance account by the CO_2 allowance transfer deadline for a control period or interim control period, the REGULATORY AGENCY or its agent will deduct CO_2 allowances available under subdivision (a) of this section to cover the source's CO_2 emissions (as determined in accordance with Subpart XX-8) for the control period or interim control period, as follows:

(1) Until the amount of CO_2 allowances deducted equals the number of tons of total CO_2 emissions (or 0.50 times the number of tons of total CO_2 emissions for an interim control period), less any CO_2 emissions attributable to the burning of eligible biomass, determined in accordance with Subpart XX-8, from all CO_2 budget units at the CO_2 budget source for the control period or interim control period; or

(2) If there are insufficient CO_2 allowances to complete the deductions in paragraph (b)(1) of this section, until no more CO_2 allowances available under subdivision (a) of this section remain in the compliance account.

(c) *Identification of available CO_2 allowances by serial number; default compliance deductions.*

(1) The CO_2 authorized account representative for a source's compliance account may request that specific CO_2 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period or interim control period in accordance with subdivision (b), or (d) of this section. Such identification shall be made in the compliance certification report submitted in accordance with section XX-4.1.

(2) The REGULATORY AGENCY or its agent will deduct CO_2 allowances for a control period or interim control period from the CO_2 budget source's compliance account, in the absence of an identification or in the case of a partial identification of available CO_2 allowances by serial number under

paragraph (c)(1) of this section, in the following order:

(i) First, subject to the relevant compliance deduction limitations under XX-6.5(a)(3) and (d)(1), CO_2 offset allowances. CO_2 offset allowances shall be deducted in chronological order (i.e., CO_2 offset allowances from earlier allocation years shall be deducted before CO_2 offset allowances from later allocation years). In the event that some, but not all, CO_2 offset allowances from a particular allocation year are to be deducted, CO_2 offset allowances shall be deducted by serial number, with lower serial number allowances deducted before higher serial number allowances.

(ii) Second, any CO_2 allowances, other than CO_2 offset allowances, that are available for deduction under subdivision (a) of this section. CO_2 allowances shall be deducted in chronological order (i.e., CO_2 allowances from earlier allocation years shall be deducted before CO_2 allowances from later allocation years). In the event that some, but not all, CO_2 allowances from a particular allocation year are to be deducted, CO_2 allowances shall be deducted by serial number, with lower serial number allowances deducted before higher serial number allowances.

(d) *Deductions for excess emissions.*

(1) After making the deductions for compliance under subdivision (b) of this section, the REGULATORY AGENCY or its agent will deduct from the CO_2 budget source's compliance account a number of CO_2 allowances, equal to three times the number of the source's excess emissions. In the event that a source has insufficient CO_2 allowances to cover three times the number of the source's excess emissions, the source shall be required to immediately transfer sufficient allowances into its compliance account. No CO_2 offset allowances may be deducted to account for the source's

excess emissions.

(2) Any CO_2 allowance deduction required under paragraph (d)(1) of this section shall not affect the liability of the owners and operators of the CO_2 budget source or the CO_2 units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under applicable State law. The following guidelines will be followed in assessing fines, penalties or other obligations.

(i) For purposes of determining the number of days of violation, if a CO_2 budget source has excess emissions for a control period, each day in the control period constitutes a day in violation unless the owners and operators of the unit demonstrate that a lesser number of days should be considered.

(ii) Each ton of excess emissions is a separate violation.

(iii) For purposes of determining the number of days of violation, if a CO_2 budget source has excess interim emissions for an interim control period, each day in the interim control period constitutes a day in violation unless the owners and operators of the unit demonstrate that a lesser number of days should be considered.

(iv) Each ton of excess interim emissions is a separate violation.

(3) The propriety of the REGULATORY AGENCY's determination that a CO_2 budget source had excess emissions and the concomitant deduction of CO_2 allowances from that CO_2 budget source's account may be later challenged in the context of the initial administrative enforcement, or any civil or criminal judicial action arising from or encompassing that excess emissions violation. The commencement or pendency of any administrative enforcement, or civil or criminal judicial action arising from or encompassing that excess emissions violation will not act to prevent the REGULATORY AGENCY or its agent from initially deducting the CO_2

allowances resulting from the REGULATORY AGENCY's original determination that the relevant CO_2 budget source has had excess emissions. Should the REGULATORY AGENCY's determination of the existence or extent of the CO_2 budget source's excess emissions be revised either by a settlement or final conclusion of any administrative or judicial action, the REGULATORY AGENCY will act as follows.

(i) In any instance where the REGULATORY AGENCY's determination of the extent of excess emissions was too low, the REGULATORY AGENCY will take further action under paragraphs (d)(1) and (2) of this section to address the expanded violation.

(ii) In any instance where the REGULATORY AGENCY's determination of the extent of excess emissions was too high, the REGULATORY AGENCY will distribute to the relevant CO_2 budget source a number of CO_2 allowances equaling the number of CO_2 allowances deducted which are attributable to the difference between the original and final quantity of excess emissions. Should such CO_2 budget source's compliance account no longer exist, the CO_2 allowances will be provided to a general account selected by the owner or operator of the CO_2 budget source from which they were originally deducted.

(e) The REGULATORY AGENCY or its agent will record in the appropriate compliance account all deductions from such an account pursuant to subdivisions (b) and (d) of this section.

(f) *Action by the REGULATORY AGENCY on submissions*.

(1) The REGULATORY AGENCY may review and conduct independent audits concerning any submission under the CO_2 Budget Trading Program and make appropriate adjustments of the information in the submissions.

(2) The REGULATORY AGENCY may deduct CO_2 allowances from or

transfer CO_2 allowances to a source's compliance account based on information in the submissions, as adjusted under paragraph (f)(1) of this section.

XX-6.6 Banking.

Each CO_2 allowance that is held in a compliance account or a general account will remain in such account unless and until the CO_2 allowance is deducted or transferred under section XX-4.2, section XX-6.5, section XX-6.7, or Subpart XX-7.

XX-6.7 Account error.

The REGULATORY AGENCY or its agent may, at its sole discretion and on his or her own motion, correct any error in any CO_2 Allowance Tracking System account. Within 10 business days of making such correction, the REGULATORY AGENCY or its agent will notify the CO_2 authorized account representative for the account.

XX-6.8 Closing of general accounts.

(a) A CO_2 authorized account representative of a general account may instruct the REGULATORY AGENCY or its agent to close the account by submitting a statement requesting deletion of the account from the CO_2 Allowance Tracking System and by correctly submitting for recordation under section XX-7.1 a CO_2 allowance transfer of all CO_2 allowances in the account to one or more other CO_2 Allowance Tracking System account.

(b) If a general account shows no activity for a period of one year or more and does not contain any CO_2 allowances, the REGULATORY AGENCY or its agent may notify the CO_2 authorized account representative for the account that the account will be closed in the CO_2 Allowance Tracking System 30 business days after the notice is sent. The account will be closed after the 30-day period unless before the end of the 30-day period the REGULATORY AGENCY or its agent receives a correctly submitted transfer

of CO_2 allowances into the account under section XX-7.1 or a statement submitted by the CO_2 authorized account representative demonstrating to the satisfaction of the REGULATORY AGENCY or its agent good cause as to why the account should not be closed. The REGULATORY AGENCY or its agent will have sole discretion to determine if the owner or operator of the unit demonstrated that the account should not be closed.

Subpart XX-7 CO_2 Allowance Transfers

XX-7.1 Submission of CO_2 allowance transfers.

The CO_2 authorized account representatives seeking recordation of a CO_2 allowance transfer shall submit the transfer to the REGULATORY AGENCY or its agent. To be considered correctly submitted, the CO_2 allowance transfer shall include the following elements in a format specified by the REGULATORY AGENCY or its agent:

(a) The numbers identifying both the transferor and transferee accounts;

(b) A specification by serial number of each CO_2 allowance to be transferred;

(c) The printed name and signature of the CO_2 authorized account representative of the transferor account and the date signed;

(d) The date of the completion of the last sale or purchase transaction for the allowance, if any; and

(e) The purchase or sale price of the allowance that is the subject of a sale or purchase transaction under subdivision (d) of this section.

XX-7.2 Recordation.

(a) Within 5 business days of receiving a CO_2 allowance transfer, except as provided in subdivision (b) of this section, the REGULATORY AGENCY or its agent will record a

CO_2 allowance transfer by moving each CO_2 allowance from the transferor account to the transferee account as specified by the request, provided that the transfer is correctly submitted under section XX-7.1; and

(1) The transferor account includes each CO_2 allowance identified by serial number in the transfer.

(2) A CO_2 allowance transfer into or out of a compliance account that is submitted for recordation following the CO_2 allowance transfer deadline and that includes any CO_2 allowances that are of allocation years that fall within a control period or interim control period prior to or the same as the control period or interim control period to which the CO_2 allowance transfer deadline applies will not be recorded until after completion of the process pursuant to XX-6.5(b).

(b) Where a CO_2 allowance transfer submitted for recordation fails to meet the requirements of subdivision (a) of this section, the REGULATORY AGENCY or its agent will not record such transfer.

XX-7.3 Notification.

(a) *Notification of recordation*. Within 5 business days of recordation of a CO_2 allowance transfer under section XX-7.2, the REGULATORY AGENCY or its agent will notify each party to the transfer. Notice will be given to the CO_2 authorized account representatives of both the transferor and transferee accounts.

(b) *Notification of non-recordation*. Within 10 business days of receipt of a CO_2 allowance transfer that fails to meet the requirements of subdivision XX-7.2(a), the REGULATORY AGENCY or its agent will notify the CO_2 authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a CO_2 allowance transfer for recordation following notification of non-recordation.

Subpart XX-8 Monitoring, Reporting & Recordkeeping

XX-8.1 General requirements.

The owners and operators, and to the extent applicable, the CO_2 authorized account representative of a CO_2 budget unit, shall comply with the monitoring, recordkeeping and reporting requirements as provided in this Subpart and all applicable sections of 40 CFR part 75. Where referenced in XX-8, the monitoring requirements of 40 CFR Part 75 shall be adhered to in a manner consistent with the purpose of monitoring and reporting CO_2 mass emissions pursuant to **[these regulations]**. For purposes of complying with such requirements, the definitions in section XX-1.2 and in 40 CFR 72.2 shall apply, and the terms ‘‘affected unit,’’ ‘‘designated representative,’’ and ‘‘continuous emissions monitoring system’’ (or ‘‘CEMS’’) in 40 CFR part 75 shall be replaced by the terms ‘‘CO_2 budget unit,’’ ‘‘CO_2 authorized account representative,’’ and ‘‘continuous emissions monitoring system’’ (or ‘‘CEMS’’), respectively, as defined in section XX-1.2.

For units not subject to an Acid Rain emissions limitation, the term “Administrator” in 40 CFR Part 75 shall be replaced with “the Administrator, REGULATORY AGENCY or its agent.” Owners or operators of a CO_2 budget unit who monitor a non-CO_2 budget unit pursuant to the common, multiple, or bypass stack procedures in 40 CFR 75.72(b)(2)(ii), or 40 CFR 75.16 (b)(2)(ii)(B) as pursuant to 40 CFR 75.13, for purposes of complying with **[these regulations]**, shall monitor and report CO_2 mass emissions from such non-CO_2 budget units according to the procedures for CO_2 budget units established in XX-8.1 through XX-8.7.

(a) *Requirements for installation, certification, and data accounting*. The owner or

operator of each CO_2 budget unit must meet the following requirements.

(1) Install all monitoring systems necessary to monitor CO_2 mass emissions in accordance with 40 CFR Part 75, except for equation G-1. Equation G-1 in Appendix G shall not be used to determine CO_2 emissions under this Part. This may require systems to monitor CO_2 concentration, stack gas flow rate, O_2 concentration, heat input, and fuel flow rate.

(2) Successfully complete all certification tests required under section XX-8.2 and meet all other requirements of this Subpart and 40 CFR part 75 applicable to the monitoring systems under paragraph (a)(1) of this section.

(3) Record, report and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance dates*. The owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) through (a)(3) of this section on or before the following dates. The owner or operator shall record, report and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) The owner or operator of a CO_2 budget unit, except for a CO_2 budget unit under paragraph (b)(2) of this section, that commences commercial operation before July 1, 2008, must comply with the requirements of this Subpart by January 1, 2009.

(2) The owner or operator of a CO_2 budget unit that commences commercial operation on or after July 1, 2008 must comply with the requirements of this Subpart by the later of the following dates:

(i) January 1, 2009; or

(ii) The earlier of:

(a) 90 unit operating days after the date on which the unit commences commercial operation; or

(b) 180 calendar days after the date on which the unit commences commercial operation.

(3) For the owner or operator of a CO_2 budget unit for which construction of a new stack or flue installation is completed after the applicable deadline under paragraph (b)(1) or (b)(2) of this section by the earlier of:

(i) 90 unit operating days after the date on which emissions first exit to the atmosphere through the new stack or flue; or

(ii) 180 calendar days after the date on which emissions first exit to the atmosphere through the new stack or flue.

(c) *Reporting data.*

(1) Except as provided in paragraph (c)(2) of this section, the owner or operator of a CO_2 budget unit that does not meet the applicable compliance date set forth in paragraphs (b)(1), (b)(2) and (b)(3) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or as appropriate minimum potential) values for CO_2 concentration, CO_2 emissions rate, stack gas moisture content, fuel flow rate, heat input, and any other parameter required to determine CO_2 mass emissions in accordance with 40 CFR 75.31(b)(2) or (c)(3), or section 2.4 of appendix D of 40 CFR part 75 as applicable.

(2) The owner or operator of a CO_2 budget unit that does not meet the applicable compliance date set forth in paragraph (b)(3) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report substitute data using the applicable missing data procedures in Subpart D, or appendix D of 40 CFR part 75, in lieu of the maximum potential (or as appropriate minimum potential) values for a parameter if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation under paragraph (b)(3) of this section.

(i) CO_2 budget units subject to an acid rain emissions limitation or

[state-specific annual or CSAPR NOx Ozone Season Trading Program] that qualify for the optional SO_2, NO_X, and CO_2 (for acid rain) or NOx (for **[state-specific annual or CSAPR NOx Ozone Season Trading Program]**) emissions calculations for low mass emissions (LME) units under 40 CFR 75.19 and report emissions for such programs using the calculations under 40 CFR 75.19 , shall also use the CO_2 emissions calculations for LME units under 40 CFR 75.19 for purposes of compliance with these regulations.

(ii) CO_2 budget units subject to an acid rain emissions limitation or **[state-specific annual or ozone season CAIR citation]** that do not qualify for the optional SO_2, NO_X, and CO_2 (for acid rain) or NOx (for **[state-specific annual or CSAPR NOx Ozone Season Trading Program]**) emissions calculations for LME units under 40 CFR 75.19, shall not use the CO_2 emissions calculations for LME units under 40 CFR 75.19 for purposes of compliance with these regulations.

(iii) CO_2 budget units not subject to an acid rain emissions limitation or **[state-specific annual or CSAPR NOx Ozone Season Trading Program]** shall qualify for the optional CO_2 emissions calculation for LME units under 40 CFR 75.19, provided that they emit less than 100 tons of NO_X annually and no more than 25 tons of SO_2 annually.

(d) *Prohibitions.*

(1) No owner or operator of a CO_2 budget unit shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emissions monitoring system without having obtained prior written approval in accordance with section XX-8.6.

(2) No owner or operator of a CO_2 budget unit shall operate the unit so as to discharge, or allow to be discharged, CO_2 emissions to the atmosphere

without accounting for all such emissions in accordance with the applicable provisions of this Subpart and 40 CFR part 75.

(3) No owner or operator of a CO_2 budget unit shall disrupt the continuous emissions monitoring system, any portion thereof, or any other approved emissions monitoring method, and thereby avoid monitoring and recording CO_2 mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this Subpart and 40 CFR part 75.

No owner or operator of a CO_2 budget unit shall retire or permanently discontinue use of the continuous emissions monitoring system, any component thereof, or any other approved emissions monitoring system under this Subpart, except under any one of the following circumstances:

(i) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this Subpart and 40 CFR part 75, by the Administrator, REGULATORY AGENCY for use at that unit that provides emissions data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(ii) The CO_2 authorized account representative submits notification of the date of certification testing of a replacement monitoring system in accordance with subparagraph XX-8.2(d)(3)(i).

XX-8.2 Initial certification and recertification procedures.

(a) The owner or operator of a CO_2 budget unit shall be exempt from the initial certification requirements of this section for a monitoring system under paragraph XX-8.1(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with 40 CFR part 75; and

(2) The applicable quality-assurance and quality-control requirements of 40 CFR 75.21 and appendix B and appendix D of 40 CFR part 75 are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under paragraph XX-8.1(a)(1) exempt from initial certification requirements under subdivision (a) of this section.

(c) Not withstanding XX-8.2(a), if the Administrator has previously approved a petition under 40 CFR 75.72(b)(2)(ii), or 40 CFR 75.16(b)(2)(ii)(B) as pursuant to 40 CFR 75.13 for apportioning the CO_2 emissions rate measured in a common stack or a petition under 40 CFR 75.66 of this chapter for an alternative requirement in 40 CFR part 75, the CO_2 authorized account representative shall submit the petition to the Administrator, REGULATORY AGENCY under subdivision XX-8.6(a) to determine whether the approval applies under this program.

(d) Except as provided in subdivision (a) of this section, the owner or operator of a CO_2 budget unit shall comply with the following initial certification and recertification procedures for a continuous emissions monitoring system and an excepted monitoring system under appendix D of 40 CFR part 75 and under paragraph XX-8.1(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology in 40 CFR 75.19 or that qualifies to use an alternative monitoring system under Subpart E of 40 CFR part 75 shall comply with the procedures in subdivision (e) or (f) of this section, respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous emissions monitoring system required under paragraph XX-8.1(a)(1) (which includes the automated data acquisition

and handling system) successfully completes all of the initial certification testing required under 40 CFR 75.20 by the applicable deadlines specified in subdivision XX-8.1(b). In addition, whenever the owner or operator installs a monitoring system in order to meet the requirements of this Subpart in a location where no such monitoring system was previously installed, initial certification in accordance with 40 CFR 75.20 is required.

(2) *Requirements for recertification.*

(i) Whenever the owner or operator makes a replacement, modification, or change in a certified continuous emissions monitoring system under paragraph XX-8.1(a)(1) that the Administrator or the Administrator, REGULATORY AGENCY determines significantly affects the ability of the system to accurately measure or record CO_2 mass emissions or to meet the quality-assurance and quality-control requirements of 40 CFR 75.21 or appendix B to 40 CFR part 75, the owner or operator shall recertify the monitoring system according to 40 CFR 75.20(b).

(ii) For systems using stack measurements such as stack flow, stack moisture content, CO_2 or O_2 monitors, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that the Administrator or the Administrator, REGULATORY AGENCY determines to significantly change the flow or concentration profile, the owner or operator shall recertify the continuous emissions monitoring system according to 40 CFR 75.20(b). Examples of changes which require recertification include: replacement of the analyzer, change in location or orientation of the sampling probe or site, or changing of flow rate monitor polynomial coefficients.

(3) *Approval process for initial certifications and recertification*. Subparagraphs (d)(3)(i) through (iv) of this section apply to both initial certification and recertification of a monitoring system under paragraph XX-8.1(a)(1). For re-certifications, replace the words "certification" and "initial certification" with the word "recertification," replace the word "certified" with "recertified," and proceed in the manner prescribed in 40 CFR 75.20(b)(5) and (g)(7) in lieu of XX-8.2(d)(3)(v).

(i) *Notification of certification.* The CO_2 authorized account representative shall submit to the Administrator, REGULATORY AGENCY or its agent, the appropriate EPA Regional Office and the Administrator a written notice of the dates of certification in accordance with section XX-8.4.

(ii) *Certification application.* The CO_2 authorized account representative shall submit to the Administrator, REGULATORY AGENCY or its agent a certification application for each monitoring system. A complete certification application shall include the information specified in 40 CFR 75.63.

(iii) *Provisional certification data.* The provisional certification date for a monitor shall be determined in accordance with 40 CFR 75.20(a)(3). A provisionally certified monitor may be used under the CO_2 budget Trading Program for a period not to exceed 120 days after receipt by the Administrator, REGULATORY AGENCY of the complete certification application for the monitoring system or component thereof under subparagraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system or component thereof, in accordance with the requirements of 40 CFR part 75, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator, REGULATORY AGENCY does not invalidate the

provisional certification by issuing a notice of disapproval within 120 days of receipt of the complete certification application by the Administrator, REGULATORY AGENCY.

(iv) *Certification application approval process.* The Administrator, REGULATORY AGENCY will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under subparagraph (d)(3)(ii) of this section. In the event the Administrator, REGULATORY AGENCY does not issue such a notice within such 120-day period, each monitoring system which meets the applicable performance requirements of 40 CFR part 75 and is included in the certification application will be deemed certified for use under the CO_2 Budget Trading Program.

(a) *Approval notice.* If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of 40 CFR part 75, then the Administrator, REGULATORY AGENCY will issue a written notice of approval of the certification application within 120 days of receipt.

(b) *Incomplete application notice.* If the certification application is not complete, then the Administrator, REGULATORY AGENCY will issue a written notice of incompleteness that sets a reasonable date by which the CO_2 authorized account representative must submit the additional information required to complete the certification application. If the CO_2 authorized account representative does not comply with the notice of incompleteness by the specified date, then the Administrator, REGULATORY AGENCY may issue a notice of disapproval under clause

(d)(3)(iv)*(c)* of this section. The 120 day review period shall not begin before receipt of a complete certification application.

(c) *Disapproval notice.* If the certification application shows that any monitoring system or component thereof does not meet the performance requirements of 40 CFR part 75, or if the certification application is incomplete and the requirement for disapproval under clause (d)(3)(iv)*(b)* of this section is met, then the REGULATORY AGENCY will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator, REGULATORY AGENCY and the data measured and recorded by each uncertified monitoring system or component thereof shall not be considered valid quality assured data beginning with the date and hour of provisional certification. The owner or operator shall follow the procedures for loss of certification in subparagraph (d)(3)(v) of this section for each monitoring system or component thereof, which is disapproved for initial certification.

(d) *Audit decertification.* The REGULATORY AGENCY may issue a notice of disapproval of the certification status of a monitor in accordance with subdivision XX-8.3(b).

(v) *Procedures for loss of certification.* If the REGULATORY AGENCY issues a notice of disapproval of a certification application under clause (d)(3)(iv)*(c)* of this section or a notice of disapproval of certification status under clause (d)(3)(iv)*(d)* of this section, then:

(a) The owner or operator shall substitute the following values for each disapproved monitoring system, for each hour of

unit operation during the period of invalid data beginning with the date and hour of provisional certification and continuing until the time, date, and hour specified under 40 CFR 75.20(a)(5)(i) or 40 CFR 75.20(g)(7):

(1) For units using or intending to monitor for CO_2 mass emissions using heat input or for units using the low mass emissions excepted methodology under 40 CFR 75.19, the maximum potential hourly heat input of the unit; or

(2) For units intending to monitor for CO_2 mass emissions using a CO_2 pollutant concentration monitor and a flow monitor, the maximum potential concentration of CO_2 and the maximum potential flow rate of the unit under section 2.1 of appendix A of 40 CFR part 75.

(b) The CO_2 authorized account representative shall submit a notification of certification retest dates and a new certification application in accordance with subparagraphs (d)(3)(i) and (ii) of this section; and

(c) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the REGULATORY AGENCY's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) *Initial certification and recertification procedures for low mass emissions units using the excepted methodologies under XX-8.1(c)(2)*. The owner or operator of a unit qualified to use the low mass emissions excepted methodology under XX-8.1(c)(2) shall meet the applicable certification and recertification requirements of 40 CFR 75.19(a)(2), 40 CFR 75.20(h) and section XX-8.2. If the owner or operator of such a unit elects to certify a fuel flow meter system for heat input determinations, the owner

or operator shall also meet the certification and recertification requirements in 40 CFR 75.20(g).

(f) *Certification/recertification procedures for alternative monitoring systems*. The CO_2 authorized account of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator and, if applicable, the Administrator, REGULATORY AGENCY under Subpart E of 40 CFR part 75 shall comply with the applicable notification and application procedures of 40 CFR 75.20(f).

XX-8.3 Out-of-control periods.

(a) Whenever any monitoring system fails to meet the quality assurance and quality control requirements or data validation requirements of 40 CFR part 75, data shall be substituted using the applicable procedures in Subpart D or appendix D of 40 CFR part 75.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under section XX-8.2 or the applicable provisions of 40 CFR part 75 , both at the time of the initial certification or recertification application submission and at the time of the audit, the REGULATORY AGENCY or Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the REGULATORY AGENCY or the Administrator. By issuing the notice of disapproval, the REGULATORY AGENCY or Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests

for the monitoring system. The owner or operator shall follow the initial certification or recertification procedures in section XX-8.2 for each disapproved monitoring system.

XX-8.4 Notifications.

The CO_2 authorized account representative for a CO_2 budget unit shall submit written notice to the REGULATORY AGENCY and the Administrator in accordance with 40 CFR 75.61.

XX-8.5 Recordkeeping and reporting.

(a) *General provisions.* The CO_2 authorized account representative shall comply with all recordkeeping and reporting requirements in this section, the applicable record keeping and reporting requirements under 40 CFR 75.73 and with the requirements of subdivision XX-2.1(e).

(b) *Monitoring plans.* The owner or operator of a CO_2 budget unit shall submit a monitoring plan in the manner prescribed in 40 CFR 75.62.

(c) *Certification applications.* The CO_2 authorized account representative shall submit an application to the Administrator, REGULATORY AGENCY within 45 days after completing all CO_2 monitoring system initial certification or recertification tests required under section XX-8.2 including the information required under 40 CFR 75.63 and 40 CFR 75.53(g) and (h).

(d) *Quarterly reports.* The CO_2 authorized account representative shall submit quarterly reports, as follows:

(1) The CO_2 authorized account representative shall report the CO_2 mass emissions data for the CO_2 budget unit, in an electronic format prescribed by the Administrator unless otherwise prescribed by the Administrator, REGULATORY AGENCY for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2008, the calendar quarter covering January 1, 2009 through March 31, 2009; or

(ii) For a unit commencing commercial operation on or after July 1, 2008, the calendar quarter corresponding to, the earlier of the date of provisional certification or the applicable deadline for initial certification under subdivision XX-8.1(b) or, unless that quarter is the third or fourth quarter of 2008, in which case reporting shall commence in the quarter covering January 1, 2009 through March 31, 2009.

(2) The CO_2 authorized account representative shall submit each quarterly report to the Administrator, REGULATORY AGENCY or its agent within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in Subpart H of 40 CFR part 75 and 40 CFR 75.64. Quarterly reports shall be submitted for each CO_2 budget unit (or group of units using a common stack), and shall include all of the data and information required in Subpart G of 40 CFR part 75, except for opacity, heat input, NOx, and SO_2 provisions.

(3) *Compliance certification.* The CO_2 authorized account representative shall submit to the Administrator, REGULATORY AGENCY or its agent a compliance certification in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(i) The monitoring data submitted were recorded in accordance with the applicable requirements of this Subpart and 40 CFR part 75, including the quality assurance procedures and specifications;

(ii) For a unit with add-on CO_2 emissions controls and for all hours

where data are substituted in accordance with 40 CFR 75.34(a)(1) , the add-on emissions controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B of 40 CFR part 75 and the substitute values do not systematically underestimate CO_2 emissions; and

(iii) The CO_2 concentration values substituted for missing data under Subpart D of 40 CFR part 75 do not systematically underestimate CO_2 emissions.

XX-8.6 Petitions.

(a) Except as provided in subdivision (c) of this section, the CO_2 authorized account representative of a CO_2 budget unit that is subject to an Acid Rain emissions limitation may submit a petition to the Administrator under 40 CFR 75.66 and to the REGULATORY AGENCY requesting approval to apply an alternative to any requirement of 40 CFR Part 75. Application of an alternative to any requirement of 40 CFR Part 75 is in accordance with this Subpart only to the extent that the petition is approved in writing by the Administrator, and subsequently approved in writing by the REGULATORY AGENCY.

(b) Petitions for a CO_2 budget unit that is not subject to an Acid Rain emissions limitation.

(1) The CO_2 authorized account representative of a CO_2 budget unit that is not subject to an Acid Rain emissions limitation may submit a petition to the Administrator under 40 CFR 75.66 and to the REGULATORY AGENCY requesting approval to apply an alternative to any requirement of 40 CFR PART 75. Application of an alternative to any requirement of 40 CFR PART 75 is in accordance with this Subpart only to the extent that the petition is approved in writing by the Administrator and subsequently approved in writing by the REGULATORY AGENCY.

(2) In the event that the Administrator declines to review a petition under XX-8.6(b)(1), the CO_2 authorized account representative of a CO_2 budget unit that is not subject to an Acid Rain emissions limitation may submit a petition to the REGULATORY AGENCY requesting approval to apply an alternative to any requirement of XX-8. That petition shall contain all of the relevant information specified in 40 CFR 75.66. Application of an alternative to any requirement of XX-8 is in accordance with XX-8 only to the extent that the petition is approved in writing by the REGULATORY AGENCY.

(c) The CO_2 authorized account representative of a CO_2 budget unit that is subject to an Acid Rain emissions limitation may submit a petition to the Administrator under 40 CFR 75.66 and to the REGULATORY AGENCY requesting approval to apply an alternative to a requirement concerning any additional CEMS required under the common stack provisions of 40 CFR 75.72 or a CO_2 concentration CEMS used under 40 CFR 75.71(a)(2). Application of an alternative to any such requirement is in accordance with this Subpart only to the extent the petition is approved in writing by the Administrator and subsequently approved in writing by the REGULATORY AGENCY.

XX-8.7 CO_2 budget units that co-fire eligible biomass.

(a) The CO_2 authorized account representative of a CO_2 budget unit that co-fires eligible biomass as a compliance mechanism under XX shall report the following information to the REGULATORY AGENCY or its agent for each calendar quarter:

(1) For each shipment of solid eligible biomass fuel fired at the CO_2 budget unit, the total eligible biomass fuel input, on an as-fired basis, in pounds;

(2) For each shipment of solid eligible biomass fuel fired at the CO_2 budget unit, the moisture content, on an as-fired basis, as a fraction by weight;

(3) For each distinct type of gaseous eligible biomass fuel fired at the CO_2 budget unit, the density of the biogas, on an as-fired basis, in pounds per standard cubic foot;

(4) For each distinct type of gaseous eligible biomass fuel fired at the CO_2 budget unit, the moisture content of the biogas, as a fraction by total weight;

(5) For each distinct type of gaseous eligible biomass fuel fired at the CO_2 budget unit, the total eligible biomass fuel input, in standard cubic feet;

(6) For each distinct type of eligible biomass fuel fired at the CO_2 budget unit, the dry basis carbon content of the fuel type, as a fraction by dry weight;

(7) For each distinct type of eligible biomass fuel fired at the CO_2 budget unit, the dry basis higher heating value, in MMBtu per dry pound;

(8) For each distinct type of eligible biomass fuel fired at the CO_2 budget unit, the total dry basis eligible biomass fuel input, in pounds, calculated in accordance with XX-8.7(b);

(9) The total amount of CO_2 emitted from the $CO2$ budget unit due to firing eligible biomass fuel, in tons, calculated in accordance with XX-8.7(c);

(10) For each distinct type of eligible biomass fuel fired at the CO_2 budget unit, the total eligible biomass fuel heat input, in MMBtu, calculated in accordance with XX-8.7(d)(1).

(11) The total amount of heat input to the CO_2 budget unit due to firing eligible biomass fuel, in MMBtu, calculated in accordance with XX-8.7(d)(2);

(12) Description and documentation of monitoring technology employed, and description and documentation of fuel sampling methodology employed, including sampling frequency; and

(13) For each distinct type of eligible biomass fuel fired at the CO_2 budget unit, chemical analysis, including heating value and carbon content.

(b) An owner or operator of a CO_2 budget unit shall calculate and submit to the REGULATORY AGENCY or its agent on a quarterly basis the total dry weight for each distinct type of eligible biomass fired by the CO_2 budget unit during the reporting quarter. The total dry weight shall be determined for each fuel type as follows:

(1) For solid fuel types:

$$F_j = \sum_{i=1}^{m} (1 - M_i) \times F_i$$

Where:

F_j = Total eligible biomass dry basis fuel input (lbs) for fuel type j;

F_i = Eligible biomass as fired fuel input (lbs) for fired shipment i;

M_i = Moisture content (fraction) for fired shipment i;

i = Fired fuel shipment;

j = Fuel type; and

m = Number of shipments.

(2) For gaseous fuel types:

$$F_j = D_j \times V_j \times (1 - M_j)$$

Where:

F_j = Total eligible biomass dry basis fuel input (lbs) for fuel type j;

D_j = Density of biogas (lbs/scf) for fuel type j;

V_j = Total volume (scf) for fuel type j;

M_j = Moisture content (fraction) for fuel type j;

j = Fuel type.

(c) CO_2 emissions due to firing of eligible biomass shall be determined as follows:

(1) For any full calendar quarter during which no fuel other than eligible biomass is combusted at the CO_2 budget unit, as measured and recorded in accordance with XX-8.1 through XX-8.6 ; or

For any full calendar quarter during which fuels other than eligible biomass are combusted at the CO_2 budget unit, as determined using the following equation:

$$CO_2\ tons = \sum_{j=1}^{n} F_j \times C_j \times O_j \times \frac{44}{12} \times 0.0005$$

Where:

CO_2 tons = CO_2 emissions due to firing of eligible biomass for the reporting quarter;

F_j = Total eligible biomass dry basis fuel input (lbs) for fuel type j, as calculated in XX-8.7(b);

C_j = Carbon fraction (dry basis) for fuel type j;

O_j = Oxidation factor for eligible biomass fuel type j, derived for solid fuels based on the ash content of the eligible biomass fired and the carbon content of this ash, as determined pursuant to XX-8.7(a)(12); for gaseous eligible biomass fuels, a default oxidation factor of 0.995 may be used;

44/12 = The number of tons of carbon dioxide that are created when one ton of carbon is combusted (44/12);

0.0005 = The number of short tons which is equal to one pound;

j = Fuel type; and

n = Number of distinct fuel types.

(d) Heat input due to firing of eligible biomass for each quarter shall be determined as follows:

(1) For each distinct fuel type:

$$H_j = F_j \times HHV_j$$

Where:

H_j = Heat input (MMBtu) for fuel type j;

F_j = Total eligible biomass dry basis fuel input (lbs) for fuel type j, as calculated in XX-8.7(b);

HHV_j = Higher heating value (MMBtu/lb), dry basis, for fuel type j, as determined through chemical analysis; and

j = fuel type.

(2) For all fuel types:

$$Heat\ input\ MMBtu = \sum_{i=1}^{n} H_j$$

Where:

H_j = Heat input (MMBtu) for fuel type j;

j = fuel type; and

n = number of distinct fuel types.

(e) Fuel sampling methods and fuel sampling technology shall be consistent with the New York State Renewable Portfolio Standard Biomass Guidebook, September 2011.

XX-8.8 Additional requirements to provide output data.

(a) A CO_2 budget unit in a state that requires the use of information submitted to the Independent System Operator (ISO) to document megawatt-hours (MWh) the CO_2 budget unit produces shall submit to the REGULATORY AGENCY or its agent the same MWh value submitted to the ISO and a statement certifying that the MWh of electrical output reported reflects the total actual electrical output for all CO_2 budget units at the facility used by the ISO to determine settlement resources of energy market participants.

(b) A CO_2 budget unit in a state that requires gross output to be used that also reports gross hourly MW to the Administrator, shall use the same electronic data report (EDR) gross output (in MW), as submitted to the Administrator, for the hour times operating time in the hour, added for all hours in a year. A CO_2 budget unit that does not report gross hourly MW to the Administrator shall submit to the REGULATORY AGENCY or its agent information in accordance with paragraph XX-8.8(e)(1).

(c) A CO_2 budget unit in a state that requires net electrical output, shall submit to the REGULATORY AGENCY or its agent information in accordance with paragraph XX-8.8(e)(1). A CO_2 budget source whose electrical output is not used in ISO energy market settlement determinations shall propose to the REGULATORY AGENCY a method for quantification of net electrical output.

(d) CO_2 budget sources selling steam should use billing meters to determine net steam output. A CO_2 budget source whose steam output is not measured by billing meters or whose steam output is combined with output from a non-CO_2 budget unit prior to measurement by the billing meter shall propose to the REGULATORY AGENCY an alternative method for quantification of net steam output. If data for steam output is not

available, the CO_2 budget source may report heat input providing useful steam output as a surrogate for steam output.

(e) *Monitoring.* The owner or operator of each CO_2 budget unit, in a state that requires the CO_2 budget unit's net output, must meet the following requirements. Each CO_2 budget source must submit an output monitoring plan. The output monitoring plan must include a description and diagram as stated below.

(1) Submit a diagram of the electrical and/or steam system for which output is being monitored, specifically including the following.

If the CO_2 budget unit monitors net electric output, the diagram should contain all CO_2 budget units and all generators served by each CO_2 budget unit and the relationship between CO_2 budget units and generators. If a generator served by a CO_2 budget unit is also served by a non-affected unit, the non-affected unit and its relationship to each generator should be indicated on the diagram as well. The diagram should indicate where the net electric output is measured and should include all electrical inputs and outputs to and from the plant. If net electric output is determined using a billing meter, the diagram should show each billing meter used to determine net sales of electricity and should show that all electricity measured at the point of sale is generated by the CO_2 budget units.

(i) If the CO_2 budget unit monitors net thermal output, the diagram should include all steam or hot water coming into the net steam system, including steam from CO_2 budget units and non-affected units, and all exit points of steam or hot water from the net steam system. In addition, each input and output stream will have an estimated temperature, pressure and phase indicator, and an enthalpy in Btu/lb. The diagram of the net steam system should identify all useful loads, house loads, parasitic loads, any other steam loads and all boiler feedwater returns. The diagram will represent all energy losses in the system as either usable or

unusable losses. The diagram will also indicate all flow meters, temperature or pressure sensors or other equipment used to calculate gross thermal output. If a sales agreement is used to determine net thermal output, the diagram should show the monitoring equipment used to determine the sales of steam.

(2) Submit a description of each output monitoring system. The description of the output monitoring system should include a written description of the output system and the equations used to calculate output. For net thermal output systems descriptions and justifications of each useful load should be included.

(3) Submit a detailed description of all quality assurance/quality control activities that will be performed to maintain the output system in accordance with subdivision XX-8.8(g).

(4) Submit documentation supporting any output value(s) to be used as a missing data value should there be periods of invalid output data. The missing data output value must be either zero or an output value that is likely to be lower than a measured value and that is approved as part of the monitoring plan required under this subdivision.

(f) *Initial certification*. A certification statement must be submitted by the CO_2 authorized account representative stating that either the output monitoring system consists entirely of billing meters or that the output monitoring system meets one of the accuracy requirements for non-billing meters at paragraph (2) of this subdivision. This statement may be submitted with the certification application required under subdivision XX-8.5(c).

(1) *Billing meters*. The billing meter must record the electric or thermal output. Any electric or thermal output values that the facility reports must be the same as the values used in billing for the output. Any output measurement equipment used as a billing meter in commercial transactions requires no additional certification or testing.

(2) *Non-billing meters*. For non-billing meters, the output monitoring system must either meet an accuracy of within 10% of the reference value, or each component monitor for the output system must meet an accuracy of within 3% of the full scale value, whichever is less stringent.

(i) *System approach to accuracy*. The system approach to accuracy must include a determination of how the system accuracy of 10% is achieved using the individual components in the system and should include data loggers and any watt meters used to calculate the final net electric output data and/or any flow meters for steam or condensate, temperature measurement devices, absolute pressure measurement devices, and differential pressure devices used for measuring thermal energy.

(ii) *Component approach to accuracy*. If testing a piece of output measurement equipment shows that the output readings are not accurate to within 3.0 percent of the full scale value, then the equipment should be repaired or replaced to meet that requirement. Data shall remain invalid until the output measurement equipment passes an accuracy test or is replaced with another piece of equipment that passes the accuracy test.

(g) *Ongoing QA/QC*. Ongoing quality assurance/quality control activities must be performed in order to maintain the output system.

(1) *Billing meters*. In the case where billing meters are used to determine output, no QA/QC activities beyond what are already performed are required.

(2) *Non-billing meters*. Certain types of equipment such as potential transformers, current transformers, nozzle and venturi type meters, and the primary element of an orifice plate only require an initial certification of calibration and do not require periodic recalibration unless the equipment is physically changed. However, the pressure and temperature

transmitters accompanying an orifice plate will require periodic retesting. For other types of equipment, either recalibrate or re-verify the meter accuracy at least once every two years (i.e., every eight calendar quarters), unless a consensus standard allows for less frequent calibrations or accuracy tests. For non- billing meters, the output monitoring system must either meet an accuracy of within 10% of the reference value, or each component monitor for the output system must meet an accuracy of within 3% of the full scale value, whichever is less stringent. If testing a piece of output measurement equipment shows that the output readings are not accurate to within 3.0 percent of the full scale value, then the equipment should be repaired or replaced to meet that requirement.

(3) *Out-of-control periods*. If testing a piece of output measurement equipment shows that the output readings are not accurate to the certification value, data remain invalid until the output measurement equipment passes an accuracy test or is replaced with another piece of equipment that passes the accuracy test. All invalid data shall be replaced by either zero or an output value that is likely to be lower than a measured value and that is approved as part of the monitoring plan required under subdivision XX-8.8(e).

(h) *Recordkeeping and reporting.*

(1) *General provisions.* The CO_2 authorized account representative shall comply with all recordkeeping and reporting requirements in this section and with the requirements of subdivisions XX-1.5(e) and XX-2.1(e).

(2) *Recordkeeping.* Facilities shall retain data used to monitor, determine, or calculate net generation for ten years.

(3) *Annual reports.* The CO_2 authorized account representative shall submit annual output reports, as follows. The data must be sent both electronically and in hardcopy by March 1 for the immediately preceding

calendar year to the REGULATORY AGENCY or its agent. The annual report shall include unit level MWh, all useful steam output and a certification statement from the CO_2 authorized account representative stating the following,

"I am authorized to make this submission on behalf of the owners and operators of the CO_2 budget sources or CO_2 budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

Subpart XX-9 Auction of CO_2 CCR and ECR allowances

XX-9.1 Purpose

The following rules shall apply to each allowance auction. The REGULATORY AGENCY or its agent may specify additional information in the auction notice for each auction. Such additional information may include the time and location of the auction, auction rules, registration deadlines, and any additional information deemed necessary or useful.

XX-9.2 General Requirements

(a) The REGULATORY AGENCY or its agent shall include the following information in the auction notice for each auction:

(1) The number of CO_2 allowances offered for sale at the auction, not including any CO_2 CCR allowances;

(2) The number of CO_2 CCR allowances that will be offered for sale at the auction if the condition of paragraph (b)(1) of this section is met;

(3) The minimum reserve price for the auction; and

(4) The CCR trigger price for the auction.

(5) The maximum number of CO_2 allowances that may be withheld from sale at the auction if the condition of paragraph (d) (1) of this section is met;

(6) The ECR trigger price for the auction.

(b) The REGULATORY AGENCY or its agent shall follow these rules for the sale of CO_2 CCR allowances:

(1) CO_2 CCR allowances shall only be sold at an auction in which total demand for allowances, above the CCR trigger price, exceeds the number of CO_2 allowances available for purchase at the auction, not including any CO_2 CCR allowances.

(2) If the condition of paragraph (1) of this subdivision is met at an auction, then the number of CO_2 CCR allowances offered for sale by the REGULATORY AGENCY or its agent at the auction shall be equal to the number of CO_2 CCR allowances in the RELEVANT STATE AUCTION ACCOUNT at the time of the auction.

(3) After all of the CO_2 CCR allowances in the RELEVANT STATE AUCTION ACCOUNT have been sold in a given calendar year, no additional CO_2 CCR allowances will be sold at any auction for the remainder of that calendar year, even if the condition of paragraph (1) of this subdivision is met at an auction; and

(4) At an auction in which CO_2 CCR allowances are sold, the reserve price at for the auction shall be the CCR trigger price.

(5) If the condition of paragraph (1) of this subdivision is not satisfied, no CO_2

CCR allowances shall be offered for sale at the auction, and the reserve price for the auction shall be equal to the minimum reserve prices.

(c) The REGULATORY AGENCY or its agent shall implement the reserve price in the following manner:

(1) No allowances shall be sold at any auction for a price below the reserve price for that auction; and

(2) If the total demand for allowances at an auction is less than or equal to the total number of allowances made available for sale in that auction, then the auction clearing price for the auction shall be the reserve price.

(d) The REGULATORY AGENCY or its agent shall follow these rules for the withholding of CO_2 ECR allowances from an auction:

(1) CO_2 ECR allowances shall only be withheld from an auction if the demand for allowances would result in an auction clearing price that is less than the ECR trigger price prior to the withholding from the auction of any ECR allowances.

(2) If the condition in paragraph (1) of this subdivision is met at an auction, then the maximum number of CO_2 ECR allowances that may be withheld from that auction will be equal to the quantity shown in section 5.3(e)(1) Table 4 minus the total quantity of CO_2 ECR allowances that have been withheld from any prior auction in that calendar year. Any CO_2 ECR allowances withheld from an auction will be transferred into the RELEVANT STATE ECR ACCOUNT.

Subpart XX-10 CO_2 Emissions Offset Projects

XX-10.1 Purpose.

The REGULATORY AGENCY will provide for the award of CO_2 offset allowances to sponsors of CO_2 emissions offset projects that have reduced or avoided atmospheric

loading of CO_2, CO_2 equivalent or sequestered carbon as demonstrated in accordance with the applicable provisions of this Subpart. The requirements of this Subpart seek to ensure that CO_2 offset allowances awarded represent CO_2 equivalent emission reductions or carbon sequestration that are real, additional, verifiable, enforceable, and permanent within the framework of a standards-based approach. Subject to the relevant compliance deduction limitations of paragraph XX-6.5(a)(3), CO_2 offset allowances may be used by any CO_2 budget source for compliance purposes.

XX-10.2 Definitions.

(a) *Anaerobic digester*. A device that promotes the decomposition of organic material to simple organics and gaseous biogas products, in the absence of elemental oxygen, usually accomplished by means of controlling temperature and volume, and including a methane recovery system.

(b) *Anaerobic digestion*. The decomposition of organic material including manure brought about through the action of microorganisms in the absence of elemental oxygen.

(c) *Anaerobic storage*. Storage of organic material in an oxygen-free environment, or under oxygen-free conditions, including but not limited to, holding tanks, ponds, and lagoons.

(d) *ANSI*. American National Standards Institute.

(e) *Biogas*. Gas resulting from the decomposition of organic matter under anaerobic conditions. The principle constituents are methane and carbon dioxide.

(f) *CO_2e*. CO_2e means carbon dioxide equivalent.

(g) *Conflict of interest*. A situation that may arise with respect to an individual in relation to any specific project sponsor, CO_2 emissions offset project or category of

offset projects, such that the individual's other activities or relationships with other persons or organizations render or may render the individual incapable of providing an impartial certification opinion, or otherwise compromise the individual's objectivity in performing certification functions.

(h) *Cooperating regulatory agency*. A regulatory agency in a state or United States jurisdiction that is not a participating state that has entered into a memorandum of understanding with the appropriate regulatory agencies of all participating states to carry out certain obligations relative to CO_2 emissions offset projects in that state or United States jurisdiction, including but not limited to the obligation to perform audits of offset project sites, and report violations of this Subpart.

(i) *Forest offset project*. An offset project involving reforestation, improved forest management, or avoided conversion.

(j) *Forest offset project data report*. The report prepared by a project sponsor each year that provides the information and documentation required by this Subpart or the forest offset protocol.

(k) *Forest offset protocol*. The protocol titled "Regional Greenhouse Gas Initiative Offset Protocol U.S. Forest Projects", published by the participating states on June 12, 2013.

(l) *Independent verifier*. An individual that has been approved by the REGULATORY AGENCY or its agent to conduct verification activities.

(m) *Intentional Reversal*. Any reversal caused by a forest owner's negligence, gross negligence, or willful intent, including harvesting, development, and harm to the area within the offset project boundary

(n) *Market penetration rate*. A measure of the diffusion of a technology, product, or practice in a defined market, as represented by the percentage of annual sales for a

product or practice, or as a percentage of the existing installed stock for a product or category of products, or as the percentage of existing installed stock that utilizes a practice. The REGULATORY AGENCY may determine an appropriate market definition and market penetration metric for a category of technology, product or practice, and may issue guidance specifying the technologies, products or practices that meet a specified market penetration rate.

(o) *Offset project*. An offset project includes all equipment, materials, items, or actions directly related to the reduction of CO_2 equivalent emissions or the sequestration of carbon specified in a consistency application submitted pursuant to section XX-10.4. Equipment, materials, items, or actions unrelated to an offset project reduction of CO_2 equivalent emissions or the sequestration of carbon, but occurring at a location where an offset project occurs, shall not be considered part of an offset project, unless specified at section XX-10.5.

(p) *Permanently retired*. A greenhouse gas allowance or credit has been "permanently retired" if it has been placed in a retirement account controlled by the jurisdiction that generated the allowance or credit, or has been placed in an allowance retirement account controlled by the REGULATORY AGENCY, or is otherwise determined by the REGULATORY AGENCY to have been rendered unusable.

(q) *Project commencement*. For an offset project involving physical construction, other work at an offset project site, or installation of equipment or materials, the date of the beginning of such activity. For an offset project that involves the implementation of a management activity or protocol, the date on which such activity is first implemented or such protocol first utilized. For an offset project involving reforestation, improved forest management, or avoided conversion, the date specified in section 3.2 of the forest offset protocol.

(r) *Regional-type anaerobic digester*. An anaerobic digester using feedstock from more than one agricultural operation, or importing feedstock from more than one

agricultural operation. Also commonly referred to as a "community digester" or "centralized digester."

(s) *Renewable portfolio standard*. A statutory or regulatory requirement that a load-serving entity provide a certain portion of the electricity it supplies to its customers from renewable energy sources, or any other statutory or regulatory requirement that a certain portion of electricity supplied to the electricity grid be generated from renewable energy sources.

(t) *Reporting Period*. The period of time covered by a forest offset project data report. The first reporting period for an offset project in an initial crediting period may consist of 6 to 24 consecutive months; all subsequent reporting periods in an initial crediting and all reporting periods in any renewed crediting period must consist of 12 consecutive months.

(u) *Reversal*. A GHG emission reduction or GHG removal enhancement for which CO_2 offset allowances have been issued that is subsequently released or emitted back into the atmosphere due to any intentional or unintentional circumstance.

(v) *System benefit fund*. Any fund collected directly from retail electricity or natural gas ratepayers.

(w) *Total solids*. Total solids are the total of all solids in a sample. They include the total suspended solids, total dissolved solids, and volatile suspended solids.

(x) *Transmission and/or distribution entity*. The assets and equipment used to transmit and distribute electricity from an electric generator to the electrical load of a customer. Includes all related assets and equipment located within the service territory of the entity, defined as the service territory of a load-serving entity specified by the applicable state regulatory agency.

(y) *Unintentional Reversal*. Any reversal, including, but not limited to, wildfires, insects, or disease that is not the result of the forest owner's negligence, gross negligence, or willful intent.

(z) *Verification*. The verification by an independent verifier that certain parts of a CO_2 emissions offset project consistency application and/or measurement, monitoring or verification report conforms to the requirements of this Subpart.

(aa) *Volatile solids*. The fraction of total solids that is comprised primarily of organic matter as defined in U.S.EPA Method Number 160.4, Methods for the Chemical Analysis of Water and Wastes (MCAWW) (EPA/600/4-79/020).

XX-10.3 General requirements.

(a) *Eligible CO_2 emissions offset projects*. To qualify for the award of CO_2 offset allowances, offset projects shall satisfy all the applicable requirements of XX-10.

(1) *Offset project types*. The following types of offset projects are eligible for the award of CO_2 offset allowances.

(i) Landfill methane capture and destruction;

(ii) Sequestration of carbon due to reforestation, improved forest management, or avoided conversion;

(iii) Avoided methane emissions from agricultural manure management operations.

(2) *Offset project locations*.

(i) To qualify for the award of CO_2 allowances under XX-10, eligible offset projects may be located in any of the following locations:

(a) In **[STATE]**; and

(b) In any state or United States jurisdiction in which a cooperating regulatory agency has entered into a memorandum of understanding with the appropriate regulatory agencies of all participating states to carry out

certain obligations relative to CO_2 emissions offset projects in that state or U.S. jurisdiction, including but not limited to the obligation to perform audits of offset project sites, and report violations of XX-10.

(ii) Projects located (in whole or in part) in one or more participating states are not eligible for CO_2 offset allowances under XX-10 unless more of the CO_2 equivalent emissions reduction or carbon sequestration due to the offset project is projected to occur in **[STATE]** than in any other participating state.

(b) *Project sponsor*. Any person may act as the sponsor of an eligible CO_2 emissions offset project, provided that person meets the requirements at section XX-10.4.

(c) *General additionality requirements.* Except as provided with respect to specific offset project standards in section XX-10.5, the following general requirements shall apply.

(1) CO_2 offset allowances shall not be awarded to an offset project that is required pursuant to any local, state or federal law, regulation, or administrative or judicial order. If an offset project receives a consistency determination under section XX-10.4 and is later required by local, state or federal law, regulation, or administrative or judicial order, then the offset project shall remain eligible for the award of CO_2 offset allowances until the end of its current allocation period but its eligibility shall not be extended for an additional allocation period.

(2) CO_2 offset allowances shall not be awarded to an offset project that includes an electric generation component, unless the project sponsor transfers legal rights to any and all attribute credits (other than the CO_2 offset allowances awarded under section XX-10.7) generated from the operation of the offset project that may be used for compliance with a

renewable portfolio standard or other regulatory requirement, to the REGULATORY AGENCY or its agent.

(3) CO_2 offset allowances shall not be awarded to an offset project that receives funding or other incentives from any system benefit fund, or funds or other incentives provided through the consumer benefit or strategic energy purpose allocation required pursuant to subdivision XX-5.3(b).

(4) CO_2 offset allowances shall not be awarded to an offset project that is awarded credits or allowances under any other mandatory or voluntary greenhouse gas program, except ~~for~~ as described in Section XX-10.5(b)(10).

(d) *Maximum allocation periods for CO_2 emissions offset projects*.

(1) *Maximum allocation periods*. Except as provided in paragraph (d)(2) of this section, the REGULATORY AGENCY may award CO_2 offset allowances under section XX-10.7 for an initial 10-year allocation period. At the end of the initial 10-year allocation period, the REGULATORY AGENCY may award CO_2 offset allowances for a second 10-year allocation period, provided the offset sponsor has submitted a consistency application pursuant to section XX-10.4 prior to the expiration of the initial allocation period, and the REGULATORY AGENCY has issued a consistency determination pursuant to paragraph XX-10.4(e)(2).

(2) *Maximum allocation period for involving reforestation, improved forest management, or avoided conversion*. The REGULATORY AGENCY may award CO_2 offset allowances under section XX-10.7 for any project involving reforestation, improved forest management, or avoided conversion offset project for an initial 25-year allocation period. At the end of the initial 25-year allocation period, or any subsequent crediting period, the REGULATORY AGENCY may award CO_2 offset allowances for a subsequent 25-year allocation period, provided the offset sponsor has

submitted a consistency application for the offset project pursuant to section XX-10.4 prior to the expiration of the initial allocation period, and the REGULATORY AGENCY has issued a consistency determination pursuant to paragraph XX-10.4(e)(2).

(e) *Offset project audit*. Project sponsors shall provide, in writing, an access agreement to the REGULATORY AGENCY granting the REGULATORY AGENCY or its agent access to the physical location of the offset project to inspect for compliance with this Subpart. For offset projects located in any state or other U.S. jurisdiction that is not a participating state, project sponsors shall also provide, in writing, an access agreement to the REGULATORY AGENCY granting the cooperating regulatory agency with access to the physical location of the offset project to inspect for compliance with this Subpart.

(f) *Ineligibility due to noncompliance*.

(1) If at any time the REGULATORY AGENCY determines that a project sponsor has not complied with the requirements of this Subpart, then the REGULATORY AGENCY may revoke and retire any and all CO_2 offset allowances in the project sponsor's account.

(2) If at any time the REGULATORY AGENCY determines that an offset project does not comply with the requirements of this Subpart, then the REGULATORY AGENCY may revoke any approvals it has issued relative to an offset project.

XX-10.4 Application process.

(a) *Establishment of general account.* The sponsor of an offset project must establish a general account under subdivision XX-6.2(b). All submissions to the REGULATORY AGENCY required for the award of CO_2 offset allowances under this Subpart must be from the CO_2 authorized account representative for the general

account of the sponsor of the relevant offset project, herein referred to as "project sponsor."

(b) *Consistency application deadlines.*

(1) For offset projects not involving reforestation, improved forest management, or avoided conversion the consistency application must be submitted by the date that is 6 months after the offset project is commenced.

(2) For offset projects involving reforestation, improved forest management, or avoided conversion the consistency application must be submitted by the date that is one year after the offset project is commenced, except for as described in Section XX 10.5(c)(9).

(3) Any consistency application that fails to meet the deadlines of this subdivision will result in the denial of the consistency application and the continued ineligibility of the subject offset project.

(c) *Consistency application contents*.

(1) For an offset project, the consistency application must include the following information.

(i) The project's sponsor's name, address, e-mail address, telephone number, facsimile transmission number, and account number.

(ii) The offset project description as required by the relevant provisions of section XX-10.5.

(iii) A demonstration that the offset project meets all applicable requirements set forth in this Subpart.

(iv) The emissions baseline determination as required by the relevant provisions of section XX-10.5.

(v) An explanation of how the projected reduction or avoidance of atmospheric loading of CO_2 or CO_2 equivalent or the sequestration

of carbon is to be quantified, monitored, and verified as required by the relevant provisions of section XX-10.5.

(vi) A completed consistency application agreement that reads as follows:

"The undersigned project sponsor recognizes and accepts that the application for, and the receipt of, CO_2 offset allowances under the CO_2 Budget Trading Program is predicated on the project sponsor following all the requirements of Subpart XX-10. The undersigned project sponsor holds the legal rights to the offset project, or has been granted the right to act on behalf of a party that holds the legal rights to the offset project. I understand that eligibility for the award of CO_2 offset allowances under Subpart XX-10 is contingent on meeting the requirements of Subpart XX-10. I authorize the REGULATORY AGENCY or its agent to audit this offset project for purposes of verifying that the offset project, including the monitoring and verification plan, has been implemented as described in this application. I understand that this right to audit shall include the right to enter the physical location of the offset project. I submit to the legal jurisdiction of **[RGGI PARTICIPATING STATE]**."

(vii) A statement and certification report signed by the offset project sponsor certifying that all offset projects for which the sponsor has received CO_2 offset allowances under this Subpart (or similar provisions in the rules of other participating states), under the sponsor's ownership or control (or under the ownership or control of any entity which controls, is controlled by, or has common control with the sponsor) are in compliance with all applicable requirements of the CO_2 Budget Trading Program in all participating states.

(vii) A verification report and certification statement signed by an independent verifier accredited pursuant to section XX-10.6 that

expresses that the independent verifier has reviewed the entire application and evaluated the following in relation to the applicable requirements at sections XX-10.3 and XX-10.5, and any applicable guidance issued by the REGULATORY AGENCY.

(a) The adequacy and validity of information supplied by the project sponsor to demonstrate that the offset project meets the applicable eligibility requirements of sections XX-10.3 and XX-10.5.

(b) The adequacy and validity of information supplied by the project sponsor to demonstrate baseline emissions pursuant to the applicable requirements at section XX-10.5.

(c) The adequacy of the monitoring and verification plan submitted pursuant to the applicable requirements at section XX-10.5.

(d) Such other evaluations and statements as may be required by the REGULATORY AGENCY.

(ix) Disclosure of any voluntary or mandatory programs, other than the CO_2 Budget Trading Program, to which greenhouse gas emissions data related to the offset project has been, or will be reported.

(x) For offset projects located in a state or United States jurisdiction that is not a participating state, a demonstration that the project sponsor has complied with all requirements of the cooperating regulatory agency in the state or United States jurisdiction where the offset project is located.

(2) Consistency applications shall be submitted in a format approved by the REGULATORY AGENCY.

(d) Consistency applications may not be submitted to **[REGULATORY AGENCY]** if a consistency application has already been submitted for the same project, or any portion of the same project, in another participating state, unless the consistency

application was rejected by another participating state solely because more of the CO_2 equivalent emissions reduction or carbon sequestration due to the offset project is projected to occur in **[STATE]** than in any other participating state.

(e) *REGULATORY AGENCY action on consistency applications.*

(1) *Completeness determination*. Within 30 days following receipt of the consistency application filed pursuant to subdivision (b) of this section, the REGULATORY AGENCY will notify the project sponsor whether the consistency application is complete. A complete consistency application is one that is in an approved form and is determined by the REGULATORY AGENCY to be complete for the purpose of commencing review of the consistency application. In no event shall a completeness determination prevent the REGULATORY AGENCY from requesting additional information in order to enable the REGULATORY AGENCY to make a consistency determination under paragraph (2) of this subdivision.

(2) *Consistency determination*. Within 90 days of making the completeness determination under paragraph (1) of this subdivision, the REGULATORY AGENCY will issue a determination as to whether the offset project is consistent with the requirements of sections XX-10.3 and XX-10.4 and the requirements of the applicable offset project standard of section XX-10.5. For any offset project found to lack consistency with these requirements, the REGULATORY AGENCY will inform the project sponsor of the offset project's deficiencies.

XX-10.5 CO_2 emissions offset project standards.

(a) *Landfill methane capture and destruction.* To qualify for the award of CO_2 offset allowances under XX-10, offset projects that capture and destroy methane from landfills shall meet the requirements of XX-10.5(a) and all other applicable requirements of XX-10.

(1) *Eligibility.* Eligible offset projects shall occur at landfills that are not subject to the New Source Performance Standards (NSPS) for municipal solid waste landfills, 40 CFR Part 60, Subpart Cc and Subpart WWW.

(2) *Offset project description*. The offset project sponsor shall provide a detailed narrative of the offset project actions to be taken, including documentation that the offset project meets the eligibility requirements of paragraph (1) of this subdivision.

The project narrative shall include the following information.

(i) Owner and operator of the offset project;

(ii) Location and specifications of the landfill where the offset project will occur, including waste in place;

(iii) Owner and operator of the landfill where the offset project will occur; and

(iv) Specifications of the equipment to be installed and a technical schematic of the offset project.

(3) *Emissions baseline determination*. The emissions baseline shall represent the potential fugitive landfill emissions of CH_4 (in tons of CO_2e), as represented by the CH_4 collected and metered for thermal destruction as part of the offset project, and calculated in accordance with this paragraph.

$$\text{Emissions (tons } CO_2e) = \frac{V \times M \times (1-OX) \times GWP}{2000}$$

Where:

V = volume of CH_4 collected (ft^3);

M = Mass of CH_4 per cubic foot (0.04246 lbs/ft^3 default value at 1 atmosphere, 20^o C);

OX= Oxidation factor (0.10), representing estimated portion of collected CH_4 that would have eventually oxidized to CO_2 if not collected; and

GWP = CO_2e global warming potential of CH_4 (28).

(4) *Calculating emissions reductions*. Emissions reductions shall be determined based on potential fugitive CH_4 emissions that would have occurred at the landfill if metered CH_4 collected from the landfill for thermal destruction as part of the offset project was not collected and destroyed. CO_2e emissions reductions shall be calculated as follows:

$$\text{Emissions Reductions (tons } CO_2e) = \frac{V \times M \times (1-OX) \times C_{ef} \times GWP}{2000}$$

Where:

V = Volume of CH_4 collected (ft_3);

M = Mass of CH_4 per cubic foot (0.04246 lbs/ft^3 default value at 1 atmosphere and 20^o C);

OX= Oxidation factor (0.10), representing estimated portion of collected CH_4 that would have eventually oxidized to CO_2 if not collected;

C_{ef} = Combustion efficiency of methane control technology (0.98); and

GWP = CO_2e global warming potential of CH_4 (28).

(5) *Monitoring and verification requirements*. Offset projects shall employ a landfill gas collection system that provides continuous metering and data computation of landfill gas volumetric flow rate and CH_4 concentration. Annual monitoring and verification reports shall include monthly volumetric flow rate and CH_4 concentration data, including documentation that the

CH_4 was actually supplied to the combustion source. Monitoring and verification is also subject to the following requirements.

(i) The project sponsor shall submit a monitoring and verification plan as part of the consistency application that includes a quality assurance and quality control program associated with equipment used to determine landfill gas volumetric flow rate and CH_4 composition. The monitoring and verification plan shall also include provisions for ensuring that measuring and monitoring equipment is maintained, operated, and calibrated based on manufacturer recommendations, as well as provisions for the retention of maintenance records for audit purposes. The monitoring and verification plan shall be certified by an independent verifier accredited pursuant to section XX-10.6.

(ii) The project sponsor shall annually verify landfill gas CH_4 composition through landfill gas sampling and independent laboratory analysis using applicable U.S. Environmental Protection Agency laboratory test methods.

(b) *Sequestration of carbon due to reforestation, improved forest management, or avoided conversion.* To qualify for the award of CO_2 offset allowances under XX-10, offset projects that involve reforestation, improved forest management, or avoided conversion shall meet all requirements of XX-10.5(b) and the forest offset protocol, and all other applicable requirements of XX-10.

(1) *Eligibility*. Eligible forest offset projects shall satisfy all eligibility requirements of the forest offset protocol and this Subpart.

(2) *Offset project descriptio*n. The offset project sponsor shall provide a detailed narrative of the offset project actions to be taken, including documentation that the offset project meets the eligibility requirements of paragraph (1) of this subdivision. The offset project description must include all information identified in sections 8.1 and 9.1 of the forest offset

protocol, and any other information deemed necessary by the REGULATORY AGENCY.

(3) *Carbon sequestration baseline determination*. Baseline onsite carbon stocks shall be determined as required by sections 6.1.1, 6.1.2, 6.2.1, 6.2.2, 6.2.3, 6.3.1, and 6.3.2 of the forest offset protocol, as applicable.

(4) *Calculating carbon sequestered*. Net GHG reductions and GHG removal enhancements shall be calculated as required by section 6 of the forest offset protocol. The project's risk reversal rating shall be calculated using the forest offset protocol Determination of a Forest Project's Reversal Risk Rating assessment worksheet.

(5) *Monitoring and verification requirements*. Monitoring and verification is subject to the following requirements.

(i) Monitoring and verification reports shall include all forest offset project data reports submitted to the REGULATORY AGENCY, including any additional data required by section 9.2.2 of the forest offset protocol.

(ii) The consistency application shall include a monitoring and verification plan certified by an independent verifier accredited pursuant to section XX-10.6. The monitoring and verification plan shall consist of a forest carbon inventory program, as required by section 8.1 of the forest offset protocol.

(iii) Monitoring and verification reports shall be submitted not less than every six years, except that the first monitoring and verification report for reforestation projects must be submitted within twelve years of project commencement

(6) *Forest Offset Project Data Reports*. A project sponsor shall submit a forest offset Project data report to the REGULATORY AGENCY for each reporting period. Each forest offset project data report must cover a single reporting period. Reporting periods must be contiguous; there must be no gaps in reporting once the first reporting period has commenced.

(7) Prior to the award of CO_2 offset allowances pursuant to XX-10.7, or to any surrender of allowances pursuant to XX-10.5(b)(8)(ii)(c), any quantity expressed in metric tons, or metric tons of CO_2 equivalent, shall be converted to tons using the conversion factor specified in XX-1.2.

(8) *Carbon sequestration permanence*. The offset project shall meet the following requirements to address reversals of sequestered carbon.

(i) *Unintentional reversals.* Requirements for unintentional reversals are as follows:

(a) The project sponsor must notify the REGULATORY AGENCY of the reversal and provide an explanation for the nature of the unintentional reversal within 30 calendar days of its discovery; and

(b) The project sponsor must submit to the REGULATORY AGENCY a verified estimate of current carbon stocks within the offset project boundary within one year of the discovery of the unintentional reversal.

(ii) *Intentional Reversals.* Requirements for intentional reversals are as follows:

(a) If an intentional reversal occurs, the project sponsor shall, within 30 calendar days of the intentional reversal:

(1) Provide notice, in writing, to the REGULATORY AGENCY of the intentional reversal; and

(2) Provide a written description and explanation of the intentional reversal to the REGULATORY AGENCY.

(b) Within one year of the occurrence of an intentional reversal, the project sponsor shall submit to the REGULATORY AGENCY a verified estimate of current carbon stocks within the offset project boundary.

(c) If an intentional reversal occurs, and CO_2 offset allowances have been awarded to the offset project, the forest owner

must surrender to the REGULATORY AGENCY or its agent for retirement a quantity of CO_2 allowances corresponding to the quantity of CO_2 equivalent tons reversed within six months of notification by the REGULATORY AGENCY.

(1) Notification by the REGULATORY AGENCY will occur after the verified estimate of carbon stocks has been submitted to the REGULATORY AGENCY, or after one year has elapsed since the occurrence of the reversal if the project sponsor fails to submit the verified estimate of carbon stocks.

(2) If the forest owner does not surrender valid CO_2 allowances to the REGULATORY AGENCY within six months of notification by the REGULATORY AGENCY, the forest owner will be subject to enforcement action and each CO_2 equivalent ton of carbon sequestration reversed will constitute a separate violation of this Part and applicable state law.

(d) *Project Termination.* Requirements for project termination are as follows:

(1) The project sponsor must surrender to the REGULATORY AGENCY or its agent for retirement a quantity of CO_2 Allowances in the amount calculated pursuant to project termination provisions in the forest offset protocol within six months of project termination.

(2) If the project sponsor does not surrender to the REGULATORY AGENCY or its agent a quantity of CO_2 Allowances in the amount calculated pursuant to project termination provisions in the forest offset

protocol within six months of project termination, they will be subject to enforcement action and each CO_2 offset allowance not surrendered will constitute a separate violation of this Part and applicable state law

(iii) *Disposition of Forest Sequestration Projects After a Reversal.* If a reversal lowers the forest offset project's actual standing live carbon stocks below its project baseline standing live carbon stocks, the forest offset project will be terminated by the REGULATORY AGENCY.

(9) *Timing of forest offset projects.* The REGULATORY AGENCY may award CO_2 offset allowances under section XX-10.7 only for forest offset projects that are initially commenced on or after January 1, 2014.

(10) *Projects that Have Been Awarded Credits by a Voluntary Greenhouse Gas Reduction Program*. The provisions of paragraphs XX-10.3(c)(4) and XX-10.4(b)(2) shall not apply to forest projects that have been awarded credits under a voluntary greenhouse gas reduction program provided that the following conditions are satisfied. For such projects, the number of CO_2 Offset Allowances will be calculated pursuant to the requirements of XX-10.5(b), without regard to quantity of credits that were awarded to the project under the voluntary program.

(i) The project satisfies all other general requirements of XX-10, including all specific requirements of XX-10.5(b), for all reporting periods for which the project has been awarded credits under a voluntary greenhouse gas program and also intends to be awarded CO_2 offset allowances pursuant to XX-10.7.

(ii) At the time of submittal of the consistency application for the project, the project submits forest offset data reports and a monitoring and verification report covering all reporting periods for which the project has been awarded credits under a voluntary greenhouse gas program and also intends to be awarded CO_2

offset allowances pursuant to XX-10.7. Forest offset data reports and monitoring and verification reports must meet all requirements of XX-10.5(b)(5) and (6).

(iii) The consistency application includes information sufficient to allow the Department to make the following determinations, and the voluntary greenhouse gas program has published information on its website to allow the Department to verify the information included in the consistency application.

(a) The offset project has met all legal and contractual requirements to allow it to terminate its relationship with the voluntary greenhouse gas program, and such termination has been completed.

(b) The project sponsor or voluntary greenhouse gas program has cancelled or retired all credits that were awarded for carbon sequestration that occurred during the time periods for which the project intends to be awarded CO_2 offset allowances pursuant to XX-10.7, and such credits were cancelled or required for the sole purpose of allowing the project to be awarded CO_2 offset allowances pursuant to XX-10.7.

(c) *Avoided methane emissions from agricultural manure management operations*. To qualify for the award of CO_2 offset allowances under XX-10, offset projects that capture and destroy methane from animal manure and organic food waste using anaerobic digesters shall meet the requirements of XX-10.5(c) and all other applicable requirements of XX-10.

(1) *Eligibility*.

(i) Eligible offset projects shall consist of the destruction of that portion of methane generated by an anaerobic digester that would have

been generated in the absence of the offset project through the uncontrolled anaerobic storage of manure or organic food waste.

(ii) Eligible offset projects shall employ only manure-based anaerobic digester systems using livestock manure as the majority of digester feedstock, defined as more than 50% of the mass input into the digester on an annual basis. Organic food waste used by an anaerobic digester shall only be that which would have been stored in anaerobic conditions in the absence of the offset project.

(iii) The provisions of paragraphs XX-10.3(c)(2) and (3) shall not apply to agricultural manure management offset projects provided either of the following requirements are met.

(a) The offset project is located in a state that has a market penetration rate for anaerobic digester projects of 5% or less. The market penetration determination shall utilize the most recent market data available at the time of submission of the consistency application pursuant to section XX-10.4 and shall be determined as follows:

$$MP\ (\%) = MG_{AD} / MG_{STATE}$$

Where:

MG_{AD} = Average annual manure generation for the number of dairy cows and swine serving all anaerobic digester projects in the applicable state at the time of submission of a consistency application pursuant to section XX-10.4.

MG_{STATE} = average annual manure production of all dairy cows and swine in the state at the time of submission of a consistency application pursuant to section XX-10.4.

(b) The offset project is located at a farm with 4,000 or less head of dairy cows, or a farm with equivalent animal units, assuming an average live weight for dairy cows (lbs./cow) of 1,400 lbs., or, if the project is a regional-type digester, total annual manure input to the digester is designed to be less than the average annual manure produced by a farm with 4,000 or less head of dairy cows, or a farm with equivalent animal units, assuming an average live weight for dairy cows (lbs./cow) of 1,400 lbs.

(2) *Offset project description.* The offset project sponsor shall provide a detailed narrative of the offset project actions to be taken, including documentation that the offset project meets the eligibility requirements of paragraph (1) of this subdivision. The offset project narrative shall include the following information:

(i) Owner and operator of the offset project;

(ii) Location and specifications of the facility where the offset project will occur;

(iii) Owner and operator of the facility where the offset project will occur;

(iv) Specifications of the equipment to be installed and a technical schematic of the offset project; and

(v) Location and specifications of the facilities from which anaerobic digester influent will be received, if different from the facility where the offset project will occur.

(3) *Emissions baseline determination.* The emissions baseline shall represent the potential emissions of the CH_4 that would have been produced in a baseline scenario under uncontrolled anaerobic storage conditions and released directly to the atmosphere in the absence of the offset project.

(i) Baseline CH_4 emissions shall be calculated as follows**:**

$$E_b = \frac{V_m \times M}{2000} \times GWP$$

Where:

E_b = Potential CO_2e emissions due to calculated CH_4 production under site-specific anaerobic storage and weather conditions (tons);

V_m = Volume of CH_4 produced each month from decomposition of volatile solids in a baseline uncontrolled anaerobic storage scenario under site-specific storage and weather conditions for the facility at which the manure or organic food waste is generated (ft^3);

M = Mass of CH_4 per cubic foot (0.04246 lb/ft^3 default value at one atmosphere and 20°C); and

GWP = Global warming potential of CH_4 (28).

(ii) The estimated amount of volatile solids decomposed each month under the uncontrolled anaerobic storage baseline scenario (kg) shall be calculated as follows:

$VS_{dec} = VS_{avail} \times f$

Where:

VS = volatile solids as determined from the equation:

$VS = M_m \times TS_{\%} \times VS_{\%}$

Where:

M_m = mass of manure or organic food waste produced per month (kg)

$TS_{\%}$ = concentration (percent) of total solids in manure or organic food waste as determined through EPA 160.3 testing method (U.S.EPA Method Number 160.3, Methods for the Chemical Analysis of Water and Wastes (MCAWW) (EPA/600/4-79/020));

$VS_{\%}$ = concentration (percent) of volatile solids in total solids as determined through EPA 160.4 testing method (U.S.EPA Method Number 160.4, Methods for the Chemical Analysis of Water and Wastes (MCAWW) (EPA/600/4-79/020)); and

VS_{avail} = volatile solids available for decomposition in manure or organic food waste storage each month as determined from the equation:

$$VS_{avail} = VS_p + \tfrac{1}{2} VS_{in} - VS_{out}$$

Where:

VS_p = volatile solids present in manure or organic food waste storage at beginning of month (left over from previous month) (kg);

VS_{in} = volatile solids added to manure or organic food waste storage during the course of the month (kg). The factor of ½ is multiplied by this number to represent the average mass of volatile solids available for decomposition for the entire duration of the month;

VS_{out} = volatile solids removed from the manure or organic food waste storage for land application or export (assumed value based on standard farm practice); and

f = van't Hoff-Arrhenius factor for the specific month as determined using the equation below. Using a base temperature of 30° C, the equation is as follows:

$$f = \exp\left[\frac{E(T_2 - T_1)}{GC \times T_1 \times T_2}\right]$$

Where:

f = conversion efficiency of VS to CH_4 per month;

E = activation energy constant (15,175 cal/mol);

T_2 = average monthly ambient temperature for facility where manure or organic food waste is generated (converted from ^{o} Celsius to ^{o} Kelvin) as determined from the nearest National Weather Service certified weather station (if reported temperature ^{o} C > 5^{o} C; if reported temperature ^{o}C < 5^{o} C, then f = 0.104);

T_1 = 303.15 (30^{o} C converted to ^{o}K); and

GC = ideal gas constant (1.987 cal/K mol)

(iii) The volume of CH_4 produced (ft^3) from decomposition of volatile solids shall be calculated as follows:

$V_m = (VS_{dec} \times B_o) \times 35.3147$

Where:

V_m = volume of CH_4 (ft^3)

VS_{dec} = volatile solids decomposed (kg)

B_o = manure or organic food waste type-specific maximum methane generation constant (m^3 CH_4/kg VS decomposed). For dairy cow manure, B_o = 0.24 m^3 CH_4/kg VS decomposed. The methane generation constant for other types of manure shall be those cited at U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2010, Annex 3, Table A 180 (U.S. EPA, February 2017) , unless the project sponsor proposes an alternate methane generation constant and that alternate is approved by the REGULATORY AGENCY. If the project sponsor proposes to use a methane generation constant other than the ones found in the above-cited reference, the project sponsor must provide justification and documentation to the REGULATORY AGENCY.

(4) *Calculating emissions reductions.* Emissions reductions shall be calculated as follows:

$ER_t = E_b – E_p$

Where:

ER_t = CO_2e emissions reductions due to project activities (tons);

E_b = Potential CO_2e emissions due to calculated CH_4 production under site-specific anaerobic storage and weather conditions (tons);

E_p = CO_2e emissions due to project activities additional to baseline (tons), including, but not limited to, manure transportation, flaring, venting, and effluent management.

Emissions reductions may not exceed the potential emissions of the anaerobic digester, as represented by the annual volume of CH_4 produced by the anaerobic digester, as monitored pursuant to paragraph (5) of this

subdivision. CO_2 emissions due to transportation of manure and organic food waste from the site where the manure and organic food waste was generated to the anaerobic digester shall be subtracted from the emissions reduction calculated pursuant to subparagraphs (3)(i) through (iii) of this subdivision. Transport CO_2 emissions shall be determined through one of the following methods:

(i) Documentation of transport fuel use for all shipments of manure and organic food waste from off-site to the anaerobic digester during each reporting year and a log of transport miles for each shipment. Off-site is defined as a location that is not contiguous with the property where the anaerobic digester is located. CO_2 emissions shall be determined through the application of an emissions factor for the fuel type used. If this option is chosen, the following emissions factors shall be applied as appropriate.

(a) Diesel fuel: 22.912 lbs. CO_2/gallon.

(b) Gasoline: 19.878 lbs. CO_2/gallon.

(c) Other fuel: submitted emissions factor approved by the REGULATORY AGENCY.

(ii) Documentation of total tons of manure and organic food waste transported from off-site for input into the anaerobic digester during each reporting year, as monitored pursuant to subparagraph (5)(i) of this subdivision, and a log of transport miles and fuel type used for each shipment. CO_2 emissions shall be determined through the application of a ton-mile transport emission factor for the fuel type used. If this option is chosen, the following emissions factors shall be applied as appropriate for each ton of manure delivered, and multiplied by the number of miles transported.

(a) Diesel fuel: 0.131 lbs. CO_2 per ton-mile.

(b) Gasoline: 0.133 lbs. CO_2 per ton-mile.

(c) Other fuel: submitted emissions factor approved by the REGULATORY AGENCY.

(5) *Monitoring and verification requirements.* Offset projects shall employ a system that provides metering of biogas volumetric flow rate and determination of CH_4 concentration. Annual monitoring and verification reports shall include monthly biogas volumetric flow rate and CH_4 concentration determination. Monitoring and verification shall also meet the following requirements.

(i) If the offset project is a regional-type digester, manure and organic food waste from each distinct source supplying to the anaerobic digester shall be sampled monthly to determine the amount of volatile solids present. Any emissions reduction will be calculated according to mass of manure and organic food waste (kg) being digested and percentage of volatile solids present before digestion, consistent with the requirements at paragraph (3) and subparagraph (5)(iii) of this subdivision, and apportioned accordingly among sources. The project sponsor shall provide supporting material and receipts tracking the monthly receipt of manure and organic food waste (kg) used to supply the anaerobic digester from each supplier.

(ii) If the offset project includes the digestion of organic food waste eligible pursuant to subparagraph (1)(ii) of this subdivision, organic food waste shall be sampled monthly to determine the amount of volatile solids present before digestion, consistent with the requirements at paragraph (3) and subparagraph (5)(iii) of this subdivision, and apportioned accordingly.

(iii) The project sponsor shall submit a monitoring and verification plan as part of the consistency application that includes a quality assurance and quality control program associated with equipment used to determine biogas volumetric flow rate and CH_4 composition.

The monitoring and verification plan shall be specified in accordance with the applicable monitoring requirements listed in Table 8 below. The monitoring and verification plan shall also include provisions for ensuring that measuring and monitoring equipment is maintained, operated, and calibrated based on manufacturer's recommendations, as well as provisions for the retention of maintenance records for audit purposes. The monitoring and verification plan shall be certified by an independent verifier accredited pursuant to section XX-10.6.

Table 8. Monitoring requirements

Parameter	Measurement Unit	Frequency of Sampling	Sampling Method(s)
Influent flow (mass) into the digester	Kilograms (kg) per month (wet mass)	Monthly total into the digester	a) Recorded mass b) Digester influent pump flow c) Livestock population and application of American Society of Agricultural and Biological Engineers (ASABE) standard (ASAE D384.2, March 2005)
Influent total solids concentration (TS)	Percent (of sample)	Monthly, depending upon recorded variations	U.S. EPA Method Number 160.3, Methods for the Chemical Analysis of Water and Wastes (MCAWW) (EPA/600/4-79/020)

Parameter	Measurement Unit	Frequency of Sampling	Sampling Method(s)
Influent volatile solids (VS) concentration	Percent (of TS)	Monthly, depending upon recorded variations	USEPA Method Number 160.4, Methods for the Chemical Analysis of Water and Wastes (MCAWW) (EPA/600/4-79/020)
Average monthly ambient temperature	Temperature ^{o}C	Monthly (based on farm averages)	Closest National Weather Service-certified weather station
Volume of biogas produced by digester	Standard cubic feet (scf)	Continuous, totalized monthly	Flow meter
Methane composition of biogas produced by digester	Percent (of sample)	Quarterly	Bag sampling and third party laboratory analysis using applicable U.S. EPA test methods

XX-10.6 Accreditation of independent verifiers.

(a) *Standards for accreditation*. Independent verifiers may be accredited by the REGULATORY AGENCY to provide verification services as required of project sponsors under this Subpart, provided that independent verifiers meet all of the requirements of this section.

(1) *Verifier minimum requirements*. Each accredited independent verifier shall demonstrate knowledge of the following topics:

(i) Utilizing engineering principles;

(ii) Quantifying greenhouse gas emissions;

(iii) Developing and evaluating air emissions inventories;

(iv) Auditing and accounting principles;

(v) Knowledge of information management systems;

(vi) Knowledge of the requirements of this Subpart and other applicable requirements of this Part; and

(vii) Such other qualifications as may be required by the REGULATORY AGENCY to provide competent verification services as required for individual offset categories specified at section XX-10.5.

(2) *Organizational qualifications*. Accredited independent verifiers shall demonstrate that they meet the following requirements:

(i) Verifiers shall have no direct or indirect financial relationship, beyond a contract for provision of verification services, with any offset project developer or project sponsor;

(ii) Verifiers shall employ staff with professional licenses, knowledge, and experience appropriate to the specific category(ies) of offset projects at section XX-10.5 that they seek to verify.

(iii) Verifiers shall hold a minimum of one million U.S. dollars of professional liability insurance. If the insurance is in the name of a related entity, the verifier shall disclose the financial relationship between the verifier and the related entity, and provide documentation supporting the description of the relationship; and

(iv) Verifiers shall demonstrate that they have implemented an adequate management protocol to identify potential conflicts of interest with regard to an offset project, offset project developer, or project sponsor, or any other party with a direct or indirect financial interest in an offset project that is seeking or has been granted approval of a consistency application pursuant to subdivision XX-10.4(e), and remedy any such conflicts of interest prior to providing verification services.

(3) *Pre-qualification of verifiers*. The REGULATORY AGENCY may require prospective verifiers to successfully complete a training course, workshop, or test developed by the REGULATORY AGENCY or its agent, prior to submitting an application for accreditation.

(b) *Application for accreditation*. An application for accreditation shall not contain any proprietary information, and shall include the following:

(1) The applicant's name, address, e-mail address, telephone number, and facsimile transmission number;

(2) Documentation that the applicant has at least two years of experience in each of the knowledge areas specified at subparagraphs (a)(1)(i) through (v) of this section, and as may be required pursuant to subparagraph (a)(1)(vii) of this section;

(3) Documentation that the applicant has successfully completed the requirements at paragraph (a)(3) of this section, as applicable;

(4) A sample of at least one work product that provides supporting evidence that the applicant meets the requirements at paragraphs (a)(1) and (2) of this section. The work product shall have been produced, in whole or part, by the applicant and shall consist of a final report or other material provided to a client under contract in previous work. For a work product that was jointly produced by the applicant and another entity, the role of the applicant in the work product shall be clearly explained;

(5) Documentation that the applicant holds professional liability insurance as required pursuant to subparagraph (a)(2)(iii) of this section; and

(6) Documentation that the applicant has implemented an adequate management protocol to address and remedy any conflict of interest issues that may arise, as required pursuant to subparagraph (a)(2)(iv) of this section.

(c) *REGULATORY AGENCY action on applications for accreditation*. The REGULATORY AGENCY shall approve or deny a complete application for accreditation within 45 days after submission. Upon approval of an application for accreditation, the independent verifier shall be accredited for a period of three years from the date of application approval.

(d) *Reciprocity*. Independent verifiers accredited in other participating states may be deemed to be accredited in **[INSERT NAME OF RGGI STATE]**, at the discretion of the REGULATORY AGENCY.

(e) *Conduct of accredited verifiers.*

(1) Prior to engaging in verification services for an offset project sponsor, the accredited verifier shall disclose all relevant information to the REGULATORY AGENCY to allow for an evaluation of potential conflict of interest with respect to an offset project, offset project developer, or project sponsor. The accredited verifier shall disclose information concerning its ownership, past and current clients, related entities, as well as any other facts or circumstances that have the potential to create a conflict of interest.

(2) Accredited verifiers shall have an ongoing obligation to disclose to the REGULATORY AGENCY any facts or circumstances that may give rise to a conflict of interest with respect to an offset project, offset project developer, or project sponsor.

(3) The REGULATORY AGENCY may reject a verification report and certification statement from an accredited verifier, submitted as part of a consistency application required pursuant to subdivision XX-10.4(b) or submitted as part of a monitoring and verification report submitted pursuant to subdivision XX-10.7(b), if the REGULATORY AGENCY determines that the accredited verifier has a conflict of interest related to the offset project, offset project developer, or project sponsor.

(4) The REGULATORY AGENCY may revoke the accreditation of a verifier at any time given cause, for the following:

(i) Failure to fully disclose any issues that may lead to a conflict of interest situation with respect to an offset project, offset project developer, or project sponsor;

(ii) The verifier is no longer qualified due to changes in staffing or other criteria;

(iii) Negligence or neglect of responsibilities pursuant to the requirements of this Subpart; and

(iv) Intentional misrepresentation of data or other intentional fraud.

XX-10.7 Award and Recordation of CO_2 offset allowances.

(a) *Quantities of CO_2 offset allowances awarded, and subsequently recorded*.

(1) *Award of CO_2 offset allowances*.

(i) *CO_2 emissions offset projects*. Following the issuance of a consistency determination under paragraph XX-10.4(e)(2) and the approval of a monitoring and verification report under the provisions of subdivision (e) of this section, the REGULATORY AGENCY will award one CO_2 offset allowance for each ton of demonstrated reduction in CO_2 or CO_2 equivalent emissions or sequestration of CO_2.

(2) *Recordation of CO_2 offset allowances*. After CO_2 offset allowances are awarded under XX-10.7(a)(1), the **[REGULATORY AGENCY]** shall record such CO_2 offset allowances in the project sponsor's general account.

(b) *Deadlines for submittal of monitoring and verification reports.*

(1) For CO_2 emissions offset projects undertaken prior to January 1, 2009, the project sponsor must submit the monitoring and verification report covering the pre-2009 period by June 30, 2009.

(2) For CO_2 emissions offset projects undertaken on or after January 1, 2009, the monitoring and verification report must be submitted within 6 months following the completion of the last calendar year during which the offset project achieved CO_2 equivalent reductions or sequestration of CO_2 for which the project sponsor seeks the award of CO_2 offset allowances.

(c) *Contents of monitoring and verification reports.* For an offset project, the monitoring and verification report must include the following information.

(1) The project's sponsor's name, address, e-mail address, telephone number, facsimile transmission number, and account number;

(2) The CO_2 emissions reduction or CO_2 sequestration determination as required by the relevant provisions of section XX-10.5, including a demonstration that the project sponsor complied with the required quantification, monitoring, and verification procedures under section XX-10.5, as well as those outlined in the consistency application approved pursuant to paragraph XX-10.4(e)(2).

(3) A signed statement that reads "The undersigned project sponsor hereby confirms and attests that the offset project upon which this monitoring and verification report is based is in full compliance with all of the requirements of Subpart XX-10. The project sponsor holds the legal rights to the offset project, or has been granted the right to act on behalf of a party that holds the legal rights to the offset project. I understand that eligibility for the award of CO_2 offset allowances under Subpart XX-10 is contingent on meeting the requirements of Subpart XX-10. I authorize the REGULATORY AGENCY or its agent to audit this offset project for purposes of verifying that the offset project, including the monitoring and verification plan, has been implemented as described in the consistency application that was the subject of a consistency determination by the REGULATORY AGENCY. I understand that this right to audit shall include the right to enter the physical location of the offset project and to make available to the REGULATORY AGENCY or its agent any and all documentation relating to the offset project at the REGULATORY AGENCY's request. I submit to the legal jurisdiction of **[RGGI PARTICIPATING STATE]**."

(4) A certification signed by the offset project sponsor certifying that all offset projects for which the sponsor has received offset allowances under this

Subpart (or similar provisions in the rules of other participating states), under the sponsor's ownership or control (or under the ownership or control of any entity which controls, is controlled by, or has common control with the sponsor) are in compliance with all applicable requirements of the CO_2 Budget Trading Program in all participating states.

(5) A verification report and certification statement signed by an independent verifier accredited pursuant to section XX-10.6 that documents that the independent verifier has reviewed the monitoring and verification report and evaluated the following in relation to the applicable requirements at section XX-10.5, and any applicable guidance issued by the REGULATORY AGENCY.

(i) The adequacy and validity of information supplied by the project sponsor to determine CO_2 emissions reductions or CO_2 sequestration pursuant to the applicable requirements at section XX-10.5.

(ii) The adequacy and consistency of methods used to quantify, monitor, and verify CO_2 emissions reductions and CO_2 sequestration in accordance with the applicable requirements at section XX-10.5 and as outlined in the consistency application approved pursuant to paragraph XX-10.4(e)(2).

(iii) Such other evaluations and verification reviews as may be required by the REGULATORY AGENCY. The adequacy and validity of information supplied by the project sponsor to demonstrate that the offset project meets the applicable eligibility requirements of section XX-10.5.

(6) Disclosure of any voluntary or mandatory programs, other than the CO_2 Budget Trading Program, to which greenhouse gas emissions data related to the offset project has been, or will be reported.

(7) For offset projects located in a state or United States jurisdiction that is not a participating state, a demonstration that the project sponsor has complied with all requirements of the cooperating regulatory agency in the state or United States jurisdiction where the offset project is located.

(d) *Prohibition against filing monitoring and verification reports in more than one participating state*. Monitoring and verification reports may only be filed under XX-10.7 for projects that have received consistency determinations under XX-10.4(e)(2) Monitoring and verification reports may not be filed under XX-10.7 for projects that have received consistency determinations in other participating states.

(e) *REGULATORY AGENCY action on monitoring and verification reports*. The REGULATORY AGENCY will approve or deny a complete monitoring and verification report, in a format approved by the REGULATORY AGENCY, filed with the REGULATORY AGENCY pursuant to XX-10.7(d), within 45 days following receipt of a complete report. A complete monitoring and verification report is one that is in an approved form and is determined by the REGULATORY AGENCY to be complete for the purpose of commencing review of the monitoring and verification report. In no event shall a completeness determination prevent the REGULATORY AGENCY from requesting additional information in order to enable the REGULATORY AGENCY to approve or deny a monitoring and verification report submitted in a format approved by the REGULATORY AGENCY, and filed under XX-10.7.

Attachment 2

The Regional Greenhouse Gas Initiative
an initiative of Eastern States of the US

About the Regional Greenhouse Gas Initiative

The **Regional Greenhouse Gas Initiative (RGGI)** is a cooperative effort among eleven Eastern states to reduce carbon dioxide (CO_2) emissions from power plants within each participating state.

Together, the participating states have established a **regional cap** on CO_2 emissions, which sets a limit on the emissions from regulated power plants within the RGGI states. Over time, the regional cap declines, so that CO_2 emissions decrease in a planned and predictable way. Since its inception, RGGI emissions have reduced by more than 50%—twice as fast as the nation as a whole—and raised over $4 billion to invest into local communities.

Who are the RGGI states? *The participating RGGI states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia.*

How Does RGGI Work?

RGGI is a market-based cap-and-invest initiative. Within the RGGI states, regulated power plants must acquire one **RGGI CO_2 allowance** for every short ton of CO_2 they emit. The RGGI states distribute allowances at quarterly auctions, where they can be purchased by power plants and other entities. Some states hold a limited number of allowances in set-aside accounts to sell at a fixed price or otherwise distribute outside of the auction process.

Each participating state originates allowances in proportion to its share of the regional cap. To comply with their state's regulations, power plants sized 25 megawatts[1] or greater must acquire enough RGGI allowances to cover their emissions. See **Tracking and Compliance** on page 2 for more details.

Happening Now: Third Program Review

The RGGI states work together to develop a Model Rule, which acts as a template for each state to shape its own **CO_2 budget trading program**. Once a state has implemented its program it is able to participate in RGGI auctions and access other shared aspects of this regional effort.

The RGGI states periodically conduct **Program Review** to examine the successes, impacts, and design of their CO_2 budget trading programs, and to consider updates to the Model Rule and their individual state programs. During the first two Program Reviews, the states implemented changes that improved program design and reduced the regional emissions cap. In September 2021, the states launched the Third Program Review, which will include opportunities for public engagement. For more information, visit the Program Review page of the RGGI website.

Photo courtesy of the Rhode Island Office of Energy Resources

Investing in a Clean and Equitable Future

*The RGGI states receive the proceeds from selling RGGI allowances, and each state has discretion over how to best use their proceeds. Most of the proceeds have been invested by states back into their communities, including funding of clean energy programs, energy efficiency, and bill assistance to local businesses and communities. Investments targeting low-income households have increased over time and reached 16% of total proceeds in 2019. View the **Investment of RGGI Proceeds** page of the RGGI website to see the latest report on how RGGI proceeds are supporting a clean energy future across the region.*

[1] In New York, power plants sized 15 megawatts or greater are regulated under RGGI.

About RGGI Auctions and Allowance Tracking

Auctions are the primary method by which the RGGI states distribute CO_2 allowances. Auctioning allowances ensures all parties have access to allowances under uniform terms, helps establish a market-based value for the price of CO_2 allowances, avoids windfall profits for power plant owners, and supports investments in a clean and equitable future. The RGGI states have established multiple ways to enhance market stability, described in **Auction Mechanisms** below. An independent market monitor provides oversight of the auctions, as well as activity on the secondary market, to ensure integrity of, and confidence in, the market. You can learn more and view the Market Monitor reports here.

Auction Mechanisms

The RGGI auction mechanisms are designed to provide some measure of stability to the market. The **Minimum Reserve Price** is the minimum price that allowances can be sold for at a RGGI auction. In 2021, the reserve price is $2.38 per allowance.

The **Cost Containment Reserve (CCR)** and **Emissions Containment Reserve (ECR)** are reserves of allowances that help provide market stability if the cost of reducing emissions is higher or lower than expected. CCR allowances are made available for sale at an auction if the allowance price would otherwise exceed a set trigger price. Conversely, ECR allowances are withheld from sale at an auction, if the price would otherwise fall below a set trigger price. In 2021, the CCR trigger price is $13.00 and the ECR trigger price is $6.00. For more information about auction mechanisms, visit the Elements of RGGI page of the RGGI website.

Setting the Auction Clearing Price

All the allowances sold at any one auction are sold at the same price. The price for an allowance is set at the value where demand for allowances equals the available supply.

To find this price, available allowances are awarded to bidders based on bid price from high to low until no allowances remain. The price of the lowest bid to be matched to an allowance becomes the ***auction clearing price*** *and is the value at which all allowances are sold for that auction. View the* ***Auction Tutorial*** *for more details about auction price setting.*

Tracking & Compliance

The acquisition, transfer, retirement, and surrender of RGGI CO_2 allowances is tracked on the RGGI CO_2 Allowance Tracking System (RGGI COATS) platform. Any individual who successfully sets up a RGGI COATS login and creates a RGGI COATS account can receive, transfer, and hold RGGI allowances within the RGGI COATS platform.

Every year, regulated power plants must surrender allowances equal to one half of their CO_2 emissions for that year. Every three years, called a **control period**, they must surrender allowances for all emissions from year three, plus all remaining emissions from years one and two. The three-year control period provides power plants flexibility for meeting the program requirements. More information on compliance is available in the Compliance section of the RGGI website.

Offset Allowances

Certain projects that reduce CO_2 and other greenhouse gas emissions outside of RGGI regulations may be eligible for awards of RGGI **CO_2 offset allowances**. To be eligible for offset allowances, a project must be located within one of the RGGI states and fall into one of the offset project categories accepted by that state. These project categories, and which states accept each category, can be found in the Offsets section of the RGGI website. Offset allowances are transferable and may be used by regulated power plants to meet up to 3.3% of compliance obligations. CO_2 offset allowances account for less than 0.01% of the total number of allowances issued by the program since its inception in 2009.

To learn more about RGGI, please visit the RGGI website or send a message to info@rggi.org.

Attachment 3

Regional Greenhouse Gas Initiative, Inc.

Scope of Work in Support of Virginia Department of Environmental Quality Implementation of the Virginia Carbon Dioxide (CO_2) Budget Trading Program

Regional Greenhouse Gas Initiative, Inc. ("RGGI, Inc.") will provide program implementation, administration and development services, as outlined in this Scope of Work, to the Virginia Department of Environmental Quality ("Department") to support the Commonwealth of Virginia's ("Commonwealth") participation in the Regional Greenhouse Gas Initiative ("RGGI") and the implementation of regulations for the Virginia CO_2 Budget Trading Program ("Program"). RGGI, Inc., a non-profit organization incorporated in the State of Delaware, was formed expressly to provide technical implementation and program development support services to the states participating in RGGI ("participating states").

Overview

As described more fully herein, RGGI, Inc. will provide services to support implementation of the Program in the following seven areas:

I. Operation of the RGGI CO2 Allowance Tracking System (RGGI COATS), for use by the Department in administering the Program in coordination with counterpart programs in other participating states.

II. Operation of a regional allowance auction platform, for use by the Department in administering the Program in coordination with counterpart programs in other participating states.

III. Development of model offset consistency applications and model offset monitoring and verification submittal forms, suitable for customization by the Department for use in administering the offset components of the Program.

IV. Development of generic and category-specific guidance documents detailing the requirements for offset projects under the RGGI Model Rule, suitable for customization by the Department for use in administering the offset components of the Program.

V. Maintenance and operation of an accreditation process and provide materials for the accreditation of independent verifiers of offset projects, suitable for customization by the Department for use in accrediting independent offset verifiers.

VI. Market monitoring services for the monitoring of both allowance auction conduct and outcomes and the secondary allowance market.

VII. Provision of program development support services on an as-requested basis, including, but not limited to, evaluation of additional offset categories and the development of technical and policy recommendations related to specific Program elements for evaluation and consideration by the Department.

I. No Policy Role or Regulatory Authority

RGGI, Inc.'s activities under this Agreement shall not include any policy role or decision-making authority regarding policy matters of the Commonwealth, including, without limitation, the Commonwealth's positions in response to federal policies, the Commonwealth's decisions regarding any future changes to the Program, and the Commonwealth's interaction with participating states or other states that may be considering becoming a participant in RGGI. RGGI, Inc. shall also have no regulatory authority under this Agreement, including, without limitation, authority to enforce the Program and authority to interpret any provisions of the Program. All such policy roles, decision-making authority, and regulatory authority shall remain with the Commonwealth under this Agreement.

I. RGGI CO2 Allowance Tracking System (RGGI COATS)

RGGI, Inc. shall provide services to support allowance tracking for the Program through RGGI COATS. Such services shall include annual program implementation and support. RGGI COATS facilitates market participation by supporting:

- The origination, allocation, award, and transfer of CO_2 allowances.
- The certification and providing of CO2 allowances for compliance-related tasks; and,
- The registration and submittal of applications and reports for offset projects.

II. RGGI, Inc. shall provide on-going implementation and operational support for RGGI COATS, including the tasks outlined below.

II-A. Allowance Program Management

RGGI, Inc. shall provide implementation support to the Department for all Program activities relating to CO2 budget source account management, allowance allocations to compliance and general accounts, and allowance transfers for both general and compliance accounts. This shall include all activities necessary to support the assignment of allowances to appropriate accounts following the successful completion and Department approval of all allowance auctions, as well as the population of user accounts after Department award of offset allowances.

II-B. Emissions Data Management and Analysis

RGGI, Inc. shall perform all data management and quality assurance tasks necessary to ensure the availability of annual CO2 emissions data from all affected units. RGGI, Inc. shall prepare and send communications to the authorized account representatives for budget sources relating to emissions values. RGGI, Inc. shall work with the Department to identify and resolve any issues relating to the submission of emissions data, and the accuracy and

completeness of the data. To the extent requested by the Department, RGGI, Inc. shall contact authorized account representatives directly to resolve any outstanding issues. RGGI, Inc. shall document all issues, their resolution, and all contacts with authorized account representatives.

II-C. Allowance Reconciliation (True-up)

RGGI, Inc. shall assist the Department with compliance assessments for the Program. RGGI COATS shall support the entry of compliance certifications required by the Program and the identification of allowances to be deducted during the compliance process. Assessments shall also factor in appropriate offset limits as a function of a source's reported emissions. RGGI, Inc. shall prepare draft and final compliance reports and will provide information to the Department regarding possible non-compliance.

II-D. User Technical Support

RGGI, Inc. shall provide technical support to industry, the Department, and public users for RGGI COATS. RGGI, Inc. shall record all technical support requests, inquiries, or other occurrences in a log that identifies the nature of the request or events, requestor, respondent, response provided, date(s) and time(s) of response, and amount of time expended on the request and response. Records shall be provided to the Department on a periodic basis, or on demand, as requested.

As necessary, RGGI, Inc. shall provide assessments and recommendations relating to performance of RGGI COATS based on the technical support levels and user feedback. RGGI, Inc. shall not be responsible for interpretation of the Department's regulations, and/or interpretation of actions taken by the Department in enforcement of those regulations.

II-E. System and Database Support

RGGI, Inc. shall be responsible for all aspects of RGGI COATS maintenance and database support and management. This shall include on-going database quality assurance activities, management of all user accounts and security, coordination and monitoring of the Application Service Provider support activities, database, security and application performance, and all other tasks designed to ensure high system availability and performance. RGGI, Inc. shall provide reports to the Department on all routine activities and on any events or technical issues that will affect the operation or performance of the system. RGGI, Inc. shall oversee all data backup and audit procedures to ensure the on-going integrity of the data.

III. Allowance Auction Platform

RGGI, Inc. shall implement and administer a process and platform for the auctioning of allowances under the Program. RGGI, Inc. shall provide auction services in three general areas: pre-auction, auction implementation, and post-auction.

Pre-auction Services

Consultation

RGGI, Inc. shall work with Department staff to maintain the draft standard allowance purchase and sales agreement that is comparable to those developed by other participating states. In addition, RGGI, Inc. may be asked to provide general consultation to the Department on auction design. This may include consultation on auction activity procedures and auction closing procedures.

Auction Notices

RGGI, Inc., in consultation with the Department and subject to its approval, shall create documents and associated information necessary to inform auction participants about details of each auction. Each notice of auction shall provide a specific description of the auction format that will be used, the quantities of allowances to be auctioned, and all applicable participation requirements, consistent with the participating states' rules. Such information shall be made available on the RGGI, Inc. auction website, which can be found through the RGGI, Inc. website, https://www.rggi.org. RGGI, Inc. shall prepare and host an auction participant training presentation for public viewing prior to each auction, as well as receive and respond to written questions submitted by conference participants.

Participant Qualification

RGGI, Inc., in consultation with the Department, shall ensure that all qualified participants have completed the applicable qualification application materials and documents prior to participation in any auction. RGGI, Inc. shall manage, under the direction of the Department, the application process, including receiving and reviewing each qualification application to determine completeness and accuracy of the information submitted. RGGI, Inc. shall be responsible for collecting and managing all auction financial security submissions and/or escrow accounts for the Department. RGGI, Inc., in consultation with the Department, shall be responsible for notifying bidders of their qualification status and maintaining a database of all qualified bidders.

Auction Documentation and Training

To prepare for each auction, RGGI, Inc. shall, subject to the Department's approval, create and distribute auction materials, such as participation instructions, final auction procedures and manuals, as well as the distribution of user codes and passwords to qualified auction participants. In addition, RGGI, Inc. shall be responsible for training auction participants in the use of the auction software platform.

III-B. Auction Implementation Services

Auction Platform

RGGI, Inc. shall maintain and administer an online auction platform for the auctioning of allowances under the Program capable of accommodating an auction in the following formats:

- A sealed bid, uniform price auction
- A sealed bid, discriminatory-price auction
- An ascending price, multiple-round auction
- A descending price, multiple-round auction

Furthermore, the online auction platform shall be capable of managing allowance purchase limits based on specifications provided by the Department. In addition, the auction platform shall be capable of tracking bidding activity and must provide for audit level documentation of such activity, in accordance with auction monitoring protocols that are established by RGGI, Inc. in consultation with the Department and subject to its approval.

IV-C. Post-auction Services

RGGI, Inc. shall arrange for and facilitate the transfer of funds from successful bidders to an account designated by the Department and arrange for the return of financial security to bidders. RGGI, Inc. shall also be responsible for coordinating the operation of RGGI COATS for the transfer of allowances, at the direction of the Department, to the compliance or general accounts of the winning bidders. RGGI, Inc. shall also be required to: (1) work with any independent third party hired by the Department to verify the results of the auction, including potential redress; (2) if directed by the Department, post appropriate information about auction results; and (3) work with the Department to use on-going auction experience to improve subsequent auctions.

RGGI, Inc. shall administer a bank account for holding financial security from bidders. RGGI, Inc. shall impose access security controls on such account to the satisfaction of the Department. RGGI, Inc. shall transfer the proceeds from the sale of allowances at auction to an account to be designated by the Department using an ACH transaction no later than one business day following the transfer of allowances to winning bidders.

IV. Model Offset Consistency Applications and Monitoring and Submittal Documents

RGGI, Inc. shall provide model offset consistency applications and model monitoring and verification report submittal forms for each eligible offset category in the RGGI Model Rule, suitable for customization by the Department. These model application and submission materials will facilitate monitoring of the Department's offset project approval process by market observers and other participating states. All materials developed by RGGI, Inc. shall be consistent with the Model Rule criteria.

V. Model Offset Guidance Documents

RGGI, Inc. shall provide model generic and category-specific offset project guidance documents suitable for customization by the Department. This model guidance shall be detailed and easily understandable by project sponsors (including small businesses or other parties that may lack experience in carbon offset markets) and by Department staff.

The model guidance documents developed by RGGI, Inc. shall cover submittal requirements and the evaluation of specific offset projects against the Model Rule requirements. The model guidance documents shall also explain the intent and letter of the offset project provisions in the RGGI Model Rule, address any ambiguities in the Model Rule provisions, and clarify how they apply to specific types of projects. Any interpretive material shall be consistent with the Model Rule criteria and shall be reviewed by the Department and the participating states.

RGGI, Inc. shall also identify project scenarios that address questions that are likely to arise in the course of the offset application and approval processes, based on the expertise of RGGI, Inc. staff, other offset program experience, and communications with the Department and the participating states.

VI. Accreditation Process and Training Program for Independent Verifiers of Offset Projects

RGGI, Inc. shall maintain a process for the accreditation of independent offset project verifiers and a related training program, consistent with the requirements of the Model Rule, which can be customized and used by the Department in accrediting independent offset verifiers.

RGGI, Inc. shall also provide supporting materials for independent verifiers, consistent with the requirements of the RGGI Model Rule, which can be customized and used by the Department, and which explain:

- The process for the accreditation of independent verifiers, including the review of candidate verifier qualifications.
- The process for evaluating candidate verifier conflicts-of-interest; and
- Application materials for accreditation.

RGGI, Inc. shall also provide materials that can be customized for use by the Department to support on-going Department review of an accredited verifier's potential conflicts-of-interest, including the following:

- Submittal forms for accredited verifier disclosure of potential conflicts-of-interest, to be reviewed by the Department prior to the verifier engaging in work with an offset project sponsor; and

- Guidance materials to support Department staff review of accredited verifier potential conflicts-of-interest.

These materials shall provide a review of existing greenhouse gas independent verifier accreditation standards and processes used by other voluntary and mandatory greenhouse gas management or regulatory programs, and incorporate, if appropriate, elements of these into the materials developed for the Department. RGGI, Inc. shall provide a brief evaluation of the standards and processes reviewed.

VII. Market Monitoring

RGGI, Inc. shall provide market monitoring services in three general areas: monitoring and auditing of allowance auctions, monitoring of relevant secondary allowance market activity, and provision of consultative services addressing market monitoring.

VII-A. Monitoring and Auditing of RGGI Allowance Auctions

RGGI, Inc. shall provide professional monitoring of all RGGI regional allowance auctions, some of which may involve a subset of the RGGI participating states and may or may not include allowances submitted for auction by the Department. RGGI, Inc. will use and develop, as appropriate, data collection methods, metrics, and analytic techniques for monitoring auction performance and thresholds for identifying any collusion, market power, and/or market manipulation that may impact the efficiency and performance of the RGGI auctions.

VII-B. Monitoring of Secondary Market Behavior

RGGI, Inc. shall monitor all relevant publicly available data and indicators of market behavior (available through both public and private sources) in the secondary allowance market that may be expected to significantly impact the performance of RGGI auctions and/or the secondary allowance market.

VII-C. Consultative Services

RGGI, Inc. shall provide expert advice to the Department regarding how any aspects of the auction process should be altered to improve the performance and efficiency of the RGGI auctions and shall ensure the functioning of fair and competitive auctions and a secondary allowance market.

VIII. Program Evaluation and Development Support

RGGI, Inc. shall provide program evaluation and development support to the Department, as requested, to facilitate Department consideration of potential modifications to and/or expansion of the Program.

IX. Effective Date, Project Term

The Effective Date of this Agreement shall be the date upon which it is signed by the Agency Director. The parties recognize and agree that the Commonwealth of Virginia will not be a Participating State as defined in the RGGI, Inc. By-Laws until January 1, 2021. Between the Effective Date and January 1, 2021, it is agreed that RGGI, Inc. staff will work with appropriate members of the Department to prepare for the Commonwealth's participation in RGGI beginning on January 1, 2021, as outlined in this Agreement.

The initial term of this Agreement shall be from February 1, 2021 to December 31, 2023.

The initial term of this Agreement may be extended for up to two (2) additional three (3) year terms, or any portion thereof, by mutual written agreement of the Department and RGGI, Inc. in accordance with the procedures set forth in this Agreement.

X. Budget/Payment

The Department shall pay to RGGI, Inc. an amount equal to the State's proportionate share of RGGI, Inc.'s annual operating budget, which shall be calculated based on the State's proportionate share of the regional CO2 allowance budget.

For services rendered for the initial term, based upon RGGI, Inc.'s projected annual operating budget for calendar year 2021, the Department shall pay RGGI, Inc. an amount not to exceed $592,920 ("2021 payment"), for the services set forth in the table below. The Department authorizes RGGI, Inc. to retain a quarter (25%) of this payment "off the top" of the Commonwealth's proceeds from the sale of allowances in each of the quarterly auctions in calendar year 2021.

General Service Category	Percentage of Funding	Approximate Amount
Allowance Tracking	20%	$118,584
Auctions	30%	$177,876
Market Monitoring	15%	$88,938
Technical Modeling	15%	$88,938
Program Management	20%	$118,584
TOTAL	**100%**	**$592,920**

For services rendered for any subsequent calendar year or portion thereof ("subject year") of this Agreement, RGGI, Inc. shall submit to the Department, by December 15 of the year preceding the subject year, a request for payment of its estimated operating costs for the subject year and the State's proportionate share (itemized as set forth above). Operating costs include staff and overhead costs, costs incurred in performance of the services and deliverables set forth in the Scope of Work and the Department's contribution to support services that may be provided jointly to the Department and agencies in other RGGI participating states.

XI. Reporting

RGGI, Inc. shall designate a Project Manager, who shall be the one point of contact with the Department. The Project Manager shall be responsible for monitoring and ensuring progress for all tasks and subtasks, and for ensuring timely delivery of all services and deliverables outlined in this Scope of Work. The RGGI, Inc. Project Manager shall be responsible for all project reporting to the Department.

The following reporting obligations shall begin February 1, 2021.

By the 15th day of January, April, July, and October of each year during the Project Term, RGGI, Inc. shall provide the Department with a detailed report of the activities undertaken by RGGI, Inc. and its subcontractors to meet its responsibilities under this Agreement during the preceding calendar quarter, including, without limitation, quarterly status reports on RGGI COATS; the auction program; offset program support; market monitoring findings; quarterly budget reports, including any audit reports; the status of progress in providing the deliverables specified in the Scope of Work, including identification of all completed/not completed work during the preceding three-month period; and description of any problems encountered by RGGI, Inc. and their actual or proposed resolution.

At least once in each calendar quarter, RGGI, Inc. shall also submit to the Department a report of its expenditures for operating costs covering each full month in the preceding completed quarter. Such report shall reconcile the actual expenses for operating costs against either the 2020 payment or estimates contained in a request for payment for a subject year, as applicable, and shall provide a net credit to be applied against subsequent requests for payment of operating costs to the extent that actual expenses were less than the estimates. For a subject year, if actual expenses are greater than the estimates contained in a request for payment, the balance shall be itemized as such and applied to subsequent requests for payment of operating costs. Any remaining credit at the end of the term of this Agreement shall be returned to the Department by RGGI, Inc. within 30 days of expiration of this Agreement. Any remaining costs at the end of the Project Term shall be paid by the Department to RGGI, Inc. within 60 days of receipt of a final request for payment in accordance with the Prompt Payment Act, N.J.S.A. 52:32-32, et seq., provided that the listed operating costs are in accordance with this Agreement.

Within 30 days after the end of the term of this Agreement, RGGI, Inc. shall prepare and submit a draft final report that provides a description and summary of all major work tasks and submitted deliverables. The draft final report shall be revised to address all Department comments within 60 days of receipt by RGGI, Inc., and RGGI, Inc. shall submit a final report addressing all such comments.

XII. Services, Deliverables

RGGI, Inc.'s performance shall include, and the Department shall cooperate in, all tasks necessary to set up or otherwise "onboard" the Department and its facilities. All services provided by RGGI Inc. in support of the Department's implementation of the Program shall be performed in accordance with and meet all applicable Program requirements.

In any area where services are requested or deliverables will be provided, all deliverables shall be presented to the Department in draft form for review and ultimate approval by the Department. All documents generated or accepted in performance of this Agreement shall be confidential and shall not be released to anyone without prior authorization by the Department, unless directed by a court of competent jurisdiction. This confidentiality provision shall govern this Agreement and shall survive the termination or expiration of this Agreement.

XIII. Notices

All notices, approvals and other communications which may or are required to be given by either party to the other shall be in writing and shall be transmitted, by certified or registered United States mail, return receipt requested, expedited delivery service, or email, return receipt requested, to the party's representatives identified below:

For the Department:

David K. Paylor, Director, Virginia Department of Environmental Quality
P.O. Box 1105
Richmond, VA 23218
Email: David.Paylor@deq.virginia.gov

For RGGI, Inc.:

Andrew J. McKeon, Executive Director
90 Church St.
New York, NY 10007-2919
Email: andrew.mckeon@rggi.org

The parties may, from time to time, specify any new or different address in the United States as their address for purpose of receiving notice by giving fifteen (15) days written notice to the other party. The parties may, from time to time, designate in writing new or different individuals as their respective representatives for the purpose of receiving notices under this Agreement. Additional individuals may be designated in writing by the parties for purposes of implementation, administration, and billing.

SIGNED:

Regional Greenhouse Gas Initiative, Inc. (RGGI, Inc.)

By: Andrew J McKeon
(signature)

Andrew McKeon
(print name)

Executive Director, RGGI, Inc.
(print title)

Date:

SIGNED:

Virginia Department of Environmental Quality

By: David K Paylor
(signature)

DAVID K. PAYLOR
(print name)

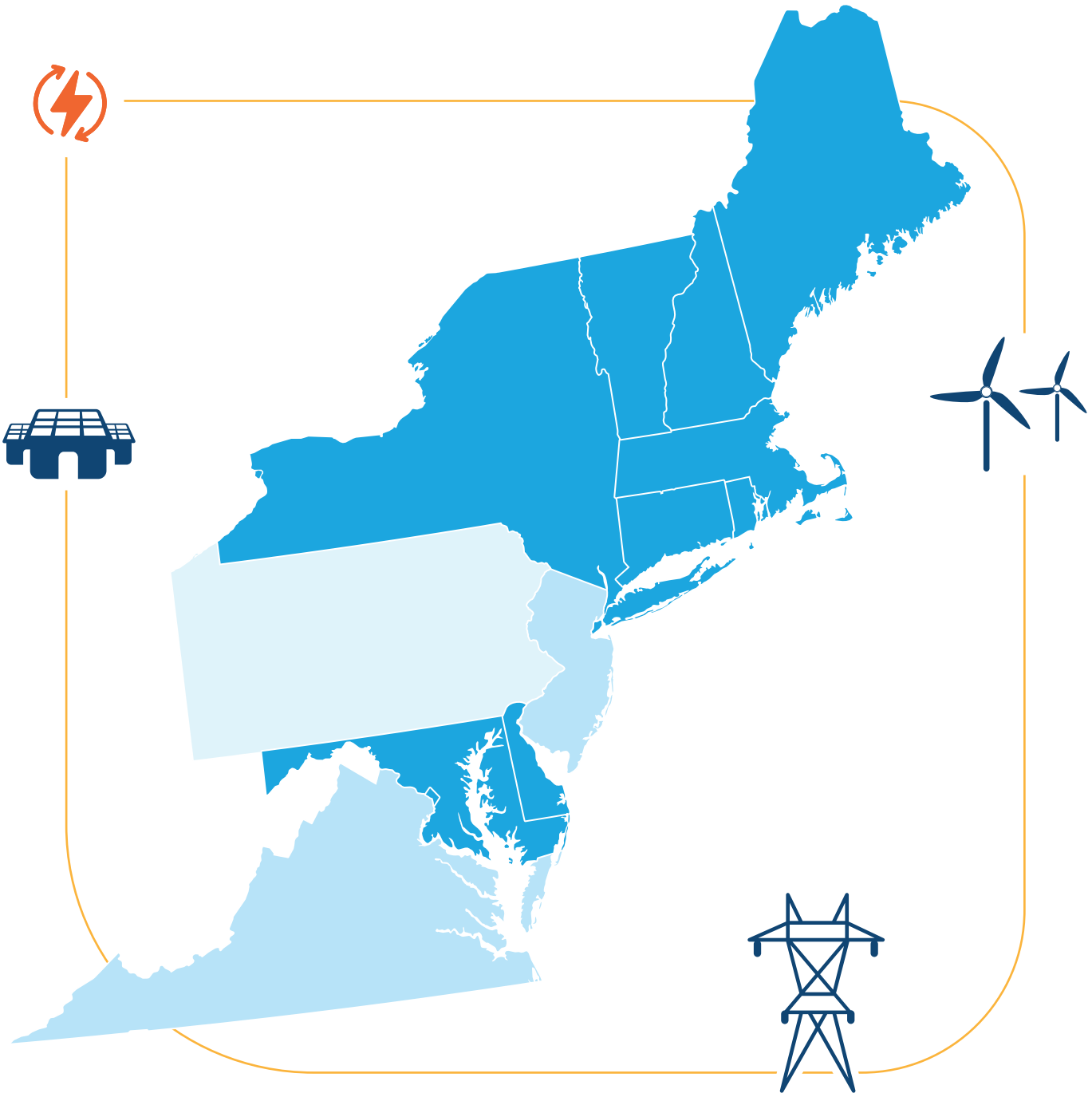
Director
(print title)

Date: 2/8/2021

Attachment 4

The Regional Greenhouse Gas Initiative

10 Years in Review



2019

Acadia Center

Executive Summary

Through ten years of operation, the Regional Greenhouse Gas Initiative (RGGI) has helped Northeast and Mid-Atlantic states[1] achieve significant reductions in emissions of carbon dioxide (CO_2) and other pollutants from the electric power sector. The country's first program designed to reduce climate change-causing pollution from power plants has provided a wealth of lessons to be incorporated into the next generation of climate policies, from successes to build on to opportunities for improvement.

The participating states have experienced substantial benefits from RGGI since 2008, the year before the program launched. Concerns that climate policy would make states less competitive have been directly refuted by RGGI's experience: the RGGI program is helping participating states outperform the rest of the country. Since 2008:

- **CO_2 emissions from RGGI power plants have fallen by 47%,** outpacing the rest of the country by 90%;
- **Electricity prices in RGGI states have fallen by 5.7%**, while prices have *increased* in the rest of the country by 8.6%;
- **GDP of the RGGI states has grown by 47%**, outpacing growth in rest of the country by 31%;
- **RGGI states have generated $3.2 billion in allowance auction proceeds**,[i] the majority of which have been invested in energy efficiency and renewable energy programs; and
- **RGGI-driven reductions in co-pollutant emissions have resulted in over $5.7 billion in health and productivity benefits.**[ii]

Much has changed since RGGI was launched, beyond the climate, economic and health improvements described above. Most notably, climate policy has advanced by leaps and bounds. When RGGI was implemented, it was just the second program in the world to regulate carbon emissions, and the first to require polluters to pay for emissions allowances (permits to emit pollution). Now, there are 57 national or subnational carbon pricing programs in place,[iii] many of them drawing on lessons learned from RGGI.

At the same time, findings from the scientific community have made the urgency of climate action increasingly hard to ignore. If the planet is to avoid crossing the 1.5 degree warming threshold, global annual GHG emissions need to be reduced by 45% from 2010 levels by 2030.[iv] To make a meaningful difference in reducing the catastrophic costs of climate change, we need urgent action.

Finally, sound climate policy needs to be oriented around climate justice. Programs designed to reduce GHG emissions must be good for the planet and for communities. In the RGGI context, that means improving air quality in environmental justice communities, ensuring that underserved populations have access to RGGI-funded energy efficiency and clean energy programs, and importantly, that those communities have a say in shaping the policy.[v] While there is much more to do to protect vulnerable communities from power plant pollution, states must also act with urgency to reduce locally-harmful pollution from other sources, most notably transportation.

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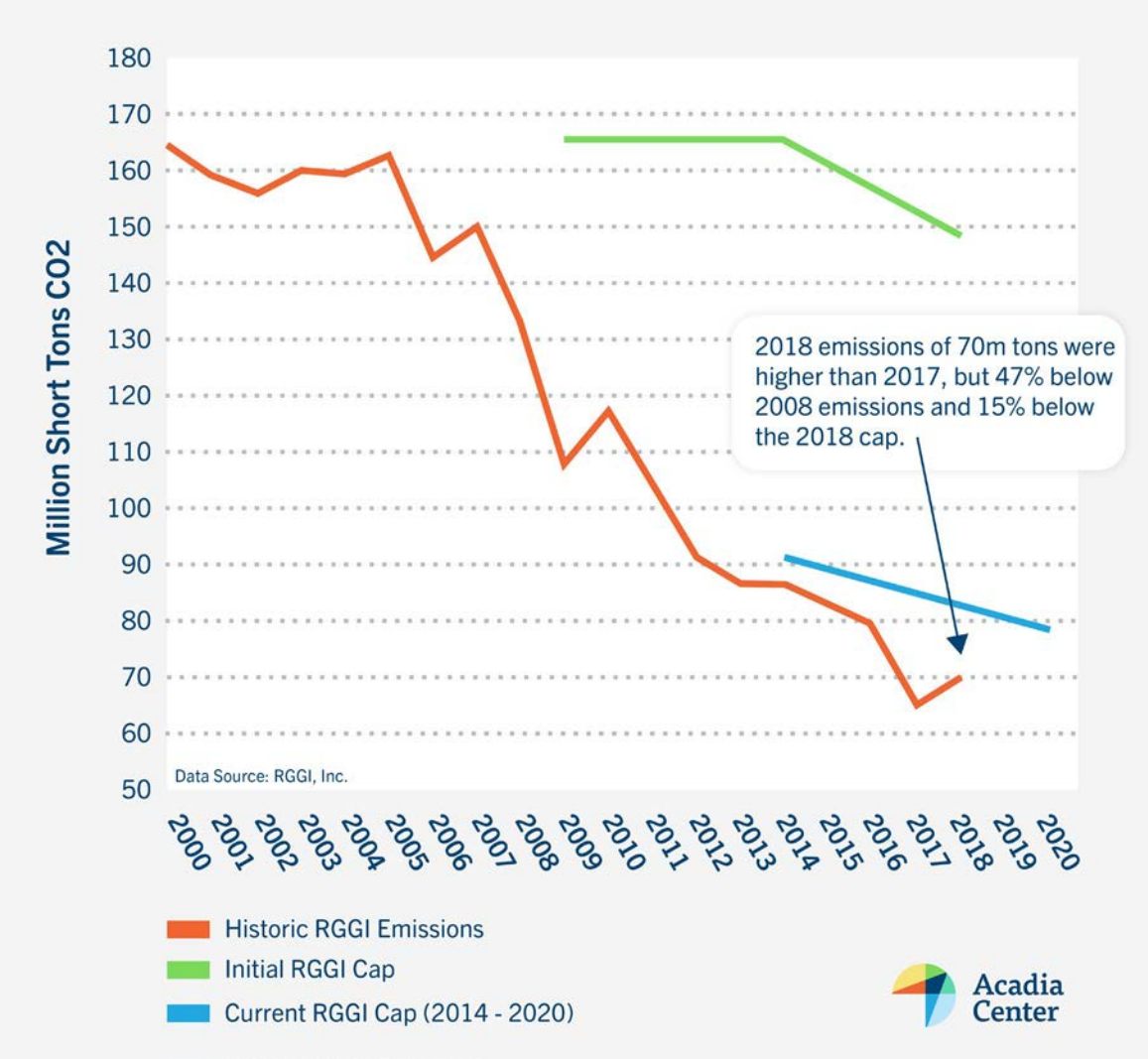
[1] Analysis in this report covers the currently participating RGGI states: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. [*Footnotes elaborate on points within this report, whereas endnotes cite references and provide detailed analytic methodologies where relevant.*]

Emissions Trends and RGGI Cap Dynamics

Rapid CO_2 Reductions Outpace the Rest of the Country

States participating in RGGI have seen a steep decline in CO_2 emissions from power plants over the last 10 years. Since 2008, the year before the program launched, RGGI emissions have fallen from 133 million short tons of CO_2 to 70 million tons in 2018, shown in Figure 1. The impressive electric sector emission reductions achieved in RGGI states over that time period have outpaced reductions in the rest of the country by a staggering 90%. While the RGGI program has not been the sole factor behind the region's rapid electric sector decarbonization, earlier analysis shows that it has been a key driver—and accelerator—of emission reductions from power plants.[vi]

Figure 1: RGGI Cap and Historic Emissions – Nine RGGI States



As Figure 2 shows, rapidly declining RGGI emissions and an oversupply of allowances have kept RGGI allowance prices relatively low. From Auctions 8 to 18, RGGI allowances sold at the reserve price—the lowest price at which allowances can be sold through auction—and the highest RGGI auction clearing price since the program launched was $7.50 per allowance. For comparison, the 2019 auction reserve price in California and Quebec's cap-and-invest program is $15.62 per allowance.[vii] This higher reserve price provides a greater incentive to pursue additional CO_2 abatement measures.

Figure 2: Quarterly RGGI Emissions and Auction Clearing Prices

Aligning the RGGI Cap with Current Emissions and the Climate Crisis

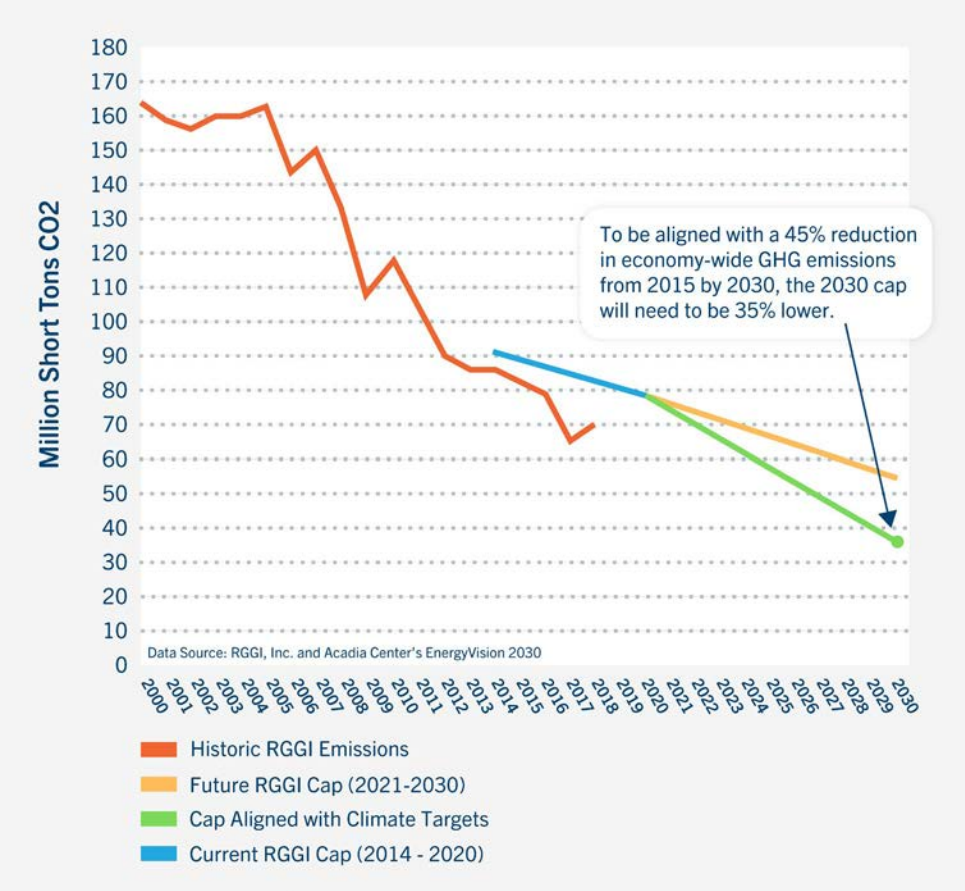
Through the first half of 2019 it appears the trend of declining RGGI emissions will continue, with RGGI COATS[viii] data showing the lowest first-half emissions in the program's history (see Figure 2).[ix] The fact that RGGI emissions have been well below the RGGI cap in every year of the program's history, as shown in Figure 1, is good for the climate and encouraging for future decarbonization efforts, but it also highlights the need for certain program reforms.

Chief among these reforms is a more stringent cap on emissions. In 2017, at the conclusion of the latest RGGI Program Review, the RGGI states committed to a new cap from 2021-2030 with a slightly faster emission reduction trajectory than the cap in place from 2014-2020. The extension of the cap and the increased ambition are positive steps, and the 2030 cap level of 54.7 million short tons commits the region to a 30% reduction in electric sector CO_2 emissions beyond the 2020 requirement. In addition to the lower cap, the Program Review resulted in measures that will strengthen the program by constraining RGGI allowance supply and limiting future emissions.[x] A third adjustment for banked allowances will eliminate the allowance surplus accrued through 2020, higher Cost Containment Reserve (CCR) price triggers will help avoid unnecessary increases in allowance supply, and the innovative Emissions Containment Reserve (ECR) will help the RGGI states secure additional, low-cost emission reductions.[xi]

Despite these measures to strengthen the program, a more ambitious RGGI cap is necessary. 2018 emissions are already well below the new, more ambitious cap set for 2021. In fact, 2018 emissions are already below the cap level set for 2023. To be most effective, the RGGI cap needs to more closely reflect the new, lower-carbon reality of the region's electric sector and the science-based GHG reduction targets adopted by the RGGI states.

The region's electric sector CO_2 emissions will need to be far below the 2030 cap if the region is to achieve its economy-wide GHG reduction goals. Acadia Center's EnergyVision 2030[xii] finds that for the Northeast states to achieve a 45% reduction in economy-wide GHG emissions by 2030 (from 2015 levels), the region would need to achieve a 57% reduction in electric sector GHG emissions by 2030 (compared to a 20% reduction from transportation and 30% reduction from buildings). As shown in Figure 3, if that 57% reduction from 2015 were applied to the RGGI cap, it would yield a 2030 cap of 35.8 million short tons: a 35% lower RGGI cap than what the states have agreed to. This more ambitious electric sector decarbonization will make it possible for the region to achieve greater emission reductions through the electrification of other sectors.

Figure 3: Aligning the Future RGGI Cap with Climate Targets



Of course, achieving economy-wide climate targets will require significant action to reduce GHG emissions from all sectors. There are critical carbon pricing policies currently in development or under consideration that, if implemented, will steer the region in the right direction. At the state level, momentum is building around carbon pricing bills that would establish a price on CO_2 emissions from sectors not covered by RGGI. Across the region, the 12 states of the Transportation & Climate Initiative (TCI) are developing a multi-state cap-and-invest program to reduce CO_2 emissions from the transportation sector.[xiii] Both of those policies can build on the best of the RGGI model, but in order to be most effective, they will depend on a decarbonized electric sector.

Economic Trends and Electricity Prices

RGGI's Economic Impacts

RGGI has generated significant economic benefits for states participating in the program. By selling allowances, RGGI states raise revenue to reinvest in energy efficiency, renewable energy, and other consumer programs that increase economic activity in participating states. The majority of program revenue (58% through 2016[xiv]) has been invested in energy efficiency programs that reduce consumers' bills and reduce demand for power. Lower power demand resulting from energy efficiency means fewer emissions from power plants, and less money leaving the region to pay for imported fossil fuels. Energy bill savings increase consumer spending, benefiting businesses that offer goods and services in the region. According to independent macroeconomic analysis of

RGGI through 2017, **the program has created over $4 billion in net economic gains and over 44,000 job-years of employment.**[xv]

Economic Growth and Emissions

The RGGI states have managed to rapidly reduce CO_2 emissions without impeding economic growth. In fact, the region has proven that decarbonization and economic growth can go hand in hand. While the country as a whole has been experiencing declining CO_2 emissions and economic growth, the RGGI states have seen faster economic growth and steeper CO_2 reductions. As shown in Figure 4, from 2008 (before RGGI's launch) to 2018, **RGGI states' economies grew by 46.9% versus 35.8% in states that do not regulate or put a price on carbon emissions** (this group of 40 states, referred to below as the "rest of the country", does not include California, which has similarly outpaced national growth since capping carbon emissions[xvi]). Over the same 2008 to 2018 period, **emissions in the RGGI region dropped by 46% versus 24% in the rest of the country**.[xvii]

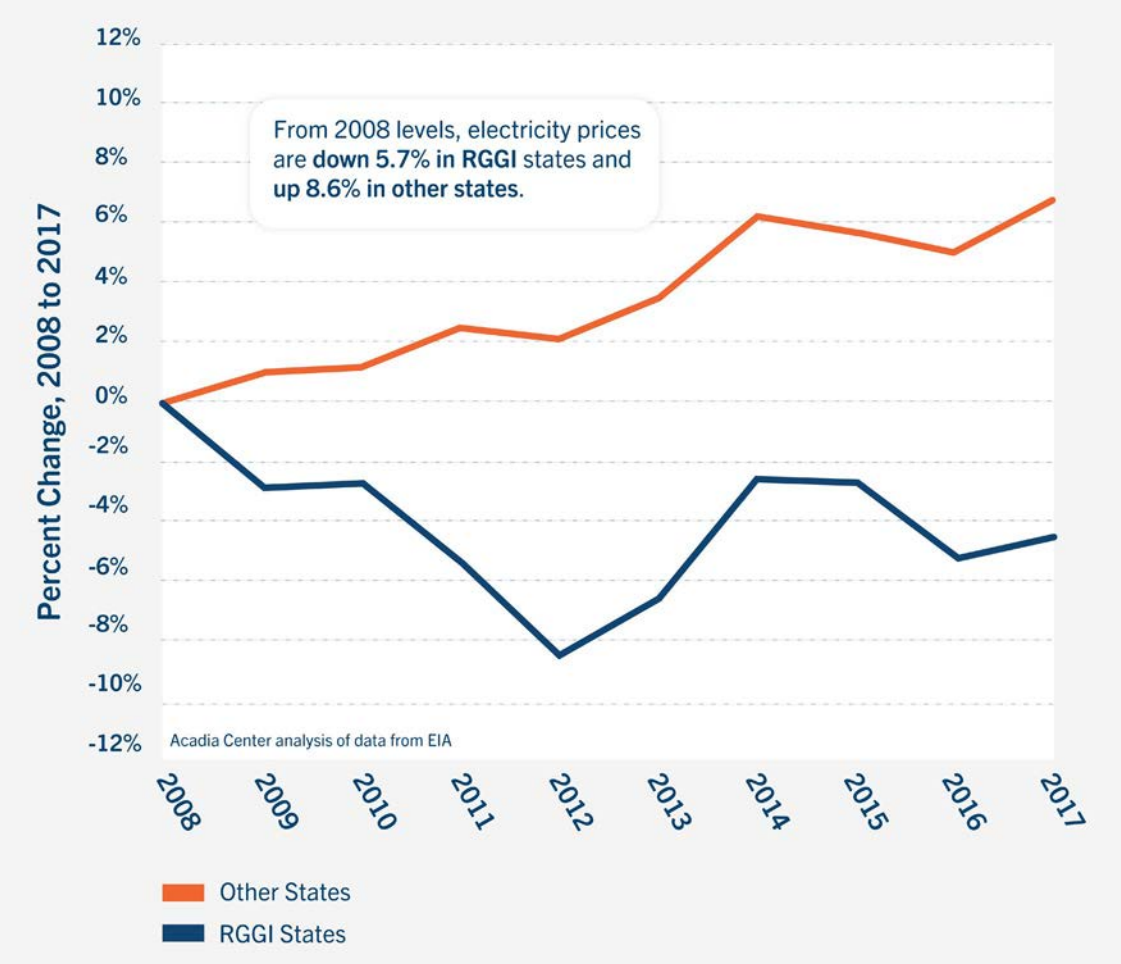
Figure 4: Change in Economic Growth and Emissions, 2008 to 2018

Electricity demand has historically been tied to economic growth, with electricity consumption and related emissions increasing during periods of economic expansion and decreasing in economic downturns. This correlation has been broken in the RGGI region, a new reality that appears to be mirrored—though slightly less dramatically—at the national level. A decade of RGGI and decarbonization of the electric power sector demonstrates that emissions reductions can be achieved as the economy grows.

Electricity Prices

Average retail electricity prices in the region have decreased since RGGI took effect. Comparing retail electricity prices from 2008 to 2017 shows that prices have dropped by 5.7% across the region.[xviii] While RGGI's direct impact on electricity prices is difficult to isolate from other factors, it is evident that the program has not caused electricity prices to rise from 2008 levels, in part due to RGGI-funded investments in energy efficiency. Concerns that climate policy will make states less competitive are directly refuted by RGGI's experience: RGGI states are faring much better than the rest of the country on electricity price trends. As shown in Figure 5, while RGGI's electricity prices have fallen from where they were in 2008, the rest of the country[2] has experienced an 8.6% increase in retail electricity prices over the same period.

Figure 5: Volume-Weighted Electricity Prices, 2008 to 2017



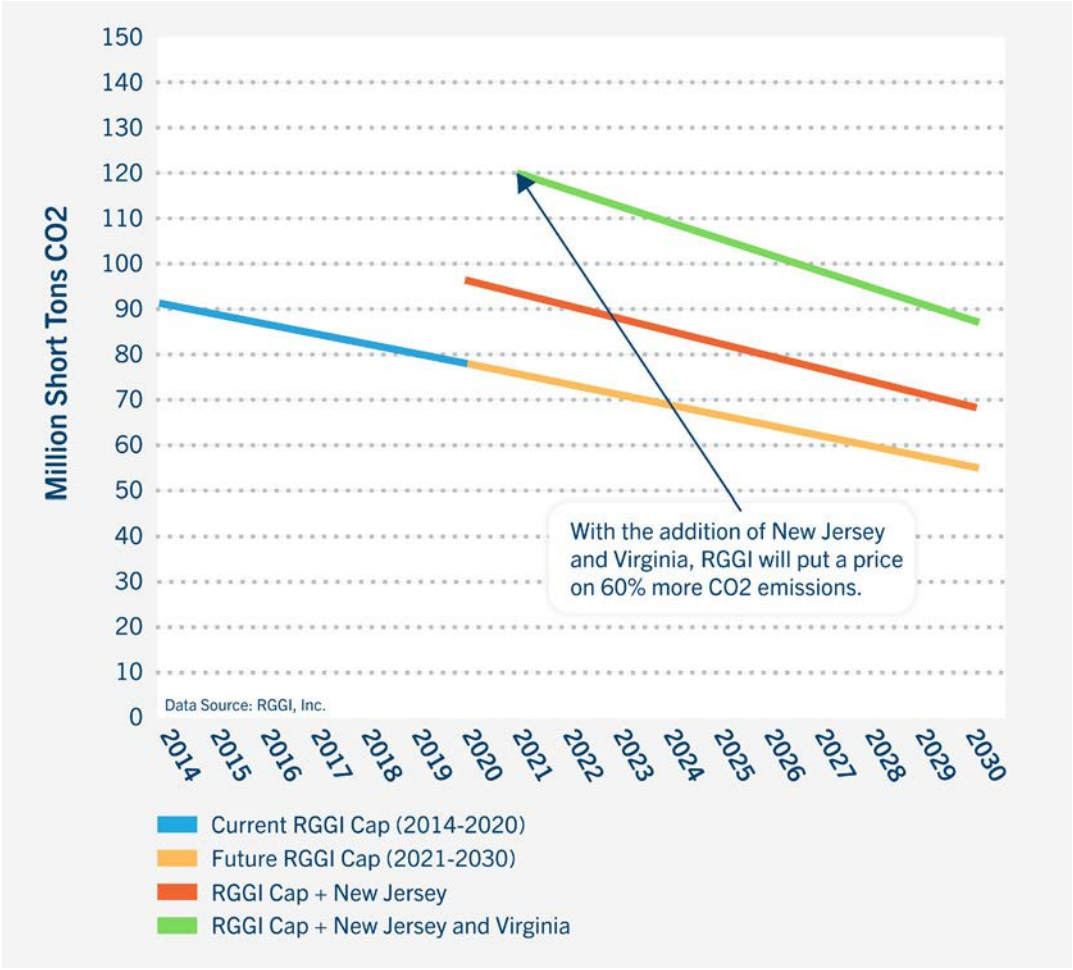
[2] The "rest of the country" excludes California, which, like the RGGI states, has implemented a cap-and-invest program to reduce CO_2 emissions.

Welcoming Additional States

There are currently nine states participating in the RGGI market, but that number is poised to grow to 11 by 2021. New Jersey is set to be the first addition, with the New Jersey Department of Environmental Protection adopting regulations in the summer of 2019 to rejoin the RGGI program on January 1st, 2020.[xix] This will mark New Jersey's return to the program, as the state participated in RGGI as a founding member until then-Governor Christie removed the state from the program in 2011. It appears likely that Virginia will follow New Jersey, with regulations approved to participate in a carbon trading program linked with the RGGI market.[xx] Virginia's participation in the RGGI market is expected to begin on January 1st, 2021.

Regulations in both New Jersey and Virginia would implement state CO_2 emission budgets aligned with the 2020-2030 RGGI cap, requiring a 30% reduction in region-wide emissions over that time period. The addition of these two states to the program will represent a substantial expansion, both in terms of CO_2 emissions and economic weight. By adding New Jersey and Virginia to the program, the combined GDP of the RGGI states would rise from $3.3 trillion to $4.5 trillion, a 35% increase, the equivalent of the world's 4th largest economy. As shown in Figure 6, expanding the RGGI cap to include these states would increase the amount of CO_2 emissions that face a carbon price by 60%.

Figure 6: RGGI Cap with New Jersey and Virginia



Conclusion

RGGI has successfully demonstrated the viability of a market-based program to reduce CO_2 emissions from the power sector while generating benefits for participating states. RGGI's experience has disproven the concerns most frequently associated with capping emissions from the power sector. Emissions have declined rapidly, far more dramatically than projected, without stifling economic growth. RGGI's reinvestment model has benefited the regional economy and increased employment while accelerating deployment of renewable energy and funding energy efficiency programs. The region's residents now pay lower electricity prices than before the program began and breathe cleaner air.

The RGGI states have committed to build on this success by extending the program through 2030. In the coming years the RGGI states will need to conduct another Program Review to reevaluate how the program aligns with the achievement of state climate targets.

A cleaner electric grid will prove vital to delivering significant CO_2 reductions from the electrification of transportation and buildings – the two other key sectors that must be decarbonized to avert climate disaster. By strengthening RGGI and applying lessons learned from the program to the transportation sector, the region can take meaningful action to address vehicle pollution—the largest source of CO_2 emissions in the country. Many of the RGGI states are currently building on their track record of bipartisan collaboration to develop a regional cap-and-invest program for the transportation sector through the Transportation and Climate Initiative (TCI). If this program applies the best of the RGGI model while delivering an even bolder, more equitable framework, the region will be well on its way to a low-carbon future that works for all.

For More Information:

Jordan Stutt, Carbon Programs Director, jstutt@acadiacenter.org, (617) 742-0054 x105

Endnotes

[i] RGGI, Inc., *Auction Results*, 2019. Available at: https://www.rggi.org/auctions/auction-results

[ii] Michelle Manion, et al., *Analysis of the Public Health Impacts of the Regional Greenhouse Gas Initiative*, Abt Associates, January 2017. Available at: https://www.abtassociates.com/insights/publications/report/analysis-of-the-public-health-impacts-of-the-regional-greenhouse-gas

[iii] World Bank, *States and Trends of Carbon Pricing 2019*, Available at: https://openknowledge.worldbank.org/handle/10986/31755

[iv] Joeri Rogelj, Drew Shindell, and Kejun Jiang, *Global Warming of 1.5°C, Chapter 2: Mitigation Pathways Compatible with 1.5°C in the Context of Sustainable Development*, IPCC, October 2018. Available at: https://www.ipcc.ch/site/assets/uploads/sites/2/2019/02/SR15_Chapter2_Low_Res.pdf

[v] Jeanne Herb and Marjorie Kaplan, *Field Notes: Equity and State Climate Policy*, Rutgers University, September 2019. Available at: https://drive.google.com/file/d/1mB-12SYJHQV4VjFe4OItZFfvQPdLB-cz/view

[vi] Brian Murray and Peter Maniloff, *Why Have Greenhouse Emissions in RGGI States Declined? An Econometric Attribution to Economic, Energy Market, and Policy Factors*, Duke Nicholas Institute, August 2015. Available at: https://nicholasinstitute.duke.edu/environment/publications/why-have-greenhouse-emissions-rggi-states-declined-econometric-attribution-economic

[vii] California Cap-and-Trade Program and Québec Cap-and-Trade System, *Joint Auction #20 Summary Results Report*, August 2019. Available at: https://ww3.arb.ca.gov/cc/capandtrade/auction/aug-2019/summary_results_report.pdf

[viii] RGGI CO_2 Allowance Tracking System: https://www.rggi.org/allowance-tracking/rggi-coats

[ix] RGGI cap levels and emissions data from RGGI, Inc., at: http://rggi.org/

[x] RGGI, Inc., *Summary of RGGI Model Rule Updates*, December 2017. Available at: https://www.rggi.org/sites/default/files/Uploads/Program-Review/12-19-2017/Summary_Model_Rule_Updates.pdf

[xi] RGGI, Inc., *Elements of RGGI*, 2019. Available at: https://www.rggi.org/program-overview-and-design/elements

[xii] EnergyVision 2030, Acadia Center, 2017. Available at: https://2030.acadiacenter.org/

[xiii] The Transportation & Climate Initiative: https://www.transportationandclimate.org/content/about-us

[xiv] RGGI, Inc., *The Investment of RGGI Proceeds in 2016*, September 2018. Available at: https://www.rggi.org/sites/default/files/Uploads/Proceeds/RGGI_Proceeds_Report_2016.pdf

[xv] Paul Hibbard, et al., *The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States*, Analysis Group, April 2018. Available at: https://www.analysisgroup.com/globalassets/uploadedfiles/content/insights/publishing/analysis_group_rggi_report_april_2018.pdf

[xvi] As detailed in the Environmental Defense Fund's recent report, *Carbon Market California: A Comprehensive Analysis of the Golden State's Cap-and-Trade Program*, California has experienced significant economic benefits resulting from AB 32, and GDP growth in the state outpaced the national average in 2011, 2012, and 2013: http://www.edf.org/sites/default/files/content/carbon-market-california-year_two.pdf

[xvii] In order to compare emissions in the RGGI states to emissions in the rest of the country, the emissions measured in this section are from EIA Form 923. This represents a broader range of emissions sources than those covered by RGGI, which explains the difference in reported RGGI emissions here versus elsewhere in this report.

[xviii] Energy Information Administration (EIA), Form 826, http://www.eia.gov/electricity/data/eia826/. The volume-weighted average shown in Figure 5 is a product of each state's electricity price multiplied by electric load in the given year.

[xix] *Governor Murphy Announces Adoption of Rules Returning New Jersey to Regional Greenhouse Gas Initiative*, Office of the Governor of New Jersey, June 2019. Available at: https://www.state.nj.us/governor/news/news/562019/approved/20190617a.shtml

[xx] *Virginia Adopts Regulation to Limit Carbon Pollution, Fight Climate Change*, Virginia Department of Environmental Quality, April 2019. Available at: https://www.deq.virginia.gov/ConnectWithDEQ/NewsReleases/CarbonRule.aspx

Attachment 5

Commonwealth of Virginia
Office of the Governor

Executive Order

NUMBER FIFTY SEVEN (2016)

DEVELOPMENT OF CARBON REDUCTION STRATEGIES FOR ELECTRIC POWER GENERATION FACILITIES

Part I – Importance of the Initiative

Though our coastal communities may be the first to witness the effects of climate change, the risks presented by increasingly fierce storms, severe flooding, and other extreme weather events are not confined to a single geographic area. Neither are their causes. The economic implications are significant, and we must do all we can to protect our critical military infrastructure, our ports, our homes, and our businesses. It is only by acting together with common purpose that the Commonwealth can effectively adapt and stave off the most severe consequences of climate change.

One key step forward is to continue with a strategic goal of reducing carbon emissions. Virginia has already made meaningful strides – between 2005 and 2014, Virginia reduced its carbon emissions from power plants by 21 percent. However, the electric sector is still responsible for approximately 30 percent of the carbon dioxide pollution in the Commonwealth. Moreover, electric companies are including carbon regulation projections in their long-term plans. The electric sector is changing rapidly through increasing reliance on low and zero carbon resources. As such, it is vital that the Commonwealth continue to facilitate and engage in a dialogue on carbon reduction methods while simultaneously creating a pathway for clean energy initiatives that will grow jobs and help diversify Virginia's economy.

Accordingly, by virtue of the authority vested in the Governor under Article V of the Constitution of Virginia and under the laws of the Commonwealth, I hereby direct the Secretary of Natural Resources to convene a Work Group, chaired by the Secretary, to study and recommend methods to reduce carbon emissions from electric power generation facilities. The Secretary shall receive input from interested stakeholders.

Such methods shall align with the Virginia Air Pollution Control Board's power to promulgate regulations abating, controlling and prohibiting air pollution throughout or in any part of the Commonwealth.

Part II – Scope and Guidance

In preparing their recommendations, the Secretary and the Work Group shall consider the following:

(1) the establishment of regulations for the reduction of carbon pollution from existing electric power generation facilities pursuant to existing authority under Virginia Code § 10.1-1300 *et seq.*;

(2) the carbon reduction requirements for existing electric power generation facilities established under § 111(d) of the federal Clean Air Act, which are currently stayed pending final disposition;

(3) the interaction between electric utilities and regional markets, including PJM Interconnection;

(4) the impact any reduction requirements place on the reliability of the electric system;

(5) the impact any reduction of carbon pollution may have on electric rates and electric bills;

(6) the impact of reducing carbon pollution on low income and vulnerable communities;

(7) the cost effectiveness of pollution reduction technologies that may be deployed;

(8) the economic development opportunities associated with deployment of new carbon reduction technologies;

(9) the implementation and administration of carbon reduction regulations; and

(10) flexibility in achieving the goals of any carbon reduction regulation.

The Secretary of Natural Resources shall complete her work, including the development of recommendations as to viable carbon reduction methods for the electric power generation facilities by April 30, 2017. The Secretary of Natural Resources shall provide a report on the recommendations to the Governor by May 31, 2017.

Effective Date of the Executive Order

This Executive Order shall be effective upon its signing and shall remain in full force and effect for one year after its signing unless amended or rescinded by further executive order.

Given under my hand and under the Seal of the Commonwealth of Virginia this 28th Day of June, 2016.

Terence R. McAuliffe, Governor

Attest:

Kelly Thomasson, Secretary of the Commonwealth

Attachment 6

COMMONWEALTH of VIRGINIA

GOVERNOR TERENCE R. MCAULIFFE'S EXECUTIVE ORDER 57 WORK GROUP

REPORT AND FINAL RECOMMENDATIONS TO THE GOVERNOR

May 12, 2017

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APPENDIX A: Text of Executive Order 57

APPENDIX B: Executive Order 57 Work Group Agendas

I. Introduction

Climate change along with associated sea-level rise and increasingly volatile weather patterns pose potentially devastating risk to Virginia. According to data compiled by the Georgetown Climate Center and Old Dominion University's Mitigation and Adaptation Research Institute, the Commonwealth has already seen a 33 percent increase in heavy rainstorms and snowstorms in the last sixty years, as well as an 11 percent increase in precipitation from the largest storms.[1] The same report found that as many as 400,000 Virginia homes are at risk of damage from increased storm surges. The researchers projected that rebuilding Virginia's at-risk residential property could cost $92 billion. Home loss disproportionately affects low-income homeowners who often lack the insurance or capital to relocate or rebuild without jeopardizing their overall financial security.

Climate change also has the potential to endanger the Commonwealth's agricultural sector, particularly small, family-owned farms without the resources to implement expensive site-specific adaptation strategies. Half of Virginia's counties face increased risk of water shortages by 2050 as the result of climate-related shifts in precipitation and weather.[2] Currently, agriculture is Virginia's largest industry, supporting almost 311,000 jobs with an annual economic impact of $52 billion.[3] Other business sectors are similarly feeling the impacts of climate change as warmer temperatures affect worker productivity and the health of the workforce.[4]

In addition to the environmental and economic consequences of climate change, carbon emissions also pose a significant risk to human health. According to data from the United States Centers for Disease Control and Prevention, the burning of fossil fuels has resulted in negative impacts to air and water quality and been linked to increased incidence of asthma and cardiovascular disease.[5] Across the United States, warmer temperatures have been linked to increased ground-level ozone[6] and more frequent and sustained wildfires,[7] a major contributor to

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[1] Georgetown Climate Center and Old Dominion University Mitigation and Adaptation Research Institute, *Understanding Virginia's Vulnerability to Climate Change*, February 17, 2017, *available at* http://www.georgetownclimate.org/files/report/understanding-virginias-vulnerability-to-climate-change.pdf (last accessed May 9, 2017).
[2] *See id*.
[3] Virginia Department of Agriculture and Consumer Services, *Virginia Agriculture Facts & Figures*, *available at* http://www.vdacs.virginia.gov/markets-and-finance-agriculture-facts-and-figures.shtml (last accessed May 9, 2017).
[4] U.S. Global Change Research Program. *Impacts of Climate Change on Human Health in the United States: A Scientific Assessment,* April 2016, *available at* https://health2016.globalchange.gov/ (last accessed May 9, 2017).
[5] Centers for Disease Control and Prevention, *A Human Health Perspective on Climate Change*, https://www.cdc.gov/climatechange/pubs/hhcc_final_508.pdf (last accessed May 9, 2017).
[6] Pfister, G. G., S. Walters, J.-F. Lamarque, J. Fast, M. C. Barth, J. Wong, J. Done, G. Holland, and C. L. Bruyère, Journal of Geophysical Research: Atmospheres, *Projections of future summertime ozone over the U.S.*, *available at* http://onlinelibrary.wiley.com/doi/10.1002/2013JD020932/abstract (last accessed May 9, 2017).

particulate matter pollution harmful to public health. Evidence from the Virginia Department of Health shows increased incidences of West Nile virus and Lyme disease,[8] an indication that recent environmental shifts may have improved survival rates for disease vectors like ticks and mosquitos.

The impacts of climate change are also causing ocean warming and ice-sheet loss, resulting in potential sea level rise of more than five feet in Virginia by the turn of the century.[9] Because of its low-lying elevation, natural geography, and high rate of land subsidence, Hampton Roads is consistently ranked as the second most vulnerable region in the country at risk from rising seas, a clear and accelerating result of climate change.[10] According to analysis by Risk Management Solutions, the Virginia Beach-Norfolk Metropolitan Statistical Area ranks 10th in the world for assets at risk of flooding as the result of relative sea level rise.[11] The Hampton Roads Planning District Commission estimates that a conservative three foot rise in sea level would cover nearly 900 miles of roads in the region, costing as much as $87 billion.[12] Naval Station Norfolk, the world's largest naval base, has replaced four World War II-era piers to compensate for higher seas and plans to build eight more, at a cost of more than $100 million per pier.[13]

Given the challenges associated with climate change and the need for solutions, Virginia is uniquely positioned to become a leader in the international efforts to reduce carbon dioxide emissions and stave off the most dramatic consequences of climate change. While carbon dioxide emissions from Virginia's electric generating units have fallen by 21 percent between 2005 and 2014, they still account for approximately 30 percent of the state's overall carbon dioxide emissions. Investments have accelerated since 2014, but the Commonwealth has tremendous potential to build on this growth and achieve even greater carbon emission reductions through additional investments in clean energy technologies.

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[7] A. L. Westerling, H. G. Hidalgo, D. R. Cayan, T. W. Swetnam, Science Magazine, *Warming and Earlier Spring Increase Western U.S. Forest Wildfire Activity*, *available at* http://science.sciencemag.org/content/313/5789/940.full (last accessed May 9, 2017).

[8] Virginia Department of Health, *Ten-Year Trend in Number of Reported Cases of Reportable Diseases in Virginia, 2006-2015*, *available at* http://www.vdh.virginia.gov/content/uploads/sites/13/2016/03/table2a_trend2015.pdf (last accessed May 9, 2017).

[9] Virginia Institute of Marine Science, *Sea Level Rise Scenarios*, *available at* http://www.vims.edu/newsandevents/topstories/slr_scenarios.php (last accessed May 9, 2017).

[10] Deconcini, C. and Tompkins, F., World Resources Institute, *Sea-level Rise and its Impact on Virginia*, *available at* https://www.wri.org/sites/default/files/wri_factsheet_virginia_final.pdf (last accessed May 9, 2017).

[11] Nicholls, R. J., Hanson, S., Herweijer, C., Patmore, N., Hallegatte, S., Corfee-Morlot, J., Château, J., & MuirWood, R., Organisation for Economic Co-operation and Development, *Ranking Port Cities with High Exposure and Vulnerability to Climate Extremes*, *available at* http://www.oecd-ilibrary.org/environment/ranking-port-cities-with-high-exposure-and-vulnerability-to-climate-extremes_011766488208 (last accessed May 9, 2017).

[12] Hampton Roads Planning District Commission, *Climate Change in Hampton Roads, Phase III: Sea Level Rise in Hampton Roads, Virginia*, *available at* http://www.hrpdcva.gov/library/view/230/climate-change-in-hampton-roads:phase-iii-sea-level-rise-in-hampton-roads-july-2012 (last accessed May 9, 2017).

[13] Evan Leghmann, E&E News, *Inside One Naval Base's Battle with Sea-Level Rise*, Oct. 27, 2016, *available at* https://www.eenews.net/stories/1060044863 (last accessed May 9, 2017).

Today, Virginia has more than 1,800 megawatts (MW) of solar currently in service or under development.[14] In the last year alone, the number of solar jobs in Virginia has increased by 65 percent, from 1,963 to 3,236.[15] Virginia's solar job market is the 9th-fastest-growing solar jobs market in the nation.[16] The Commonwealth is already home to over 75,000 energy efficiency workers.[17] Energy efficiency business revenue in Virginia has increased from $300 million in 2013 to $1.5 billion in 2016, a five-fold increase.[18] The continued growth of clean energy investment in the Commonwealth has the potential to bring about long-term sustainable economic development while also mitigating the impacts of climate change through reduced carbon dioxide emissions.

With these two principals in mind – the enormity of climate change impacts and the potential for clean energy industry growth – Governor McAuliffe signed Executive Order 57 ("EO 57") on June 28, 2016. When the Governor issued EO 57, he recognized that the Commonwealth must continue to facilitate and engage in a dialogue on carbon reduction methods while simultaneously creating a pathway for clean energy initiatives that will grow jobs and help diversify Virginia's economy. Through the Executive Order, Governor McAuliffe directed the Virginia Secretary of Natural Resources, Molly Ward, to convene an EO 57 Work Group ("Work Group") to study these issues and recommend methods to reduce carbon emissions from the electric sector in Virginia. The focus of the Work Group was to evaluate options under the Governor's existing authority while simultaneously creating more clean energy jobs.

In addition to Secretary Ward, the Work Group was comprised of Secretary of Commerce and Trade Todd Haymore, Virginia Department of Environmental Quality Director David Paylor, Virginia Department of Mines, Minerals and Energy Director John Warren, and Deputy Attorney General for Commerce, Environment, and Technology John Daniel. Through a robust stakeholder engagement process, the Work Group received presentations and feedback from a variety of perspectives including electric utilities, clean energy businesses, industrial manufacturing, academic institutions, environmental organizations, and other interested stakeholders. This report is the result of the efforts of the Work Group.

The full text of Executive Order 57 is provided in Appendix A and the complete agendas for all of the Work Group meetings are provided in Appendix B of this report.

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[14] Department of Mines Minerals and Energy, Solar Tracking Data, Updated May 5, 2017.
[15] The Solar Foundation, *National Solar Jobs Census 2016*, *available at* http://www.thesolarfoundation.org/national/ (last accessed May 9, 2017).
[16] *See id*.
[17] U.S. Department of Energy, *2017 US Energy and Employment Report*, *available at* https://energy.gov/downloads/2017-us-energy-and-employment-report (last accessed May 9, 2017).
[18] The Virginia Energy Efficiency Council, *Why Energy Efficiency is a Smart Investment in Virginia, available at* http://vaeec.org/resources/data/ (last accessed May 15, 2017).

II. Process

EO 57 outlined a process for the Governor, through the Secretary of Natural Resources, to receive recommendations from the public to further reduce the Commonwealth's carbon emissions and grow the clean energy economy under existing state authority. This process ensured that the Work Group would have the necessary public input to develop recommendations and submit a report to the Governor by the May 31, 2017 deadline stipulated in the Executive Order.

The process consisted of six monthly meetings that began on August 31, 2016 and ended on February 28, 2017. Each public meeting lasted between two and three hours, and the meetings consisted of presentations from members of the public. The presentations were voluntary, and all members of the public were invited to send suggested topics and presenter information to the Secretary of Natural Resources' office. In total, the Work Group received more than forty presentations. Each presentation was made publicly available on the Secretary of Natural Resources' website.[19]

In addition to the public meetings, the Work Group also facilitated a three month written public comment period that opened on February 1, 2017 and closed on April 30, 2017. Members of the public were invited to submit comments either electronically or in hard copy to the Office of the Secretary of Natural Resources. In total, the Work Group received over 8,000 written comments.

III. Recommendations

The recommendations set forth in this report are drawn from the information developed and understanding gained through the public meetings and the public comment process. The Work Group synthesized the many presentations and comment topics down to the five recommendations set forth below. This list does not attempt to include every recommendation that was provided to the Work Group, but it covers the broad categories of recommendations for the Governor's consideration.

1.) Promulgate regulations to limit carbon dioxide emissions

The Work Group received a number of presentations and written comments from stakeholders advocating for a regulation to limit carbon dioxide emissions from power plants. These comments included recommendations that the Commonwealth join or participate in the Regional Greenhouse Gas Initiative ("RGGI") or another regional trading program, that a price be put on carbon, and that Virginia strive to reduce its greenhouse gas emissions by 30 to 40 percent by the year 2030.

[19] *See* Office of the Secretary of Natural Resources Website*, available at* http://naturalresources.virginia.gov/initiatives/eo-57/.

The Work Group received information on both ratepayer impacts and potential job creation opportunities associated with a regulation to limit carbon emissions. Advanced Energy Economy modeled carbon reduction targets similar to those in the federal Clean Power Plan that would be achieved through implementation of power generation fleet changes already planned by utilities along with the addition of renewable energy and energy efficiency measures. They found that these actions would result in 54,231 cumulative additional job years by 2030 and, if Virginia reduced its imports while applying the same carbon reduction actions, we could see the number of cumulative additional job-years double to more than 120,000. The Natural Resources Defense Council, which advocated for a 30 percent reduction target by the year 2030 (i.e., 30x30), also performed utility-sector modeling. They found that if the target included 20 percent in-state renewable generation and 1.5 percent annual energy efficiency savings, Virginia customer electric bills would decrease by almost $100 per year.

The business community also weighed in on the establishment of carbon dioxide regulations. Mars, Nestle, and Unilever filed joint comments noting that "an annual emissions reduction cap or clean energy standard are models that have been effective in other states' efforts to foster clean energy development." These companies stated that while they do not support one particular policy over another, they "believe that such policies will create market certainty and drive private-sector investments."

The Business Council for Sustainable Energy stated that "[s]uccessful reduction of Virginia's carbon emissions will require embracing the full portfolio of clean energy and energy efficiency technologies, products, and services." Dominion Resources filed comments stating that they "have confidence the Commonwealth can devise a forward-looking plan ensuring the continued decline in carbon emissions that is compatible with promoting a growing economy and keeping Virginia the most attractive state for new businesses." In addition, Dominion stated, "a rate-based approach or a mass-based limit on existing sources is the most accurate way to stimulate economic growth and job creation while achieving measurable carbon emission reductions."

The University of Virginia's Environmental and Regulatory Law Clinic and the Southern Environmental Law Center provided information on the legal justification for regulatory action. Both presentations focused on the current authority of the State Air Pollution Control Board ("Board") and the Department of Environmental Quality under Virginia Code § 10.1-1300 *et seq*. Each concluded that the Board has authority to regulate carbon dioxide from electric power generation facilities. This has since been confirmed by Attorney General Mark Herring in an official opinion dated May 12, 2017.

In short, there was tremendous public interest in this particular recommendation. Although many stakeholders provided feedback focused on specific in-state targets (such as 30x30), the Work Group believes that it is important and necessary that Virginia work through a

regional model, like the established and successful RGGI, in order to both achieve lower compliance costs and address the interstate nature of the electric grid.

The Work Group recommends that the Governor consider taking action via a regulatory process to establish a "trading-ready" carbon emissions reduction program for fossil fuel fired electric generating facilities that will enable participation in a broader, established multi-state carbon market.

2.) Update state building codes to reflect current technology and standards

Buildings account for approximately 70 percent of America's electricity consumption and more than 40 percent of total national energy usage annually, producing 39 percent of the United States' overall carbon emissions.[20] Inefficiency in building design was a major source of stakeholder concern, and a number of presenters and written comments focused on the need to strengthen Virginia's building codes. Some commenters recommended that Virginia adopt the 2015 International Energy Conservation Code (IECC) with no alterations while others recommended updating to the 2012 IECC without amendments.

Currently, Virginia's building code embraces the standards from the 2012 IECC for commercial properties and the 2009 equivalent for residential structures. Arlington County recommended adoption of the 2015 IECC with no alterations, and noted that "Virginia homeowners would save $2.5 billion between 2010-2040 and avoid nearly 16 million metric tons of carbon emissions." The Southeast Energy Efficiency Alliance also recommended that Virginia update its building codes to the 2015 IECC, and noted that "Virginia could achieve annual carbon savings of 1.21 million metric tons CO2 by 2030, and cumulative savings of 15.66 million metric tons CO2 from 2010 to 2030." The Virginia Energy Efficiency Council and Local Energy Alliance Program similarly recommended updating the building codes to the 2015 IECC. The Virginia Poverty Law Center recommended that Virginia update the building codes to the 2012 IECC, but that Virginia develop a plan to adopt the 2018 updates when they are released.

The Work Group also received information evaluating compliance with Virginia's current building codes. Recent testing in both Charlottesville and McLean, presented by the Virginia Energy Efficiency Council and the Local Energy Alliance Program, shows that a significant portion of the Commonwealth's homes do not meet established standards for air-tightness or ductwork. The U.S. Department of Energy (DOE) is conducting a statewide research field study investigating energy code implementation in residential buildings in Virginia. This study will provide valuable Virginia-specific data on energy code compliance as well as insight into market-driven efficiency decisions of homebuilders.

[20]Presentation by Virginia Energy Efficiency Council and Local Energy Alliance Program, *The Role of Building Energy Codes in a Carbon Reduction Strategy for Virginia*, *available at* http://naturalresources.virginia.gov/media/8635/4-vaeec.pdf.

The Virginia Board of Housing and Community Development (BHCD) is currently in the process of updating the Commonwealth's Uniform State building codes (USBC). This spring, BHCD began accepting amendments to the draft code and stakeholder workgroups began meeting. By November of 2017, BHCD will vote on the final State Building Codes.

The Work Group recommends that BHCD update the commercial building codes to reflect the 2015 IECC and that the residential building codes be consistent with current technology and be more reflective of the 2015 IECC. In addition, the Department of Mines, Minerals and Energy should participate in data collection efforts, including the previously-mentioned DOE energy code field study, to better inform the building code process and to provide data and best practices for implementation.

3.) Improve access to clean energy resources like solar, wind, and energy efficiency

Stakeholders from a variety of constituencies across the Commonwealth presented or filed comments on the need to further increase deployment of clean energy resources. However, the policy recommendations that would achieve such a result varied. Some presenters recommended adoption of a mandatory Renewable Portfolio Standard (RPS) while others focused on market opportunities and customer choice.

A number of presenters focused on recommendations regarding the adoption of a mandatory RPS. Virginia's Renewable Energy Portfolio goal was created via legislation in 2007 as part of the re-regulation of the Commonwealth's electrical industry. The goal was set to incrementally increase until 2025, at which point it would level off to 15 percent of electricity sold by a utility. Two years after adoption of this preliminary goal, legislation was passed allowing research and development expenses to be counted towards up to 20 percent of the goal. Further legislative modifications were made in 2013 to remove the incentive structure supporting utility compliance. While there are merits to the RPS, a mandatory RPS would require legislation, and the Work Group has aimed its focus on recommendations that could be implemented through the Governor's executive authority.

The Governor has used his executive authority to show state leadership in powering state operations with renewable energy. In 2014, the Governor announced a goal of getting 8 percent of state government's electricity from renewable sources within three years. The Commonwealth is moving toward achieving this goal through partnerships with the U.S. Navy and the University of Virginia. However, some presenters noted that Virginia should expand on this lead-by-example model by meeting stated energy reduction targets and expanding the state renewable procurement target.

Another set of recommendations addressed the need to grow market opportunities and increase customer choice, both at the business and residential levels. Mars, Nestle, and Unilever recommended that the Governor develop an "explicit legal framework to allow companies to enter into contracts with non-utility energy providers through third-party financing or offering

utility-administered, cost-of-service-based renewable energy tariffs for large buyers." E2 recommended that the Governor convene a task force including DMME, the State Corporation Commission, the Department of Environmental Quality, the Virginia Economic Development Partnership, Dominion, and Appalachian Power to discuss corporate renewable procurement needs and how to meet them. Ceres noted that corporate procurement targets increasingly focus on achieving 100 percent renewable energy and companies will factor this into site selection when considering investments in new facilities or expansion of existing operations.

A number of activities have occurred in the General Assembly to drive increased solar development. Solar industry and utility representatives met over fifty times in 2016 to break the legislative impasse over needed changes to the existing legislative framework governing solar generation in Virginia. This group (the "Solar Group"), facilitated by the Virginia Center for Consensus Building at VCU, crafted three pieces of legislation that passed the General Assembly unanimously in 2017 and were signed into law by the Governor. Senate Bill 1393 created a pilot program for community solar projects administered by utilities. Senate Bill 1394 and House Bill 2303 enacted an additional option for agricultural customers with solar installations. Senate Bill 1395 opened the streamlined Permit by Rule process for regulatory approval to certain projects not previously eligible. The EO 57 Work Group received recommendations to tackle additional solar deployment access issues. Building on the trust and respect that was established in 2016, the Solar Group could tackle even more complex issues in 2017 with more outreach to additional stakeholders.

The Work Group recommends that the Governor update Virginia's current renewable energy procurement target and work with the Solar Group to develop a comprehensive plan to increase corporate access to renewable energy as an economic development tool.

4.) Develop an energy efficiency accounting and registry tool

The Work Group received many presentations focused on the fact that Virginia faces challenges in the effort to improve and increase energy efficiency. Many other states are already in the process of implementing energy efficiency programs that are much more expansive than those in Virginia. In addition to recommendations on specific energy efficiency deployment mechanisms, the Work Group also received a presentation from E4TheFuture on the National Energy Efficiency Registry ("NEER").

This presentation noted that many regulatory systems and their supporting computer infrastructure have been developed independently at the state level, making it difficult to accurately track and compare results across state lines. To remedy this problem, the Tennessee Department of Environment & Conservation has partnered with the U.S. Department of Energy, the National Association of State Energy Officials, the Climate Registry, and agencies from Michigan, Minnesota, Oregon, and Pennsylvania to create the NEER. The registry, currently

under development, is intended to serve as a software platform for credibly evaluating the benefits of energy efficiency projects.

By providing a consistent framework for measuring and assessing energy efficiency initiatives, the registry could help states apply efficiency savings to their self-selected energy goals as well as existing or future federal or state regulation. In addition, NEER will use best practices in data management, reporting, and registry design, to improve data collection and management efficiency and, where possible, automate processes. Increased transparency could allow both private and public sector entities to see validated cost savings that can be achieved through improved efficiency, thus encouraging increased investments in conservation.

The Work Group recommends that the Department of Mines, Minerals and Energy investigate the NEER model and evaluate whether the registry could be a starting point for an energy efficiency accounting and trading mechanism conceptually similar to the currently used Renewable Energy Certificate.

5.) Establish a statewide Environmental Justice Advisory Council

An important element of the Executive Order 57 process, which was spelled out in the text of the order itself, is to make a particular effort to ensure that all people and perspectives have a voice in environmental discussions. This concept, known as environmental justice, is defined as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental law, regulations, and policies."[21]

Some environmental issues can be compounded or concentrated as the result of sociological factors. Low-income communities at risk from sea level rise often lack the resources to adequately improve resiliency and can suffer more sustained consequences as the result of personal property loss and damage. Virginia's power plants are disproportionately located in areas with high concentrations of poverty and people of color. Many of the most severe health consequences arising from coal-fired electrical generation are localized in nature, so this distribution unfairly burdens already disadvantaged communities with increased health problems and accompanying costs.

The Virginia Environmental Justice Collaborative proposed the creation of a statewide Environmental Justice Advisory Council ("EJAC"). Pursuant to this recommendation, the EJAC would serve as a sustained conduit for conversations about environmental justice and underserved communities.

The Work Group recommends that the Governor convene an EJAC consisting of appointed representatives to communicate directly with the Secretary of Natural Resources, the

[21]U.S. Environmental Protection Agency, *Learn About Environmental Justice*, *available at* https://www.epa.gov/environmentaljustice/learn-about-environmental-justice.

Secretary of Commerce and Trade, the Secretary of Health and Human Resources, the Secretary of Public Safety and Homeland Security, and the Commission on Local Government. The EJAC should provide a forum for sharing information and making recommendations to policy makers to help ensure fair treatment and meaningful involvement by all people with respect to policy decisions that impact the environment and health of local communities.

IV. Conclusion

Climate change is among the most pressing issues facing humanity, but it is not insurmountable. While no single solution exists, the recommendations in this report offer attainable strategies that could be performed under the Governor's existing executive authority. These recommendations are aimed at both reducing carbon dioxide emissions from the electrical generation sector and driving economic growth from the clean energy sector. While Virginia cannot solve the problem of climate change alone, we can take important and necessary steps at the state level to protect our citizens from the most extreme impacts and create meaningful opportunities to grow the clean energy sector.

Appendix A:

Text of Executive Order 57

Commonwealth of Virginia
Office of the Governor

Executive Order

NUMBER FIFTY SEVEN (2016)

DEVELOPMENT OF CARBON REDUCTION STRATEGIES FOR ELECTRIC POWER GENERATION FACILITIES

Part I – Importance of the Initiative

Though our coastal communities may be the first to witness the effects of climate change, the risks presented by increasingly fierce storms, severe flooding, and other extreme weather events are not confined to a single geographic area. Neither are their causes. The economic implications are significant, and we must do all we can to protect our critical military infrastructure, our ports, our homes, and our businesses. It is only by acting together with common purpose that the Commonwealth can effectively adapt and stave off the most severe consequences of climate change.

One key step forward is to continue with a strategic goal of reducing carbon emissions. Virginia has already made meaningful strides – between 2005 and 2014, Virginia reduced its carbon emissions from power plants by 21 percent. However, the electric sector is still responsible for approximately 30 percent of the carbon dioxide pollution in the Commonwealth. Moreover, electric companies are including carbon regulation projections in their long-term plans. The electric sector is changing rapidly through increasing reliance on low and zero carbon resources. As such, it is vital that the Commonwealth continue to facilitate and engage in a dialogue on carbon reduction methods while simultaneously creating a pathway for clean energy initiatives that will grow jobs and help diversify Virginia's economy.

Accordingly, by virtue of the authority vested in the Governor under Article V of the Constitution of Virginia and under the laws of the Commonwealth, I hereby direct the Secretary of Natural Resources to convene a Work Group, chaired by the Secretary, to study and recommend methods to reduce carbon emissions from electric power generation facilities. The Secretary shall receive input from interested stakeholders.

Such methods shall align with the Virginia Air Pollution Control Board's power to promulgate regulations abating, controlling and prohibiting air pollution throughout or in any part of the Commonwealth.

Part II – Scope and Guidance

In preparing their recommendations, the Secretary and the Work Group shall consider the following:

(1) the establishment of regulations for the reduction of carbon pollution from existing electric power generation facilities pursuant to existing authority under Virginia Code § 10.1-1300 *et seq.;*

(2) the carbon reduction requirements for existing electric power generation facilities established under § 11l(d) of the federal Clean Air Act, which are currently stayed pending final disposition;

(3) the interaction between electric utilities and regional markets, including PJM Interconnection;

(4) the impact any reduction requirements place on the reliability of the electric system;

(5) the impact any reduction of carbon pollution may have on electric rates and electric bills;

(6) the impact of reducing carbon pollution on low income and vulnerable communities;

(7) the cost effectiveness of pollution reduction technologies that may be deployed;

(8) the economic development opportunities associated with deployment of new carbon reduction technologies;

(9) the implementation and administration of carbon reduction regulations; and

(10) flexibility in achieving the goals of any carbon reduction regulation.

The Secretary of Natural Resources shall complete her work, including the development of recommendations as to viable carbon reduction methods for the electric power generation facilities by April 30, 2017. The Secretary of Natural Resources shall provide a report on the recommendations to the Governor by May 31, 2017.

Effective Date of the Executive Order

This Executive Order shall be effective upon its signing and shall remain in full force and effect for one year after its signing unless amended or rescinded by further executive order.

Given under my hand and under the Seal of the Commonwealth of Virginia this 28th Day of June, 2016.

_____

Terence R. McAuliffe, Governor

Attest:

_____

Kelly Thomasson, Secretary of the Commonwealth

Appendix B:

Executive Order 57
Work Group Agendas

Executive Order 57 Work Group Meeting

August 31, 2016
1:00pm – 4:00pm
Patrick Henry Building, West Reading Room
1111 E. Broad St., Richmond, VA 23219

Agenda

I. Welcome and Overview of Work Group Structure – Molly Ward, Secretary of Natural Resources

II. Presentation on Virginia's Carbon Reduction Efforts – Mike Dowd, Virginia Department of Environmental Quality

III. Presentation on the Legal Status of Carbon Reduction Rules – Matt Gooch, Virginia Office of the Attorney General

IV. Presentation on Supportive Research Regarding Climate Impacts – Emily Steinhilber and Molly Mitchell, Center for Recurrent Flooding Resiliency

V. Next Steps and Adjournment – Molly Ward, Secretary of Natural Resources

Work Group Members

1. Molly Ward, Secretary of Natural Resources
2. Maurice Jones, Secretary of Commerce and Trade
3. David Paylor, Director of the Virginia Department of Environmental Quality
4. John Warren, Director of the Virginia Department of Mines, Minerals, and Energy
5. John Daniel, Deputy Attorney General for Commerce, Environment and Technology

Executive Order 57 Work Group Meeting

October 6, 2016
1:00pm – 4:00pm
Patrick Henry Building, East Reading Room
1111 E. Broad St., Richmond, VA 23219

Agenda

I. Welcome – Molly Ward, Secretary of Natural Resources

II. Presentations:

a. PJM Interconnection, LLC

b. Tenaska

c. Advanced Energy Economy

d. Business Council for Sustainable Energy

e. Virginia League of Conservation Voters

f. Faith Alliance for Climate Solutions

g. Warrenton Climate Change Group

III. Next Steps and Adjournment – Molly Ward, Secretary of Natural Resources

Work Group Members

1. Molly Ward, Secretary of Natural Resources
2. Todd Haymore, Secretary of Commerce and Trade
3. David Paylor, Director of the Virginia Department of Environmental Quality
4. John Warren, Director of the Virginia Department of Mines, Minerals, and Energy
5. John Daniel, Deputy Attorney General for Commerce, Environment and Technology

Executive Order 57 Work Group Meeting

October 31, 2016
1:00pm – 4:00pm
Patrick Henry Building, East Reading Room
1111 E. Broad St., Richmond, VA 23219

Agenda

I. Welcome – Molly Ward, Secretary of Natural Resources

II. Presentations:

a. American Council for an Energy Efficient Economy

b. Oil Change International

c. Alliance for Industrial Efficiency

d. Sierra Club

e. Virginia Housing Alliance

f. National Green Fuels

III. Next Steps and Adjournment – Molly Ward, Secretary of Natural Resources

For those unable to attend in person, we have arranged a webcast using the following link: https://attendee.gotowebinar.com/register/6736447537171170050

Work Group Members

1. Molly Ward, Secretary of Natural Resources
2. Todd Haymore, Secretary of Commerce and Trade
3. David Paylor, Director of the Virginia Department of Environmental Quality
4. John Warren, Director of the Virginia Department of Mines, Minerals, and Energy
5. John Daniel, Deputy Attorney General for Commerce, Environment and Technology

Executive Order 57 Work Group Meeting

December 1, 2016
1:00pm – 4:00pm
Patrick Henry Building, West Reading Room
1111 E. Broad St., Richmond, VA 23219

Agenda

I. Welcome – Molly Ward, Secretary of Natural Resources

II. Presentations:

a. EnerNOC

b. Covanta

c. WestRock

d. Third Party Delivered Energy Efficiency Coalition

e. UVA School of Law's Environmental and Regulatory Law Clinic

f. Birchwood Power

g. Virginia Poverty Law Center

III. Next Steps and Adjournment – Molly Ward, Secretary of Natural Resources

For those unable to attend in person, we have arranged a webcast using the following link: https://attendee.gotowebinar.com/register/5842017918223385090

Work Group Members

1. Molly Ward, Secretary of Natural Resources
2. Todd Haymore, Secretary of Commerce and Trade
3. David Paylor, Director of the Virginia Department of Environmental Quality
4. John Warren, Director of the Virginia Department of Mines, Minerals, and Energy
5. John Daniel, Deputy Attorney General for Commerce, Environment and Technology

Executive Order 57 Work Group Meeting

January 10, 2017
1:00pm – 4:00pm
Patrick Henry Building, West Reading Room
1111 E. Broad St., Richmond, VA 23219

Agenda

I. Welcome – Molly Ward, Secretary of Natural Resources

II. Presentations:

a. E2

b. Appalachian Voices

c. Southeastern Wind Coalition

d. Virginia Energy Efficiency Council

e. American Lung Association

f. Southeast Energy Efficiency Alliance

g. ACN Energy Solutions

III. Next Steps and Adjournment – Molly Ward, Secretary of Natural Resources

For those unable to attend in person, we have arranged a webcast using the following link: https://attendee.gotowebinar.com/register/5975119298986349057

Work Group Members

1. Molly Ward, Secretary of Natural Resources
2. Todd Haymore, Secretary of Commerce and Trade
3. David Paylor, Director of the Virginia Department of Environmental Quality
4. John Warren, Director of the Virginia Department of Mines, Minerals, and Energy
5. John Daniel, Deputy Attorney General for Commerce, Environment and Technology

Executive Order 57 Work Group Meeting

February 28, 2017
1:00pm – 4:00pm
Patrick Henry Building, West Reading Room
1111 E. Broad St., Richmond, VA 23219

Agenda

I. Welcome – Molly Ward, Secretary of Natural Resources

II. Presentations:

a. Ceres

b. Gerdau Long Steel North America

c. Virginia Environmental Justice Collective

d. E4TheFuture

e. Dominion

f. Southern Environmental Law Center

g. American Petroleum Institute

h. Verde Sources

i. Virginia Nuclear Energy Consortium

j. Natural Resources Defense Council

III. Next Steps and Adjournment – Molly Ward, Secretary of Natural Resources

For those unable to attend in person, we have arranged a webcast using the following link: https://attendee.gotowebinar.com/register/6504634204203803393

Work Group Members

1. Molly Ward, Secretary of Natural Resources
2. Todd Haymore, Secretary of Commerce and Trade
3. David Paylor, Director of the Virginia Department of Environmental Quality
4. John Warren, Director of the Virginia Department of Mines, Minerals, and Energy
5. John Daniel, Deputy Attorney General for Commerce, Environment and Technology

Attachment 7

COMMONWEALTH of VIRGINIA

Executive Department

Executive Directive 11 (2017)

REDUCING CARBON DIOXIDE EMISSIONS FROM ELECTRIC POWER FACILITIES AND GROWING VIRGINIA'S CLEAN ENERGY ECONOMY

There is no denying the science and the real-world evidence that climate change threatens the Commonwealth of Virginia, from our homes and businesses to our critical military installations and ports. Rising storm surges and flooding could impact as many as 420,000 properties along Virginia's coast that would require $92 billion of reconstruction costs.

The challenges and costs of bolstering resilience and minimizing risk are too great for any locality to bear alone. While the impacts are significant, there are technologies in the clean energy sector that could help mitigate these impacts while simultaneously creating jobs in twenty-first century industries. The number of solar jobs in Virginia has grown by 65 percent in the last year alone, and Virginia is now the ninth fastest growing solar jobs market in the country. Revenue for energy efficiency businesses in Virginia has increased from $300 million in 2014 to $1.5 billion in 2016. Through state leadership, Virginia can face the threats of climate change head on and do so in a way that makes clean energy a pillar of our future economic growth and a meaningful part of our energy portfolio.

With these considerations in mind, I issued Executive Order 57 (EO 57) on June 28, 2016. Under EO 57, I directed the Secretary of Natural Resources to convene a work group to study and recommend methods to reduce carbon dioxide emissions from electric power facilities and grow the clean energy economy within existing state authority. The group consisted of the Secretary of Natural Resources, the Secretary of Commerce and Trade, the Director of the Virginia Department of Environmental Quality, the Director of the Virginia Department of

Mines, Minerals and Energy, and the Deputy Attorney General for Commerce, Environment, and Technology. This group facilitated extensive stakeholder engagement over the last year, including six in-person meetings and a three month public comment period, before compiling the recommendations and submitting a final report to me on May 12, 2017.

Among the most significant recommendations from the group is the need to develop regulations limiting the total amount of carbon dioxide emitted from electric power facilities. Given the nature of the climate change threat and the promise of clean energy solutions, I agree with this recommendation.

Accordingly, pursuant to the authority vested in me as the Chief Executive Officer of the Commonwealth, and pursuant to Article V of the Constitution and the laws of Virginia, I hereby direct the Director of the Department of Environmental Quality, in coordination with the Secretary of Natural Resources, to take the following actions in accordance with the provisions and requirements of Virginia Code § 10.1-1300, *et seq.* and Virginia Code § 2.2-4000, *et seq.*:

1. Develop a proposed regulation for the State Air Pollution Control Board's consideration to abate, control, or limit carbon dioxide emissions from electric power facilities that:

    a. Includes provisions to ensure that Virginia's regulation is "trading-ready" to allow for the use of market-based mechanisms and the trading of carbon dioxide allowances through a multi-state trading program; and

    b. Establishes abatement mechanisms providing for a corresponding level of stringency to limits on carbon dioxide emissions imposed in other states with such limits.

2. By no later than December 31, 2017, present the proposed regulation to the State Air Pollution Control Board for consideration for approval for public comment in accordance with the Board's authority pursuant to Virginia Code § 10.1-1308.

Effective Date

This Executive Directive shall be effective upon its signing and shall remain in force and effect unless amended or rescinded by further executive order or directive.

Given under my hand and under the Seal of the Commonwealth of Virginia, this 16th day of May, 2017.

Terence R. McAuliffe, Governor

Attest:

Kelly Thomasson, Secretary of the Commonwealth

Attachment 8

The Washington Post
Democracy Dies in Darkness

Youngkin says he will take Virginia out of the Regional Greenhouse Gas Initiative to save ratepayers money

By Laura Vozzella

Updated December 8, 2021 at 8:08 p.m. EST | Published December 8, 2021 at 6:37 p.m. EST

CORRECTION

A previous version of this article incorrectly calculated the amount ratepayers would save yearly on electric bills if Virginia pulled out of a regional greenhouse gas compact. They would save $52.44 per year, not $227.24 per year. This article has been corrected.

RICHMOND — Gov.-elect Glenn Youngkin (R) told a business group Wednesday that he will use executive action to pull Virginia out of a regional greenhouse gas compact, a plan that Democrats said would cost the state hundreds of millions a year in flooding and energy-assistance funding.

The typical residential customer would save $4.37 a month on electric bills, or $52.44 per year, if Virginia pulled out, Youngkin's transition office said.

Nearly two years ago, as Democrats took control of the House of Delegates, Virginia joined the Regional Greenhouse Gas Initiative — a carbon cap-and-trade market among states in the Northeast and Mid-Atlantic. It was part of sweeping environmental legislation that also set a goal of going carbon-free by 2050.

In a speech to the Hampton Roads Chamber of Commerce, Youngkin said he will take the state out of the RGGI, as the regional initiative is known.

“RGGI describes itself as a regional market for carbon. It is really a carbon tax that is fully passed on to ratepayers,” he said. “It’s a bad deal for Virginians. It’s a bad deal for Virginia businesses. And as governor, I will withdraw us from RGGI by executive action. I promised to lower the cost of living in Virginia, and this is just the beginning.”

Del. Todd Gilbert (R-Shenandoah), who is slated to become House speaker when Republicans take back control of the chamber in January, cheered the news, saying RGGI’s impact on climate change has been “negligible at best.”

“Virginia was reducing carbon emissions from power plants at a rate comparable to RGGI states before joining the cap and trade group,” Gilbert said in a written statement. “When a policy costs the public a significant amount of money for no tangible benefit, that policy should be examined carefully, and if practical, rolled back.”

Some RGGI supporters said they were disappointed and questioned Youngkin’s authority to single-handedly pull the state out.

“I can assure you there’s a lot of lawyers … that are busy going to the books right now,” said Sen. Lynwood W. Lewis Jr. (D-Accomack), who sponsored the legislation in the Senate.

Regardless of Youngkin’s action on RGGI, the carbon targets will remain in state code — something that cannot be changed without new legislation from the General Assembly, said Cale Jaffe, an associate professor at the University of Virginia School of Law and director of the school’s Environmental Law and Community Engagement Clinic. The Senate remains under narrow Democratic control.

“You might leave this multistate trading program but still have to meet the zero-carbon mandate in the code,” Jaffe said. “Leaving the trading program just seems like cutting off your nose to spite your face. … I don’t know why you would relinquish a market that is helping to make the Clean Economy Act more affordable.”

Lewis said Virginia raised $227 million early this year in its first auction of carbon credits — money earmarked for flood preparedness across the state and energy-efficiency programs for low-income ratepayers.

“Regardless of your political party, if you’re a legislator in an area that’s impacted by sea-level rise of just recurrent flooding … you should be very reluctant and cautious in completely devastating that fund,” Lewis said. “This was going to provide a significant source of revenue.”

In his remarks to the chamber, Youngkin pledged to formulate a plan to “combat sea-level rise” before vowing to get the state out of RGGI via executive action. Asked about his authority to do so, Youngkin’s transition office issued a statement saying, “Virginia’s participation is governed by a contract agreement, signed by the Department of Environmental Quality and other regulations.”

Language in the statute directs the Department of Environmental Quality to manage the auction program under RGGI, Jaffe said, so that may be the avenue Youngkin is exploring, because the governor has the authority to direct the department’s actions. But under the legislation, the state’s Air Pollution Control Board has already promulgated regulations establishing a multistate trading program, he said.

“The governor cannot just undo regulations that he might not like via executive order,” Jaffe said, noting that it would be up to the seven-member board, currently all Democratic appointees, to change the regulations. Youngkin will not have the chance to put his own appointees on the board until July, when two seats will become open.

The members’ staggered four-year terms are “designed so you avoid this kind of whiplash,” Jaffe said.

Attachment 9

COMMONWEALTH of VIRGINIA

Office of the Attorney General

Mark R. Herring
Attorney General

202 North Ninth Street
Richmond, Virginia 23219
804-786-2071
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Virginia Relay Services
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7-1-1

January 11, 2022

The Honorable Charniele L. Herring
Member, Virginia House of Delegates
Post Office Box 11779
Alexandria, Virginia 22312

The Honorable Richard "Rip" Sullivan
Member, Virginia House of Delegates
Post Office Box 50753
Arlington, Virginia 22205

Dear Delegates Herring and Sullivan:

I am responding to your request for an official advisory opinion in accordance with § 2.2-505 of the Code of Virginia.

Issue Presented

You ask whether the Governor, solely through an executive order or other executive action, can repeal or eliminate the regulatory requirement that electric utilities and other electricity producers hold carbon dioxide allowances that equal the amount of their carbon dioxide emissions.

Discussion and Analysis

The Clean Energy and Community Flood Preparedness Act (the "Act") was passed by the General Assembly in 2020, amended Va. Code § 10.1-1330. The Act directs the Virginia Department of Environmental Quality to amend its regulations that established a carbon dioxide cap and trade program to reduce carbon dioxide emissions. Section 10.1-1330(B) authorizes the Director of DEQ "to establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the [Regional Greenhouse Gas Initiative] program and this article."[1]

Consistent with the Act's requirements, DEQ issued amendments to its CO_2 Budget Trading Program regulations. Pursuant to those regulations, an owner or operator of a CO_2 budget source, such as an electric utility, must "hold CO2 allowances . . . in an amount not less than CO2 emissions that have been

[1] VA. CODE ANN. § 10.1-1300(B). This and other citations to the Code of Virginia herein are from the electronic version of the Code on LexisNexis and are current through the 2021 Regular Session and Special Session I and II of the General Assembly.

generated as a result of combusting fossil fuel" for a given time period.[2] Put differently, in order to lawfully produce electricity in Virginia by combusting fossil fuels, producers must now hold carbon dioxide allowances that equal the amount of their carbon dioxide emissions. One of the ways producers obtain CO_2 allowances in order to comply with this regulation is by purchasing them through the Regional Greenhouse Gas Initiative auction. You have asked whether the Governor may, through an executive order or other executive action, do away with this regulatory requirement.

A recent Attorney General opinion discussed the separation of powers doctrine with respect to the Governor's power to alter tax laws.[3] The same rationale applies to validly enacted laws. The Constitution of Virginia does not grant the Governor the power to suspend laws, and in fact, it requires the opposite that "[t]he Governor shall take care that the laws be faithfully executed."[4] Article I, § 7 of the Constitution of Virginia provides "[t]hat all power of suspending laws, or the execution of laws, by any authority, without consent of the representatives of the people, is injurious to their rights, and ought not to be exercised."

A previous Attorney General opinion explained the interplay between these sections of the Constitution. "Thus, the prohibition that is implicit in Article V, § 7's 'take care' clause is made explicit by Article I, § 7: the Governor may not unilaterally direct, by any means, that a validly adopted regulation that has the force of law be suspended or ignored."[5] In my opinion, the Governor may not repeal or eliminate, through an executive order or other action, the enacted statutes and regulations pertaining to the Commonwealth's participation in the Regional Greenhouse Gas Initiative and/or a market-based trading program like the Regional Greenhouse Gas Initiative, or do away with the requirement that electricity producers hold carbon dioxide allowances that equal the amount of their carbon dioxide emissions.

Conclusion

Accordingly, it is my opinion that the Governor may not, solely through an executive order or other executive action, repeal or eliminate the regulatory requirement that electric utilities and other electricity producers hold carbon dioxide allowances that equal the amount of their carbon dioxide emissions.

With kindest regards, I am,

Very truly yours,

Mark R. Herring

Mark R. Herring
Attorney General

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[2] 9 VA. ADMIN. CODE § 5-140-6050(C) (2021).

[3] 2021 Op. Va. Att'y Gen. No. 21-087, available at https://www.oag.state.va.us/citizen-resources/opinions/official-opinions/30-resource/opinions/1917-2021-official-opinions#november.

[4] VA. CONST., art. V § 7.

[5] 2014 Op. Va. Att'y Gen. 43, 45-46.

Attachment 10

Commonwealth of Virginia
Office of the Governor

Executive Order

NUMBER NINE (2022)

PROTECTING RATEPAYERS FROM THE RISING COST OF LIVING DUE TO THE REGIONAL GREENHOUSE GAS INITIATIVE

By virtue of the authority vested in me as Governor, I hereby issue this Executive Order to re-evaluate Virginia's participation in the Regional Greenhouse Gas Initiative and immediately begin regulatory processes to end it.

Importance of the Initiative

Reliable and affordable access to electricity is imperative to the health and safety of all Virginians. Our hospitals, schools, businesses, and homes all rely on this essential service. And the unpredictable and rising cost of electricity poses a significant and immediate threat to our Commonwealth and its citizens. In 2019, alone, over 100,000 Virginian households required Energy Assistance with a cost of $46 million to the Commonwealth.

Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI) risks contributing to the increased cost of electricity for our citizens. Virginia's utilities have sold over $227 million in allowances in 2021 during the RGGI auctions, doubling the initial estimates. Those utilities are allowed to pass on the costs of purchasing allowances to their ratepayers. Under the initial bill "RGGI rider" created for Dominion Energy customers, typical residential customer bills were increased by $2.39 a month and the typical industrial customer bill by was raised by $1,554 per month. In a filling before the State Corporation Commission, Dominion Energy stated that RGGI will cost ratepayers between $1 billion and $1.2 billion over the next four years.

Simply stated, the benefits of RGGI have not materialized, while the costs have skyrocketed. Re-evaluation of the Initiative represents a meaningful step toward alleviating this financial burden on the Commonwealth's businesses and households. Regulations must be evaluated in view of the costs and benefits to all Virginians.

Directive

Accordingly, by virtue of the authority vested in me as the Chief Executive Officer of the Commonwealth, and pursuant to Article V of the Constitution and the laws of Virginia, I hereby direct the Director of the Department of Environmental Quality, in coordination with the Secretary of Natural and Historic Resources, to take the following actions in accordance with the provisions and requirements of § 10.1-1300, et seq. and § 2.2-4000, et seq. of the *Code of Virginia*:

1. Provide me a full report re-evaluating the costs and benefits of participation in the Regional Greenhouse Gas Initiative Inc. in view of all available data, within 30 days.

2. During this same period, develop a proposed emergency regulation for the State Air Pollution Control Board's consideration to repeal 9VAC5-140.

3. During this same period, take all necessary steps to so that any proposed regulation to the State Air Pollution Control Board can be immediately presented for consideration for approval for public comment in accordance with the Board's authority pursuant to § 10.1-1308 of the *Code of Virginia*.

4. During this same period, notify the Regional Greenhouse Gas Initiative Inc. (RGGI Inc.) of the review and the Governor's intent to withdraw from RGGI, whether by legislative or regulatory action.

Effective Date

This Executive Order shall be effective upon its signing and shall remain in force and effect unless amended or rescinded by further executive order or directive.

Given under my hand and under the Seal of the Commonwealth of Virginia, this 15th day of January 2022.

Glenn Youngkin, Governor

Attest:

Kelly Thomasson, Secretary of the Commonwealth

Attachment 11

Commonwealth of Virginia

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY

1111 E. Main Street, Suite 1400, Richmond, Virginia 23219
P.O. Box 1105, Richmond, Virginia 23218
(800) 592-5482 FAX (804) 698-4178
www.deq.virginia.gov

Andrew R. Wheeler
Secretary of Natural and Historic Resources

Michael S. Rolband, PE, PWD, PWS Emeritus
Director
(804) 698-4000

March 11, 2022

Via email:andrew.wheeler@governor.virginia.gov

The Honorable Andrew S. Wheeler
Secretary of Natural and Historic Resources
1111 East Broad Street
Fourth Floor
Richmond, VA 23219

Re: EO-9

Dear Secretary Wheeler:

Governor Youngkin's Executive Order (EO) 9, signed on January 15, directs the Department of Environmental Quality to coordinate with you in completing the following by February 14:

1. Provide [the Governor] a full report re-evaluating the costs and benefits of participation in the Regional Greenhouse Gas Initiative Inc. in view of all available data;

2. Develop a proposed emergency regulation for the State Air Pollution Control Board's consideration to repeal Part VII of 9VAC5-140;

3. Take all necessary steps to so that any proposed regulation to the State Air Pollution Control Board can be immediately presented for consideration for approval for public comment in accordance with the Board's authority pursuant to § 10.1-1308 of the Code of Virginia; and

4. Notify the Regional Greenhouse Gas Initiative Inc. (RGGI Inc.) of the review and the Governor's intent to withdraw from RGGI, whether by legislative or regulatory action.

Pursuant to EO-9, therefore, enclosed for your review are the following:

- A draft report re-evaluating the costs and benefits of participation in RGGI in view of all available data (Item 1);

- A draft emergency regulation (Item 2), along with a brief description of the process for promulgating an emergency regulation under Va. Code §2.2-4011, including a draft letter to the Attorney General asking for his approval as required by that statute (Item 3);

- A brief description of the process and timetable for turning an emergency regulation into a permanent regulation under the Administrative Process Act, including a draft Notice of Intended Regulatory Action (NOIRA) to commence that process (Item 3); and

- A draft letter for your signature notifying RGGI, Inc., of the Governor's intent of withdrawing the Commonwealth from the RGGI program (Item 4).

Please let me know if you have any questions. My staff and I would be glad to brief this report with you at your convenience.

Sincerely,

Michael S. Rolband

VIRGINIA CARBON TRADING RULE AND REGIONAL GREENHOUSE GAS INITIATIVE (RGGI) PARTICIPATION

COSTS AND BENEFITS

A Report to the Honorable Glenn Youngkin, Governor Commonwealth of Virginia

Department of Environmental Quality
in coordination with
The Secretary of Natural and Historic Resources

MARCH 11, 2022

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EXECUTIVE SUMMARY

On July 10, 2020, Virginia formally adopted the CO_2 Budget Trading Program (Part VII of 9VAC5-140) for the power sector to implement a carbon emissions trading and reduction program as authorized by the Clean Energy and Community Flood Preparedness Act (Article 4 of Chapter 1219 of the 2020 Acts of Assembly). The rule allowed for full participation in the Regional Greenhouse Gas Initiative (RGGI) to reduce carbon dioxide (CO_2) emissions and make emissions allowances available for sale through an auction program that power producers use for compliance purposes. Proceeds from allowance sales are returned to Virginia to fund climate mitigation and resilience programs. Adoption of the rule was the result of a 3-year process that produced a program based on a consignment auction approach, and then transitioned into a full auction program as authorized by the General Assembly in 2020. Virginia began full participation in RGGI on January 1, 2021, and participated in five quarterly auctions to date.

On January 15, 2022, Governor Youngkin issued Executive Order 9 (2022) (EO-9) to re-evaluate Virginia's participation in RGGI and immediately begin the regulatory process to end its participation. The re-evaluation is based on new information that points to higher costs for residential and industrial ratepayers due to participation in RGGI, and that the benefits of RGGI participation have not been realized. Most of this cost increase information come from the State's largest regulated utility, Dominion Energy, in rate increase filings before the State Corporation Commission to recover the costs of compliance with the carbon-trading rule that includes the cost of purchasing emissions allowances to cover their CO_2 emissions.

This report serves as the required program re-evaluation in light of all available data regarding the costs and benefits of the carbon-trading rule and participation in RGGI. However, the availability of new information is limited since Virginia has just completed its first year of participation. The focus of the evaluation will be on the program areas of ratepayer impacts, allowance prices, and emissions trends. It will also look at the various analyses performed on RGGI and related clean power programs such as the Virginia Clean Economy Act (VCEA). The report also refers to the recently submitted annual report to the Governor and General Assembly on the Virginia Clean Energy and Community Flood Preparedness Act.

Our review of the data in the report provides the following high level conclusions regarding RGGI:

- Because of the captive nature of their ratepayers, the ability for power-generators to fully pass on costs to consumers, and the fact that the Code of Virginia dedicates RGGI proceeds to grants programs, participation in RGGI is in effect a direct carbon tax on all households and businesses;
- RGGI fails to achieve its goal as a carbon "cap-and-trade" system because it lacks any incentive for power-generators to actually reduce carbon-intensive gas emissions;
- Carbon emissions rates have been reduced in Virginia by over 50% in the past 10 years, prior to the Commonwealth's participation in RGGI.

Summary of Findings

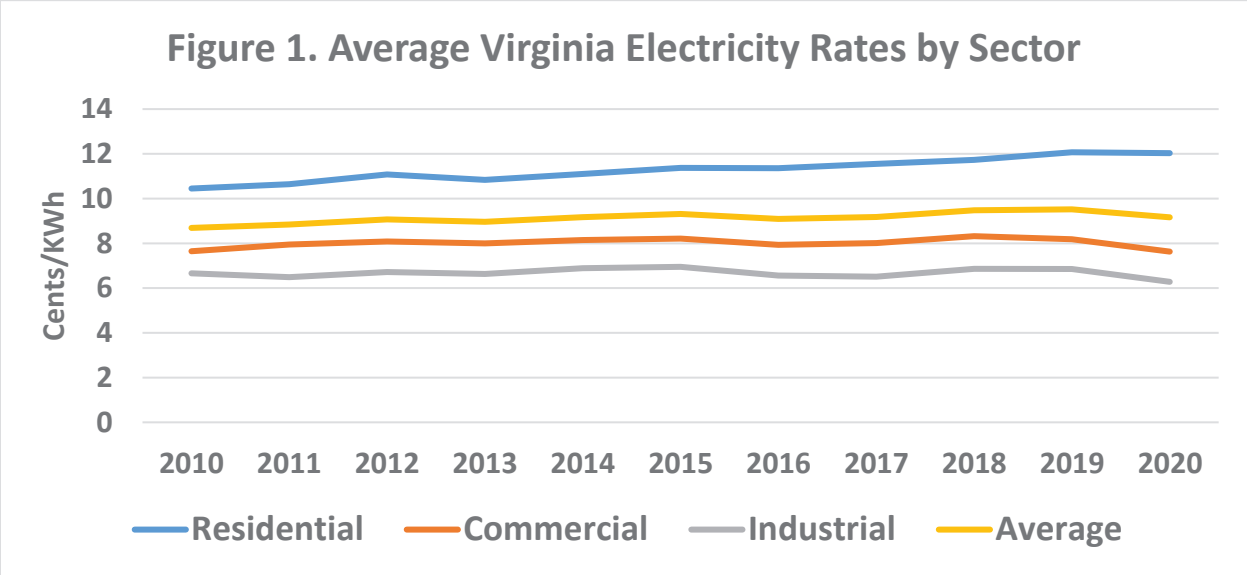
- Participation in RGGI in effect operates as a direct tax on households and businesses because all fees paid to the RGGI Board are passed through to utility-captive ratepayers.

- In addition, consumers are unable to avoid the pass through of these costs because they do not have the opportunity to switch electric providers – Dominion and other providers are monopolies in most regions of Virginia.
- The imposition of the RGGI "carbon tax" fails to offer any incentive to change behavior. Current law allows power generators, such Dominion Energy, to pass on all their costs, essentially bearing no cost for the carbon credits.
- Other states return the RGGI proceeds to consumers through rebates, while Virginia has opted to use the proceeds for separate and unrelated grant programs resulting in an effective tax increase on all ratepayers
- The original RGGI approach, prior to enactment, was designed to return the proceeds to the ratepayers in order to offset the costs of the program to the consumer, but this was not how Virginia implemented the program
- The costs of compliance with the trading rule and participation in RGGI have materialized in higher electricity rates as identified in the filings before the State Corporation Commission by Dominion Energy.
- Emission allowance prices have increased over time and substantially in the last year and are expected to continue increasing which will increase the tax on ratepayers.
- Lastly, without and prior to RGGI, electricity generation has increased while CO_2 per MWh has almost been cut in half in Virginia over the last ten years.
- RGGI is a bad construct that taxes consumers without providing incentives for change to the electricity producers.

SECTION 1 – ELECTRICITY RATE IMPACTS

One of the main concerns with participation in RGGI identified in EO-9 is the environmental compliance cost of RGGI on Virginia ratepayers. EO-9 states that the RGGI environmental compliance cost will increase "a typical" residential customer bill by $2.39 per month, and a typical industrial customer bill by $1,554 per month. EO-9 also states that Dominion Energy projects that RGGI will cost ratepayers between $1 billion and $1.2 billion over the next four years.

For background purposes, the historical trends of electricity rates from 2010 to 2020 are presented in Figure 1 below. These data show a gradual increase in all sector rates until 2020 where rates decline. Residential rates are the highest, followed by commercial with the industrial sector having the lowest average rates.



Source: Energy Information Administration

The first three-year control period for Virginia "CO_2 Budget Sources" began on January 1, 2021 and extends through December 31, 2023. Under each RGGI participating state's CO_2 Budget Trading Program, each "CO_2 budget source" is required to provide one CO_2 allowance for each ton of CO_2 emitted during the preceding three-year control period. Virginia utility law (Code of Virginia 56-585.1 A 4) allows Dominion and Appalachian Power ("CO_2 Budget Sources" under the CO_2 Budget Trading Program) to recover environmental compliance costs associated with participating in RGGI through new rate adjustment clauses.

On November 9, 2020, Dominion Energy filed a petition with the Virginia State Corporation Commission (SCC) to establish a new RGGI rate adjustment clause ("Rider RGGI") to recover $168,260,000 in "projected" RGGI compliance costs for the rate year of August 1, 2021 to July 31, 2022 (i.e., Case No. PUR-2020-00169), including:

- $129,960,000 for the purchase of 19 million allowances at $6.84 per allowance), and
- $38,330,000 of financing costs and a 9.2% rate of return associated with the purchase of 19 million allowances.

On August 4, 2021, the Commission issued an Order approving the Rider RGGI for initial year cost recovery starting on September 1, 2021 of $167.76 million (projected quantity and prices of allowances), 9.2% rate of return on projected allowance purchases, and finance costs associated with projected allowance purchases). As such, "the charge for service under Virginia Electric and Power Company's Filed Rate Schedules, as well as applicable energy charges specified in any special rates, contracts or incentives approved by the State Corporation Commission pursuant to Virginia Code § 56-235.2 shall be increased by 0.2393 cents per kilowatt-hour." The approved Rider RGGI explains the increase in a monthly residential customer electric bill and a monthly industrial customer electric bill of $2.39 and $1,554. The Order approving the Rider RGGI states, "RGGI is expected to cost Dominion's Virginia jurisdictional ratepayers approximately $3 billion [excluding finance costs] through 2045." The Order also states that any projected environmental compliance costs such as projected quantity and/or price of allowances and associated ROE and finance costs are to be trued-up in future Rider RGGI proceedings.

On August 24, 2021, a Petition for Reconsideration or Clarification ("Petition") was filed with the Commission. On November 17, 2021, the Commission issued its Order on Reconsideration, and elected not to modify the August 6, 2021 Order approving the Rider RGGI, with the exception of revised effective dates of the Rider RGGI:

- The first Rider RGGI tariff sheet is effective for usage on and after September 1, 2021 and reflects a rate of zero; and
- The next Rider RGGI tariff sheet is effective for usage on and after January 1, 2022, and reflects the 0.2393 cents per kilowatt-hour rate approved in the Rider RGGI Approval Order.

In December 2021, Dominion Energy filed a petition with the Commission for a revision of rate adjustment clause, "Rider RGGI" pursuant to § 56-585.1 A 5 e of the Code of Virginia (i.e., Case No. PUR-2021-0028). Dominion Energy withdrew the petition on January 10, 2022. The total environmental compliance cost recovery (i.e., revenue requirement) requested in the withdrawn Rider RGGI Petition for the Rate Year beginning September 1, 2022, was $323,411,000. It assumed an average price of $10.53 per allowance for the period of October 2021 through December 2023, a 9.35% ROE of allowances purchases, and finance costs associated with the allowance purchases. The withdrawn proposed petition for a revised rate adjustment clause would increase the approved Rider RGGI by 0.198 cents per kilowatt-hour, increasing the total Ride RGGI to 0.437 cents per kilowatt-hour.

Prices and quantities of allowances affect compliance costs, therefore, impact rate ratepayers. Data available on RGGI compliance costs are projected costs, because the actual quantity of allowance purchases and actual prices were not known at the time the new Rider RGGI was approved by the Commission.

Also, the second RGGI Program Review was completed in December 2017, resulting in the 2017 Model Rule, which was the foundation for the final rule subsequently adopted by Virginia as Part VII of 9VAC5-140 in accordance with the Clean Energy and Community Flood Preparedness Act. Resulting program modifications included changes to the Cost Containment Reserve (CCR) size and trigger price. The proposed CCR size from 2021 onwards will be 10% of the regional cap. The CCR trigger price will be $13.00 in 2021, and rise at 7% per year, ensuring that the CCR will only trigger if emission reduction costs are higher than projected.

In response to electricity rate concerns resulting from program compliance, four participating RGGI states, including Delaware, Maryland, Maine, and New Hampshire use a percentage of their allowance proceeds for direct bill assistance to mitigate the costs impact on ratepayers. In addition, North Carolina is seriously considering joining the RGGI program using the consignment approach modeled on the previous Virginia rule.

On February 2, 2021, the RGGI states, which include Virginia, released a statement announcing the plan for the Third Program Review to consider further updates to their programs, and in Summer 2021 the states released a preliminary timeline for conducting the Third Program Review, which will include a REMI macroeconomic analysis and bill impact analysis which may provide new information of future program costs and benefits.

The main conclusions of this section are as follows:

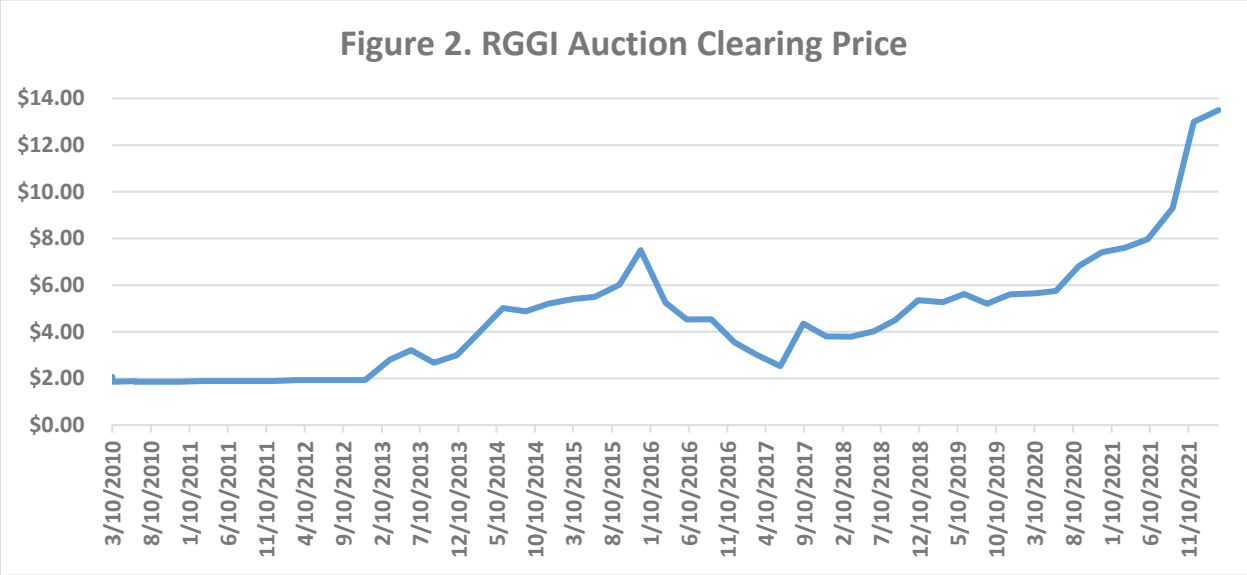
- The compliance costs of RGGI program participation have submitted by Dominion Energy and approved by the SCC, and have begun to impact electricity rates.
- These costs are and will continue to be directly related to the cost of allowances, along with other charges allowed under current law and regulations.
- Allowance prices have varied significantly in the past, and future prices will continue to vary.
- The social cost of carbon as required by VCEA has not been fully incorporated in the SCC process to date, but will be going forward, and may change future cost/benefit analyses.
- Four other RGGI participating states (and prospectively a fifth) provide bill assistance to customers using some of their auction proceeds.

SECTION 2 – ALLOWANCE PRICES AND AUCTION REVENUE

A central feature of any cap and trade program to reduce climate or criteria pollutant emissions is the concept of an emissions "allowance." An allowance usually represents the emission of one ton of pollution. These allowances are either sold or given to regulated entities for compliance or other purposes. As such, the allowance has value that is determined by the market through supply and demand. Reductions are achieved by gradually lowering the amount of allowances available in the market over time. RGGI operates under the concept where the allowances are allocated to the participating states and then sold through auctions. The proceeds are then returned to the states to support climate related programs.

Concern was raised in EO-9 about the rising cost of RGGI allowances and the resulting impact on electricity rates as described in more detail in Section 1 of this report. Therefore a review of allowance prices has been performed. Figure 2 shows the values of the RGGI auction clearing prices from 2010-2021. As shown in the figure, clearing prices have been volatile over time. Until 2014, prices remained below $4.00. From 2014 to 2017, the price rose to a high of $7.50 before falling to a low of $2.53. Since 2017, prices have risen steadily until experiencing a large jump in Auction 54, where the clearing price rose to the cost containment reserve (CCR) trigger level of $13.00. The cost containment reserve is a safeguard function of the RGGI program that sets a ceiling for allowance prices. Auction 54 is only the second time in the history of the program where the CCR has been triggered. The allowance price again increased slightly in Auction 55 to $13.50, an all-time high for the program, but did not trigger the updated CCR level

of $13.91 for 2022.



Source: Regional Greenhouse Gas Initiative Website

On the flip side of allowance prices is the proceeds generated by their sale that will go to support climate related mitigation and resilience programs. Thus far, Virginia has raised $301 million from the sale of allowances.

RGGI, Inc., administers quarterly auctions on behalf of the RGGI states where it offers allowances for sale to compliance entities and other groups. Virginia first participated in Auction 51, which was held on March 3, 2021, and the Commonwealth has participated in four additional auctions for a total of five. A summary of auction results is available in Table 1, and a distribution of funds raised from auctions is shown in Table 2.

It should be noted that RGGI, Inc., receives a small portion (0.3%) of Virginia's quarterly auction proceeds to fund its annual operating budget. Virginia's total payment to RGGI, Inc. for 2021 was $592,920.08. The payment due to RGGI Inc. for 2022 is $638,237.81.

Table 1: 2021 Auction Results Summary

	Allowances Sold	Allowance Price	Allowance Proceeds
Auction #51	5,735,509	$7.60	$43,589,868.40
Auction #52	5,698,446	$7.97	$45,416,614.62
Auction #53	5,698,445	$9.30	$52,995,538.50
Auction #54	6,587,274	$13.00	$85,634,562.00
Auction #55	5,497,712	$13.50	$74,219,112.00
Total	29,217,386		$301,855,695.52

The Clean Energy and Community Flood Preparedness Act provides that 45% and 50% of the proceeds generated from the auctions be used to fund the Virginia Community Flood

Preparedness Fund (CFPF) and the Housing Innovations in Energy Efficiency (HIEE) program, respectively. Administered by the Department of Housing and Community Development (DHCD), the CFPF helps localities across the Commonwealth reduce the impacts of flooding by implementing flood prevention and protection projects. Administered by the Department of Conservation and Recreation (DCR), the HIEE program makes energy efficiency upgrades to new and existing residential buildings to reduce energy bills for low-income Virginians. DEQ receives 3% of auction revenues to cover administrative expenses related to running the program and to carry out statewide climate change planning and mitigation activities. In partnership with the Virginia Department of Energy, DHCD receives 2% of the proceeds to administer and implement the HIEE program.

Table 2: Distribution of Funding

	RGGI	DHCD	DCR	DEQ	DHCD Admin
#51	$148,230.02	$21,720,819.19	$19,548,737.27	$1,303,249.15	$868,832.77
#52	$148,230.02	$22,634,192.30	$20,379,773.07	$1,358,051.54	$905,367.69
#53	$148,230.02	$26,423,654.24	$23,781,288.82	$1,585,419.25	$1,056,946.17
#54	$148,230.02	$42,743,165.99	$38,468,849.39	$2,564,589.96	$1,709,726.64
#55*	$159,559.45	$37,029,776.28	$33,326,798.65	$2,221,786.58	$1,481,191.05
Total	$75,2479.53	$150,551,608.00	$135,505,447.20	$9,033,096.48	$6,022,064.32

* Preliminary estimates

More information on the low-income energy efficiency and resiliency programs funded by auction proceeds can be found in the previously mentioned annual report on the Clean Energy and Community Flood Preparedness Act.

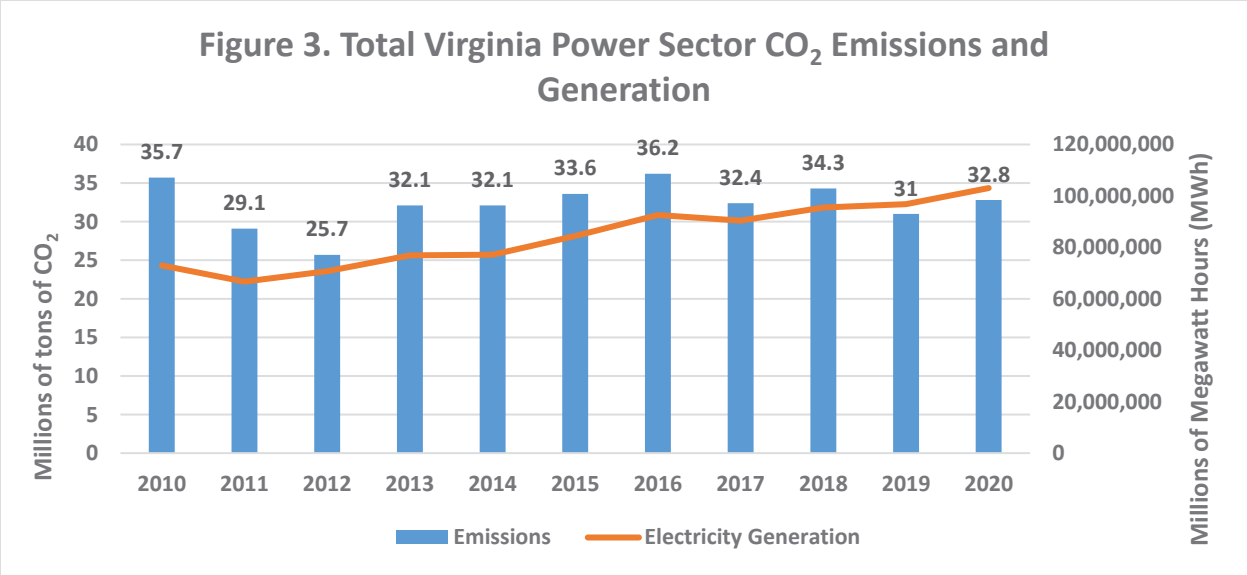
The main conclusions of this section are as follows:

- Allowance prices have varied widely over time.
- Allowance prices have increased sharply since 2020.
- Auction proceeds to Virginia for climate related programs have also increased based on these prices.
- Future allowance prices have been and will continue to be hard to predict.

SECTION 3 – POWER SECTOR GHG EMISSIONS TRENDS

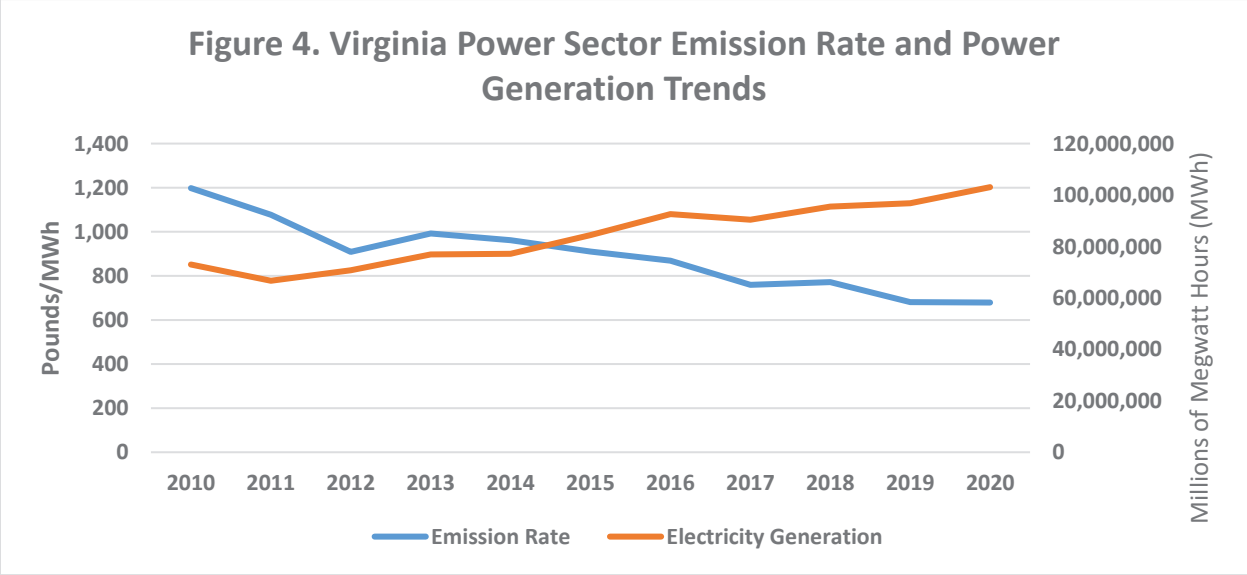
As mentioned earlier, emission reductions are the principle purpose and rationale of the carbon-trading rule and RGGI program. This is accomplished through setting emissions budgets and reducing them over time to achieve the desired reduction goal. It is too early to determine the impact of the program on emissions since 2021 is Virginia's first participation year.

However, to begin to assess this impact, the recent emission trends of the Virginia power sector must be evaluated. Emissions of CO_2 from the power sector are estimated and tracked by both the federal Environmental Protection Agency (EPA) and the DEQ. The recent trends in sector emissions are provided in Figure 3 below. It can be seen from the data that these emissions have fluctuated over the past 10 years with no discernable trend. During this period the average annual power sector emissions total in Virginia was 33.3 million tons.



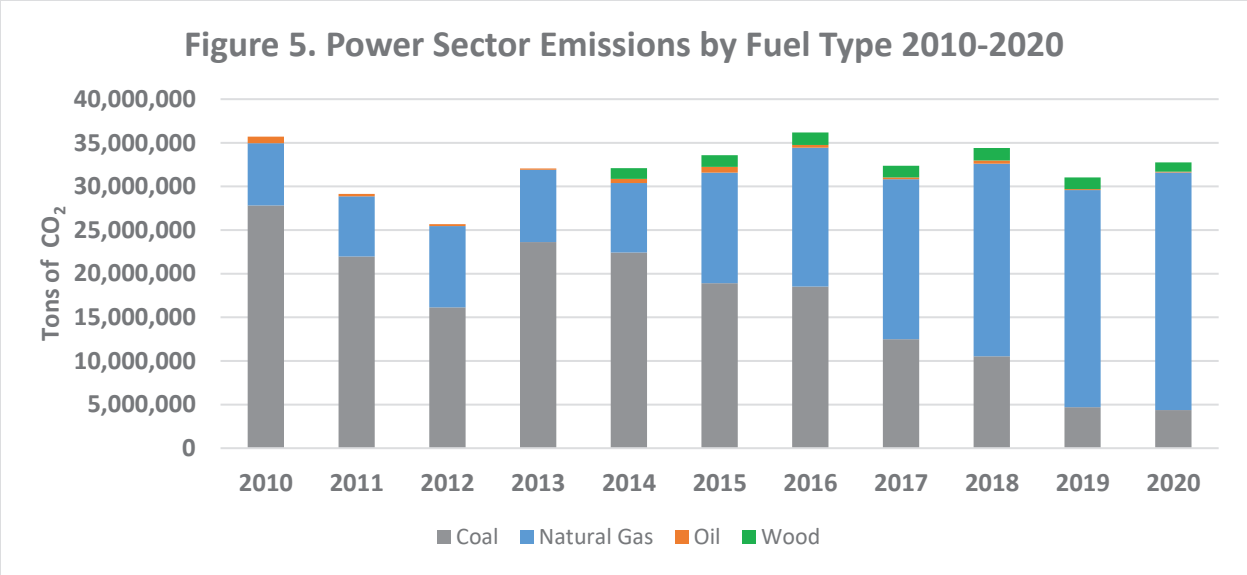
Source: EPA Air Markets Program Data and Energy Information Administration

While mass emissions have remained fairly constant, the overall state emission rate, which is the amount of CO_2 emissions produced by a set amount of electricity, has steadily and significantly been reduced. This trend is documented in Figure 4 where the statewide emission rate in 2010 was just under 1,200 lbs. per MWh that has then decreased to 679 lbs./MWh, which represents a 43% reduction in this average rate of CO_2 emissions per unit of electricity.



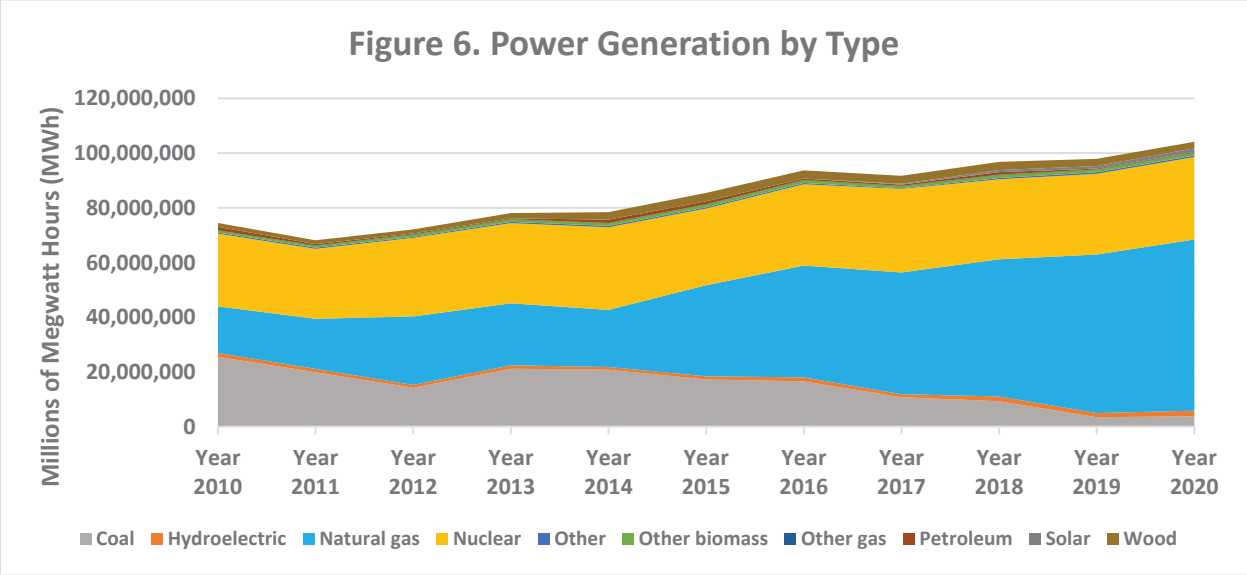
Source: Energy Information Administration

Given this mix of mass and emissions rate data and trends, a further data analysis is presented below in Figure 5 that shows that a major shift has occurred in the Virginia power sector where electricity generation from coal has been replaced by cleaner generation sources of natural gas and more recently renewable energy generation sources. Also during the same time, in-state electricity generation has increased by about 30%, which has led to the mass emissions levels remaining relatively constant.



Source: EPA Air Markets Program Data

A similar analysis of electricity generation by type is presented in Figure 6 that again shows the decrease in coal generation, increase in natural gas generation, and the introduction of renewable generation into the mix.



Source: Energy Information Administration

While these overall emissions and generation trends have occurred in the Virginia power sector, a number of source specific changes have occurred in Virginia's mix of power generation that will influence current and future emissions and generation trends. These changes, identified as new sources, closures and fuel conversions, are presented below in Table 3. From 2010 to 2020, six coal facilities closed, while five large combined cycle natural gas facilities have opened. Three coal facilities converted to biomass (wood) and one converted to gas.

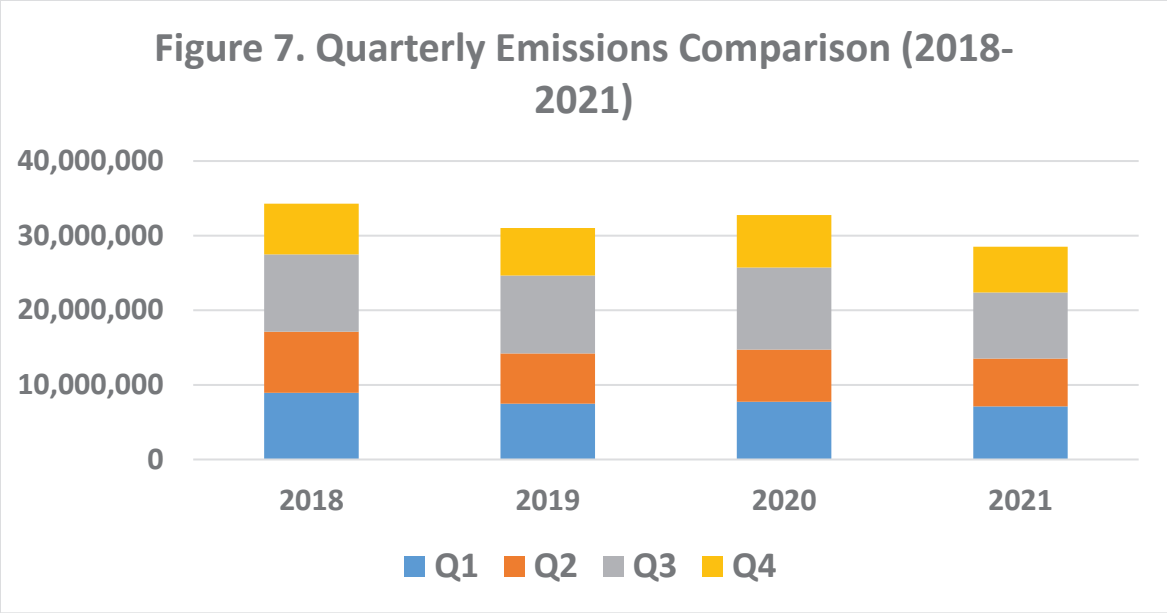
Table 3: Changes to Power Generation Sources in Virginia (2010-2020)

Plant Name	Change In Operation/Fuel	Year
Bear Garden Generating Station	Gas facility began operating	2011
Potomac River	Coal facility permanently closed	2012
Virginia City Hybrid Energy Center	Coal/biomass facility began operating	2012
Hopewell Power Station	Converted to biomass (wood) from coal	2013
NOVEC Halifax County Biomass Plant	Biomass facility began operating	2013
Southampton Power Station	Converted to biomass (wood) from coal	2013
Altavista Power Station	Converted to biomass (wood) from coal	2014
Bremo Power Station	Converted to gas from coal	2014
Chesapeake Energy Center	Coal facility permanently closed	2014
Warren County Power Station	Gas facility began operating	2014
Clinch River	Coal unit 3 retired, units 1 and 2 converted to gas	2015
Glen Lyn	Coal facility permanently closed	2015
Portsmouth Genco LLC	Coal facility permanently closed	2015
Brunswick County Power Station	Gas facility began operating	2016
Panda Stonewall Power Project	Gas facility began operating	2017
Bellemeade Power Station	Gas facility permanently closed	2018
Bremo Power Station	Gas facility permanently closed	2018
Chesterfield Power Station	Coal units 3 and 4 permanently closed	2018
Greensville County Power Station	Gas facility began operating	2018
Mecklenburg Power Station	Coal facility permanently closed	2018
Possum Point Power Station	Gas units 3 and 4 retired	2018
City Point Energy Center	Coal facility permanently closed	2019
Yorktown Power Station	Coal units 1 and 2 retired	2019
Possum Point Power Station	Oil unit 5 retired	2020

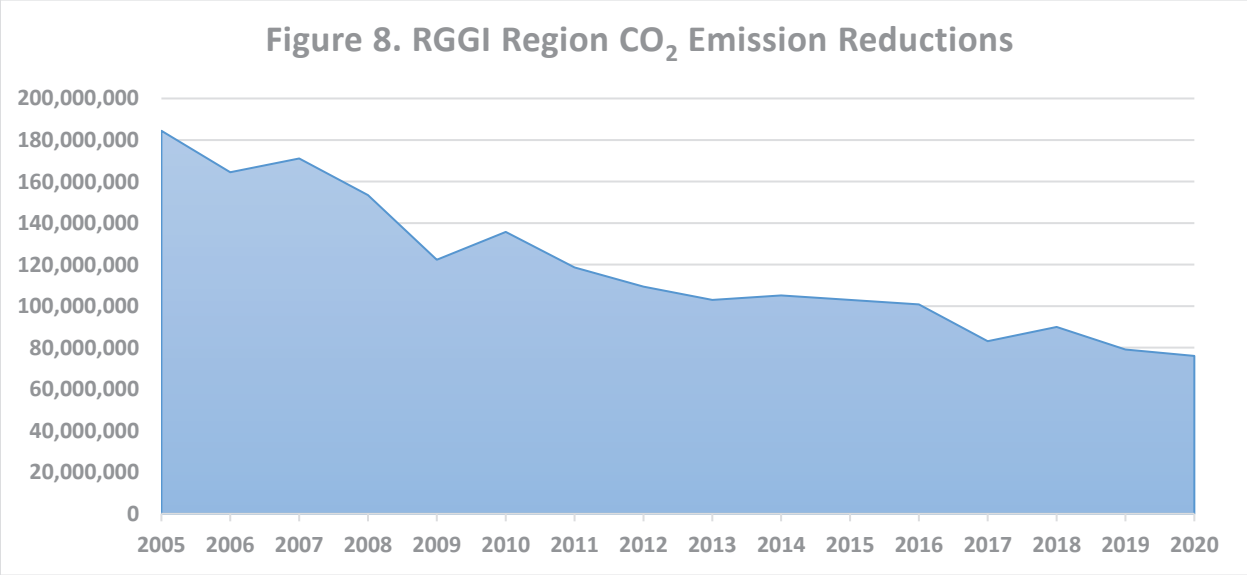
Source: PJM Generation Deactivations, EPA Air Markets Program Data tool

The carbon-trading rule and the RGGI program are designed to reduce regional CO_2 emissions over time by setting descending annual emission budgets to meet established reduction goals. The Virginia trading rule has established a starting emissions budget for 2021 of 27.6 million tons, which is then reduced annually at a consistent rate to 19.6 million tons in 2030. This is consistent with the RGGI goal of a 30% reduction between 2020 and 2030. However, since this is a regional trading program, the actual emissions reductions during this period may vary by state.

An analysis of control year 2021 emissions to date has been performed to see if any initial impact of the RGGI program can be seen in the Virginia power sector. To do so, the quarterly emissions data for 2021 have been compared the same data for past years. The results of this analysis are provided below in Figure 7. While there has been a decrease in emissions for 2021 as compared to prior years, this cannot be directly or solely attributed to RGGI participation.



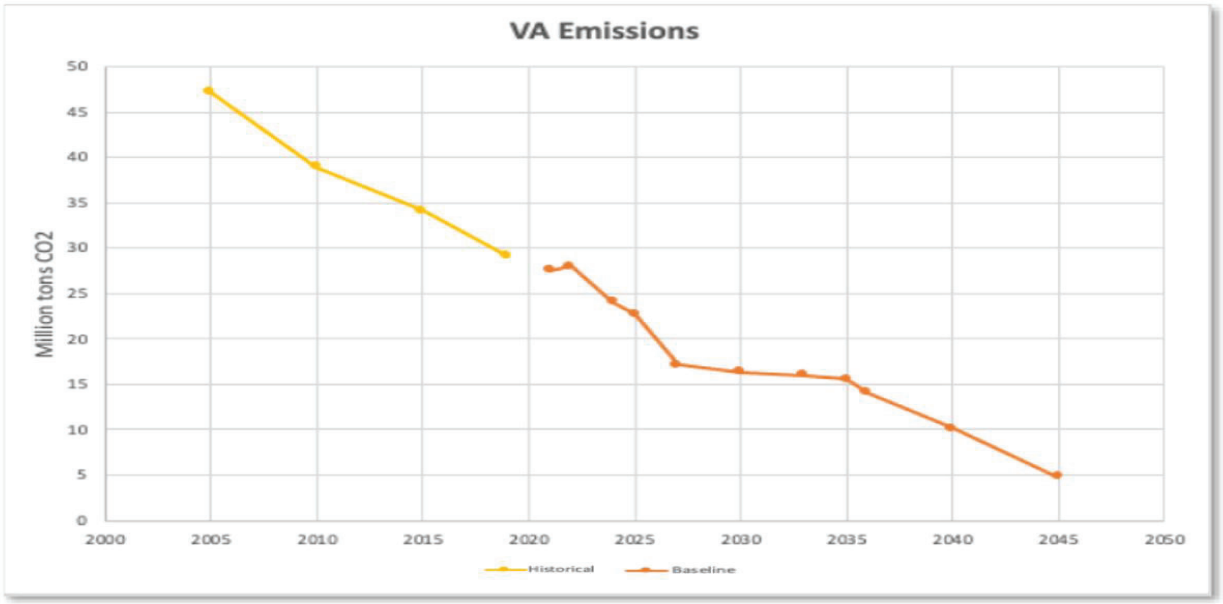
While the emissions data and impact of RGGI participation by Virginia is limited and inconclusive, the RGGI region has a long track record of emission reductions since the beginning of the program. This is shown in Figure 8 below where CO_2 emissions have decreased in the RGGI participating states by 59% from 2005 to 2020. Note that Virginia is not included in these data.



To assess the future of the power sector and predicted emissions reductions we must turn to modeling efforts that have been completed. A recently completed study and report completed by the Virginia Department of Energy, in consultation with the DEQ on the Virginia Clean Economy Act (VCEA) – Achieving Clean Electricity Generation at Least Cost to the Ratepayers by 2045. This study and report shows that the combination of participation in RGGI along with the specific mandates of the VCEA including the closure of most of the remaining coal and biomass electric generating facilities in Virginia, along with specific renewable energy

generation targets and standards, is expected to lead to a carbon free power sector in the 2045-2050 timeframe. This supports the requirements of both the VCEA and statutory goal of net-zero carbon emissions economy-wide by 2045. The CO_2 emissions reduction predictions of the study are provided in Figure 9.

Figure 9. CO_2 Emissions Reduction Predictions, VCEA Study



The main conclusions of this section are as follows:

- Mass emissions levels of CO_2 from the Virginia power sector have remained fairly constant over the last 10 years despite a 30% increase in power production.
- Average emission rates have substantially decreased during the same time and in-state electricity generation has increased.
- There is insufficient data to determine the impact of the trading rule and RGGI in reducing CO_2 emissions, since 2021 has been the first year of Virginia's participation in the program.
- The DOE study of the Virginia power sector indicates that an emission reduction program or combination of programs will be required to meet the Commonwealth's climate goals of the VCEA and the 2045 net-zero carbon emissions goal. In the absence of any such program, emissions may not reduce sufficiently to achieve these goals.

SECTION 4 – OTHER INFORMATION

Program Impact Analyses

As part of the regulatory process for the carbon-trading rule, a number of power sector and economic analyses were performed to determine the impact of the rule on generation, emissions, power prices, and allowance prices.

Prior to enactment of the Clean Energy and Community Flood Preparedness Act (CECFPA) in 2020 and subsequent carbon trading rule based on full auction participation, DEQ developed and

the SAPCB approved a trading rule that operated under a consignment auction approach. Under the consignment auction rule, Virginia's RGGI allowance budget was to be distributed directly to regulated sources on a pro rata basis according to a formula based on a source's historical CO_2 emissions. The regulated sources would then have been required to consign those allowances to the RGGI auction, with proceeds from the sale of the allowances at auction paid back to the regulated sources. The intention was that proceeds from consigned allowances would then flow to the ratepayers pursuant to a SCC process, thereby mitigating the cost of the RGGI program to ratepayers to the maximum extent. Two early analyses of the consignment auction approach indicated that electricity prices in Virginia would increase only nominally while consumer bills would actually go down. However, the CECFPA was enacted before the consignment rule could go into effect. The results of these analyses from 2017 and 2018 can be found at the following links.

November 2017

1. Policy Scenario 1
2. Policy Scenario 2
3. Reference Case 1
4. Reference Case 2
5. A bill analysis

November 2018

1. IPM reference case results
2. IPM policy case results
3. A bill analysis presentation
4. A co-benefits analysis

Also prior to Virginia becoming a full participant in RGGI, several economic impact analyses of the original CO_2 trading rule were completed by Virginia Department of Planning and Budget (DPB). This iteration of the rule implemented a consignment auction approach in lieu of a traditional auction approach in order to comply with as-then current state law. As required by § 2.2-4007.04 of the Administrative Process Act, DPB considered the economic impacts of the proposed, revised proposed, and final rule. These analyses considered a number of fiscal impact studies that were conducted as part of the regulatory development process. Note that the final regulation, which adopted the traditional auction approach, was exempt from the APA and therefore not subject to DPB review.

While these analyses informed the regulatory process at the time, they did not evaluate the rule in its current form. The IPM modeling also consistently underestimated allowance prices given the current price.

An independent comprehensive report on RGGI: Background, Impacts, and Selected Issues was published by the Congressional Research Service in 2019.

Finally, a more current study and report on the current and future power sector in Virginia has been performed to evaluate the combined impacts of the RGGI and VCEA programs as previously described in Section 3. However, this report does not assess the cost impact of the programs in detail.

Program Proceeds Investment

The RGGI program publishes annual reports on the investment of proceeds by its member states.

SECTION 5 - CONCLUSION

In conclusion, the results of this re-evaluation of the costs and benefits of the RGGI program on Virginia are as follows:

- RGGI operates as a direct tax on households and businesses because all fees paid to the RGGI Board are passed through to the ratepayers per Virginia Legislation. Since the utilities are allowed to increase their rates due to the costs associated with their required participation in the RGGI auction process, there is little correlation to emission reductions. By design the utilities are not penalized for failure to meet RGGI CO_2 emissions since they can pass on the costs to the ratepayers.
- Consumers are unable to avoid the pass through of these costs because they do not have the opportunity to switch electric providers – Dominion and other providers are monopolies in most regions of Virginia.
- Other states participating in the RGGI program designed their systems to provide rebates to their ratepayers, in Virginia the program operates as a hidden tax in which the legislature then disburses the funds through grant programs. Virginia consumers were originally told that the program would not increase their energy bills.
- The original RGGI auction approach was designed to return the proceeds to the ratepayers but this was not how Virginia implemented the program. The original analysis, conducted prior to the adoption of RGGI by the legislature, showed little impact on electricity prices to the consumer because of the anticipated return of the proceeds to the ratepayers.
- The costs of compliance with the trading rule and participation in RGGI are materializing in higher electricity rates for all ratepayers, as identified in the Dominion rate case filings. The first of these rate increase requests by Dominion Energy has been approved and went into effect on January 1. Future rate increases due to RGGI are expected and will be tied to the allowance prices which are difficult to predict.
- RGGI emissions allowance prices have increased over time and substantially in the last year. In fact, in Auction 54, the clearing price rose from $9.30 to the cost containment reserve trigger level of $13.00. The allowance price rose again slightly in Auction 55 to $13.50, an all-time high for the program. Future allowance price predictions will continue to be uncertain, but by design will continue to increase.
- In Virginia over the last 10 years energy generation has increased substantially while the CO_2 mass emissions has remained fairly constant. This is due to fuel switching and efficiencies, which is signified by the decreased emission rate. In 2010 the state produced 1,200 lbs/month of CO_2 per MWh compared to 679 lbs/CO_2 per MWh in 2020, prior to RGGI taking effect. Overall, CO_2 emissions in Virginia have fallen substantially since 2005, demonstrating that Virginia has been reducing their CO_2 emissions without regard to RGGI.
- RGGI is a bad construct that taxes consumers without providing incentives for change to the electricity producers. The program was not implemented in the way it was originally sold, and simply results in increased pricing to consumers out of the marketplace.

COMMONWEALTH OF VIRGINIA
DEPARTMENT OF ENVIRONMENTAL QUALITY

PROCESS FOR ADDRESSING EO-9 EMERGENCY REGULATION AND REPEAL CO_2 EMISSIONS TRADING PROGRAM (PART VII OF 9VAC5-140)

Executive Order 9 (2022) (EO-9) **(Attachment A)** requires that DEQ in coordination with the Secretary develop an emergency regulation to repeal the CO_2 Emissions Trading Program regulation that enables Virginia to participate in the Regional Greenhouse Gas Initiative (RGGI), and begin the process for making the emergency regulation permanent. **Attachment B** shows the general process for doing so - in sum:

- in accordance with § 2.2-4011 A of the Administrative Process Act (APA) (**Attachment C**), the department consults with the Office of Attorney General to establish the nature of the emergency and requests the approval of the Attorney General in writing (**Attachment D**) to proceed with the emergency regulation;
- the State Air Pollution Control Board adopts the emergency regulation and submits it via Town Hall for executive review; and
- the emergency regulation becomes effective on approval by the Governor and submittal to the Registrar for publication.

In accordance with § 2.2-4011 C of the APA, an emergency regulation is effective for 18 months (24 months if an extension is requested). For an emergency regulation to become permanent, it must undergo the full regulatory adoption process during those 18 months. Thus, a Notice of Intended Regulatory Action (NOIRA) is usually issued concurrently with the emergency regulation. **Attachment E** describes this process and the schedule on which it must proceed. A draft proposed emergency regulation (**Attachment F**) and NOIRA for the permanent regulation (**Attachment G**) are provided.

EO-9 also requires DEQ in coordination with the Secretary to provide the Governor, "a full report re-evaluating the costs and benefits of participation in the Regional Greenhouse Gas Initiative Inc. in view of all available data, within 30 days," a draft of which will be provided separately. Finally, EO-9 directs the Secretary or DEQ to, ". . . notify the Regional Greenhouse Gas Initiative Inc. (RGGI Inc.) of the review and the Governor's intent to withdraw from RGGI, whether by legislative or regulatory action." A draft letter providing this notification for the Secretary's signature is provided at **Attachment H**.

Commonwealth of Virginia
Office of the Governor

Executive Order

NUMBER NINE (2022)

PROTECTING RATEPAYERS FROM THE RISING COST OF LIVING DUE TO THE REGIONAL GREENHOUSE GAS INITIATIVE

By virtue of the authority vested in me as Governor, I hereby issue this Executive Order to re-evaluate Virginia's participation in the Regional Greenhouse Gas Initiative and immediately begin regulatory processes to end it.

Importance of the Initiative

Reliable and affordable access to electricity is imperative to the health and safety of all Virginians. Our hospitals, schools, businesses, and homes all rely on this essential service. And the unpredictable and rising cost of electricity poses a significant and immediate threat to our Commonwealth and its citizens. In 2019, alone, over 100,000 Virginian households required Energy Assistance with a cost of $46 million to the Commonwealth.

Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI) risks contributing to the increased cost of electricity for our citizens. Virginia's utilities have sold over $227 million in allowances in 2021 during the RGGI auctions, doubling the initial estimates. Those utilities are allowed to pass on the costs of purchasing allowances to their ratepayers. Under the initial bill "RGGI rider" created for Dominion Energy customers, typical residential customer bills were increased by $2.39 a month and the typical industrial customer bill by was raised by $1,554 per month. In a filling before the State Corporation Commission, Dominion Energy stated that RGGI will cost ratepayers between $1 billion and $1.2 billion over the next four years.

Simply stated, the benefits of RGGI have not materialized, while the costs have skyrocketed. Re-evaluation of the Initiative represents a meaningful step toward alleviating this financial burden on the Commonwealth's businesses and households. Regulations must be evaluated in view of the costs and benefits to all Virginians.

Directive

Accordingly, by virtue of the authority vested in me as the Chief Executive Officer of the Commonwealth, and pursuant to Article V of the Constitution and the laws of Virginia, I hereby direct the Director of the Department of Environmental Quality, in coordination with the Secretary of Natural and Historic Resources, to take the following actions in accordance with the provisions and requirements of § 10.1-1300, et seq. and § 2.2-4000, et seq. of the *Code of Virginia*:

1. Provide me a full report re-evaluating the costs and benefits of participation in the Regional Greenhouse Gas Initiative Inc. in view of all available data, within 30 days.

2. During this same period, develop a proposed emergency regulation for the State Air Pollution Control Board's consideration to repeal 9VAC5-140.

3. During this same period, take all necessary steps to so that any proposed regulation to the State Air Pollution Control Board can be immediately presented for consideration for approval for public comment in accordance with the Board's authority pursuant to § 10.1-1308 of the *Code of Virginia*.

4. During this same period, notify the Regional Greenhouse Gas Initiative Inc. (RGGI Inc.) of the review and the Governor's intent to withdraw from RGGI, whether by legislative or regulatory action.

Effective Date

This Executive Order shall be effective upon its signing and shall remain in force and effect unless amended or rescinded by further executive order or directive.

Given under my hand and under the Seal of the Commonwealth of Virginia, this 15th day of January 2022.

Glenn Youngkin, Governor

Attest:

Kelly Thomasson, Secretary of the Commonwealth

Emergency regulations:

Information especially for state agencies

An emergency regulation is:

--Promulgated if (1) there is an "emergency situation" or (2) legislation requires a regulation to be promulgated within 280 days.

--Effective upon filing with the Registrar of Regulations.

--Initially effective for up to 18 months, and then may be extended for up to an additional 6 months if the Governor approves (for a total of 2 years).

--Usually replaced with a permanent regulation; therefore, a Notice of Intended Regulatory Action (NOIRA) to promulgate the permanent replacement regulation is normally filed at the same time as the emergency regulation.

Source: Section 2.2-4011 of the Code of Virginia

For more information, view the Town Hall User Manual at townhall.virginia.gov/UM/toc.cfm

Steps to promulgating:

Agency/board adopts emergency regulation and submits (Form TH-05 or TH06 and syncs RIS project) on the Town Hall for executive branch review.

↓

Executive branch review:
(In order of review)
Office of the Attorney General – no deadline;
Department of Planning & Budget – 14 day deadline;
Cabinet Secretary –14 day deadline;
Governor – no deadline.

↓

Once Governor approves, submit emergency regulation to the Virginia *Register of Regulations* via the Town Hall.
The emergency regulation is effective immediately upon filing.

↓

Ten days before publication in the *Register*, email notification is sent to registered public Town Hall users.

↓

The emergency regulation is published in the Register.
If NOIRA for permanent replacement regulation was also published, then 30-day public comment begins and Town Hall public comment forum opens.

Produced by the Virginia Department of Planning and Budget's Planning, Evaluation, and Regulation Division, 11/2018

ATTACHMENT C

Code of Virginia
Title 2.2. Administration of Government
Subtitle II. Administration of State Government
Part B. Transaction of Public Business
Chapter 40. Administrative Process Act
Article 2. Regulations

§ 2.2-4011. Emergency regulations; publication; exceptions

A. Regulations that an agency finds are necessitated by an emergency situation may be adopted by an agency upon consultation with the Attorney General, which approval shall be granted only after the agency has submitted a request stating in writing the nature of the emergency, and the necessity for such action shall be at the sole discretion of the Governor.

B. Agencies may also adopt emergency regulations in situations in which Virginia statutory law or the appropriation act or federal law or federal regulation requires that a regulation be effective in 280 days or less from its enactment and the regulation is not exempt under the provisions of subdivision A 4 of § 2.2-4006. In such cases, the agency shall state in writing the nature of the emergency and of the necessity for such action and may adopt the regulations. Pursuant to § 2.2-4012, such regulations shall become effective upon approval by the Governor and filing with the Registrar of Regulations.

C. All emergency regulations shall be limited to no more than 18 months in duration. During the 18-month period, an agency may issue additional emergency regulations as needed addressing the subject matter of the initial emergency regulation, but any such additional emergency regulations shall not be effective beyond the 18-month period from the effective date of the initial emergency regulation. If the agency wishes to continue regulating the subject matter governed by the emergency regulation beyond the 18-month limitation, a regulation to replace the emergency regulation shall be promulgated in accordance with this article. The Notice of Intended Regulatory Action to promulgate a replacement regulation shall be filed with the Registrar within 60 days of the effective date of the emergency regulation and published as soon as practicable, and the proposed replacement regulation shall be filed with the Registrar within 180 days after the effective date of the emergency regulation and published as soon as practicable.

D. In the event that an agency concludes that despite its best efforts a replacement regulation cannot be adopted before expiration of the 18-month period described in subsection C, it may seek the prior written approval of the Governor to extend the duration of the emergency regulation for a period of not more than six additional months. Any such request must be submitted to the Governor at least 30 days prior to the scheduled expiration of the emergency regulation and shall include a description of the agency's efforts to adopt a replacement regulation together with the reasons that a

replacement regulation cannot be adopted before the scheduled expiration of the emergency regulation. Upon approval of the Governor, provided such approval occurs prior to the scheduled expiration of the emergency regulation, the duration of the emergency regulation shall be extended for a period of no more than six months. Such approval shall be in the sole discretion of the Governor and shall not be subject to judicial review. Agencies shall notify the Registrar of Regulations of the new expiration date of the emergency regulation as soon as practicable.

E. Emergency regulations shall be published as soon as practicable in the Register.

F. The Regulations of the Marine Resources Commission shall be excluded from the provisions of this section.

ATTACHMENT D

January XX, 2022

The Honorable Jason S. Miyares
Attorney General of Virginia
202 North Ninth Street
Richmond, VA 23219

Dear Attorney General Miyares:

Pursuant to Va. Code §2.2-4011, the Department of Environmental Quality (DEQ) is asking your concurrence that an emergency situation exists with respect to Virginia's carbon trading program and participation in the Regional Greenhouse Gas Initiative (RGGI), and approval for DEQ to issue an emergency regulation to repeal the sections of 9VAC5-140 that establish and regulate the state's carbon trading program and participation in RGGI (VAC5-140-6010 through 6440). DEQ is making this request in accordance with Executive Order (EO) 9 issued by Governor Youngkin on January 15, 2021. (A copy of EO-9 is attached.)

Va. Code §2.2-4011 states that your approval of an emergency regulation, "shall be granted only after the agency has submitted a request stating in writing the nature of the emergency, and the necessity for such action shall be at the sole discretion of the Governor." The nature of this emergency is described by the Governor in EO-9 as follows:

> Reliable and affordable access to electricity is imperative to the health and safety of all Virginians. Our hospitals, schools, businesses, and homes all rely on this essential service. And the unpredictable and rising cost of electricity poses a significant and immediate threat to our Commonwealth and its citizens. In 2019, alone, over 100,000 Virginian households required Energy Assistance with a cost of $46 million to the Commonwealth.
>
> Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI) risks contributing to the increased cost of electricity for our citizens. Virginia's utilities have sold over $227 million in allowances in 2021 during the RGGI auctions, doubling the initial estimates. Those utilities are allowed to pass on the costs of purchasing allowances to their ratepayers. Under the initial bill "RGGI rider" created for Dominion Energy customers, typical residential customer bills were increased by $2.39 a month and the typical industrial customer bill by was raised by $1,554 per month. In a filling before the State Corporation Commission, Dominion Energy stated that RGGI will cost ratepayers between $1 billion and $1.2 billion over the next four years.

Simply stated, the benefits of RGGI have not materialized, while the costs have skyrocketed. Re-evaluation of the Initiative represents a meaningful step toward alleviating this financial burden on the Commonwealth's businesses and households. Regulations must be evaluated in view of the costs and benefits to all Virginians.

Concurrent with making this request and in conformance with Va. Code §2.2-4011 and EO-9, DEQ is preparing a Notice of Intended Regulatory Action (NOIRA) to commence the process of bringing to the State Air Pollution Control Board for its consideration a proposed rule to make the repeal of Virginia's carbon trading program permanent.

Should you find that further consultation between your office and DEQ pursuant to Va. Code §2.2-4011 would be helpful in this matter, please do not hesitate to contact me. Thank you for your prompt attention to this request.

Sincerely,

Michael S. Rolband

ATTACHMENT E

The following table summarizes the emergency regulation/NOIRA process.

	DEQ/OAG consultation period via letter
	Board adopts emergency regulation (ER)
	DEQ submits adopted ER for executive branch review (OAG/DPB/SNR/Governor)
	Governor approves ER which is effective on filing; NOIRA filed same time
	Replacement Regulation (RR) Clock Starts
MONTH	DELIVERABLE
1	Submit NOIRA (filed automatically with ER)
2	30 day NOIRA comment period
3	prepare response to comments and board book
4	
5	board adopt proposed RR for public comment
6	proposed RR filed for executive branch review within 180 days after ER effective date
7	60 day proposed comment period starts
8	60 day proposed comment period ends
9	
10	
11	
12	
13	board adopt final RR
14	final RR filed for executive branch review within 180 days after end of proposed comment period
15	
16	
17	*request extension if needed*
18	original RR completion date
19	*6-month extension*
20	
21	
22	
23	
24	*RR final*

ATTACHMENT F

Project 7070 - Emergency/NOIRA

State Air Pollution Control Board

Repeal CO2 Budget Trading Program as required by Executive Order 9 (Revision A22)

~~Part VII~~

~~CO_2 Budget Trading Program~~

~~Article 1~~

~~CO_2 Budget Trading Program General Provisions~~

9VAC5-140-6010. ~~Purpose.~~ (Repealed.)

~~Article 1~~

~~CO_2 Budget Trading Program General Provisions~~

~~This part establishes the Virginia component of the CO_2 Budget Trading Program, which is designed to reduce anthropogenic emissions of CO_2, a greenhouse gas, from CO_2 budget sources in a manner that is protective of human health and the environment and is economically efficient.~~

9VAC5-140-6020. ~~Definitions.~~ (Repealed.)

~~A. As used in this part, all words or terms not defined here shall have the meanings given them in 9VAC5-10 (General Definitions), unless otherwise required by the context.~~

~~B. For the purpose of this part and any related use, the words or terms shall have the meanings given them in this section.~~

~~C. Terms defined.~~

~~"Account number" means the identification number given by the department or its agent to each COATS account.~~

~~"Acid Rain emission limitation" means, as defined in 40 CFR 72.2, a limitation on emissions of sulfur dioxide (SO_2) or nitrogen oxides (NO_x) under the Acid Rain Program under Title IV of the CAA.~~

~~"Acid Rain Program" means a multistate SO_2 and NO_x air pollution control and emission reduction program established by the administrator under Title IV of the CAA and 40 CFR Parts 72 through 78.~~

~~"Adjustment for banked allowances" means an adjustment applied to the Virginia CO_2 Budget Trading Program base budget for allocation years 2021 through 2025 to address allowances held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program, but not including accounts opened by participating states.~~

~~"Administrator" means the administrator of the U.S. Environmental Protection Agency or the administrator's authorized representative.~~

~~"Allocate" or "allocation" means the determination by the department of the number of CO_2 allowances recorded in the CO_2 allowance account of a CO_2 budget unit.~~

~~"Allocation year" means a calendar year for which the department allocates CO_2 allowances pursuant to Article 5 (9VAC5-140-6190 et seq.) of this part. The allocation year~~

of each CO_2 allowance is reflected in the unique identification number given to the allowance pursuant to 9VAC5-140-6250 C.

"Allowance auction" or "auction" means an auction in which the department or its agent offers CO_2 allowances for sale.

"Attribute" means a characteristic associated with electricity generated using a particular renewable fuel, such as its generation date, facility geographic location, unit vintage, emissions output, fuel, state program eligibility, or other characteristic that can be identified, accounted for, and tracked.

"Attribute credit" means a credit that represents the attributes related to one megawatt-hour of electricity generation.

"Automated Data Acquisition and Handling System" or "DAHS" means that component of the Continuous Emissions Monitoring System (CEMS), or other emissions monitoring system approved for use under Article 8 (9VAC5-140-6330 et seq.) of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by Article 8 (9VAC5-140-6330 et seq.) of this part.

"Billing meter" means a measurement device used to measure electric or thermal output for commercial billing under a contract. The facility selling the electric or thermal output shall have different owners from the owners of the party purchasing the electric or thermal output.

"Boiler" means an enclosed fossil or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

"CO_2 allowance" means a limited authorization by the department or participating state under the CO_2 Budget Trading Program to emit up to one ton of CO_2, subject to all applicable limitations contained in this part.

"CO_2 allowance deduction" or "deduct CO_2 allowances" means the permanent withdrawal of CO_2 allowances by the department or its agent from a COATS compliance account to account for the number of tons of CO_2 emitted from a CO_2 budget source for a control period or an interim control period determined in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part, or for the forfeit or retirement of CO_2 allowances as provided by this part.

"CO_2 Allowance Tracking System" or "COATS" means the system by which the department or its agent records allocations, deductions, and transfers of CO_2 allowances under the CO_2 Budget Trading Program. The tracking system may also be used to track CO_2 allowance prices and emissions from affected sources.

"CO_2 Allowance Tracking System account" means an account in COATS established by the department or its agent for purposes of recording the allocation, holding, transferring, or deducting of CO_2 allowances.

"CO_2 allowance transfer deadline" means midnight of March 1 occurring after the end of the relevant control period and each relevant interim control period, or if that March 1 is not a business day, midnight of the first business day thereafter and is the deadline by which CO_2 allowances shall be submitted for recordation in a CO_2 budget source's compliance account for the source to meet the CO_2 requirements of 9VAC5-140-6050 C for a control period and each interim control period immediately preceding such deadline.

"CO_2 allowances held" or "hold CO_2 allowances" means the CO_2 allowances recorded by the department or its agent, or submitted to the department or its agent for recordation, in

accordance with Article 6 (9VAC5-140-6220 et seq.) and Article 7 (9VAC5-140-6300 et seq.) of this part, in a COATS account.

"CO_2 authorized account representative" means, for a CO_2 budget source and each CO_2 budget unit at the source, the natural person who is authorized by the owners and operators of the source and all CO_2 budget units at the source, in accordance with Article 2 (9VAC5-140-6080 et seq.) of this part, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Budget Trading Program or, for a general account, the natural person who is authorized, under Article 6 (9VAC5-140-6220 et seq.) of this part, to transfer or otherwise dispose of CO_2 allowances held in the general account. If the CO_2 budget source is also subject to the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then for a CO_2 Budget Trading Program compliance account, this natural person shall be the same person as the designated representative as defined in the respective program.

"CO_2 authorized alternate account representative" means, for a CO_2 budget source and each CO_2 budget unit at the source, the alternate natural person who is authorized by the owners and operators of the source and all CO_2 budget units at the source, in accordance with Article 2 (9VAC5-140-6080 et seq.) of this part, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Budget Trading Program or, for a general account, the alternate natural person who is authorized, under Article 6 (9VAC5-140-6220 et seq.) of this part, to transfer or otherwise dispose of CO_2 allowances held in the general account. If the CO_2 budget source is also subject to the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program then, for a CO_2 Budget Trading Program compliance account, this alternate natural person shall be the same person as the alternate designated representative as defined in the respective program.

"CO_2 budget emissions limitation" means, for a CO_2 budget source, the tonnage equivalent, in CO_2 emissions in a control period or an interim control period of the CO_2 allowances available for compliance deduction for the source for a control period or an interim control period.

"CO_2 budget permit" means the portion of the legally binding permit issued by the department pursuant to 9VAC5-85 (Permits for Stationary Sources of Pollutants Subject to Regulation) to a CO_2 budget source or CO_2 budget unit that specifies the CO_2 Budget Trading Program requirements applicable to the CO_2 budget source, to each CO_2 budget unit at the CO_2 budget source, and to the owners and operators and the CO_2 authorized account representative of the CO_2 budget source and each CO_2 budget unit.

"CO_2 budget source" means a source that includes one or more CO_2 budget units.

"CO_2 Budget Trading Program" means a multistate CO_2 air pollution control and emissions reduction program established according to this part and corresponding regulations in other states as a means of reducing emissions of CO_2 from CO_2 budget sources.

"CO_2 budget unit" means a unit that is subject to the CO_2 Budget Trading Program requirements under 9VAC5-140-6040.

"CO_2 cost containment reserve allowance" or "CO_2 CCR allowance" means an allowance that has been sold at an auction for the purpose of containing the cost of CO_2 allowances. CO_2 CCR allowances offered for sale at an auction are separate from and additional to CO_2 allowances allocated from the Virginia CO_2 Budget Trading Program base and adjusted budgets. CO_2 CCR allowances are subject to all applicable limitations contained in this part.

~~"CO_2 cost containment reserve trigger price" or "CCR trigger price" means the minimum price at which CO_2 CCR allowances are offered for sale by the department or its agent at an auction. The CCR trigger price in calendar year 2021 shall be $13. The CCR trigger price in calendar year 2022 shall be $13.91. Each calendar year thereafter, the CCR trigger price shall be 1.07 multiplied by the CCR trigger price from the previous calendar year, rounded to the nearest whole cent, as shown in Table 140-1A.~~

~~Table 140-1A~~
~~CO_2 CCR Trigger Price~~

~~2021~~	~~$13.00~~
~~2022~~	~~$13.91~~
~~2023~~	~~$14.88~~
~~2024~~	~~$15.92~~
~~2025~~	~~$17.03~~
~~2026~~	~~$18.22~~
~~2027~~	~~$19.50~~
~~2028~~	~~$20.87~~
~~2029~~	~~$22.33~~
~~2030~~	~~$23.89~~

~~"CO_2 emissions containment reserve allowance" or "CO_2 ECR allowance" means a CO_2 allowance that is withheld from sale at an auction by the department for the purpose of additional emission reduction in the event of lower than anticipated emission reduction costs.~~

~~"CO_2 emissions containment reserve trigger price" or "ECR trigger price" means the price below which CO_2 allowances will be withheld from sale by the department or its agent at an auction. The ECR trigger price in calendar year 2021 shall be $6.00. Each calendar year thereafter, the ECR trigger price shall be 1.07 multiplied by the ECR trigger price from the previous calendar year, rounded to the nearest whole cent, as shown in Table 140-1B.~~

~~Table 140-1B~~
~~CO_2 ECR Trigger Price~~

~~2021~~	~~$ 6.00~~
~~2022~~	~~$ 6.42~~
~~2023~~	~~$ 6.87~~
~~2024~~	~~$ 7.35~~
~~2025~~	~~$ 7.86~~
~~2026~~	~~$8.41~~
~~2027~~	~~$ 9.00~~
~~2028~~	~~$ 9.63~~

2029	$10.30
2030	$11.02

"CO_2 offset allowance" means a CO_2 allowance that is awarded to the sponsor of a CO_2 emissions offset project by a participating state and is subject to the relevant compliance deduction limitations of the participating state's corresponding offset regulations as a means of reducing CO_2 from CO_2 budget sources.

"Combined cycle system" means a system comprised of one or more combustion turbines, heat recovery steam generators, and steam turbines configured to improve overall efficiency of electricity generation or steam production.

"Combustion turbine" means an enclosed fossil or other fuel-fired device that is comprised of a compressor (if applicable), a combustor, and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine.

"Commence commercial operation" means, with regard to a unit that serves a generator, to have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation. For a unit that is a CO_2 budget unit under 9VAC5-140-6040 on the date the unit commences commercial operation, such date shall remain the unit's date of commencement of commercial operation even if the unit is subsequently modified, reconstructed, or repowered. For a unit that is not a CO_2 budget unit under 9VAC5-140-6040 on the date the unit commences commercial operation, the date the unit becomes a CO_2 budget unit under 9VAC5-140-6040 shall be the unit's date of commencement of commercial operation.

"Commence operation" means to begin any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber. For a unit that is a CO_2 budget unit under 9VAC5-140-6040 on the date of commencement of operation, such date shall remain the unit's date of commencement of operation even if the unit is subsequently modified, reconstructed, or repowered. For a unit that is not a CO_2 budget unit under 9VAC5-140-6040 on the date of commencement of operation, the date the unit becomes a CO_2 budget unit under 9VAC5-140-6040 shall be the unit's date of commencement of operation.

"Compliance account" means a COATS account, established by the department or its agent for a CO_2 budget source under Article 6 (9VAC5-140-6220 et seq.) of this part, in which CO_2 allowances available for use by the source for a control period and each interim control period are held for the purpose of meeting the CO_2 requirements of 9VAC5-140-6050 C.

"Continuous Emissions Monitoring System" or "CEMS" means the equipment required under Article 8 (9VAC5-140-6330 et seq.) of this part to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated DAHS), a permanent record of stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with 40 CFR Part 75 and Article 8 (9VAC5-140-6330 et seq.) of this part. The following systems are types of CEMS required under Article 8 (9VAC5-140-6330 et seq.) of this part:

a. A flow monitoring system, consisting of a stack flow rate monitor and an automated DAHS and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour;

b. A NO_x emissions rate (or NO_x-diluent) monitoring system, consisting of a NO_x pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated

DAHS and providing a permanent, continuous record of NO_X concentration, in parts per million (ppm), diluent gas concentration, in percent CO_2 or O_2, and NO_X emissions rate, in pounds per million British thermal units (lb/MMBtu);

c. A moisture monitoring system, as defined in 40 CFR 75.11(b)(2) and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

d. A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated DAHS and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

e. An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated DAHS and providing a permanent, continuous record of O_2, in percent O_2.

"Control period" means a three-calendar-year time period. The fifth control period is from January 1, 2021, to December 31, 2023, inclusive, which is the first control period of Virginia's participation in the CO_2 Budget Trading Program. The first two calendar years of each control period are each defined as an interim control period, beginning on January 1, 2021.

"Cross State Air Pollution Rule (CSAPR) NO_X Annual Trading Program" means a multistate NO_X air pollution control and emission reduction program established in accordance with Subpart AAAAA of 40 CFR Part 97 and 40 CFR 52.38(a), including such a program that is revised in a SIP revision approved by the administrator under 40 CFR 52.38(a)(3) or (4) or that is established in a SIP revision approved by the administrator under 40 CFR 52.38(a)(5), as a means of mitigating interstate transport of fine particulates and NO_X.

"Cross State Air Pollution Rule (CSAPR) NO_X Ozone Season Trading Program" means a multistate NO_X air pollution control and emission reduction program established in accordance with Subpart BBBBB of 40 CFR Part 97 and 40 CFR 52.38(b), including such a program that is revised in a SIP revision approved by the administrator under 40 CFR 52.38(b)(3) or (4) or that is established in a SIP revision approved by the administrator under 40 CFR 52.38(b)(5), as a means of mitigating interstate transport of ozone and NO_X.

"Cross State Air Pollution Rule (CSAPR) SO_2 Group 1 Trading Program" means a multistate SO_2 air pollution control and emission reduction program established in accordance with Subpart CCCCC of 40 CFR Part 97 and 40 CFR 52.39(a), (b), (d) through (f), (j), and (k), including such a program that is revised in a SIP revision approved by the administrator under 40 CFR 52.39(d) or (e) or that is established in a SIP revision approved by the administrator under 40 CFR 52.39(f), as a means of mitigating interstate transport of fine particulates and SO_2.

"Cross State Air Pollution Rule (CSAPR) SO_2 Group 2 Trading Program" means a multistate SO_2 air pollution control and emission reduction program established in accordance with Subpart DDDDD of 40 CFR Part 97 and 40 CFR 52.39(a), (c), and (g) through (k), including such a program that is revised in a SIP revision approved by the administrator under 40 CFR 52.39(g) or (h) or that is established in a SIP revision approved by the administrator under 40 CFR 52.39(i), as a means of mitigating interstate transport of fine particulates and SO_2.

"Department" means the Virginia Department of Environmental Quality.

"Excess emissions" means any tonnage of CO_2 emitted by a CO_2 budget source during an interim control period or a control period that exceeds the CO_2 budget emissions limitation for the source.

"Excess interim emissions" means any tonnage of CO_2 emitted by a CO_2 budget source during an interim control period multiplied by 0.50 that exceeds the CO_2 budget emissions limitation for the source.

"Fossil fuel" means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

"Fossil fuel-fired" means the combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel combusted comprises, or is projected to comprise, more than 5.0% of the annual heat input on a Btu basis during any year.

"General account" means a COATS account established under Article 6 (9VAC5-140-6220 et seq.) of this part that is not a compliance account.

"Gross generation" means the electrical output in MWe at the terminals of the generator.

"Interim control period" means a one-calendar-year time period during each of the first and second calendar years of each three-year control period. The first interim control period starts January 1, 2021, and ends December 31, 2021, inclusive. The second interim control period starts January 1, 2022, and ends December 31, 2022, inclusive. Each successive three-year control period will have two interim control periods, comprised of each of the first two calendar years of that control period.

"Life-of-the-unit contractual arrangement" means either:

a. A unit participation power sales agreement under which a customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity or associated energy from any specified unit pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period equal to or greater than 25 years or 70% of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period; or

b. Any energy conversion or energy tolling agreement that has a primary term of 20 years or more and pursuant to which the purchaser is required to deliver fuel to the CO_2 budget source or CO_2 budget unit and is entitled to receive all of the nameplate capacity and associated energy generated by such source or unit for the entire contractual period. Such agreements shall be subject to 9VAC5-140-6325. Such purchaser shall not be considered an "owner" as defined under this section.

"Maximum potential hourly heat input" means an hourly heat input used for reporting purposes when a unit lacks certified monitors to report heat input. If the unit intends to use Appendix D of 40 CFR Part 75 to report heat input, this value shall be calculated, in accordance with 40 CFR Part 75, using the maximum fuel flow rate and the maximum gross calorific value. If the unit intends to use a flow monitor and a diluent gas monitor, this value shall be reported, in accordance with 40 CFR Part 75, using the maximum potential flow rate and either the maximum CO_2 concentration in percent CO_2 or the minimum O_2 concentration in percent O_2.

"Minimum reserve price" means, in calendar year 2021, $2.38. Each calendar year thereafter, the minimum reserve price shall be 1.025 multiplied by the minimum reserve price from the previous calendar year, rounded to the nearest whole cent.

"Monitoring system" means any monitoring system that meets the requirements of Article 8 (9VAC5-140-6330 et seq.) of this part, including a CEMS, an excepted monitoring system, or an alternative monitoring system.

"Nameplate capacity" means the maximum electrical output in MWe that a generator can sustain over a specified period of time when not restricted by seasonal or other deratings as measured in accordance with the U.S. Department of Energy standards.

"Net-electric output" means the amount of gross generation in MWh the generators produce, including output from steam turbines, combustion turbines, and gas expanders, as measured at the generator terminals, less the electricity used to operate the plant (i.e., auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

"Non-CO_2 budget unit" means a unit that does not meet the applicability criteria of 9VAC5-140-6040.

"Operator" means any person who operates, controls, or supervises a CO_2 budget unit or a CO_2 budget source and shall include any holding company, utility system, or plant manager of such a unit or source.

"Owner" means any of the following persons:

a. Any holder of any portion of the legal or equitable title in a CO_2 budget unit;

b. Any holder of a leasehold interest in a CO_2 budget unit, other than a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the CO_2 budget unit;

c. Any purchaser of power from a CO_2 budget unit under a life-of-the-unit contractual arrangement in which the purchaser controls the dispatch of the unit; or

d. With respect to any general account, any person who has an ownership interest with respect to the CO_2 allowances held in the general account and who is subject to the binding agreement for the CO_2 authorized account representative to represent that person's ownership interest with respect to the CO_2 allowances.

"Participating state" means a state that has established a corresponding regulation as part of the CO_2 Budget Trading Program.

"Receive" or "receipt of" means, when referring to the department or its agent, to come into possession of a document, information, or correspondence (whether sent in writing or by authorized electronic transmission) as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence by the department or its agent in the regular course of business.

"Recordation," "record," or "recorded" means, with regard to CO_2 allowances, the movement of CO_2 allowances by the department or its agent from one COATS account to another for purposes of allocation, transfer, or deduction.

"Reserve price" means the minimum acceptable price for each CO_2 allowance in a specific auction. The reserve price at an auction is either the minimum reserve price or the CCR trigger price, as specified in Article 9 (9VAC5-140-6410 et seq.) of this part.

"Serial number" means, when referring to CO_2 allowances, the unique identification number assigned to each CO_2 allowance by the department or its agent under 9VAC5-140-6250 C.

"Source" means any governmental, institutional, commercial, or industrial structure, installation, plant, building, or facility that emits or has the potential to emit any air pollutant. A source, including a source with multiple units, shall be considered a single facility.

"Submit" or "serve" means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

a. In person;

b. By United States Postal Service; or

c. By other means of dispatch or transmission and delivery.

Compliance with any "submission," "service," or "mailing" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

"Ton" or "tonnage" means any short ton, or 2,000 pounds. For the purpose of determining compliance with the CO_2 requirements of 9VAC5-140-6050 C, total tons for an interim control period or a control period shall be calculated as the sum of all recorded hourly emissions, or the tonnage equivalent of the recorded hourly emissions rates, in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part, with any remaining fraction of a ton equal to or greater than 0.50 ton deemed to equal one ton and any fraction of a ton less than 0.50 ton deemed to equal zero tons. A short ton is equal to 0.9072 metric tons.

"Total useful energy" means the sum of gross electrical generation and useful net thermal energy.

"Undistributed CO_2 allowances" means CO_2 allowances originally allocated to a set aside account as pursuant to 9VAC5-140-6210 that were not distributed.

"Unit" means a fossil fuel-fired stationary boiler, combustion turbine, or combined cycle system.

"Unit operating day" means a calendar day in which a unit combusts any fuel.

"Unsold CO_2 allowances" means CO_2 allowances that have been made available for sale in an auction conducted by the department or its agent, but not sold.

"Useful net thermal energy" means energy:

a. In the form of direct heat, steam, hot water, or other thermal form that is used in the production and beneficial measures for heating, cooling, humidity control, process use, or other thermal end use energy requirements, excluding thermal energy used in the power production process (e.g., house loads and parasitic loads); and

b. For which fuel or electricity would otherwise be consumed.

"Virginia CO_2 Budget Trading Program adjusted budget" means an adjusted budget determined in accordance with 9VAC5-140-6210 and is the annual amount of CO_2 tons available in Virginia for allocation in a given allocation year, in accordance with the CO_2 Budget Trading Program. CO_2 CCR allowances offered for sale at an auction are separate from and additional to CO_2 allowances allocated from the Virginia CO_2 Budget Trading Program adjusted budget.

"Virginia CO_2 Budget Trading Program base budget" means the budget specified in 9VAC5-140-6190. CO_2 CCR allowances offered for sale at an auction are separate from and additional to CO_2 allowances allocated from the Virginia CO_2 Budget Trading Program base budget.

9VAC5-140-6030. Measurements, abbreviations, and acronyms. (Repealed.)

Measurements, abbreviations, and acronyms used in this part are defined as follows:

Btu - British thermal unit.

~~CAA - federal Clean Air Act.~~

~~CCR - cost containment reserve.~~

~~CEMS - Continuous Emissions Monitoring System.~~

~~COATS - CO_2 Allowance Tracking System.~~

~~CO_2 - carbon dioxide.~~

~~DAHS - Data Acquisition and Handling System.~~

~~H_2O - water.~~

~~lb - pound.~~

~~LME - low mass emissions.~~

~~MMBtu - million British thermal units.~~

~~MW - megawatt.~~

~~MWe - megawatt electrical.~~

~~MWh - megawatt hour.~~

~~NO_x - nitrogen oxides.~~

~~O_2 - oxygen.~~

~~ORIS - Office of Regulatory Information Systems.~~

~~QA/QC - quality assurance/quality control.~~

~~ppm - parts per million.~~

~~SO_2 - sulfur dioxide.~~

9VAC5-140-6040. ~~Applicability.~~ (Repealed.)

~~A. Any fossil fuel-fired unit that serves an electricity generator with a nameplate capacity equal to or greater than 25 MWe shall be a CO_2 budget unit, and any source that includes one or more such units shall be a CO_2 budget source, subject to the requirements of this part.~~

~~B. Exempt from the requirements of this part is any fossil fuel CO_2 budget source located at or adjacent to and physically interconnected with a manufacturing facility that, prior to January 1, 2020, and in every subsequent calendar year, met either of the following requirements:~~

~~1. Supplies less than or equal to 10% of its annual net electrical generation to the electric grid; or~~

~~2. Supplies less than or equal to 15% of its annual total useful energy to any entity other than the manufacturing facility to which the CO_2 budget source is interconnected.~~

~~For the purpose of subdivision 1 of this subsection, annual net electrical generation shall be determined as follows:~~

~~(ES – EP) / EG x 100~~

~~Where:~~

~~ES = electricity sales to the grid from the CO_2 budget source~~

~~EP = electricity purchases from the grid by the CO_2 budget source and the manufacturing facility to which the CO_2 budget source is interconnected~~

~~EG = electricity generation~~

~~Such exempt CO_2 budget source shall have an operating permit containing the applicable restrictions under this subsection. An application for such operating permit shall be submitted to the department no later than January 1, 2022.~~

9VAC5-140-6050. ~~Standard requirements.~~ (Repealed.)

~~A. Permit requirements shall be as follows.~~

1. The CO_2 authorized account representative of each CO_2 budget source required to have an operating permit pursuant to 9VAC5-85 (Permits for Stationary Sources of Pollutants Subject to Regulation) and each CO_2 budget unit required to have an operating permit pursuant to 9VAC5-85 shall:

a. Submit to the department a complete CO_2 budget permit application under 9VAC5-140-6160 in accordance with the deadlines specified in 9VAC5-140-6150; and

b. Submit in a timely manner any supplemental information that the department determines is necessary in order to review the CO_2 budget permit application and issue or deny a CO_2 budget permit.

2. The owners and operators of each CO_2 budget source required to have an operating permit pursuant to 9VAC5-85 (Permits for Stationary Sources of Pollutants Subject to Regulation) and each CO_2 budget unit required to have an operating permit pursuant to 9VAC5-85 for the source shall have a CO_2 budget permit and operate the CO_2 budget source and the CO_2 budget unit at the source in compliance with such CO_2 budget permit.

B. Monitoring requirements shall be as follows.

1. The owners and operators and, to the extent applicable, the CO_2 authorized account representative of each CO_2 budget source and each CO_2 budget unit at the source shall comply with the monitoring requirements of Article 8 (9VAC5-140-6330 et seq.) of this part.

2. The emissions measurements recorded and reported in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part shall be used to determine compliance by the unit with the CO_2 requirements under subsection C of this section.

C. CO_2 requirements shall be as follows.

1. The owners and operators of each CO_2 budget source and each CO_2 budget unit at the source shall hold CO_2 allowances available for compliance deductions under 9VAC5-140-6260, as of the CO_2 allowance transfer deadline, in the source's compliance account in an amount not less than the total CO_2 emissions that have been generated as a result of combusting fossil fuel for an interim control period or control period from all CO_2 budget units at the source, less the CO_2 allowances deducted to meet the requirements of subdivision 2 of this subsection, with respect to the previous two interim control periods as determined in accordance with Article 6 (9VAC5-140-6220 et seq.) and Article 8 (9VAC5-140-6330 et seq.) of this part.

2. The owners and operators of each CO_2 budget source and each CO_2 budget unit at the source shall hold CO_2 allowances available for compliance deductions under 9VAC5-140-6260, as of the CO_2 allowance transfer deadline, in the source's compliance account in an amount not less than the total CO_2 emissions that have been generated as a result of combusting fossil fuel for the interim control period from all CO_2 budget units at the source multiplied by 0.50, as determined in accordance with Article 6 (9VAC5-140-6220 et seq.) and Article 8 (9VAC5-140-6330 et seq.) of this part.

3. Each ton of CO_2 emitted in excess of the CO_2 budget emissions limitation for a control period shall constitute a separate violation of this part and applicable state law.

4. Each ton of excess interim emissions shall constitute a separate violation of this part and applicable state law.

5. A CO_2 budget unit shall be subject to the requirements under subdivision 1 of this subsection starting on the later of January 1, 2021, or the date on which the unit commences operation.

6. CO_2 allowances shall be held in, deducted from, or transferred among COATS accounts in accordance with Article 5 (9VAC5-140-6190 et seq.), Article 6 (9VAC5-140-6220 et seq.), and Article 7 (9VAC5-140-6300 et seq.) of this part.

7. A CO_2 allowance shall not be deducted, to comply with the requirements under subdivision 1 or 2 of this subsection, for a control period that ends prior to the year for which the CO_2 allowance was allocated.

8. A CO_2 allowance under the CO_2 Budget Trading Program is a limited authorization by the department to emit one ton of CO_2 in accordance with the CO_2 Budget Trading Program. No provision of the CO_2 Budget Trading Program, the CO_2 budget permit application, or the CO_2 budget permit or any provision of law shall be construed to limit the authority of the department or a participating state to terminate or limit such authorization.

9. A CO_2 allowance under the CO_2 Budget Trading Program does not constitute a property right.

D. The owners and operators of a CO_2 budget source that has excess emissions in a control period shall:

1. Forfeit the CO_2 allowances required for deduction under 9VAC5-140-6260 D 1; and

2. Pay any fine, penalty, or assessment or comply with any other remedy imposed under 9VAC5-140-6260 D 2.

E. Recordkeeping and reporting requirements shall be as follows:

1. Unless otherwise provided, the owners and operators of the CO_2 budget source and each CO_2 budget unit at the source shall keep on site at the source each of the following documents for a period of 10 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 10 years, in writing by the department.

a. The account certificate of representation for the CO_2 authorized account representative for the source and each CO_2 budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with 9VAC5-140-6110, provided that the certificate and documents shall be retained on site at the source beyond such 10-year period until such documents are superseded because of the submission of a new account certificate of representation changing the CO_2 authorized account representative.

b. All emissions monitoring information, in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part and 40 CFR 75.57.

c. Copies of all reports, compliance certifications, and other submissions and all records made or required under the CO_2 Budget Trading Program.

d. Copies of all documents used to complete a CO_2 budget permit application and any other submission under the CO_2 Budget Trading Program or to demonstrate compliance with the requirements of the CO_2 Budget Trading Program.

2. The CO_2 authorized account representative of a CO_2 budget source and each CO_2 budget unit at the source shall submit the reports and compliance certifications required under the CO_2 Budget Trading Program, including those under Article 4 (9VAC5-140-6170 et seq.) of this part.

F. Liability requirements shall be as follows.

1. No permit revision shall excuse any violation of the requirements of the CO_2 Budget Trading Program that occurs prior to the date that the revision takes effect.

2. Any provision of the CO_2 Budget Trading Program that applies to a CO_2 budget source, including a provision applicable to the CO_2 authorized account representative of a CO_2 budget source, shall also apply to the owners and operators of such source and of the CO_2 budget units at the source.

3. Any provision of the CO_2 Budget Trading Program that applies to a CO_2 budget unit, including a provision applicable to the CO_2 authorized account representative of a CO_2 budget unit, shall also apply to the owners and operators of such unit.

G. No provision of the CO_2 Budget Trading Program, a CO_2 budget permit application, or a CO_2 budget permit shall be construed as exempting or excluding the owners and operators and, to the extent applicable, the CO_2 authorized account representative of the CO_2 budget source or CO_2 budget unit from compliance with any other provisions of applicable state and federal law or regulations.

9VAC5-140-6060. ~~Computation of time.~~ (Repealed.)

A. Unless otherwise stated, any time period scheduled, under the CO_2 Budget Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

B. Unless otherwise stated, any time period scheduled, under the CO_2 Budget Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

C. Unless otherwise stated, if the final day of any time period, under the CO_2 Budget Trading Program, falls on a weekend or a state or federal holiday, the time period shall be extended to the next business day.

9VAC5-140-6070. ~~Severability.~~ (Repealed.)

If any provision of this part, or its application to any particular person or circumstances, is held invalid, the remainder of this part, and the application thereof to other persons or circumstances, shall not be affected thereby.

Article 2

CO_2 Authorized Account Representative for CO_2 Budget Sources

9VAC5-140-6080. ~~Authorization and responsibilities of the CO2 authorized account representative.~~ (Repealed.)

Article 2

CO_2 Authorized Account Representative for CO_2 Budget Sources

A. Except as provided under 9VAC5-140-6090, each CO_2 budget source, including all CO_2 budget units at the source, shall have one and only one CO_2 authorized account representative, with regard to all matters under the CO_2 Budget Trading Program concerning the source or any CO_2 budget unit at the source.

B. The CO_2 authorized account representative of the CO_2 budget source shall be selected by an agreement binding on the owners and operators of the source and all CO_2 budget units at the source and must act in accordance with the account certificate of representation under 9VAC5-140-6110.

C. Upon receipt by the department or its agent of a complete account certificate of representation under 9VAC5-140-6110, the CO_2 authorized account representative of the source shall represent and, by his representations, actions, inactions, or submissions, legally bind each owner and operator of the CO_2 budget source represented and each CO_2 budget unit at the source in all matters pertaining to the CO_2 Budget Trading Program, notwithstanding any agreement between the CO_2 authorized account representative and such owners and operators. The owners

and operators shall be bound by any decision or order issued to the CO_2 authorized account representative by the department or a court regarding the source or unit.

D. No CO_2 budget permit shall be issued, and no COATS account shall be established for a CO_2 budget source, until the department or its agent has received a complete account certificate of representation under 9VAC5-140-6110 for a CO_2 authorized account representative of the source and the CO_2 budget units at the source.

E. Each submission under the CO_2 Budget Trading Program shall be submitted, signed, and certified by the CO_2 authorized account representative for each CO_2 budget source on behalf of which the submission is made. Each such submission shall include the following certification statement by the CO_2 authorized account representative: "I am authorized to make this submission on behalf of the owners and operators of the CO_2 budget sources or CO_2 budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

F. The department or its agent will accept or act on a submission made on behalf of owners or operators of a CO_2 budget source or a CO_2 budget unit only if the submission has been made, signed, and certified in accordance with subsection E of this section.

9VAC5-140-6090. ~~CO2 authorized alternate account representative.~~ (Repealed.)

A. An account certificate of representation may designate one and only one CO_2 authorized alternate account representative who may act on behalf of the CO_2 authorized account representative. The agreement by which the CO_2 authorized alternate account representative is selected shall include a procedure for authorizing the CO_2 authorized alternate account representative to act in lieu of the CO_2 authorized account representative.

B. Upon receipt by the department or its agent of a complete account certificate of representation under 9VAC5-140-6110, any representation, action, inaction, or submission by the CO_2 authorized alternate account representative shall be deemed to be a representation, action, inaction, or submission by the CO_2 authorized account representative.

C. Except in this section and 9VAC5-140-6080 A, 9VAC5-140-6100, 9VAC5-140-6110, and 9VAC5-140-6230, whenever the term "CO_2 authorized account representative" is used in this part, the term shall be construed to include the CO_2 authorized alternate account representative.

9VAC5-140-6100. ~~Changing the CO2 authorized account representatives and the CO2 authorized alternate account representative; changes in the owners and operators.~~ (Repealed.)

A. The CO_2 authorized account representative may be changed at any time upon receipt by the department or its agent of a superseding complete account certificate of representation under 9VAC5-140-6110. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative or CO_2 authorized alternate account representative prior to the time and date when the department or its agent receives the superseding account certificate of representation shall be binding on the new CO_2 authorized account representative and the owners and operators of the CO_2 budget source and the CO_2 budget units at the source.

B. The CO_2 authorized alternate account representative may be changed at any time upon receipt by the department or its agent of a superseding complete account certificate of representation under 9VAC5-140-6110. Notwithstanding any such change, all representations,

~~actions, inactions, and submissions by the previous CO_2 authorized alternate account representative or CO_2 authorized alternate account representative prior to the time and date when the department or its agent receives the superseding account certificate of representation shall be binding on the new CO_2 authorized alternate account representative and the owners and operators of the CO_2 budget source and the CO_2 budget units at the source.~~

~~C. Changes in the owners and operators shall be addressed as follows.~~

~~1. In the event a new owner or operator of a CO_2 budget source or a CO_2 budget unit is not included in the list of owners and operators submitted in the account certificate of representation, such new owner or operator shall be deemed to be subject to and bound by the account certificate of representation, the representations, actions, inactions, and submissions of the CO_2 authorized account representative and any CO_2 authorized alternate account representative of the source or unit, and the decisions, orders, actions, and inactions of the department, as if the new owner or operator were included in such list.~~

~~2. Within 30 days following any change in the owners and operators of a CO_2 budget source or a CO_2 budget unit, including the addition of a new owner or operator, the CO_2 authorized account representative or CO_2 authorized alternate account representative shall submit a revision to the account certificate of representation amending the list of owners and operators to include the change.~~

9VAC5-140-6110. ~~Account certificate of representation.~~ (Repealed.)

~~A. A complete account certificate of representation for a CO_2 authorized account representative or a CO_2 authorized alternate account representative shall include the following elements in a format prescribed by the department or its agent:~~

~~1. Identification of the CO_2 budget source and each CO_2 budget unit at the source for which the account certificate of representation is submitted;~~

~~2. The name, address, email address, telephone number, and facsimile transmission number of the CO_2 authorized account representative and any CO_2 authorized alternate account representative;~~

~~3. A list of the owners and operators of the CO_2 budget source and of each CO_2 budget unit at the source;~~

~~4. The following certification statement by the CO_2 authorized account representative and any CO_2 authorized alternate account representative: "I certify that I was selected as the CO_2 authorized account representative or CO_2 authorized alternate account representative, as applicable, by an agreement binding on the owners and operators of the CO_2 budget source and each CO_2 budget unit at the source. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Budget Trading Program on behalf of the owners and operators of the CO_2 budget source and of each CO_2 budget unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the department or a court regarding the source or unit."; and~~

~~5. The signature of the CO_2 authorized account representative and any CO_2 authorized alternate account representative and the dates signed.~~

~~B. Unless otherwise required by the department or its agent, documents of agreement referred to in the account certificate of representation shall not be submitted to the department or its agent. Neither the department nor its agent shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.~~

9VAC5-140-6120. ~~Objections concerning the CO2 authorized account representative.~~ (Repealed.)

~~A. Once a complete account certificate of representation under 9VAC5-140-6110 has been submitted and received, the department and its agent will rely on the account certificate of representation unless and until the department or its agent receives a superseding complete account certificate of representation under 9VAC5-140-6110.~~

~~B. Except as provided in 9VAC5-140-6100 A or B, no objection or other communication submitted to the department or its agent concerning the authorization, or any representation, action, inaction, or submission of the CO_2 authorized account representative shall affect any representation, action, inaction, or submission of the CO_2 authorized account representative or the finality of any decision or order by the department or its agent under the CO_2 Budget Trading Program.~~

~~C. Neither the department nor its agent will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any CO_2 authorized account representative, including private legal disputes concerning the proceeds of CO_2 allowance transfers.~~

9VAC5-140-6130. ~~Delegation by CO2 authorized account representative and CO2 authorized alternate account representative.~~ (Repealed.)

~~A. A CO_2 authorized account representative may delegate, to one or more natural persons, his authority to make an electronic submission to the department or its agent under this part.~~

~~B. A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his authority to make an electronic submission to the department or its agent under this part.~~

~~C. To delegate authority to make an electronic submission to the department or its agent in accordance with subsections A and B of this section, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, shall submit to the department or its agent a notice of delegation, in a format prescribed by the department that includes the following elements:~~

~~1. The name, address, email address, telephone number, and facsimile transmission number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;~~

~~2. The name, address, email address, telephone number, and facsimile transmission number of each such natural person, referred to as the "electronic submission agent";~~

~~3. For each such natural person, a list of the type of electronic submissions under subsection A or B of this section for which authority is delegated to him; and~~

~~4. The following certification statement by such CO_2 authorized account representative or CO_2 authorized alternate account representative: "I agree that any electronic submission to the department or its agent that is by a natural person identified in this notice of delegation and of a type listed for such electronic submission agent in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 9VAC5-140-6130 D shall be deemed to be an electronic submission by me. Until this notice of delegation is superseded by another notice of delegation under 9VAC5-140-6130 D, I agree to maintain an email account and to notify the department or its agent immediately of any change in my email address unless all delegation authority by me under 9VAC5-140-6130 is terminated."~~

D. A notice of delegation submitted under subsection C of this section shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the department or its agent and until receipt by the department or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of delegation may replace any previously identified electronic submission agent, add a new electronic submission agent, or eliminate entirely any delegation of authority.

E. Any electronic submission covered by the certification in subdivision C 4 of this section and made in accordance with a notice of delegation effective under subsection D of this section shall be deemed to be an electronic submission by the CO_2 authorized account representative or CO_2 authorized alternate account representative submitting such notice of delegation.

F. A CO_2 authorized account representative may delegate, to one or more natural persons, his authority to review information in the CO_2 allowance tracking system under this part.

G. A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his authority to review information in the CO_2 allowance tracking system under this part.

H. To delegate authority to review information in the CO_2 allowance tracking system in accordance with subsections F and G of this section, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, shall submit to the department or its agent a notice of delegation, in a format prescribed by the department that includes the following elements:

1. The name, address, email address, telephone number, and facsimile transmission number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;

2. The name, address, email address, telephone number, and facsimile transmission number of each such natural person, referred to as the "reviewer";

3. For each such natural person, a list of the type of information under subsection F or G of this section for which authority is delegated to him; and

4. The following certification statement by such CO_2 authorized account representative or CO_2 authorized alternate account representative: "I agree that any information that is reviewed by a natural person identified in this notice of delegation and of a type listed for such information accessible by the reviewer in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under subsection I of this section shall be deemed to be a reviewer by me. Until this notice of delegation is superseded by another notice of delegation under subsection I of this section, I agree to maintain an email account and to notify the department or its agent immediately of any change in my email address unless all delegation authority by me under this section is terminated."

I. A notice of delegation submitted under subsection H of this section shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the department or its agent and until receipt by the department or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of delegation may replace any previously identified reviewer, add a new reviewer, or eliminate entirely any delegation of authority.

~~Article 3~~

~~Permits~~

9VAC5-140-6140. ~~CO2 budget permit requirements.~~ (Repealed.)

~~Article 3~~
~~Permits~~

~~A. Each CO_2 budget source shall have a permit issued by the department pursuant to 9VAC5-85 (Permits for Stationary Sources of Pollutants Subject to Regulation).~~

~~B. Each CO_2 budget permit shall contain all applicable CO_2 Budget Trading Program requirements and shall be a complete and distinguishable portion of the permit under subsection A of this section.~~

9VAC5-140-6150. ~~Submission of CO2 budget permit applications.~~ (Repealed.)

~~For any CO_2 budget source, the CO_2 authorized account representative shall submit a complete CO_2 budget permit application under 9VAC5-140-6160 covering such CO_2 budget source to the department by the later of January 1, 2021, or 12 months before the date on which the CO_2 budget source, or a new unit at the source, commences operation.~~

9VAC5-140-6160. ~~Information requirements for CO2 budget permit applications.~~ (Repealed.)

~~A complete CO_2 budget permit application shall include the following elements concerning the CO_2 budget source for which the application is submitted, in a format prescribed by the department:~~

~~1. Identification of the CO_2 budget source, including plant name and the ORIS (Office of Regulatory Information Systems) or facility code assigned to the source by the Energy Information Administration of the U.S. Department of Energy if applicable;~~

~~2. Identification of each CO_2 budget unit at the CO_2 budget source; and~~

~~3. The standard requirements under 9VAC5-140-6050.~~

~~Article 4~~

~~Compliance Certification~~

9VAC5-140-6170. ~~Compliance certification report.~~ (Repealed.)

~~Article 4~~
~~Compliance Certification~~

~~A. For each control period in which a CO_2 budget source is subject to the CO_2 requirements of 9VAC5-140-6050 C, the CO_2 authorized account representative of the source shall submit to the department by March 1 following the relevant control period, a compliance certification report. A compliance certification report is not required as part of the compliance obligation during an interim control period.~~

~~B. The CO_2 authorized account representative shall include in the compliance certification report under subsection A of this section the following elements, in a format prescribed by the department:~~

~~1. Identification of the source and each CO_2 budget unit at the source;~~

~~2. At the CO_2 authorized account representative's option, the serial numbers of the CO_2 allowances that are to be deducted from the source's compliance account under 9VAC5-140-6260 for the control period; and~~

~~3. The compliance certification under subsection C of this section.~~

C. In the compliance certification report under subsection A of this section, the CO_2 authorized account representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the source and the CO_2 budget units at the source in compliance with the CO_2 Budget Trading Program, whether the source and each CO_2 budget unit at the source for which the compliance certification is submitted was operated during the calendar years covered by the report in compliance with the requirements of the CO_2 Budget Trading Program, including:

1. Whether the source was operated in compliance with the CO_2 requirements of 9VAC5-140-6050 C;

2. Whether the monitoring plan applicable to each unit at the source has been maintained to reflect the actual operation and monitoring of the unit, and contains all information necessary to attribute CO_2 emissions to the unit, in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part;

3. Whether all the CO_2 emissions from the units at the source were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports, including whether conditional data were reported in the quarterly reports in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part. If conditional data were reported, the owner or operator shall indicate whether the status of all conditional data has been resolved and all necessary quarterly report resubmissions have been made;

4. Whether the facts that form the basis for certification under Article 8 (9VAC5-140-6330 et seq.) of this part of each monitor at each unit at the source, or for using an excepted monitoring method or alternative monitoring method approved under Article 8 (9VAC5-140-6330 et seq.) of this part, if any, have changed; and

5. If a change is required to be reported under subdivision 4 of this subsection, specify the nature of the change, the reason for the change, when the change occurred, and how the unit's compliance status was determined subsequent to the change, including what method was used to determine emissions when a change mandated the need for monitor recertification.

9VAC5-140-6180. ~~Action on compliance certifications.~~ (Repealed.)

A. The department or its agent may review and conduct independent audits concerning any compliance certification or any other submission under the CO_2 Budget Trading Program and make appropriate adjustments of the information in the compliance certifications or other submissions.

B. The department or its agent may deduct CO_2 allowances from or transfer CO_2 allowances to a source's compliance account based on the information in the compliance certifications or other submissions, as adjusted under subsection A of this section.

Article 5

CO_2 Allowance Allocations

9VAC5-140-6190. ~~Base budgets.~~ (Repealed.)

Article 5

CO_2 Allowance Allocations

A. The Virginia CO_2 Budget Trading Program base budget shall be as follows:

1.

For 2021, the Virginia CO_2 Budget Trading Program base budget is 27.16 million tons.

2. For 2022, the Virginia CO_2 Budget Trading Program base budget is 26.32 million tons.

~~3. For 2023, the Virginia CO_2 Budget Trading Program base budget is 25.48 million tons.~~

~~4. For 2024, the Virginia CO_2 Budget Trading Program base budget is 24.64 million tons.~~

~~5. For 2025, the Virginia CO_2 Budget Trading Program base budget is 23.80 million tons.~~

~~6. For 2026, the Virginia CO_2 Budget Trading Program base budget is 22.96 million tons.~~

~~7. For 2027, the Virginia CO_2 Budget Trading Program base budget is 22.12 million tons.~~

~~8. For 2028, the Virginia CO_2 Budget Trading Program base budget is 21.28 million tons.~~

~~9. For 2029, the Virginia CO_2 Budget Trading Program base budget is 20.44 million tons.~~

~~10. For 2030, the Virginia CO_2 Budget Trading Program base budget is 19.60 million tons.~~

~~B.~~

~~For 2031 and each succeeding calendar year, the Virginia CO_2 Budget Trading Program base budget is 19.60 million tons unless modified as a result of a program review and future regulatory action.~~

9VAC5-140-6200. ~~Undistributed and unsold conditional CO2 allowances.~~ (Repealed.)

~~A. The department will retire undistributed CO_2 allowances at the end of each control period.~~

~~B. The department will retire unsold CO_2 allowances at the end of each control period.~~

9VAC5-140-6210. ~~CO2 allowance allocations.~~ (Repealed.)

~~A. The department will allocate the Virginia CO_2 Budget Trading Program base budget CO_2 allowances to the Virginia Auction Account.~~

~~B. For allocation years 2021 through 2030, the Virginia CO_2 Budget Trading Program adjusted budget shall be the maximum number of allowances available for allocation in a given allocation year, except for CO_2 CCR allowances.~~

~~C.~~

~~In the event that the CCR is triggered during an auction, the department will allocate CO_2 CCR allowances, separate from and additional to the Virginia CO_2 Budget Trading Program base budget set forth in 9VAC5-140-6190 to the Virginia Auction Account. The CCR allocation is for the purpose of containing the cost of CO_2 allowances. The department will allocate CO_2 CCR allowances as follows:~~

~~1.~~

~~On or before January 1, 2021, and each year thereafter, the department will allocate CO_2 CCR allowances equal to the quantity in Table 140-5A.~~

~~Table 140-5A~~
~~CO_2 CCR Allowances from 2021 Forward~~

~~2021~~	~~2.716 million tons~~
~~2022~~	~~2.632 million tons~~
~~2023~~	~~2.548 million tons~~
~~2024~~	~~2.464 million tons~~
~~2025~~	~~2.380 million tons~~
~~2026~~	~~2.296 million tons~~
~~2027~~	~~2.212 million tons~~

2028	2.128 million tons
2029	2.044 million tons
2030 and each year thereafter	1.960 million tons

2. CCR allowances allocated for a calendar year will be automatically transferred to the Virginia Auction Account to be auctioned. Following each auction, all CO_2 CCR allowances sold at auction will be transferred to winning bidders' accounts as CO_2 CCR allowances.

3. Unsold CO_2 CCR allowances will remain in the Virginia Auction Account to be re-offered for sale at auction within the same calendar year. CO_2 CCR allowances remaining unsold at the end of the calendar year in which they were originated will be made unavailable for sale at future auctions.

D. In the event that the ECR is triggered during an auction, the department will authorize its agent to withhold CO_2 allowances as needed. The department will further authorize its agent to convert and transfer any CO_2 allowances that have been withheld from any auction into the Virginia ECR account. The ECR withholding is for the purpose of additional emission reduction in the event of lower than anticipated emission reduction costs. The department's agent will withhold CO_2 ECR allowances as follows:

1. If the condition in 9VAC5-140-6420 C 1 is met at an auction, then the maximum number of CO_2 ECR allowances that will be withheld from that auction will be equal to the quantity shown in Table 140-5B minus the total quantity of CO_2 ECR allowances that have been withheld from any prior auction in that calendar year. Any CO_2 ECR allowances withheld from an auction will be transferred into the Virginia ECR account.

Table 140-5B ECR Allowances from 2021 Forward	
2021	2.716 million tons
2022	2.632 million tons
2023	2.548 million tons
2024	2.464 million tons
2025	2.380 million tons
2026	2.296 million tons
2027	2.212 million tons
2028	2.128 million tons
2029	2.044 million tons
2030 and each year thereafter	1.960 million tons

2. Allowances that have been transferred into the Virginia ECR account shall not be withdrawn.

E. The adjustment for banked allowances will be as follows. On March 15, 2021, the department may determine the adjustment for banked allowances quantity for allocation years 2021 through 2025 through the application of the following formula:

TABA = ((TA – TAE)/5) x RS%

Where:

TABA is the adjustment for banked allowances quantity in tons.

TA, adjustment, is the total quantity of allowances of vintage years prior to 2021 held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program but not including accounts opened by participating states, as reflected in the CO_2 Allowance Tracking System on March 15, 2021.

TAE, adjustment emissions, is the total quantity of 2018, 2019, and 2020 emissions from all CO_2 budget sources in all participating states, reported pursuant to CO_2 Budget Trading Program as reflected in the CO_2 Allowance Tracking System on March 15, 2021.

RS% is Virginia budget divided by the regional budget.

F. CO_2 Budget Trading Program adjusted budgets for 2021 through 2025 shall be determined as follows: on April 15, 2021, the department will determine the Virginia CO_2 Budget Trading Program adjusted budgets for the 2021 through 2025 allocation years by the following formula:

AB = BB – TABA

Where:

AB is the Virginia CO_2 Budget Trading Program adjusted budget.

BB is the Virginia CO_2 Budget Trading Program base budget.

TABA is the adjustment for banked allowances quantity in tons.

G. The department or its agent will publish the CO_2 trading program adjusted budgets for the 2021 through 2025 allocation years.

Article 6

CO_2 Allowance Tracking System

9VAC5-140-6220. CO2 Allowance Tracking System accounts. (Repealed.)

Article 6

CO_2 Allowance Tracking System

A. Consistent with 9VAC5-140-6230 A, the department or its agent will establish one compliance account for each CO_2 budget source. Allocations of CO_2 allowances pursuant to Article 5 (9VAC5-140-6190 et seq.) of this part and deductions or transfers of CO_2 allowances pursuant to 9VAC5-140-6180, 9VAC5-140-6260, 9VAC5-140-6280, or Article 7 (9VAC5-140-6300 et seq.) of this part will be recorded in the compliance accounts in accordance with this section.

B. Consistent with 9VAC5-140-6230 B, the department or its agent will establish, upon request, a general account for any person. Transfers of CO_2 allowances pursuant to Article 7 (9VAC5-140-6300 et seq.) of this part will be recorded in the general account in accordance with this article.

9VAC5-140-6230. Establishment of accounts. (Repealed.)

A. Upon receipt of a complete account certificate of representation under 9VAC5-140-6110, the department or its agent will establish an allowance account and a compliance account for each CO_2 budget source for which an account certificate of representation was submitted.

B. General accounts shall operate as follows.

1. Any person may apply to open a general account for the purpose of holding and transferring CO_2 allowances. An application for a general account may designate one and only one CO_2 authorized account representative and one and only one CO_2 authorized alternate account representative who may act on behalf of the CO_2 authorized account representative. The agreement by which the CO_2 authorized alternate account representative is selected shall include a procedure for authorizing the CO_2 authorized alternate account representative to act in lieu of the CO_2 authorized account

representative. A complete application for a general account shall be submitted to the department or its agent and shall include the following elements in a format prescribed by the department or its agent:

a. Name, address, email address, telephone number, and facsimile transmission number of the CO_2 authorized account representative and any CO_2 authorized alternate account representative;

b. At the option of the CO_2 authorized account representative, organization name and type of organization;

c. A list of all persons subject to a binding agreement for the CO_2 authorized account representative or any CO_2 authorized alternate account representative to represent their ownership interest with respect to the CO_2 allowances held in the general account;

d. The following certification statement by the CO_2 authorized account representative and any CO_2 authorized alternate account representative: "I certify that I was selected as the CO_2 authorized account representative or the CO_2 authorized alternate account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CO_2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Budget Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the department or its agent or a court regarding the general account.";

e. The signature of the CO_2 authorized account representative and any CO_2 authorized alternate account representative and the dates signed; and

f. Unless otherwise required by the department or its agent, documents of agreement referred to in the application for a general account shall not be submitted to the department or its agent. Neither the department nor its agent shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

2. Authorization of the CO_2 authorized account representative shall be as follows:

a. Upon receipt by the department or its agent of a complete application for a general account under subdivision 1 of this subsection:

(1) The department or its agent will establish a general account for the person for whom the application is submitted.

(2) The CO_2 authorized account representative and any CO_2 authorized alternate account representative for the general account shall represent and, by his representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CO_2 allowances held in the general account in all matters pertaining to the CO_2 Budget Trading Program, notwithstanding any agreement between the CO_2 authorized account representative or any CO_2 authorized alternate account representative and such person. Any such person shall be bound by any order or decision issued to the CO_2 authorized account representative or any CO_2 authorized alternate account representative by the department or its agent or a court regarding the general account.

(3) Any representation, action, inaction, or submission by any CO_2 authorized alternate account representative shall be deemed to be a representation, action, inaction, or submission by the CO_2 authorized account representative.

b. Each submission concerning the general account shall be submitted, signed, and certified by the CO_2 authorized account representative or any CO_2 authorized alternate

account representative for the persons having an ownership interest with respect to CO_2 allowances held in the general account. Each such submission shall include the following certification statement by the CO_2 authorized account representative or any CO_2 authorized alternate account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CO_2 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

c. The department or its agent will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with subdivision 2 b of this subsection.

3. Changing CO_2 authorized account representative and CO_2 authorized alternate account representative, and changes in persons with ownership interest, shall be accomplished as follows:

a. The CO_2 authorized account representative for a general account may be changed at any time upon receipt by the department or its agent of a superseding complete application for a general account under subdivision 1 of this subsection. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative, or the previous CO_2 authorized alternate account representative, prior to the time and date when the department or its agent receives the superseding application for a general account shall be binding on the new CO_2 authorized account representative and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

b. The CO_2 authorized alternate account representative for a general account may be changed at any time upon receipt by the department or its agent of a superseding complete application for a general account under subdivision 1 of this subsection. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative, or the previous CO_2 authorized alternate account representative, prior to the time and date when the department or its agent receives the superseding application for a general account shall be binding on the new alternate CO_2 authorized account representative and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

c. In the event a new person having an ownership interest with respect to CO_2 allowances in the general account is not included in the list of such persons in the application for a general account, such new person shall be deemed to be subject to and bound by the application for a general account, the representations, actions, inactions, and submissions of the CO_2 authorized account representative and any CO_2 authorized alternate account representative, and the decisions, orders, actions, and inactions of the department or its agent, as if the new person were included in such list.

d. Within 30 days following any change in the persons having an ownership interest with respect to CO_2 allowances in the general account, including the addition or deletion of persons, the CO_2 authorized account representative or any CO_2 authorized

alternate account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CO_2 allowances in the general account to include the change.

4. Objections concerning CO_2 authorized account representative shall be governed as follows:

a. Once a complete application for a general account under subdivision 1 of this subsection has been submitted and received, the department or its agent will rely on the application unless and until a superseding complete application for a general account under subdivision 1 of this subsection is received by the department or its agent.

b. Except as provided in subdivisions 3 a and 3 b of this subsection, no objection or other communication submitted to the department or its agent concerning the authorization, or any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative for a general account shall affect any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative or the finality of any decision or order by the department or its agent under the CO_2 Budget Trading Program.

c. Neither the department nor its agent will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative for a general account, including private legal disputes concerning the proceeds of CO_2 allowance transfers.

5. Delegation by CO_2 authorized account representative and CO_2 authorized alternate account representative shall be accomplished as follows:

a. A CO_2 authorized account representative may delegate, to one or more natural persons, his authority to make an electronic submission to the department or its agent provided for under this article and Article 7 (9VAC5-140-6300 et seq.) of this part.

b. A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his authority to make an electronic submission to the department or its agent provided for under this article and Article 7 (9VAC5-140-6300 et seq.) of this part.

c. To delegate authority to make an electronic submission to the department or its agent in accordance with subdivisions 5 a and 5 b of this subsection, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, shall submit to the department or its agent a notice of delegation, in a format prescribed by the department that includes the following elements:

(1) The name, address, email address, telephone number, and facsimile transmission number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;

(2) The name, address, email address, telephone number, and facsimile transmission number of each such natural person, referred to as "electronic submission agent";

(3) For each such natural person, a list of the type of electronic submissions under subdivision 5 c (1) or 5 c (2) of this subsection for which authority is delegated to him; and

(4) The following certification statement by such CO_2 authorized account representative or CO_2 authorized alternate account representative: "I agree that any electronic submission to the department or its agent that is by a natural person

identified in this notice of delegation and of a type listed for such electronic submission agent in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 9VAC5-140-6230 B 5 d shall be deemed to be an electronic submission by me. Until this notice of delegation is superseded by another notice of delegation under 9VAC5-140-6230 B 5 d, I agree to maintain an email account and to notify the department or its agent immediately of any change in my email address unless all delegation authority by me under 9VAC5-140-6230 B 5 is terminated."

d. A notice of delegation submitted under subdivision 5 c of this subsection shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the department or its agent and until receipt by the department or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of delegation may replace any previously identified electronic submission agent, add a new electronic submission agent, or eliminate entirely any delegation of authority.

e. Any electronic submission covered by the certification in subdivision 5 c (4) of this subsection and made in accordance with a notice of delegation effective under subdivision 5 d of this subsection shall be deemed to be an electronic submission by the CO_2 authorized account representative or CO_2 authorized alternate account representative submitting such notice of delegation.

C. The department or its agent will assign a unique identifying number to each account established under subsection A or B of this section.

9VAC5-140-6240. CO2 Allowance Tracking System responsibilities of CO2 authorized account representative. (Repealed.)

Following the establishment of a COATS account, all submissions to the department or its agent pertaining to the account, including submissions concerning the deduction or transfer of CO_2 allowances in the account, shall be made only by the CO_2 authorized account representative for the account.

9VAC5-140-6250. Recordation of CO2 allowance allocations. (Repealed.)

A. By January 1 of each calendar year, the department or its agent will record in the following accounts:

1. In each CO_2 budget source's allowance account, the CO_2 allowances allocated to those sources by the department prior to being auctioned; and

2. In each CO_2 budget source's compliance account, the allowances purchased at auction by CO_2 budget units at the source under 9VAC5-140-6210 A.

B. Each year the department or its agent will record CO_2 allowances, as allocated to the unit under Article 5 (9VAC5-140-6190 et seq.) of this part, in the compliance account for the year after the last year for which CO_2 allowances were previously allocated to the compliance account. Each year, the department or its agent will also record CO_2 allowances, as allocated under Article 5 (9VAC5-140-6190 et seq.) of this part, in an allocation set-aside for the year after the last year for which CO_2 allowances were previously allocated to an allocation set-aside.

C. Serial numbers for allocated CO_2 allowances shall be managed as follows. When allocating CO_2 allowances to and recording them in an account, the department or its agent will assign each CO_2 allowance a unique identification number that will include digits identifying the year for which the CO_2 allowance is allocated.

9VAC5-140-6260. ~~Compliance.~~ (Repealed.)

~~A. CO_2 allowances that meet the following criteria are available to be deducted for a CO_2 budget source to comply with the CO_2 requirements of 9VAC5-140-6050 C for a control period or an interim control period.~~

~~1. The CO_2 allowances are of allocation years that fall within a prior control period, the same control period, or the same interim control period for which the allowances will be deducted.~~

~~2. The CO_2 allowances are held in the CO_2 budget source's compliance account as of the CO_2 allowance transfer deadline for that control period or interim control period or are transferred into the compliance account by a CO_2 allowance transfer correctly submitted for recordation under 9VAC5-140-6300 by the CO_2 allowance transfer deadline for that control period or interim control period.~~

~~3. For CO_2 offset allowances generated by other participating states, the number of CO_2 offset allowances that are available to be deducted in order for a CO_2 budget source to comply with the CO_2 requirements of 9VAC5-140-6050 C for a control period or an interim control period shall not exceed 3.3% of the CO_2 budget source's CO_2 emissions for that control period, or may not exceed 3.3% of 0.50 times the CO_2 budget source's CO_2 emissions for an interim control period, as determined in accordance with this article and Article 8 (9VAC5-140-6330 et seq.) of this part.~~

~~4. The CO_2 allowances are not necessary for deductions for excess emissions for a prior control period under subsection D of this section.~~

~~B. Following the recordation, in accordance with 9VAC5-140-6310, of CO_2 allowance transfers submitted for recordation in the CO_2 budget source's compliance account by the CO_2 allowance transfer deadline for a control period or an interim control period, the department or its agent will deduct CO_2 allowances available under subsection A of this section to cover the source's CO_2 emissions, as determined in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part, for the control period or interim control period, as follows:~~

~~1. Until the amount of CO_2 allowances deducted equals the number of tons of total CO_2 emissions, or 0.50 times the number of tons of total CO_2 emissions for an interim control period, determined in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part, from all CO_2 budget units at the CO_2 budget source for the control period or interim control period; or~~

~~2. If there are insufficient CO_2 allowances to complete the deductions in subdivision 1 of this subsection, until no more CO_2 allowances available under subsection A of this section remain in the compliance account.~~

~~C. Identification of available CO_2 allowances by serial number and default compliance deductions shall be managed as follows:~~

~~1. The CO_2 authorized account representative for a source's compliance account may request that specific CO_2 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period or interim control period in accordance with subsection B or D of this section. Such identification shall be made in the compliance certification report submitted in accordance with 9VAC5-140-6170.~~

~~2. The department or its agent will deduct CO_2 allowances for an interim control period or a control period from the CO_2 budget source's compliance account, in the absence of an identification or in the case of a partial identification of available CO_2 allowances by serial number under subdivision 1 of this subsection, as follows: Any CO_2 allowances that are available for deduction under subdivision 1 of this subsection. CO_2 allowances shall be~~

deducted in chronological order (i.e., CO_2 allowances from earlier allocation years shall be deducted before CO_2 allowances from later allocation years). In the event that some, but not all, CO_2 allowances from a particular allocation year are to be deducted, CO_2 allowances shall be deducted by serial number, with lower serial number allowances deducted before higher serial number allowances.

D. Deductions for excess emissions shall be managed as follows.

1. After making the deductions for compliance under subsection B of this section, the department or its agent will deduct from the CO_2 budget source's compliance account a number of CO_2 allowances equal to three times the number of the source's excess emissions. In the event that a source has insufficient CO_2 allowances to cover three times the number of the source's excess emissions, the source shall be required to immediately transfer sufficient allowances into its compliance account.

2. Any CO_2 allowance deduction required under subdivision 1 of this subsection shall not affect the liability of the owners and operators of the CO_2 budget source or the CO_2 budget units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under applicable state law. The following guidelines will be followed in assessing fines, penalties, or other obligations:

a. For purposes of determining the number of days of violation, if a CO_2 budget source has excess emissions for a control period, each day in the control period constitutes a day in violation unless the owners and operators of the unit demonstrate that a lesser number of days should be considered.

b. Each ton of excess emissions is a separate violation.

c. For purposes of determining the number of days of violation, if a CO_2 budget source has excess interim emissions for an interim control period, each day in the interim control period constitutes a day in violation unless the owners and operators of the unit demonstrate that a lesser number of days should be considered.

d. Each ton of excess interim emissions is a separate violation.

3. The propriety of the department's determination that a CO_2 budget source had excess emissions and the concomitant deduction of CO_2 allowances from that CO_2 budget source's account may be later challenged in the context of the initial administrative enforcement, or any civil or criminal judicial action arising from or encompassing that excess emissions violation. The commencement or pendency of any administrative enforcement, or civil or criminal judicial action arising from or encompassing that excess emissions violation will not act to prevent the department or its agent from initially deducting the CO_2 allowances resulting from the department's original determination that the relevant CO_2 budget source has had excess emissions. Should the department's determination of the existence or extent of the CO_2 budget source's excess emissions be revised either by a settlement or final conclusion of any administrative or judicial action, the department will act as follows:

a. In any instance where the department's determination of the extent of excess emissions was too low, the department will take further action under subdivisions 1 and 2 of this subsection to address the expanded violation.

b. In any instance where the department's determination of the extent of excess emissions was too high, the department will distribute to the relevant CO_2 budget source a number of CO_2 allowances equaling the number of CO_2 allowances deducted which are attributable to the difference between the original and final quantity of excess emissions. Should such CO_2 budget source's compliance account no longer exist, the

~~CO_2 allowances will be provided to a general account selected by the owner or operator of the CO_2 budget source from which they were originally deducted.~~

~~E. The department or its agent will record in the appropriate compliance account all deductions from such an account pursuant to subsections B and D of this section.~~

~~F. Action by the department on submissions shall be as follows:~~

~~1. The department may review and conduct independent audits concerning any submission under the CO_2 Budget Trading Program and make appropriate adjustments of the information in the submissions.~~

~~2. The department may deduct CO_2 allowances from or transfer CO_2 allowances to a source's compliance account based on information in the submissions, as adjusted under subdivision 1 of this subsection.~~

9VAC5-140-6270. ~~Banking.~~ (Repealed.)

~~Each CO_2 allowance that is held in a compliance account or a general account will remain in such account unless and until the CO_2 allowance is deducted or transferred under 9VAC5-140-6180, 9VAC5-140-6260, 9VAC5-140-6280, or Article 7 (9VAC5-140-6300 et seq.) of this part.~~

9VAC5-140-6280. ~~Account error.~~ (Repealed.)

~~The department or its agent may, at its sole discretion and on its own motion, correct any error in any COATS account. Within 10 business days of making such correction, the department or its agent will notify the CO_2 authorized account representative for the account.~~

9VAC5-140-6290. ~~Closing of general accounts.~~ (Repealed.)

~~A. A CO_2 authorized account representative of a general account may instruct the department or its agent to close the account by submitting a statement requesting deletion of the account from the COATS and by correctly submitting for recordation under 9VAC5-140-6300 a CO_2 allowance transfer of all CO_2 allowances in the account to one or more other COATS accounts.~~

~~B. If a general account shows no activity for a period of one year or more and does not contain any CO_2 allowances, the department or its agent may notify the CO_2 authorized account representative for the account that the account will be closed in the COATS 30 business days after the notice is sent. The account will be closed after the 30-day period unless before the end of the 30-day period the department or its agent receives a correctly submitted transfer of CO_2 allowances into the account under 9VAC5-140-6300 or a statement submitted by the CO_2 authorized account representative demonstrating to the satisfaction of the department or its agent good cause as to why the account should not be closed. The department or its agent will have sole discretion to determine if the owner or operator of the unit demonstrated that the account should not be closed.~~

~~Article 7~~

~~CO_2 Allowance Transfers~~

9VAC5-140-6300. ~~Submission of CO2 allowance transfers.~~ (Repealed.)

~~Article 7~~

~~CO_2 Allowance Transfers~~

~~The CO_2 authorized account representatives seeking recordation of a CO_2 allowance transfer shall submit the transfer to the department or its agent. To be considered correctly submitted, the CO_2 allowance transfer shall include the following elements in a format specified by the department or its agent:~~

~~1. The numbers identifying both the transferor and transferee accounts;~~

~~2. A specification by serial number of each CO_2 allowance to be transferred;~~

3. The printed name and signature of the CO_2 authorized account representative of the transferor account and the date signed;

4. The date of the completion of the last sale or purchase transaction for the allowance, if any; and

5. The purchase or sale price of the allowance that is the subject of a sale or purchase transaction under subdivision 4 of this section.

9VAC5-140-6310. ~~Recordation.~~ (Repealed.)

A. Within five business days of receiving a CO_2 allowance transfer, except as provided in subsection B of this section, the department or its agent will record a CO_2 allowance transfer by moving each CO_2 allowance from the transferor account to the transferee account as specified by the request, provided that:

1. The transfer is correctly submitted under 9VAC5-140-6300; and

2. The transferor account includes each CO_2 allowance identified by serial number in the transfer.

B. A CO_2 allowance transfer into or out of a compliance account that is submitted for recordation following the CO_2 allowance transfer deadline and that includes any CO_2 allowances that are of allocation years that fall within a control period prior to or the same as the control period to which the CO_2 allowance transfer deadline applies will not be recorded until after completion of the process pursuant to 9VAC5-140-6260 B.

C. Where a CO_2 allowance transfer submitted for recordation fails to meet the requirements of subsection A of this section, the department or its agent will not record such transfer.

9VAC5-140-6320. ~~Notification.~~ (Repealed.)

A. Within five business days of recordation of a CO_2 allowance transfer under 9VAC5-140-6310, the department or its agent will notify each party to the transfer. Notice will be given to the CO_2 authorized account representatives of both the transferor and transferee accounts.

B. Within 10 business days of receipt of a CO_2 allowance transfer that fails to meet the requirements of 9VAC5-140-6310 A, the department or its agent will notify the CO_2 authorized account representatives of both accounts subject to the transfer of (i) a decision not to record the transfer and (ii) the reasons for such nonrecordation.

C. Nothing in this section shall preclude the submission of a CO_2 allowance transfer for recordation following notification of nonrecordation.

9VAC5-140-6325. ~~Life-of-the-unit contractual arrangements.~~ (Repealed.)

A. A power purchaser entered into a life-of-the-unit contractual arrangement as described in subdivision b of the definition of "life-of-the-unit contractual arrangement" with a CO_2 budget source or unit shall be responsible for acquiring and transferring all allowances to the CO_2 budget source or unit that are necessary for demonstrating compliance with the CO_2 budget trading program.

B. The CO_2 budget source or unit shall provide a copy of the energy conversion or energy tolling agreement to the department within six months of July 10, 2020. If such agreement is subject to third-party disclosure restrictions, the CO_2 budget source or unit shall provide purchaser within 10 days prior written notice of its intention to disclose the agreement to the department and request confidential treatment from the public disclosure of such agreement. The department will grant a request for confidential treatment pursuant to applicable statutory and regulatory requirements addressing confidential information.

C. The CO_2 budget source or unit shall be responsible for compliance with and otherwise be subject to all other requirements of this part and the CO_2 budget trading program.

~~Article 8~~

~~Monitoring, Reporting, and Recordkeeping~~

9VAC5-140-6330. ~~General requirements.~~ (Repealed.)

~~Article 8~~

~~Monitoring, Reporting, and Recordkeeping~~

~~A. The owners and operators, and to the extent applicable, the CO_2 authorized account representative of a CO_2 budget unit shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this section and all applicable sections of 40 CFR Part 75. Where referenced in this article, the monitoring requirements of 40 CFR Part 75 shall be adhered to in a manner consistent with the purpose of monitoring and reporting CO_2 mass emissions pursuant to this part. For purposes of complying with such requirements, the definitions in 9VAC5-140-6020 and in 40 CFR 72.2 shall apply, and the terms "affected unit," "designated representative," and "CEMS" in 40 CFR Part 75 shall be replaced by the terms "CO_2 budget unit," "CO_2 authorized account representative," and "CEMS," respectively, as defined in 9VAC5-140-6020. For units not subject to an Acid Rain emissions limitation, the term "administrator" in 40 CFR Part 75 shall be replaced with "the department or its agent." Owners or operators of a CO_2 budget unit who monitor a non-CO_2 budget unit pursuant to the common, multiple, or bypass stack procedures in 40 CFR 75.72(b)(2)(ii), or 40 CFR 75.16 (b)(2)(ii)(B) pursuant to 40 CFR 75.13, for purposes of complying with this part, shall monitor and report CO_2 mass emissions from such non-CO_2 budget units according to the procedures for CO_2 budget units established in this article.~~

~~B. The owner or operator of each CO_2 budget unit shall meet the following general requirements for installation, certification, and data accounting.~~

~~1. Install all monitoring systems necessary to monitor CO_2 mass emissions in accordance with 40 CFR Part 75, except for equation G-1. Equation G-1 in Appendix G shall not be used to determine CO_2 emissions under this part. This may require systems to monitor CO_2 concentration, stack gas flow rate, O_2 concentration, heat input, and fuel flow rate.~~

~~2. Successfully complete all certification tests required under 9VAC5-140-6340 and meet all other requirements of this section and 40 CFR Part 75 applicable to the monitoring systems under subdivision 1 of this subsection.~~

~~3. Record, report, and quality-assure the data from the monitoring systems under subdivision 1 of this subsection.~~

~~C. The owner or operator shall meet the monitoring system certification and other requirements of subsection B of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under subdivision B 1 of this section on and after the following dates:~~

~~1. The owner or operator of a CO_2 budget unit, except for a CO_2 budget unit under subdivision 2 of this subsection, shall comply with the requirements of this section by January 1, 2021.~~

~~2. The owner or operator of a CO_2 budget unit that commences commercial operation July 1, 2021, shall comply with the requirements of this section by (i) January 1, 2022, or (ii) the earlier of 90 unit operating days after the date on which the unit commences commercial operation or 180 calendar days after the date on which the unit commences commercial operation.~~

~~3. For the owner or operator of a CO_2 budget unit for which construction of a new stack or flue installation is completed after the applicable deadline under subdivision 1 or 2 of this subsection by the earlier of (i) 90 unit operating days after the date on which emissions~~

first exit to the atmosphere through the new stack or flue or (ii) 180 calendar days after the date on which emissions first exit to the atmosphere through the new stack or flue.

D. Data shall be reported as follows:

1. Except as provided in subdivision 2 of this subsection, the owner or operator of a CO_2 budget unit that does not meet the applicable compliance date set forth in subsection C of this section for any monitoring system under subdivision B 1 of this section shall, for each such monitoring system, determine, record, and report maximum potential, or as appropriate minimum potential, values for CO_2 concentration, CO_2 emissions rate, stack gas moisture content, fuel flow rate, heat input, and any other parameter required to determine CO_2 mass emissions in accordance with 40 CFR 75.31(b)(2) or (c)(3) or Section 2.4 of Appendix D of 40 CFR Part 75 as applicable.

2. The owner or operator of a CO_2 budget unit that does not meet the applicable compliance date set forth in subdivision C 3 of this section for any monitoring system under subdivision B 1 of this section shall, for each such monitoring system, determine, record, and report substitute data using the applicable missing data procedures in Subpart D, or Appendix D of 40 CFR Part 75, in lieu of the maximum potential, or as appropriate minimum potential, values for a parameter if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation under subdivision C 3 of this section.

a. CO_2 budget units subject to an Acid Rain emissions limitation or CSAPR NO_X Ozone Season Trading Program that qualify for the optional SO_2, NO_x, and CO_2 (for Acid Rain) or NO_X (for CSAPR NO_X Ozone Season Trading Program) emissions calculations for low mass emissions (LME) units under 40 CFR 75.19 and report emissions for such programs using the calculations under 40 CFR 75.19, shall also use the CO_2 emissions calculations for LME units under 40 CFR 75.19 for purposes of compliance with these regulations.

b. CO_2 budget units subject to an Acid Rain emissions limitation that do not qualify for the optional SO_2, NO_x, and CO_2 (for Acid Rain) or NO_X (for CSAPR NO_X Ozone Season Trading Program) emissions calculations for LME units under 40 CFR 75.19 shall not use the CO_2 emissions calculations for LME units under 40 CFR 75.19 for purposes of compliance with these regulations.

c. CO_2 budget units not subject to an Acid Rain emissions limitation shall qualify for the optional CO_2 emissions calculation for LME units under 40 CFR 75.19, provided that they emit less than 100 tons of NO_X annually and no more than 25 tons of SO_2 annually.

3. The owner or operator of a CO_2 budget unit shall report net-electric output data to the department as required by Article 5 (9VAC5-140-6190 et seq.) of this part.

E. Prohibitions shall be as follows.

1. No owner or operator of a CO_2 budget unit shall use any alternative monitoring system, alternative reference method, or any other alternative for the required CEMS without having obtained prior written approval in accordance with 9VAC5-140-6380.

2. No owner or operator of a CO_2 budget unit shall operate the unit so as to discharge, or allow to be discharged, CO_2 emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this article and 40 CFR Part 75.

3. No owner or operator of a CO_2 budget unit shall disrupt the CEMS, any portion thereof, or any other approved emissions monitoring method, and thereby avoid monitoring and recording CO_2 mass emissions discharged into the atmosphere, except for periods of

~~recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this article and 40 CFR Part 75.~~

~~4. No owner or operator of a CO_2 budget unit shall retire or permanently discontinue use of the CEMS, any component thereof, or any other approved emissions monitoring system under this article, except under any one of the following circumstances:~~

~~a. The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this article and 40 CFR Part 75, by the department for use at that unit that provides emissions data for the same pollutant or parameter as the retired or discontinued monitoring system; or~~

~~b. The CO_2 authorized account representative submits notification of the date of certification testing of a replacement monitoring system in accordance with 9VAC5-140-6340 D 3 a.~~

9VAC5-140-6340. ~~Initial certification and recertification procedures.~~ (Repealed.)

~~A. The owner or operator of a CO_2 budget unit shall be exempt from the initial certification requirements of this section for a monitoring system under 9VAC5-140-6330 B 1 if the following conditions are met:~~

~~1. The monitoring system has been previously certified in accordance with 40 CFR Part 75; and~~

~~2. The applicable quality-assurance and quality-control requirements of 40 CFR 75.21 and Appendix B and Appendix D of 40 CFR Part 75 are fully met for the certified monitoring system described in subdivision 1 of this subsection.~~

~~B. The recertification provisions of this section shall apply to a monitoring system under 9VAC5-140-6330 B 1 exempt from initial certification requirements under subsection A of this section.~~

~~C. Notwithstanding subsection A of this section, if the administrator has previously approved a petition under 40 CFR 75.72(b)(2)(ii), or 40 CFR 75.16(b)(2)(ii)(B) as pursuant to 40 CFR 75.13 for apportioning the CO_2 emissions rate measured in a common stack or a petition under 40 CFR 75.66 for an alternative requirement in 40 CFR Part 75, the CO_2 authorized account representative shall submit the petition to the department under 9VAC5-140-6380 A to determine whether the approval applies under this program.~~

~~D. Except as provided in subsection A of this section, the owner or operator of a CO_2 budget unit shall comply with the following initial certification and recertification procedures for a CEMS and an excepted monitoring system under Appendix D of 40 CFR Part 75 and under 9VAC5-140-6330 B 1. The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology in 40 CFR 75.19 or that qualifies to use an alternative monitoring system under Subpart E of 40 CFR Part 75 shall comply with the procedures in subsection E or F of this section, respectively.~~

~~1. For initial certification, the owner or operator shall ensure that each CEMS required under 9VAC5-140-6330 B 1, which includes the automated DAHS, successfully completes all of the initial certification testing required under 40 CFR 75.20 by the applicable deadlines specified in 9VAC5-140-6330 C. In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this article in a location where no such monitoring system was previously installed, initial certification in accordance with 40 CFR 75.20 is required.~~

~~2. For recertification, the following requirements shall apply.~~

~~a. Whenever the owner or operator makes a replacement, modification, or change in a certified CEMS under 9VAC5-140-6330 B 1 that the administrator or the department~~

~~determines significantly affects the ability of the system to accurately measure or record CO_2 mass emissions or to meet the quality-assurance and quality-control requirements of 40 CFR 75.21 or Appendix B to 40 CFR Part 75, the owner or operator shall recertify the monitoring system according to 40 CFR 75.20(b).~~

~~b. For systems using stack measurements such as stack flow, stack moisture content, CO_2 or O_2 monitors, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that the administrator or the department determines to significantly change the flow or concentration profile, the owner or operator shall recertify the CEMS according to 40 CFR 75.20(b). Examples of changes that require recertification include replacement of the analyzer, change in location or orientation of the sampling probe or site, or change of flow rate monitor polynomial coefficients.~~

~~3. The approval process for initial certifications and recertification shall be as follows: subdivisions 3 a through 3 d of this subsection apply to both initial certification and recertification of a monitoring system under 9VAC5-140-6330 B 1. For recertifications, replace the words "certification" and "initial certification" with the word "recertification," replace the word "certified" with "recertified," and proceed in the manner prescribed in 40 CFR 75.20(b)(5) and (g)(7) in lieu of subdivision 3 e of this subsection.~~

~~a. The CO_2 authorized account representative shall submit to the department or its agent, the appropriate EPA Regional Office and the administrator a written notice of the dates of certification in accordance with 9VAC5-140-6360.~~

~~b. The CO_2 authorized account representative shall submit to the department or its agent a certification application for each monitoring system. A complete certification application shall include the information specified in 40 CFR 75.63.~~

~~c. The provisional certification date for a monitor shall be determined in accordance with 40 CFR 75.20(a)(3). A provisionally certified monitor may be used under the CO_2 Budget Trading Program for a period not to exceed 120 days after receipt by the department of the complete certification application for the monitoring system or component thereof under subdivision 3 b of this subsection. Data measured and recorded by the provisionally certified monitoring system or component thereof, in accordance with the requirements of 40 CFR Part 75, will be considered valid quality-assured data, retroactive to the date and time of provisional certification, provided that the department does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of receipt of the complete certification application by the department.~~

~~d. The department will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under subdivision 3 b of this subsection. In the event the department does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of 40 CFR Part 75 and is included in the certification application will be deemed certified for use under the CO_2 Budget Trading Program.~~

~~(1) If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of 40 CFR Part 75, then the department will issue a written notice of approval of the certification application within 120 days of receipt.~~

~~(2) If the certification application is incomplete, then the department will issue a written notice of incompleteness that sets a reasonable date by which the CO_2 authorized account representative shall submit the additional information required to complete the~~

certification application. If the CO_2 authorized account representative does not comply with the notice of incompleteness by the specified date, then the department may issue a notice of disapproval under subdivision 3 d (3) of this subsection. The 120-day review period shall not begin before receipt of a complete certification application.

(3) If the certification application shows that any monitoring system or component thereof does not meet the performance requirements of 40 CFR Part 75, or if the certification application is incomplete and the requirement for disapproval under subdivision 3 d (2) of this subsection is met, then the department will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the department and the data measured and recorded by each uncertified monitoring system or component thereof shall not be considered valid quality assured data beginning with the date and hour of provisional certification. The owner or operator shall follow the procedures for loss of certification in subdivision 3 e of this subsection for each monitoring system or component thereof, which is disapproved for initial certification.

(4) The department may issue a notice of disapproval of the certification status of a monitor in accordance with 9VAC5-140-6350 B.

e. If the department issues a notice of disapproval of a certification application under subdivision 3 d (3) of this subsection or a notice of disapproval of certification status under subdivision 3 d (3) of this subsection, then:

(1) The owner or operator shall substitute the following values for each disapproved monitoring system, for each hour of unit operation during the period of invalid data beginning with the date and hour of provisional certification and continuing until the time, date, and hour specified under 40 CFR 75.20(a)(5)(i) or 40 CFR 75.20(g)(7): (i) for units using or intending to monitor for CO_2 mass emissions using heat input or for units using the low mass emissions excepted methodology under 40 CFR 75.19, the maximum potential hourly heat input of the unit; or (ii) for units intending to monitor for CO_2 mass emissions using a CO_2 pollutant concentration monitor and a flow monitor, the maximum potential concentration of CO_2 and the maximum potential flow rate of the unit under Section 2.1 of Appendix A of 40 CFR Part 75;

(2) The CO_2 authorized account representative shall submit a notification of certification retest dates and a new certification application in accordance with subdivisions 3 a and 3 b of this subsection; and

(3) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the department's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

E. The owner or operator of a unit qualified to use the low mass emissions excepted methodology under 9VAC5-140-6330 D 3 shall meet the applicable certification and recertification requirements of 40 CFR 75.19(a)(2), 40 CFR 75.20(h), and this section. If the owner or operator of such a unit elects to certify a fuel flow meter system for heat input determinations, the owner or operator shall also meet the certification and recertification requirements in 40 CFR 75.20(g).

F. The CO_2 authorized account of each unit for which the owner or operator intends to use an alternative monitoring system approved by the administrator and, if applicable, the department under Subpart E of 40 CFR Part 75 shall comply with the applicable notification and application procedures of 40 CFR 75.20(f).

9VAC5-140-6350. ~~Out-of-control periods.~~ (Repealed.)

~~A. Whenever any monitoring system fails to meet the quality assurance/quality control (QA/QC) requirements or data validation requirements of 40 CFR Part 75, data shall be substituted using the applicable procedures in Subpart D or Appendix D of 40 CFR Part 75.~~

~~B. Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under 9VAC5-140-6340 or the applicable provisions of 40 CFR Part 75, both at the time of the initial certification or recertification application submission and at the time of the audit, the department or administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this subsection, an audit shall be either a field audit or an audit of any information submitted to the department or the administrator. By issuing the notice of disapproval, the department or administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the initial certification or recertification procedures in 9VAC5-140-6340 for each disapproved monitoring system.~~

9VAC5-140-6360. ~~Notifications.~~ (Repealed.)

~~The CO_2 authorized account representative for a CO_2 budget unit shall submit written notice to the department and the administrator in accordance with 40 CFR 75.61.~~

9VAC5-140-6370. ~~Recordkeeping and reporting.~~ (Repealed.)

~~A. The CO_2 authorized account representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements under 40 CFR 75.73, and the requirements of 9VAC5-140-6080 E.~~

~~B. The owner or operator of a CO_2 budget unit shall submit a monitoring plan in the manner prescribed in 40 CFR 75.62.~~

~~C. The CO_2 authorized account representative shall submit an application to the department within 45 days after completing all CO_2 monitoring system initial certification or recertification tests required under 9VAC5-140-6340, including the information required under 40 CFR 75.63 and 40 CFR 75.53(e) and (f).~~

~~D. The CO_2 authorized account representative shall submit quarterly reports, as follows:~~

~~1. The CO_2 authorized account representative shall report the CO_2 mass emissions data for the CO_2 budget unit, in an electronic format prescribed by the department unless otherwise prescribed by the department for each calendar quarter.~~

~~2. The CO_2 authorized account representative shall submit each quarterly report to the department or its agent within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in Subpart H of 40 CFR Part 75 and 40 CFR 75.64. Quarterly reports shall be submitted for each CO_2 budget unit, or group of units using a common stack, and shall include all of the data and information required in Subpart G of 40 CFR Part 75, except for opacity, heat input, NO_x, and SO_2 provisions.~~

~~3. The CO_2 authorized account representative shall submit to the department or its agent a compliance certification in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:~~

a. The monitoring data submitted were recorded in accordance with the applicable requirements of this article and 40 CFR Part 75, including the quality assurance procedures and specifications;

b. For a unit with add-on CO_2 emissions controls and for all hours where data are substituted in accordance with 40 CFR 75.34(a)(1), the add-on emissions controls were operating within the range of parameters listed in the QA/QC program under Appendix B of 40 CFR Part 75 and the substitute values do not systematically underestimate CO_2 emissions; and

c. The CO_2 concentration values substituted for missing data under Subpart D of 40 CFR Part 75 do not systematically underestimate CO_2 emissions.

9VAC5-140-6380. ~~Petitions.~~ (Repealed.)

A. Except as provided in subsection C of this section, the CO_2 authorized account representative of a CO_2 budget unit that is subject to an Acid Rain emissions limitation may submit a petition to the administrator under 40 CFR 75.66 and to the department requesting approval to apply an alternative to any requirement of 40 CFR Part 75. Application of an alternative to any requirement of 40 CFR Part 75 is in accordance with this article only to the extent that the petition is approved in writing by the administrator, and subsequently approved in writing by the department.

B. Petitions for a CO_2 budget unit that is not subject to an Acid Rain emissions limitation shall meet the following requirements.

1. The CO_2 authorized account representative of a CO_2 budget unit that is not subject to an Acid Rain emissions limitation may submit a petition to the administrator under 40 CFR 75.66 and to the department requesting approval to apply an alternative to any requirement of 40 CFR Part 75. Application of an alternative to any requirement of 40 CFR Part 75 is in accordance with this article only to the extent that the petition is approved in writing by the administrator and subsequently approved in writing by the department.

2. In the event that the administrator declines to review a petition under subdivision 1 of this subsection, the CO_2 authorized account representative of a CO_2 budget unit that is not subject to an Acid Rain emissions limitation may submit a petition to the department requesting approval to apply an alternative to any requirement of this article. That petition shall contain all of the relevant information specified in 40 CFR 75.66. Application of an alternative to any requirement of this article is in accordance with this article only to the extent that the petition is approved in writing by the department.

C. The CO_2 authorized account representative of a CO_2 budget unit that is subject to an Acid Rain emissions limitation may submit a petition to the administrator under 40 CFR 75.66 and to the department requesting approval to apply an alternative to a requirement concerning any additional CEMS required under the common stack provisions of 40 CFR 75.72 or a CO_2 concentration CEMS used under 40 CFR 75.71(a)(2). Application of an alternative to any such requirement is in accordance with this article only to the extent the petition is approved in writing by the administrator and subsequently approved in writing by the department.

9VAC5-140-6390. ~~[Reserved].~~ (Repealed.)

9VAC5-140-6400. ~~[Reserved].~~ (Repealed.)

~~Article 9~~

~~Auction of CO_2 CCR and ECR Allowances~~

9VAC5-140-6410. ~~Purpose.~~ (Repealed.)

~~Article 9~~

~~Auction of CO_2 CCR and ECR Allowances~~

~~The following requirements shall apply to each allowance auction. The department or its agent may specify additional information in the auction notice for each auction. Such additional information may include the time and location of the auction, auction rules, registration deadlines, and any additional information deemed necessary or useful.~~

9VAC5-140-6420. ~~General requirements.~~ (Repealed.)

~~A. The department's agent will include the following information in the auction notice for each auction:~~

~~1. The number of CO_2 allowances offered for sale at the auction, not including any CO_2 CCR allowances;~~

~~2. The number of CO_2 CCR allowances that will be offered for sale at the auction if the condition of subdivision B 1 of this section is met;~~

~~3. The minimum reserve price for the auction;~~

~~4. The CCR trigger price for the auction;~~

~~5. The maximum number of CO_2 allowances that may be withheld from sale at the auction if the condition of subdivision D 1 of this section is met; and~~

~~6. The ECR trigger price for the auction.~~

~~B. The department's agent will follow these rules for the sale of CO_2 CCR allowances.~~

~~1. CO_2 CCR allowances shall only be sold at an auction in which total demand for allowances, above the CCR trigger price, exceeds the number of CO_2 allowances available for purchase at the auction, not including any CO_2 CCR allowances.~~

~~2. If the condition of subdivision 1 of this subsection is met at an auction, then the number of CO_2 CCR allowances offered for sale by the department or its agent at the auction shall be equal to the number of CO_2 CCR allowances in the Virginia Auction Account at the time of the auction.~~

~~3. After all of the CO_2 CCR allowances in the Virginia Auction Account have been sold in a given calendar year, no additional CO_2 CCR allowances will be sold at any auction for the remainder of that calendar year, even if the condition of subdivision 1 of this subsection is met at an auction.~~

~~4. At an auction in which CO_2 CCR allowances are sold, the reserve price for the auction shall be the CCR trigger price.~~

~~5. If the condition of subdivision 1 of this subsection is not satisfied, no CO_2 CCR allowances shall be offered for sale at the auction, and the reserve price for the auction shall be equal to the minimum reserve price.~~

~~C. The department's agent shall implement the reserve price as follows: (i) no allowances shall be sold at any auction for a price below the reserve price for that auction and (ii) if the total demand for allowances at an auction is less than or equal to the total number of allowances made available for sale in that auction, then the auction clearing price for the auction shall be the reserve price.~~

~~D. The department's agent will meet the following rules for the withholding of CO_2 ECR allowances from an auction.~~

~~1. CO_2 ECR allowances shall only be withheld from an auction if the demand for allowances would result in an auction clearing price that is less than the ECR trigger price prior to the withholding from the auction of any ECR allowances.~~

~~2. If the condition in subdivision 1 of this subsection is met at an auction, then the maximum number of CO_2 ECR allowances that may be withheld from that auction will be equal to the quantity shown in Table 140-5B of 9VAC5-140-6210 E minus the total quantity of CO_2 ECR allowances that have been withheld from any prior auction in that calendar year. Any CO_2 ECR allowances withheld from an auction will be transferred into the Virginia ECR Account.~~

9VAC5-140-6440. ~~Program monitoring and review.~~ (Repealed.)

~~Article 10~~

~~Program Monitoring and Review~~

~~In conjunction with the CO_2 Budget Trading Program program monitoring and review process, the department will evaluate impacts of the program specific to Virginia, including economic, energy, and environmental impacts and impacts on vulnerable and environmental justice and underserved communities. The department will, in evaluating the impacts on environmental justice communities, including low income, minority, and tribal communities, develop and implement a plan to ensure increased participation of environmental justice communities in the review.~~

Form: TH-05
April 2020

townhall.virginia.gov

Emergency Regulation and Notice of Intended Regulatory Action (NOIRA) Agency Background Document

Agency name	State Air Pollution Control Board
Virginia Administrative Code (VAC) Chapter citation(s)	Part VII of 9VAC5-140
VAC Chapter title(s)	Regulation for Emissions Trading
Action title	Repeal CO_2 Budget Trading Program as required by Executive Order 9 (Revision A22-E)
Date this document prepared	

This information is required for executive branch review and the Virginia Registrar of Regulations, pursuant to the Virginia Administrative Process Act (APA), Executive Order 14 (as amended, July 16, 2018), the Regulations for Filing and Publishing Agency Regulations (1VAC7-10), and the *Form and Style Requirements for the Virginia Register of Regulations and Virginia Administrative Code*.

Brief Summary

Provide a brief summary (preferably no more than 2 or 3 paragraphs) of the subject matter, intent, and goals of this this regulatory change (i.e., new regulation, amendments to an existing regulation, or repeal of an existing regulation). Alert the reader to all substantive matters or changes. If applicable, generally describe the existing regulation.

Executive Order 9 (2022), "Protecting Ratepayers from the Rising Cost of Living Due to the Regional Greenhouse Gas Initiative," requires that the department re-evaluate Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI) and immediately begin regulatory processes to end it. Specifically, the order requires that the department develop a proposed emergency regulation for the State Air Pollution Control Board's consideration to repeal the implementing regulation implementing participation in RGGI (Part VII of 9VAC5-140), and take all necessary steps to so that any proposed regulation to the State Air Pollution Control Board can be immediately presented for consideration for approval for public comment in accordance with the board's authority pursuant to § 10.1-1308 of the Code of Virginia.

Acronyms and Definitions

Define all acronyms used in this form, and any technical terms that are not also defined in the "Definitions" section of the regulation.

EO-9 - Executive Order 9 (2022)
RGGI - Regional Greenhouse Gas Initiative

Mandate and Impetus (Necessity for Emergency)

Explain why this rulemaking is an emergency situation in accordance with § 2.2-4011 A and B of the Code of Virginia. In doing so, either:

a) Indicate whether the Governor's Office has already approved the use of emergency regulatory authority for this regulatory change.
b) Provide specific citations to Virginia statutory law, the appropriation act, federal law, or federal regulation that require that a regulation be effective in 280 days or less from its enactment.

As required by § 2.2-4011, also describe the nature of the emergency and of the necessity for this regulatory change. In addition, delineate any potential issues that may need to be addressed as part of this regulatory change

The Governor's Office has already approved the use of emergency regulatory authority for this regulatory change via EO-9. The nature of the emergency and the necessity for this regulatory change are described in EO-9 as follows:

> Reliable and affordable access to electricity is imperative to the health and safety of all Virginians. Our hospitals, schools, businesses, and homes all rely on this essential service. And the unpredictable and rising cost of electricity poses a significant and immediate threat to our Commonwealth and its citizens. In 2019, alone, over 100,000 Virginian households required Energy Assistance with a cost of $46 million to the Commonwealth.
>
> Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI) risks contributing to the increased cost of electricity for our citizens. Virginia's utilities have sold over $227 million in allowances in 2021 during the RGGI auctions, doubling the initial estimates. Those utilities are allowed to pass on the costs of purchasing allowances to their ratepayers. Under the initial bill "RGGI rider" created for Dominion Energy customers, typical residential customer bills were increased by $2.39 a month and the typical industrial customer bill by was raised by $1,554 per month. In a filling before the State Corporation Commission, Dominion Energy stated that RGGI will cost ratepayers between $1 billion and $1.2 billion over the next four years.
>
> Simply stated, the benefits of RGGI have not materialized, while the costs have skyrocketed. Re-evaluation of the Initiative represents a meaningful step toward alleviating this financial burden on the Commonwealth's businesses and households. Regulations must be evaluated in view of the costs and benefits to all Virginians.

Legal Basis

Identify (1) the promulgating agency, and (2) the state and/or federal legal authority for the regulatory change, including the most relevant citations to the Code of Virginia or Acts and Assembly chapter number(s), if applicable. Your citation must include a specific provision, if any, authorizing the

promulgating agency to regulate this specific subject or program, as well as a reference to the agency's overall regulatory authority.

Statutory Authority

Section 10.1-1308 of the Virginia Air Pollution Control Law (Title 10.1, Chapter 13 of the Code of Virginia) authorizes the State Air Pollution Control Board to promulgate regulations abating, controlling and prohibiting air pollution in order to protect public health and welfare.

Promulgating Entity

The promulgating entity for this regulation is the State Air Pollution Control Board.

State Requirements

The specific directive of EO-9 states:

> . . . I hereby direct the Director of the Department of Environmental Quality, in coordination with the Secretary of Natural and Historic Resources, to take the following actions in accordance with the provisions and requirements of § 10.1-1300, et seq. and § 2.2-4000, et seq. of the Code of Virginia:
>
> > 1. Provide me a full report re-evaluating the costs and benefits of participation in the Regional Greenhouse Gas Initiative Inc. in view of all available data, within 30 days.
> >
> > 2. During this same period, develop a proposed emergency regulation for the State Air Pollution Control Board's consideration to repeal 9VAC5-140.
> >
> > 3. During this same period, take all necessary steps to so that any proposed regulation to the State Air Pollution Control Board can be immediately presented for consideration for approval for public comment in accordance with the Board's authority pursuant to § 10.1-1308 of the Code of Virginia.
> >
> > 4. During this same period, notify the Regional Greenhouse Gas Initiative Inc. (RGGI Inc.) of the review and the Governor's intent to withdraw from RGGI, whether by legislative or regulatory action.

This NOIRA is intended to implement items 2 and 3 of the directive.

Purpose

Describe the specific reasons why the agency has determined that this regulation is essential to protect the health, safety, or welfare of citizens. In addition, explain any potential issues that may need to be addressed as the regulation is developed.

As described in the Mandate and Impetus section of this document, EO-9 describes nature of the emergency and the necessity for this regulatory change in order to protect public health, safety and welfare.

Substance

Briefly identify and explain the new substantive provisions, the substantive changes to existing sections, or both. A more detailed discussion is provided in the "Detail of Changes" section below.

The purpose of this regulatory action is to repeal Part VII of 9VAC5-140 in its entirety.

Issues

Identify the issues associated with the regulatory change, including: 1) the primary advantages and disadvantages to the public, such as individual private citizens or businesses, of implementing the new or amended provisions; 2) the primary advantages and disadvantages to the agency or the Commonwealth; and 3) other pertinent matters of interest to the regulated community, government officials, and the public. If there are no disadvantages to the public or the Commonwealth, include a specific statement to that effect.

The primary advantage associated with the regulatory change is to protect the health, safety and welfare of the public through the reduced cost of electricity for citizens and businesses. Any potential adverse impacts are speculative as of this writing; however, should adverse impacts become apparent, they can be addressed at the appropriate time and by the appropriate regulatory means.

Alternatives to Regulation

Describe any viable alternatives to the regulatory change that were considered, and the rationale used by the agency to select the least burdensome or intrusive alternative that meets the essential purpose of the regulatory change. Also, include discussion of less intrusive or less costly alternatives for small businesses, as defined in § 2.2-4007.1 of the Code of Virginia, of achieving the purpose of the regulatory change.

Alternatives to the proposal will be considered by the board. It has been tentatively determined that the first alternative is appropriate, as it is the least burdensome and least intrusive alternative that fully meets the purpose of the regulatory action. The alternatives being considered, along with the reasoning by which any of the alternatives have been rejected, are discussed below.

1. Repeal the regulation to satisfy the provisions of EO-9. This option is being selected because it meets the stated purpose of the regulatory action.

2. Make alternative regulatory changes to those required by EO-9. This option is not being selected because it would not meet the stated purpose of the regulatory action.

3. Take no action. This option is not being selected because it would not satisfy the provisions of EO-9.

Periodic Review and Small Business Impact Review Announcement

If you wish to use this regulatory action to conduct, and this Emergency/NOIRA to announce, a periodic review (pursuant to § 2.2-4017 of the Code of Virginia and Executive Order 14 (as amended, July 16, 2018)), and a small business impact review (§ 2.2-4007.1 of the Code of Virginia) of this regulation, keep the following text. Modify as necessary for your agency. Otherwise, delete the paragraph below and insert "This NOIRA is not being used to announce a periodic review or a small business impact review."

This NOIRA is not being used to announce a periodic review or a small business impact review.

Public Participation

Indicate how the public should contact the agency to submit comments on this regulation, and whether a public hearing will be held, by completing the text below. In addition, as required by § 2.2-4007.02 of the Code of Virginia describe any other means that will be used to identify and notify interested parties and seek their input, such as regulatory advisory panels or general notices.

The the board is seeking comments on this regulation, including but not limited to: ideas to be considered in the development of this regulation, the costs and benefits of the alternatives stated in this background document or other alternatives, and the potential impacts of the regulation. The the board is also seeking information on impacts on small businesses as defined in § 2.2-4007.1 of the Code of Virginia. Information may include: 1) projected reporting, recordkeeping, and other administrative costs; 2) the probable effect of the regulation on affected small businesses; and 3) the description of less intrusive or costly alternatives for achieving the purpose of the regulation.

Anyone wishing to submit written comments may do so by mail, email or fax to Karen G. Sabasteanski, Department of Environmental Quality, P.O. Box 1105, Richmond VA 23218, phone 804-659-1973, fax 804-698-4178, email karen.sabasteanski@deq.virginia.gov. Comments may also be submitted through the Public Forum feature of the Virginia Regulatory Town Hall (http://www.townhall.virginia.gov). Written comments must include the name and address of the commenter. In order to be considered, comments must be received before midnight on the last day of the public comment period.

Public Hearing at Proposed Stage

[If holding a public hearing after the proposed stage, insert:]
A public hearing will be held following the publication of the proposed stage of this regulatory action and notice of the hearing will be posted on the Virginia Regulatory Town Hall (http://www.townhall.virginia.gov) and on the Commonwealth Calendar (https://www.virginia.gov/connect/commonwealth-calendar).

[If not holding a public hearing during the proposed stage, insert:]
A public hearing will not be held following the publication of the proposed stage of this regulatory action unless requests for a public hearing are received during the NOIRA public comment period from at least 25 persons.

Regulatory Advisory Panel

Please indicate, to the extent known, if advisers (e.g., regulatory advisory panel or negotiated rulemaking panel) will be involved in the development of the proposed regulation. Indicate that 1) the agency is not using a panel in the development of the proposal; 2) the agency is using a panel in the development of the proposal; or 3) the agency is inviting comment on whether to use a panel to assist the agency in the development of a proposal.

The board does not intend to establish a panel to assist in the development of the proposal. However, in response to requests received during the NOIRA public comment period the board will consider establishing a panel. Persons requesting the agency use a panel and interested in assisting in the development of a proposal should notify the Department's contact person by the end of the comment period and provide their name, address, phone number, email address and their organization (if any). If a panel is used, notification of the composition of the panel will be sent to all applicants.

Detail of Changes

List all regulatory changes and the consequences of the changes. Explain the new requirements and what they mean rather than merely quoting the text of the regulation. For example, describe the intent of the language and the expected impact. Describe the difference between existing requirement(s) and/or agency practice(s) and what is being proposed in this regulatory change. Use all tables that apply, but delete inapplicable tables.

Current chapter-section number	New chapter-section number, if applicable	Current requirements in VAC	Change, intent, rationale, and likely impact of new requirements
9VAC5-140-6010		Purpose of the regulation is described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6020		Terms defined.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6030		Measurements, abbreviations, and acronyms used in the regulation are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6040		Entities to which the regulation applies are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6050		Standard requirements for permitting, monitoring, recordkeeping, liability, etc., are explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6060		Computation of time is described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6070		Severability is established.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6080		Authorization and responsibilities of the CO_2 authorized account representative are explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6090		The role of the CO_2 authorized alternate account representative is described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6100		Changing the CO_2 authorized account representatives and the CO_2 authorized alternate account representative; changes in the owners and operators are delineated.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6110		The elements of an account certificate of representation are provided.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6120		Objections concerning the CO_2 authorized account representative are addressed.	Repealed in accordance with the directives of EO-9.

9VAC5-140-6130		Delegation by CO_2 authorized account representatives and CO_2 authorized alternate account representatives is explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6140		CO_2 budget permit requirements are provided.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6150		Submission of CO_2 budget permit applications.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6160		Information requirements for CO_2 budget permit applications are established.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6170		Compliance certification reports are explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6180		Actions on compliance certifications are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6190		The Virginia CO_2 Budget Trading Program base budgets are listed.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6200		How to handle undistributed and unsold CO_2 allowances is found in this section.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6210		Allowance allocations are provided.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6220		CO_2 allowance tracking system accounts are established.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6230		Establishment of accounts is described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6240		The CO_2 allowance tracking system responsibilities of CO_2 authorized account representatives are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6250		How the recordation of allowance allocations is to be accomplished.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6260		Compliance requirements are established.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6270		Banking requirements are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6280		Management of account errors is explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6290		How to close general accounts.	Repealed in accordance with the directives of EO-9.

9VAC5-140-6300		How to submit CO_2 allowance transfers.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6310		The recordation of allowance transfers is explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6320		Notification of allowance transfers is explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6325		Life-of-the-unit contractual arrangements are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6330		General requirements for monitoring, reporting, and recordkeeping.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6340		The initial certification and recertification procedures for a monitoring system are delineated.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6350		Out-of-control periods are addressed.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6360		Notifications are described.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6370		Recordkeeping and reporting requirements are explained.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6380		Petitions for approval to apply an alternative to any acid rain requirement are provided.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6390		Reserved.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6400		Reserved.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6410		The purpose of the requirements for allowance auctions is provided.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6420		General requirements for the auction notice.	Repealed in accordance with the directives of EO-9.
9VAC5-140-6430		[repealed section]	[already repealed]
9VAC5-140-6440		Program monitoring and review requirements.	Repealed in accordance with the directives of EO-9.

Family Impact

In accordance with § 2.2-606 of the Code of Virginia, assess the potential impact of the proposed regulatory action on the institution of the family and family stability including to what extent the regulatory action will: 1) strengthen or erode the authority and rights of parents in the education, nurturing, and supervision of their children; 2) encourage or discourage economic self-sufficiency, self-pride, and the assumption of responsibility for oneself, one's spouse, and one's children and/or elderly parents; 3) strengthen or erode the marital commitment; and 4) increase or decrease disposable family income.

A positive impact to the institution of the family may be anticipated as a result of improved health, safety and welfare of the public through the reduced cost of electricity for citizens.

REG\DEV\A22-E-01PD

ATTACHMENT H

#[date]

Andrew McKeon
Executive Director
The Regional Greenhouse Gas Initiative, Inc.
90 Church Street, 4th Floor
New York, NY 10007

Re: Notice of Intent to Withdraw the Commonwealth of Virginia from RGGI

Dear Mr. McKeon:

In accordance with Governor Youngkin's Executive Order 9 (2022), this letter is to notify the Regional Greenhouse Gas Initiative, Inc. (RGGI, Inc.) of the following actions to be undertaken by the Virginia Department of Environmental Quality:

1. Provide the Governor with a full report re-evaluating the costs and benefits of participation in RGGI in view of all available data, within 30 days.

2. During this same period, develop a proposed emergency regulation for the State Air Pollution Control Board's consideration to repeal the CO_2 Budget Trading Program (Part VII of 9VAC5-140).

3. During this same period, take all necessary steps so that any proposed regulation to the State Air Pollution Control Board can be immediately presented for consideration for approval for public comment in accordance with the Board's authority pursuant to § 10.1-1308 of the Code of Virginia.

4. During this same period, notify RGGI, Inc., of the review and the Governor's intent to withdraw from RGGI, whether by legislative or regulatory action.

Accordingly, this letter notifies RGGI, Inc., of the Governor's intent to withdraw the Commonwealth of Virginia from RGGI upon the conclusion of an appropriate legislative or regulatory process. I will keep you informed as this process progresses. Please contact either me or my staff if you have any questions.

Sincerely,

MSR/MGD/kgs

Attachment 12

ENERGY + ENVIRONMENT

Youngkin administration outlines plan to withdraw Virginia from carbon market by regulation

Opponents insist legislation is required for RGGI withdrawal

By: Charlie Paullin - September 1, 2022 12:04 am

Environmental activists rally outside of Community College Workforce Alliance in Richmond before a Air Pollution Control Board meeting in which Secretary of Natural and Historic Resources Travis Voyles announced the plan to withdrawal Virginia from the Regional Greenhouse Gas Initiative, or RGGI. RGGI aims to reduce energy producer carbon emissions. The activists want to stay in it. (Charlie Paullin/The Mercury).

Gov. Glenn Youngkin's administration announced their newest plans for how they intend to withdraw Virginia from a regional carbon market Wednesday, a move critics say is not allowed by law, would drain important state programs of funding and would hurt the fight against climate change.

Acting Secretary of Natural and Historic Resources Travis Voyles said at a State Air Pollution Control Board meeting that the administration plans to withdraw Virginia from the Regional Greenhouse Gas Initiative through changes to the regulations that govern the state's participation in the market.

The regulatory process typically takes 18 to 24 months from start to finish, after which the air board will vote on repealing the regulation.

The move is a pivot from the approach outlined in an executive order Youngkin issued at the start of his term. That plan called for a two-track approach that would first repeal the regulation through an emergency provision and then eliminate it permanently through the normal regulatory process.

The full regulatory process "will allow for public comment … provides some certainty and times well with the contractual period," Voyles told the Virginia Mercury after the meeting.

Virginia's three-year contract with RGGI, Inc., the body that coordinates the market, ends next year.

RGGI is a carbon reduction market involving 10 other Mid-Atlantic and New England states in which energy producers must buy allowances for the carbon they emit, and a cap is placed on overall carbon emissions.

The proceeds of purchasing those allowances are then returned to the state. In Virginia, they're funneled into flood assistance and low-income energy efficiency programs. Virginia has received some $379 million in RGGI proceeds to date.

Under state law, electric utilities are permitted to pass on the costs of RGGI participation to ratepayers. The Youngkin administration has said those increased costs, which averaged $2.39 per month for Dominion residential customers, are a burden on ratepayers. Dominion has since stopped charging customers a specific fee for RGGI participation.

"RGGI is a bad deal for Virginia," Voyles said, adding that the state can't control the market costs for allowances, which have increased.

But groups like the Southern Environmental Law Center continue to say the Youngkin administration can't withdraw Virginia from RGGI by changing regulations because the regulations were the result of legislation passed by the General Assembly in 2020.

"That's not consistent with the law," SELC attorney Nate Benforado said.

From 2010 to 2020, before Virginia joined RGGI, power plant emissions did not decrease, Benforado stated, referencing a March report on the program that the Department of Environmental Quality completed at Youngkin's request. Emissions dropped over 30% with RGGI participation, he added.

"Virginia needs RGGI," Benforado said.

Board response

Reactions from the seven-member board differed among the four appointees made by Youngkin, a Republican, and the three appointees made by former Gov. Ralph Northam, a Democrat.

Northam appointee Hope Cupit, president and CEO of SERCAP, an organization that helps low- to moderate-income people in the southeastern U.S, asked whether it was constitutional to override the RGGI law passed by the General Assembly through regulations.

Cupit has previously said she received an email from an attorney with the Office of the Attorney General saying the air board doesn't have the authority to withdraw Virginia from RGGI. A lawsuit seeking to force the release of that email under the state's Freedom of Information Act is still awaiting an order from a judge in Charlottesville Circuit Court.

She also noted the benefits of flood protection programs funded by RGGI given recent flooding in Buchanan County.

"We feel forgotten sometimes," said Cupit, who lives in Bedford.

Another Northam appointee, retired pulmonologist Lornel Tompkins, said one year's worth of data on Virginia's participation in RGGI is not enough to determine its effectiveness. She also questioned why the RGGI fee was being attacked, versus other fees utility customers pay, and said costs could be lower in the long run.

"Why are we not going after the General Assembly to change the rules, rather than taking away something from the state or the commonwealth which is turning out by some factors to be a positive?" Tompkins said.

Conversely, Youngkin appointee David Hudgins, executive director for the Virginia Energy Consumer Trust, an advocacy group skeptical of renewables, said he was concerned about RGGI's impact on the state's ability to appeal to business because of rising energy costs. Virginia has previously been able to attract businesses from the Northeast by touting its lower electricity rates, he said.

"If we get affiliated (with) the Northeast, southern states are going to start sending their economic development teams up here because our cost structure is changing and reflecting more of the Northeast than we do with the people to the south," Hudgins said.

Another Youngkin appointee, retired attorney Jay Holloway, asked whether RGGI actually caps carbon emissions because it allows producers to buy allowances beyond the cap.

But Michael Dowd, director of DEQ's Air and Renewable Energy Division, clarified that allowances can only exceed the cap by a certain percentage.

"There is a cap, in a general sense, because it is a regional cap. There is a finite number of allowances for sale," Dowd said.

Environmental outcry

Several environmental groups rallied outside the meeting's location at the Community College Workforce Alliance in Richmond, with rallies also held throughout the state in Roanoke, Harrisonburg, Woodbridge, Abingdon and Virginia Beach.

In Richmond, activists displayed caricatures of Youngkin and former Environmental Protection Agency chief Andrew Wheeler while chanting "RGGI is the law."

Wheeler, who is serving as an adviser to Youngkin, was appointed to his current position after Senate Democrats stymied his nomination to be secretary of natural and historic resources. The Democrats' move led to Republicans blocking 11 other Northam-era appointments, including two air board members.

Leah Jones, a coordinator with Virginia Interfaith Power & Light, a group focused on climate and environmental justice, called RGGI "an important stepping stone for our state to provide funds to those affected by energy burden and severe flooding while also providing an incentive … to act on climate and reduce Virginia's carbon emissions."

Jones and five other public speakers spoke in support of RGGI during Wednesday's meeting. Virginia Manufacturers Association executive director Brett Vassey spoke against it, calling RGGI a tax and accusing it of being redundant given Virginia's emission reduction efforts through the Virginia Clean Economy Act.

While the Virginia Clean Economy Act sets aggressive carbon reduction goals for the state's regulated utilities, it does not apply to non-utility power producers, who generate more than a quarter of the state's carbon emissions subject to RGGI.

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Attachment 13

https://richmond.com/news/state-and-regional/youngkin-i-have-the-power-to-pull-out-of-rggi/article_02aff6e8-bf4a-5925-ae4c-90d671e50dea.html

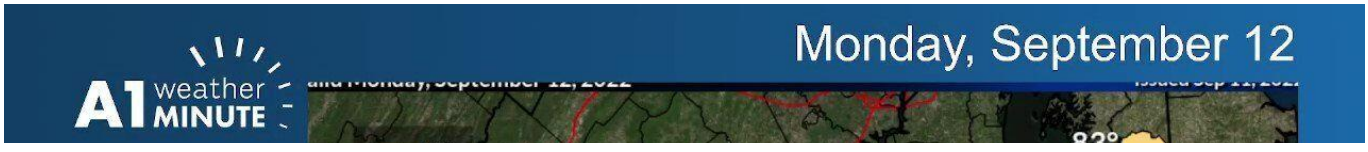
ALERT TOP STORY

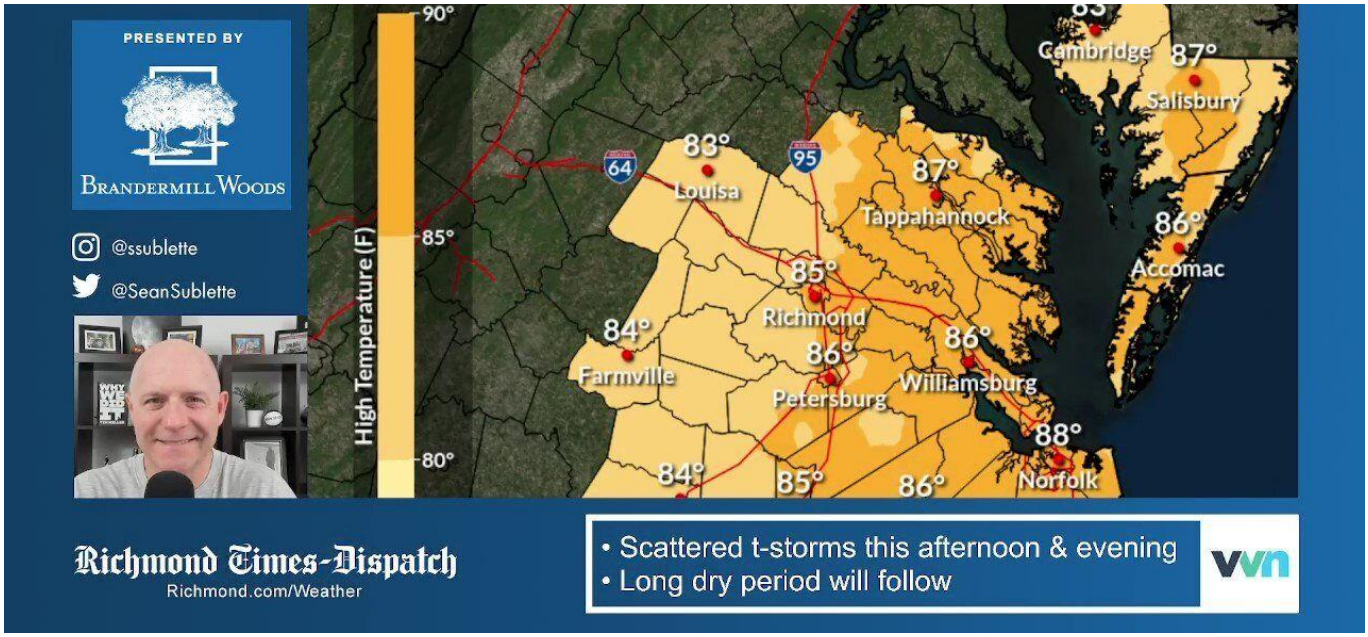
Youngkin: I have the power to pull out of RGGI

David Ress
Sep 12, 2022

In Stafford County, Gov. Glenn Youngkin ceremonially signed legislation to give military retirees a tax break. At right
PETER CIHELKA/THE FREE LANCE-STAR

David Ress





Tuesday through this coming weekend looks like a dry and more seasonable period.

For Gov. Glenn Youngkin, the problem with the **Regional Greenhouse Gas Initiative** is that it's a market that sends the wrong signals to the wrong people.

He wants out.

And so Youngkin and Democratic legislators, along with environmentalists across the state, are **drawing battle lines** over the 11-state carbon market, in which power companies can buy or sell carbon dioxide credits. They can be buyers, if their CO2 emissions exceed a cap, or sellers, if they want to get some extra money for emitting less of the greenhouse gas than their cap.

Many Democratic lawmakers say a state law calls for Virginia's participation in RGGI and that only the legislature can remove Virginia from the compact. Youngkin says that law allowed Virginia to join RGGI, but did not mandate Virginia's participation.

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4 **Watch now: Police chief reacts to stabbing at Brookland Middle School**

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61 Dems say Virginia's participation in RGGI is up to legislature

The idea behind RGGI is that the price of those credits, along with the cost of buying allowances authorizing utilities to emit a limited amount of CO2, will affect decisions about using coal, oil and natural gas to spin the generators that make electricity — and emit CO2.

In the end, RGGI expects its market will move utilities toward generating power with sources that don’t emit CO2.

Download PDF

SENATE OF VIRGINIA

LYNWOOD W. LEWIS, JR.
6TH SENATORIAL DISTRICT
ALL OF ACCOMACK, NORTHAMPTON, AND MATHEWS COUNTIES; AND PART OF THE CITIES OF NORFOLK AND VIRGINIA BEACH

P. O. BOX 760
ACCOMAC, VIRGINIA 23301

COMMITTEE ASSIGNMENTS:
LOCAL GOVERNMENT, CHAIR
AGRICULTURE, CONSERVATION AND NATURAL RESOURCES
COMMERCE AND LABOR
EDUCATION AND HEALTH
RULES

September 8, 2022

Members of the Virginia Air Pollution Control Board
c/o Office of Regulatory Affairs
Department of Environmental Quality
P.O. Box 1105
Richmond, Virginia 23218

Sent via email: CitizenBoards@DEQ.Virginia.gov

Dear Members of the Air Pollution Control Board:

As current members of the Virginia General Assembly who voted for the Clean Energy and Community Flood Preparedness Act in 2020 or voted against changes to that same law in 2022, we write to express our continued support for Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI). Further, we write to articulate the reality that Virginia's participation in RGGI is mandated by *law*. Therefore, ultimately only a change in the *law* that passes both chambers of the General Assembly and is signed by the Governor can remove Virginia's participation. No proposed regulation, emergency regulation, regulatory act, or any subsequent administrative process can do so.

In addition to the Commonwealth's participation being mandated, RGGI is already delivering benefits to the residents of Virginia. As legislators, we believe it is important that you consider and understand the following benefits to Virginians from our participation in RGGI:

- RGGI has generated $378 million to support low-income energy efficiency programs and flood resilience infrastructure in Virginia.[1]
    - Energy efficiency upgrades are the best way to lower electricity bills, and Virginia's funds are directed to helping those households most in need.[2]
    - Flood resilience infrastructure protects Virginians against increased flooding and extreme weather events.
- RGGI has demonstrated Energy Cost Savings.
    - Electricity prices in RGGI states dropped by almost 6% while they went up by almost 9% throughout the rest of the country.[3] RGGI is a proven tool to reduce utilities'

[1] https://www.rggi.org/sites/default/files/Uploads/Auction-Materials/Cumulative-State-Charts/VA_Proceeds_by_Auction.xlsx
[2] https://vaeec.org/rggi/
[3] https://acadiacenter.org/wp-content/uploads/2019/09/Acadia-Center_RGGI_10-Years-in-Review_2019-09-17.pdf

But Youngkin, whose time at the multi-billion-dollar Carlyle Group saw the firm move into carbon-reducing investments in a major way, doesn't buy that argument.

“Let’s not have a hidden tax … that was mis-sold and misrepresented as some sort of market-based incentive, because RGGI is not a market-based incentive,” Youngkin said in an interview with the Richmond Times-Dispatch.

Legislators mull ways to keep power bills down amid Regional Greenhouse Gas Initiative debate

“In this case, the utility can decide but they don’t have to worry about it because they can pass it right on to the consumer and the consumer Has. No. Choice,” he said.

“They have to buy power from the monopoly utility.”

That was shaping up to a fairly big bill.

The State Corporation Commission last year agreed with Dominion’s view that it would spend some $168 million to buy RGGI credits and that in order to cover that cost the bill for a typical residential customer using 1,000 kilowatt hours a month should rise by $2.39.

Youngkin seeks regulatory route to remove Virginia from RGGI

“We must recognize that utilities in this case are monopolies … were told they had to buy these allowances and all they do is 100 percent pass ’em on to the consumer, who has no say in this,” Youngkin said.

But Dominion this year asked, and the SCC agreed, to suspend the surcharge, noting that Virginia was on track to pull out of RGGI. Dominion said it could cover sums it had previously spent through base rates.

Youngkin said he won’t renew Virginia’s contract with RGGI when it expires in December 2023.

Meanwhile, he wants the state Air Pollution Control Board to repeal 2020 amendments to its C02 trading regulations requiring utilities to buy CO2 allowances — that is, RGGI authorization to emit a limited amount of the greenhouse gas.

Environmental group sues to get AG document on withdrawal from RGGI

The board can do that because it is part of the executive branch that the governor leads, he said.

General Assembly Democrats beg to differ. In a letter to the air board last week, 61 of them said the agency's powers are limited because the General Assembly created the air board.

"You only have the powers that the General Assembly grants you," the letter said.

The Democrats' letter also cites the law that enables participation in RGGI — the Clean Energy and Community Flood Preparedness Act — adding, "it is clear our intent for Virginia to participate in RGGI."

RGGI has generated $378 million to support low-income energy efficiency programs and flood protection in Virginia, the Democrats said.

Youngkin sees it differently:

"The bill that was passed … said that you could — it allowed you to go put this in place. It never mandated it," Youngkin said. "It allowed it, it never mandated it."

The bill says the director of the air board "is hereby authorized" to run the program to sell allowances that can be used in RGGI's trading system or something similar. It says the director "shall seek to sell 100 percent of all allowances" unless doing so would mean a net loss of benefit to consumers.

Youngkin said he reads that as allowing the air board to do away with the requirement that utilities buy the allowances, "and then we get to — as a government, the General Assembly — to work and if we want to provide funding for flood resiliency, then let's go provide funding for flood resiliency.

"Let's not have a hidden tax that was, that was mis-sold and misrepresented."

PAGES: Richmond Times-Dispatch coverage of Queen Elizabeth II in Virginia

dress@timesdispatch.com

(804) 649-6948

Twitter: @daveress1

By David Ress

Attachment 14

Archived Content

Warning: Some referenced links may not function correctly.

For Immediate Release: April 12, 2020

Contacts: Office of the Governor: Alenaa Yarmosky, Alena.Yarmosky@governor.virginia.gov

Governor Northam Signs Clean Energy Legislation

RICHMOND—Governor Ralph Northam is accelerating Virginia's transition to clean energy by signing the Virginia Clean Economy Act and by amending the Clean Energy and Community Flood Preparedness Act that requires Virginia to join the Regional Greenhouse Gas Initiative.

"These new clean energy laws propel Virginia to leadership among the states in fighting climate change," **said Governor Northam**. "They advance environmental justice and help create clean energy jobs. In Virginia, we are proving that a clean environment and a strong economy go hand-in-hand."

The **Virginia Clean Economy Act** was passed as House Bill 1526 and Senate Bill 851, which were sponsored by Delegate Richard C. "Rip" Sullivan, Jr. and Senator Jennifer McClellan, respectively. The Act incorporates clean energy directions that the Governor issued in Executive Order Forty-Three in September 2019. It results from extensive stakeholder input and incorporates environmental justice concepts related to the Green New Deal.

The law requires new measures to promote energy efficiency, sets a schedule for closing old fossil fuel power plants, and requires electricity to come from 100 percent renewable sources such as solar or wind. Energy companies must pay penalties for not meeting their targets, and part of that revenue would fund job training and renewable energy programs in historically disadvantaged communities. The Act accomplishes the following broad goals:

- **Establishes renewable portfolio standards**. The Act requires Dominion Energy Virginia to be 100 percent carbon-free by 2045 and Appalachian Power to be 100 percent carbon-

free by 2050. It requires nearly all coal-fired plants to close by the end of 2024.

- **Establishes energy efficiency standards**. The Act declares energy efficiency pilot programs to be "in the public interest." It creates a new program to reduce the energy burden for low-income customers, and it requires the Department of Social Services and the Department of Housing and Community Development to convene stakeholders to develop recommendations to implement this program. The Act sets an energy efficiency resource standard, requiring third party review of whether energy companies meet savings goals.
- **Advances offshore wind**. The Act provides that 5,200 megawatts of offshore wind generation is "in the public interest." It requires Dominion Energy Virginia to prioritize hiring local workers from historically disadvantaged communities, to work with the Commonwealth to advance apprenticeship and job training, and to include an environmental and fisheries mitigation plan.
- **Advances solar and distributed generation**. The Act establishes that 16,100 megawatts of solar and onshore wind is "in the public interest." The law expands "net metering," making it easier for rooftop solar to advance across Virginia. The new law requires Virginia's largest energy companies to construct or acquire more than 3,100 megawatts of energy storage capacity.

"This is a terrific day for Virginia," **said Delegate Richard C. "Rip" Sullivan, Jr**. "While some said Virginia is moving too fast, we said this is the year to get it right. This is an historic step forward on clean energy in Virginia."

"This is the most significant clean energy law in Virginia's history," **said Senator Jennifer McClellan**. "The bill that the Governor signed will make Virginia the first southern state with a 100 percent clean energy standard. The Act will create thousands of clean energy jobs, make major progress on fighting climate change, and break Virginia's reliance on fossil fuels."

The Clean Energy and Community Flood Preparedness Act was passed as House Bill 981 and Senate Bill 1027, sponsored by House Majority Leader Charniele Herring and Senator Lynwood Lewis, respectively.

The Act establishes a carbon dioxide cap-and-trade program to reduce emissions from power plants, in compliance with the Regional Greenhouse Gas Initiative (RGGI). The Department of Environmental Quality will establish and operate an auction program to sell allowances into a market-based trading program.

The Act creates a Virginia Community Flood Preparedness Fund to enhance flood prevention, protection, and coastal resilience. It creates a low-interest loan program to help inland and coastal communities that are subject to recurrent flooding. The sale of emissions allowances would fund it.

The Governor proposed technical amendments to clarify how the fund would operate. The amendments provide for forgiveness of loans used in low-income geographic areas.

“By joining RGGI, Virginia will take part in a proven, market-based program for reducing carbon pollution in a manner that protects consumers,” **said Governor Northam**. “I am proposing important refinements and I look forward to signing it into law soon.”

“Advocates have worked hard for many years to put Virginia on the path to clean energy,” **said House Majority Leader Charniele Herring**. “This will bring cleaner air and water to Virginia, and the Governor’s amendments will make a good law even better.”

“Joining RGGI will secure a sustainable clean energy future for Virginia,” **said Senator Lynwood Lewis**. “Thanks to the Governor’s leadership, we’re almost at the finish line.”

Last year’s budget explicitly prevented Virginia from joining RGGI.

# # #

Attachment 15

ENERGY + ENVIRONMENT

COMMENTARY

Clean air and clean water are more important now than ever

GUEST COLUMN

APRIL 24, 2020 12:01 AM

The sun sets over the James River in Richmond. (Ned Oliver/Virginia Mercury)

By David K. Paylor

In the face of the greatest public health crisis in decades, we are more aware than ever of the connection between environmental protection, public and individual health and a strong economy. As we enter a new decade of environmentalism, it is worth reflecting on how far we have come so we can move forward with confidence and commitment to address new and urgent challenges.

This week, amid the COVID-19 pandemic, we celebrated the 50th anniversary of Earth Day. This movement started in 1970, when 20 million people gathered in the streets of America to encourage our leaders to rise to the challenge of protecting the environment. From the decimation of our bald eagle population from DDT use to contaminated rivers catching fire, the evidence was painfully clear that we were not adequately aware of our impact on the environment, and its importance to human health. Out of this new awareness, a movement was born.

The 1970s saw the passage of the most comprehensive environmental legislation in U.S. history, including the Clean Air Act, the Clean Water Act, the Endangered Species Act, the Toxic Substances Control Act and the Surface Mining Control and Reclamation Act. In addition, just months after the first Earth Day, a new federal organization tasked with monitoring the nation's natural assets – the Environmental Protection Agency – was created.

The Virginia Department of Environmental Quality is the environmental agency in the commonwealth, safeguarding the places we live and promoting the health and well-being of eight million people. The agency follows laws that provide us with the framework to keep air, water and land clean by preparing and issuing permits to businesses, local governments and state and federal facilities. These permits establish safe limits, reduce pollution and hold violators accountable.

Our efforts are paying off. For example, Virginia is breathing cleaner air than ever before. Water quality improvements have helped bring the Chesapeake Bay back to life. Thousands of acres of contaminated land are being cleaned up and recovered. We have worked with businesses and environmental partners to ensure that strong environmental protections and a strong economy can go hand in hand.

To carry out DEQ's extensive permitting programs and environmental protection and conservation initiatives, we collaborate with a statewide team of partners to help develop clean-up plans for waterbodies, work with dedicated volunteers to monitor recreational waters, oversee the revitalization of contaminated sites to turn distressed property into viable real estate, and respond to pollution complaints and environmental emergencies to assist first responders and mitigate destructive impacts.

This takes a talented team of professionals from six regional locations and the central office. We are engineers, biologists, hydrologists, geologists, meteorologists, inspectors, regulators, modelers, policy makers, permit writers, administrators, communicator and, of course, environmentalists. Most of all, we are mission-driven problem solvers.

The challenges ahead will require innovative approaches to environmental protection that extend into much more complex areas of public policy such as addressing climate change, environmental justice and sustainable economic development. As demonstrated by the COVID-19 pandemic, community health is a vital component of community resilience.

To that end, with direction and support from the governor's office and the secretary of natural resources, DEQ is invested in being part of the solution. We are currently engaged in a wholesale review of our environmental justice procedures, we are committed to transparency, public accessibility of our work and establishing programs to continue to effectively administer our environmental protection programs.

We are also committed to reducing the pollution that causes climate change. The governor has signed the Virginia Clean Economy Act and amended the Clean Energy and Community Flood Preparedness Act to require Virginia to join the Regional Greenhouse Gas Initiative (RGGI).

As the governor has said, by joining RGGI, Virginia will take part in a proven, market-based program for reducing carbon pollution in a manner that protects consumers.

On Earth Day – and every day – our number one priority remains to protect the commonwealth's diverse and abundant natural resources in everything we do. Through this important work, DEQ supports agriculture, industry and commerce, and provides a rich, healthy environment for plants, wildlife and people.

Together, we have made much progress in Virginia over the past few decades. We plan on continuing this legacy as we move forward to address the new challenges in the years ahead.

David K. Paylor is director of the Virginia Department of Environmental Quality.

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GUEST COLUMN

Views of guest columnists are their own. To submit an op-ed for consideration, contact Editor Sarah Vogelsong at svogelsong@virginiamercury.com.

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Attachment 16

VIRGINIA:

IN THE CIRCUIT COURT OF THE CITY OF RICHMOND

RECEIVED
MAR 22 2021
BY:

Virginia Manufacturers Association,

Appellant,

v. Case No.: CL20004918-00

Virginia Department of Environmental Quality, et al.

Appellees.

CERTIFICATION AND NOTICE OF FILING AGENCY RECORD

PLEASE TAKE NOTICE that the Department of Environmental Quality, in accordance with Rule 2A:3 of the Rules of the Virginia Supreme Court, certifies the attached documents are the agency record and files the same as the agency record for this matter.

RESPECTFULLY SUBMITTED,

DAVID K. PAYLOR, DIRECTOR
DEPARTMENT OF ENVIRONMENTAL QUALITY

STATE OF VIRGINIA
City
COUNTY OF Richmond

The foregoing instrument was acknowledged before me this 18th of March, 2021, by David K. Paylor.

Notary Public Elsie Marie Walker

Printed Name: Elsie Marie Walker My Commission Expires: 1/31/2024

ELSIE MARIE WALKER
NOTARY PUBLIC
Commonwealth of Virginia
Reg. #341333
My Commission Expires 1/31/24

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VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY

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Matthew J. Strickler
Secretary of Natural Resources

David K. Paylor
Director
(804) 698-4000

Memorandum

To: David K. Paylor

From: Michael G. Dowd, Director, Air and Renewable Energy Division

Date: June 16, 2020

Subject: Clean Energy and Community Flood Preparedness Act, § 10.1-1329 et seq., RGGI Program Regulation (Part VII of 9VAC5-140)

Introduction

Chapter 1219 of the 2020 Acts of Assembly amends the Air Pollution Control Law to add a new Article 4, the Clean Energy and Community Flood Preparedness Act. Under § 10.1-1330 A, Clean Energy and Community Flood Preparedness, "[T]he provisions of this article shall be incorporated by the Department, without further action by the Board, into the final regulation adopted by the Board on April 19, 2019, and published in the Virginia Register on May 27, 2019. Such incorporation by the Department shall be exempt from the provisions of the Virginia Administrative Process Act (§ 2.2-4000 et seq.)."

Accordingly, we have drafted revisions to Part VII of 9VAC5-140, Regulation for Emissions Trading such that it comports with the full Regional Greenhouse Gas Initiative (RGGI) CO_2 emissions trading program and associated auction as mandated by Chapter 1219 (see Attachment 1). To this end, the draft (i) removes references to a "consignment" auction and its associated mechanisms, such as conditional allowances; (ii) removes DMME allowances; (iii) removes program backstops and other transitional provisions that have been resolved, such as "initial control periods"; and (iv) removes the concept of "linking" to RGGI instead of being a "participating state." (See Attachment 2.)

Additionally, Chapter 1219 adds a new § 10.1-1331, which requires that (i) the definition a "life-of-the-unit contractual arrangement" include any energy conversion or energy tolling agreement that has a primary term of 20 years or more and pursuant to which the purchaser is required to deliver fuel to the CO_2 budget source or unit and is entitled to receive all of the nameplate

capacity and associated energy generated by such source or unit for the entire contractual period and (ii) any purchaser under an energy conversion or energy tolling agreement is responsible for acquiring any CO_2 allowances required in relation to a CO_2 budget source or unit that is subject to such agreement. The regulation has been amended accordingly (see Attachment 2).

The regulation has been reviewed by the Assistant Attorney General, who concurs that the revisions comport with the RGGI program and thus Chapter 1219 (see Attachment 3). Additionally, the participating RGGI states have reviewed these revisions and agree that they are consistent with the requirements of the RGGI program for full participation.

The final regulation will submitted to the Registrar of Regulations for publication in the Virginia Register at the earliest possible filing date, to become effective upon such filing date.

Recommendation

I recommend that the Director adopt the attached amendments to Part VII of 9VAC5-140 in accordance with Chapter 1219 of the 2020 Acts of Assembly, to be effective upon filing of the amendments with the Virginia Register of Regulations.

Recommendation approved by: David K Paylor

David K. Paylor

Date: 6/25/2020

MGD\kgs
Attachments

REG\DEV\A20-DIR-MEM

CHAPTER 140. REGULATION FOR EMISSIONS TRADING

Part VII. CO_2 Budget Trading Program

Article 1. CO_2 Budget Trading Program General Provisions

9VAC5-140-6010. Purpose.

This part establishes the Virginia component of the CO_2 Budget Trading Program, which is designed to reduce anthropogenic emissions of CO_2, a greenhouse gas, from CO_2 budget sources in a manner that is protective of human health and the environment and is economically efficient.

9VAC5-140-6020. Definitions.

A. As used in this part, all words or terms not defined here shall have the meanings given them in 9VAC5-10 (General Definitions), unless otherwise required by the context.

B. For the purpose of this part and any related use, the words or terms shall have the meanings given them in this section.

C. Terms defined.

"Account number" means the identification number given by the department or its agent to each COATS account.

"Acid ~~rain~~ Rain emission limitation" means, as defined in 40 CFR 72.2, a limitation on emissions of sulfur dioxide (SO_2) or nitrogen oxides (NO_x) under the Acid Rain Program under Title IV of the CAA.

"Acid Rain Program" means a multistate SO_2 and NO_x air pollution control and emission reduction program established by the administrator under Title IV of the CAA and 40 CFR Parts 72 through 78.

"Adjustment for banked allowances" means an adjustment applied to the Virginia CO_2 Budget Trading Program base budget for allocation years 2021 through 2025 to address allowances held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program, but not including accounts opened by participating states~~, that are in addition to the aggregate quantity of emissions from all CO_2 budget sources in all of the participating states at the end of the initial control period in 2020 and as reflected in the CO_2 Allowance Tracking System on March 15, 2021~~.

"Administrator" means the administrator of the U.S. Environmental Protection Agency or the administrator's authorized representative.

"Allocate" or "allocation" means the determination by the department of the number of ~~conditional~~ CO_2 allowances recorded in the ~~conditional~~ allowance account of a CO_2 budget unit ~~or to the Department of Mines, Minerals and Energy (DMME) pursuant to 9VAC5-140-6211~~.

"Allocation year" means a calendar year for which the department allocates ~~conditional~~ CO_2 allowances pursuant to Article 5 (9VAC5-140-6190 et seq.) of this part. The allocation year of each ~~conditional~~ CO_2 allowance is reflected in the unique identification number given to the allowance pursuant to 9VAC5-140-6250 C.

"Allowance auction" or "auction" means an auction in which the department or its agent offers ~~conditional~~ CO_2 allowances for sale.

"Attribute" means a characteristic associated with electricity generated using a particular renewable fuel, such as its generation date, facility geographic location, unit vintage, emissions output, fuel, state program eligibility, or other characteristic that can be identified, accounted for, and tracked.

"Attribute credit" means a credit that represents the attributes related to one ~~megawatthour~~ megawatt hour of electricity generation.

"Automated Data Acquisition and Handling System" or "DAHS" means that component of the Continuous Emissions Monitoring System (CEMS), or other emissions monitoring system approved for use under Article 8 (9VAC5-140-6330 et seq.) of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by Article 8 (9VAC5-140-6330 et seq.) of this part.

"Billing meter" means a measurement device used to measure electric or thermal output for commercial billing under a contract. The facility selling the electric or thermal output shall have different owners from the owners of the party purchasing the electric or thermal output.

"Boiler" means an enclosed fossil or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

"CO_2 allowance" means a limited authorization by the department or ~~another~~ participating state under the CO_2 Budget Trading Program to emit up to one ton

of CO_2, subject to all applicable limitations contained in this part. ~~CO_2 offset allowances generated by other participating states will be recognized by the department.~~

"CO_2 allowance deduction" or "deduct CO_2 allowances" means the permanent withdrawal of CO_2 allowances by the department or its agent from a COATS compliance account to account for the number of tons of CO_2 emitted from a CO_2 budget source for ~~the initial control period,~~ a control period ~~,~~ or an interim control period determined in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part, or for the forfeit or retirement of CO_2 allowances as provided by this part.

"CO_2 Allowance Tracking System" or "COATS" means the system by which the department or its agent records allocations, deductions, and transfers of CO_2 allowances under the CO_2 Budget Trading Program. The tracking system may also be used to track CO_2 allowance prices and emissions from affected sources.

"CO_2 Allowance Tracking System account" means an account in COATS established by the department or its agent for purposes of recording the allocation, holding, transferring, or deducting of CO_2 allowances.

"CO_2 allowance transfer deadline" means midnight of March 1 occurring after the end of the ~~initial~~ relevant control period~~, the control period,~~ and each relevant interim control period, or if that March 1 is not a business day, midnight of the first business day thereafter and is the deadline by which CO_2 allowances shall be submitted for recordation in a CO_2 budget source's compliance account for the source to meet the CO_2 requirements of 9VAC5-140-6050 C for ~~the initial control period,~~ a control period ~~,~~ and each interim control period immediately preceding such deadline.

"CO_2 allowances held" or "hold CO_2 allowances" means the CO_2 allowances recorded by the department or its agent, or submitted to the department or its agent for recordation, in accordance with Article 6 (9VAC5-140-6220 et seq.) and Article 7 (9VAC5-140-6300 et seq.) of this part, in a COATS account.

"CO_2 authorized account representative" means, for a CO_2 budget source and each CO_2 budget unit at the source, the natural person who is authorized by the owners and operators of the source and all CO_2 budget units at the source, in accordance with Article 2 (9VAC5-140-6080 et seq.) of this part, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Budget Trading Program or, for a general account, the natural person who is authorized, under Article 6 (9VAC5-140-6220 et seq.) of this part, to transfer or otherwise dispose of CO_2 allowances held in the general account. If the CO_2 budget source is also subject to the Acid Rain Program, CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then for a CO_2 Budget Trading Program compliance account, this natural person shall be the same person as the designated representative as defined in the respective program.

"CO_2 authorized alternate account representative" means, for a CO_2 budget source and each CO_2 budget unit at the source, the alternate natural person who is authorized by the owners and operators of the source and all CO_2 budget units at the source, in accordance with Article 2 (9VAC5-140-6080 et seq.) of this part, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Budget Trading Program or, for a general account, the alternate natural person who is authorized, under Article 6 (9VAC5-140-6220 et seq.) of this part, to transfer or otherwise dispose of CO_2 allowances held in the general account. If the CO_2 budget source is also subject to the Acid Rain Program, CSAPR NO_x Annual Trading Program, CSAPR NO_x Ozone Season Trading Program, CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program then, for a CO_2 Budget Trading Program compliance account, this alternate natural person shall be the same person as the alternate designated representative as defined in the respective program.

"CO_2 budget emissions limitation" means, for a CO_2 budget source, the tonnage equivalent, in CO_2 emissions in ~~the initial control period,~~ a control period ~~,~~ or an interim control period of the CO_2 allowances available for compliance deduction for the source for a control period or an interim control period.

"CO_2 budget permit" means the portion of the legally binding permit issued by the department pursuant to 9VAC5-85 (Permits for Stationary Sources of Pollutants Subject to Regulation) to a CO_2 budget source or CO_2 budget unit that specifies the CO_2 Budget Trading Program requirements applicable to the CO_2 budget source, to each CO_2 budget unit at the CO_2 budget source, and to the owners and operators and the CO_2 authorized account representative of the CO_2 budget source and each CO_2 budget unit.

"CO_2 budget source" means a source that includes one or more CO_2 budget units.

"CO_2 Budget Trading Program" means a multistate CO_2 air pollution control and emissions reduction program established according to this part and corresponding regulations in other states as a means of reducing emissions of CO_2 from CO_2 budget sources.

"CO_2 budget unit" means a unit that is subject to the CO_2 Budget Trading Program requirements under 9VAC5-140-6040.

"CO_2 cost containment reserve allowance" or "CO_2 CCR allowance" means an allowance that has been sold at an auction for the purpose of containing the cost of CO_2 allowances. CO_2 CCR allowances offered for sale at an auction are separate from and additional to CO_2 allowances allocated from the Virginia CO_2 Budget Trading Program base and adjusted budgets. CO_2 CCR allowances are subject to all applicable limitations contained in this part.

"CO_2 cost containment reserve trigger price" or "CCR trigger price" means the minimum price at which CO_2 CCR allowances are offered for sale by the department or its agent at an auction. The CCR trigger price in calendar year ~~2020~~ 2021 shall be ~~$10.77~~ $13.00. The CCR trigger price in calendar year ~~2021~~ 2022 shall be ~~$13~~ $13.91. Each calendar year thereafter, the CCR trigger price shall be 1.07 multiplied by the CCR trigger price from the previous calendar year, rounded to the nearest whole cent, as shown in Table 140-1A.

Table 140-1A
CO_2 CCR Trigger Price

~~2020~~	~~$10.77~~
2021	$13.00
2022	$13.91
2023	$14.88
2024	$15.92
2025	$17.03
2026	$18.22
2027	$19.50
2028	$20.87
2029	$22.33
2030	$23.89

"CO_2 emissions containment reserve allowance" or "CO_2 ECR allowance" means a ~~conditional~~ CO_2 allowance that is withheld from sale at an auction by the department for the purpose of additional emission reduction in the event of lower than anticipated emission reduction costs.

"CO_2 emissions containment reserve trigger price" or "ECR trigger price" means the price below which ~~conditional~~ CO_2 allowances will be withheld from sale by the department or its agent at an auction. The ECR trigger price in calendar year 2021 shall be $6.00. Each calendar year thereafter, the ECR trigger price shall be 1.07 multiplied by the ECR trigger price from the previous calendar year, rounded to the nearest whole cent, as shown in Table 140-1B.

Table 140-1B
CO_2 ECR Trigger Price

2021	$ 6.00
2022	$ 6.42
2023	$ 6.87
2024	$ 7.35
2025	$ 7.86
2026	$8.41
2027	$ 9.00

2028	$ 9.63
2029	$10.30
2030	$11.02

"CO_2 offset allowance" means a CO_2 allowance that is awarded to the sponsor of a CO_2 emissions offset project by a participating state and is subject to the relevant compliance deduction limitations of the participating state's corresponding offset regulations as a means of reducing CO_2 from CO_2 budget sources.

"Combined cycle system" means a system comprised of one or more combustion turbines, heat recovery steam generators, and steam turbines configured to improve overall efficiency of electricity generation or steam production.

"Combustion turbine" means an enclosed fossil or other fuel-fired device that is comprised of a compressor (if applicable), a combustor, and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine.

"Commence commercial operation" means, with regard to a unit that serves a generator, to have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation. For a unit that is a CO_2 budget unit under 9VAC5-140-6040 on the date the unit commences commercial operation, such date shall remain the unit's date of commencement of commercial operation even if the unit is subsequently modified, reconstructed, or repowered. For a unit that is not a CO_2 budget unit under 9VAC5-140-6040 on the date the unit commences commercial operation, the date the unit becomes a CO_2 budget unit under 9VAC5-140-6040 shall be the unit's date of commencement of commercial operation.

"Commence operation" means to begin any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber. For a unit that is a CO_2 budget unit under 9VAC5-140-6040 on the date of commencement of operation, such date shall remain the unit's date of commencement of operation even if the unit is subsequently modified, reconstructed, or repowered. For a unit that is not a CO_2 budget unit under 9VAC5-140-6040 on the date of commencement of operation, the date the unit becomes a CO_2 budget unit under 9VAC5-140-6040 shall be the unit's date of commencement of operation.

"Compliance account" means a COATS account, established by the department or its agent for a CO_2 budget source under Article 6 (9VAC5-140-6220 et seq.) of this part, in which CO_2 allowances available for use by the source for ~~the initial control period,~~ a control period ~~,~~ and each interim control period are held for the purpose of meeting the CO_2 requirements of 9VAC5-140-6050 C.

~~"Conditional allowance" means an allowance allocated by the department to a CO_2 budget source or to DMME. Such conditional allowance shall be consigned by~~

~~the entity to whom it is allocated to the consignment auction as specified under Article 9 (9VAC5-140-6410 et seq.) of this part, after which the conditional allowance becomes a CO_2 allowance once it is sold to an auction participant.~~

~~"Conditional allowance account" means a general COATS account established by the department for CO_2 budget sources and DMME or its contractor where conditional allowances allocated to CO_2 budget sources and DMME are held until auction.~~

~~"Conditional cost containment reserve allowance" or "conditional CCR allowance" means an allowance that may be offered for sale when the CCR is triggered. If any conditional CCR allowances are unsold, they may be offered for sale in future auctions during the same year. Conditional CCR allowances offered for sale at an auction are separate from and additional to conditional allowances allocated from the Virginia CO_2 Budget Trading Program base and adjusted budgets. Conditional CCR allowances are subject to all applicable limitations contained in this part.~~

~~"Consignment auction" or "auction" means the CO_2 auction conducted on a quarterly basis by the CO_2 Budget Trading Program, in which CO_2 budget sources and DMME are allocated a share of allowances by the department that CO_2 budget sources and the holder of a public contract with DMME consign into the auction, and auction revenue is returned to CO_2 budget sources and the holder of a public contract with DMME in accordance with procedures established by the department.~~

"Continuous Emissions Monitoring System" or "CEMS" means the equipment required under Article 8 (9VAC5-140-6330 et seq.) of this part to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated DAHS), a permanent record of stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with 40 CFR Part 75 and Article 8 (9VAC5-140-6330 et seq.) of this part. The following systems are types of CEMS required under Article 8 (9VAC5-140-6330 et seq.) of this part:

a. A flow monitoring system, consisting of a stack flow rate monitor and an automated DAHS and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour;

b. A NO_X emissions rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated DAHS and providing a permanent, continuous record of NO_X concentration, in parts per million (ppm), diluent gas concentration, in percent CO_2 or O_2, and NO_X emissions rate, in pounds per million British thermal units (lb/MMBtu);

c. A moisture monitoring system, as defined in 40 CFR 75.11(b)(2) and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

d. A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated DAHS and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

e. An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated DAHS and providing a permanent, continuous record of O_2, in percent O_2.

"Control period" means a three-calendar-year time period. The fifth control period is from January 1, 2021, to December 31, 2023, inclusive, which is the first control period of Virginia's participation in the CO_2 Budget Trading Program. The first two calendar years of each control period are each defined as an interim control period, beginning on January 1, 2021.

"Cross State Air Pollution Rule (CSAPR) NO_X Annual Trading Program" means a multistate NO_X air pollution control and emission reduction program established in accordance with Subpart AAAAA of 40 CFR Part 97 and 40 CFR 52.38(a), including such a program that is revised in a SIP revision approved by the administrator under 40 CFR 52.38(a)(3) or (4) or that is established in a SIP revision approved by the administrator under 40 CFR 52.38(a)(5), as a means of mitigating interstate transport of fine particulates and NO_X.

"Cross State Air Pollution Rule (CSAPR) NO_X Ozone Season Trading Program" means a multistate NO_X air pollution control and emission reduction program established in accordance with Subpart BBBBB of 40 CFR Part 97 and 40 CFR 52.38(b), including such a program that is revised in a SIP revision approved by the administrator under 40 CFR 52.38(b)(3) or (4) or that is established in a SIP revision approved by the administrator under 40 CFR 52.38(b)(5), as a means of mitigating interstate transport of ozone and NO_X.

"Cross State Air Pollution Rule (CSAPR) SO_2 Group 1 Trading Program" means a multistate SO_2 air pollution control and emission reduction program established in accordance with Subpart CCCCC of 40 CFR Part 97 and 40 CFR 52.39(a), (b), (d) through (f), (j), and (k), including such a program that is revised in a SIP revision approved by the administrator under 40 CFR 52.39(d) or (e) or that is established in a SIP revision approved by the administrator under 40 CFR 52.39(f), as a means of mitigating interstate transport of fine particulates and SO_2.

"Cross State Air Pollution Rule (CSAPR) SO_2 Group 2 Trading Program" means a multistate SO_2 air pollution control and emission reduction program

established in accordance with Subpart DDDDD of 40 CFR Part 97 and 40 CFR 52.39(a), (c), and (g) through (k), including such a program that is revised in a SIP revision approved by the administrator under 40 CFR 52.39(g) or (h) or that is established in a SIP revision approved by the administrator under 40 CFR 52.39(i), as a means of mitigating interstate transport of fine particulates and SO_2.

"Department" means the Virginia Department of Environmental Quality.

~~"DMME" means the Virginia Department of Mines, Minerals and Energy.~~

"Excess emissions" means any tonnage of CO_2 emitted by a CO_2 budget source during ~~the initial~~ an interim control period or a control period that exceeds the CO_2 budget emissions limitation for the source.

"Excess interim emissions" means any tonnage of CO_2 emitted by a CO_2 budget source during an interim control period multiplied by 0.50 that exceeds the CO_2 budget emissions limitation for the source.

"Fossil fuel" means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

"Fossil fuel-fired" means the combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel combusted comprises, or is projected to comprise, more than 5.0% of the annual heat input on a Btu basis during any year.

"General account" means a COATS account established under Article 6 (9VAC5-140-6220 et seq.) of this part that is not a compliance account.

"Gross generation" means the electrical output in MWe at the terminals of the generator.

~~"Initial control period" means the period beginning January 1, 2020, and ending December 31, 2020.~~

"Interim control period" means a one-calendar-year time period during each of the first and second calendar years of each three-year control period. The first interim control period starts January 1, 2021, and ends December 31, 2021, inclusive. The second interim control period starts January 1, 2022, and ends December 31, 2022, inclusive. Each successive three-year control period will have two interim control periods, comprised of each of the first two calendar years of that control period.

"Life-of-the-unit contractual arrangement" means either:

~~a~~ a. A unit participation power sales agreement under which a customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity or associated energy from any specified unit pursuant to a contract:

~~a.~~ 1. For the life of the unit;

~~b.~~ 2. For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

~~c.~~ 3. For a period equal to or greater than 25 years or 70% of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period~~.~~ ; or

b. For any energy conversion or energy tolling agreement that has a primary term of 20 years or more and pursuant to which the purchaser is required to deliver fuel to the CO_2 budget source or CO_2 budget unit and is entitled to receive all of the nameplate capacity and associated energy generated by such source or unit for the entire contractual period. Such agreements shall be subject to 9VAC5-140-6325. Such purchaser shall not be considered an "owner" as defined under this subsection.

"Maximum potential hourly heat input" means an hourly heat input used for reporting purposes when a unit lacks certified monitors to report heat input. If the unit intends to use Appendix D of 40 CFR Part 75 to report heat input, this value shall be calculated, in accordance with 40 CFR Part 75, using the maximum fuel flow rate and the maximum gross calorific value. If the unit intends to use a flow monitor and a diluent gas monitor, this value shall be reported, in accordance with 40 CFR Part 75, using the maximum potential flow rate and either the maximum CO_2 concentration in percent CO_2 or the minimum O_2 concentration in percent O_2.

"Minimum reserve price" means, in calendar year ~~2020, $2.32~~ 2021, $2.38. Each calendar year thereafter, the minimum reserve price shall be 1.025 multiplied by the minimum reserve price from the previous calendar year, rounded to the nearest whole cent.

"Monitoring system" means any monitoring system that meets the requirements of Article 8 (9VAC5-140-6330 et seq.) of this part, including a CEMS, an excepted monitoring system, or an alternative monitoring system.

"Nameplate capacity" means the maximum electrical output in MWe that a generator can sustain over a specified period of time when not restricted by seasonal or other deratings as measured in accordance with the U.S. Department of Energy standards.

"Net-electric output" means the amount of gross generation in MWh the generators produce, including output from steam turbines, combustion turbines, and gas expanders, as measured at the generator terminals, less the electricity used to operate the plant (i.e., auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

"Non-CO_2 budget unit" means a unit that does not meet the applicability criteria of 9VAC5-140-6040.

"Operator" means any person who operates, controls, or supervises a CO_2 budget unit or a CO_2 budget source and shall include any holding company, utility system, or plant manager of such a unit or source.

"Owner" means any of the following persons:

a. Any holder of any portion of the legal or equitable title in a CO_2 budget unit;

b. Any holder of a leasehold interest in a CO_2 budget unit, other than a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the CO_2 budget unit;

c. Any purchaser of power from a CO_2 budget unit under a life-of-the-unit contractual arrangement in which the purchaser controls the dispatch of the unit; or

d. With respect to any general account, any person who has an ownership interest with respect to the CO_2 allowances held in the general account and who is subject to the binding agreement for the CO_2 authorized account representative to represent that person's ownership interest with respect to the CO_2 allowances.

"Participating state" means a state that ~~participates in~~ <u>has established a corresponding regulation as part of</u> the CO_2 Budget Trading Program.

"Receive" or "receipt of" means, when referring to the department or its agent, to come into possession of a document, information, or correspondence (whether sent in writing or by authorized electronic transmission) as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence by the department or its agent in the regular course of business.

"Recordation," "record," or "recorded" means, with regard to CO_2 allowances, the movement of CO_2 allowances by the department or its agent from one COATS account to another, for purposes of allocation, transfer, or deduction.

"Reserve price" means the minimum acceptable price for each ~~conditional~~ CO_2 allowance in a specific auction. The reserve price at an auction is either the minimum reserve price or the CCR trigger price, as specified in Article 9 (9VAC5-140-6410 et seq.) of this part.

"Serial number" means, when referring to CO_2 allowances, the unique identification number assigned to each CO_2 allowance by the department or its agent under 9VAC5-140-6250 C.

"Source" means any governmental, institutional, commercial, or industrial structure, installation, plant, building, or facility that emits or has the potential to emit any air pollutant. A source, including a source with multiple units, shall be considered a single facility.

"Submit" or "serve" means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

a. In person;

b. By United States Postal Service; or

c. By other means of dispatch or transmission and delivery.

Compliance with any "submission," "service," or "mailing" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

"Ton" or "tonnage" means any short ton, or 2,000 pounds. For the purpose of determining compliance with the CO_2 requirements of 9VAC5-140-6050 C, total tons for ~~the initial control period,~~ an interim control period , or a control period shall be calculated as the sum of all recorded hourly emissions, or the tonnage equivalent of the recorded hourly emissions rates, in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part, with any remaining fraction of a ton equal to or greater than 0.50 ton deemed to equal one ton and any fraction of a ton less than 0.50 ton deemed to equal zero tons. A short ton is equal to 0.9072 metric tons.

"Total useful energy" means the sum of gross electrical generation and useful net thermal energy.

"Undistributed ~~conditional~~ CO_2 allowances" means ~~conditional~~ CO_2 allowances originally allocated to a set aside account as pursuant to 9VAC5-140-6210 that were not distributed.

"Unit" means a fossil fuel-fired stationary boiler, combustion turbine, or combined cycle system.

"Unit operating day" means a calendar day in which a unit combusts any fuel.

"Unsold ~~conditional~~ CO_2 allowances" means ~~conditional~~ CO_2 allowances that have been made available for sale in an auction conducted by the department or its agent, but not sold.

"Useful net thermal energy" means energy:

~~1.~~ a. In the form of direct heat, steam, hot water, or other thermal form that is used in the production and beneficial measures for heating, cooling, humidity control, process use, or other thermal end use energy requirements, excluding thermal energy used in the power production process (e.g., house loads and parasitic loads); and

~~2.~~ b. For which fuel or electricity would otherwise be consumed.

"Virginia CO_2 Budget Trading Program adjusted budget" means an adjusted budget determined in accordance with 9VAC5-140-6210 and is the annual amount of CO_2 tons available in Virginia for allocation in a given allocation year, in accordance with the CO_2 Budget Trading Program. ~~Conditional~~ CO_2 CCR allowances offered for sale at an auction are separate from and additional to ~~conditional~~ CO_2 allowances allocated from the Virginia CO_2 Budget Trading Program adjusted budget.

"Virginia CO_2 Budget Trading Program base budget" means the budget specified in 9VAC5-140-6190. ~~Conditional~~ CO_2 CCR allowances offered for sale at an auction are separate from and additional to ~~conditional~~ CO_2 allowances allocated from the Virginia CO_2 Budget Trading Program base budget.

9VAC5-140-6030. Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this part are defined as follows:

Btu - British thermal unit.
CAA - federal Clean Air Act.
CCR - cost containment reserve.
CEMS - Continuous Emissions Monitoring System.
COATS - CO_2 Allowance Tracking System.
CO_2 - carbon dioxide.
DAHS - Data Acquisition and Handling System.
H2O - water.
lb - pound.
LME - low mass emissions.

MMBtu - million British thermal units.
MW - megawatt.
MWe - megawatt electrical.
MWh - megawatt hour.
NO_X - nitrogen oxides.
O2 - oxygen.
ORIS - Office of Regulatory Information Systems.
QA/QC - quality assurance/quality control.
ppm - parts per million.
SO_2 - sulfur dioxide.

9VAC5-140-6040. Applicability.

A. Any fossil fuel-fired unit that serves an electricity generator with a nameplate capacity equal to or greater than 25 MWe shall be a CO_2 budget unit, and any source that includes one or more such units shall be a CO_2 budget source, subject to the requirements of this part.

B. Exempt from the requirements of this part is any fossil fuel CO_2 budget source located at or adjacent to and physically interconnected with a manufacturing facility that, prior to January 1, ~~2019~~ 2020, and in every subsequent calendar year, met either of the following requirements:

1. Supplies less than or equal to 10% of its annual net electrical generation to the electric grid; or

2. Supplies less than or equal to 15% of its annual total useful energy to any entity other than the manufacturing facility to which the CO_2 budget source is interconnected.

For the purpose of subdivision 1 of this subsection, annual net electrical generation shall be determined as follows:

$$(ES - EP) / EG \times 100$$

Where:

ES = electricity sales to the grid from the CO_2 budget source
EP = electricity purchases from the grid by the CO_2 budget source and the manufacturing facility to which the CO_2 budget source is interconnected
EG = electricity generation

Such exempt CO_2 budget source shall have an operating permit containing the applicable restrictions under this subsection. An application for such operating permit shall be submitted to the department no later than January 1, 2022.

9VAC5-140-6045. ~~CO_2 Budget Trading Program implementation.~~ (Repealed.)

~~In the event the allocation of conditional allowances by the department as required by 9VAC5-140-6190 B has not occurred by January 1, 2020, the program will be considered to be operating and effective as of the calendar year following the date on which the department allocates the conditional allowances as it corresponds to the schedule of 9VAC5-140-6190 A. Permitting and compliance dates, including the due date for a permit as required by 9VAC5-140-6150 , shall be adjusted to be in force six months after the date the department allocates the conditional allowances. Any excess emissions tonnage identified by the new program implementation date may be addressed through program review and regulatory action as necessary to ensure compliance with the final compliance date. The department will notify the board and each affected CO_2 budget source accordingly.~~

9VAC5-140-6050. Standard requirements.

A. Permit requirements shall be as follows.

1. The CO_2 authorized account representative of each CO_2 budget source required to have an operating permit pursuant to 9VAC5-85 (Permits for Stationary Sources of Pollutants Subject to Regulation) and each CO_2 budget unit required to have an operating permit pursuant to 9VAC5-85 shall:

a. Submit to the department a complete CO_2 budget permit application under 9VAC5-140-6160 in accordance with the deadlines specified in 9VAC5-140-6150; and

b. Submit in a timely manner any supplemental information that the department determines is necessary in order to review the CO_2 budget permit application and issue or deny a CO_2 budget permit.

2. The owners and operators of each CO_2 budget source required to have an operating permit pursuant to 9VAC5-85 (Permits for Stationary Sources of Pollutants Subject to Regulation) and each CO_2 budget unit required to have an operating permit pursuant to 9VAC5-85 for the source shall have a CO_2 budget permit and operate the CO_2 budget source and the CO_2 budget unit at the source in compliance with such CO_2 budget permit.

B. Monitoring requirements shall be as follows.

1. The owners and operators and, to the extent applicable, the CO_2 authorized account representative of each CO_2 budget source and each CO_2 budget unit at the source shall comply with the monitoring requirements of Article 8 (9VAC5-140-6330 et seq.) of this part.

2. The emissions measurements recorded and reported in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part shall be used to determine compliance by the unit with the CO_2 requirements under subsection C of this section.

C. CO_2 requirements shall be as follows.

1. The owners and operators of each CO_2 budget source and each CO_2 budget unit at the source shall hold CO_2 allowances available for compliance deductions under 9VAC5-140-6260, as of the CO_2 allowance transfer deadline, in the source's compliance account in an amount not less than the total CO_2 emissions that have been generated as a result of combusting fossil fuel for ~~the initial control period,~~ an interim control period ~~,~~ or control period from all CO_2 budget units at the source, less the CO_2 allowances deducted to meet the requirements of subdivision 2 of this subsection, with respect to the previous two interim control periods as determined in accordance with Article 6 (9VAC5-140-6220 et seq.) and Article 8 (9VAC5-140-6330 et seq.) of this part.

2. The owners and operators of each CO_2 budget source and each CO_2 budget unit at the source shall hold CO_2 allowances available for compliance deductions under 9VAC5-140-6260, as of the CO_2 allowance transfer deadline, in the source's compliance account in an amount not less than the total CO_2 emissions that have been generated as a result of combusting fossil fuel for ~~the initial control period, an interim control period, or for~~ the interim control period from all CO_2 budget units at the source multiplied by 0.50, as determined in accordance with Article 6 (9VAC5-140-6220 et seq.) and Article 8 (9VAC5-140-6330 et seq.) of this part.

3. Each ton of CO_2 emitted in excess of the CO_2 budget emissions limitation for ~~the initial control period or~~ a control period shall constitute a separate violation of this part and applicable state law.

4. Each ton of excess interim emissions shall constitute a separate violation of this part and applicable state law.

5. A CO_2 budget unit shall be subject to the requirements under subdivision 1 of this subsection starting on the later of January 1, ~~2020~~ 2021, or the date on which the unit commences operation.

6. CO_2 allowances shall be held in, deducted from, or transferred among COATS accounts in accordance with Article 5 (9VAC5-140-6190 et seq.), Article 6 (9VAC5-140-6220 et seq.), and Article 7 (9VAC5-140-6300 et seq.) of this part.

7. A CO_2 allowance shall not be deducted, to comply with the requirements under subdivision 1 or 2 of this subsection, for a control period that ends prior to the year for which the CO_2 allowance was allocated.

8. A CO_2 allowance under the CO_2 Budget Trading Program is a limited authorization by the department to emit one ton of CO_2 in accordance with the CO_2 Budget Trading Program. No provision of the CO_2 Budget Trading Program, the CO_2 budget permit application, or the CO_2 budget permit or any provision of law shall be construed to limit the authority of the department or a participating state to terminate or limit such authorization.

9. A CO_2 allowance under the CO_2 Budget Trading Program does not constitute a property right.

D. The owners and operators of a CO_2 budget source that has excess emissions in ~~an initial control period or~~ a control period shall:

1. Forfeit the CO_2 allowances required for deduction under 9VAC5-140-6260 D 1; and

2. Pay any fine, penalty, or assessment or comply with any other remedy imposed under 9VAC5-140-6260 D 2.

E. Recordkeeping and reporting requirements shall be as follows:

1. Unless otherwise provided, the owners and operators of the CO_2 budget source and each CO_2 budget unit at the source shall keep on site at the source each of the following documents for a period of 10 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 10 years, in writing by the department.

a. The account certificate of representation for the CO_2 authorized account representative for the source and each CO_2 budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with 9VAC5-140-6110, provided that the certificate and documents shall be retained on site at the source beyond such 10-year period until such documents are superseded because of the submission of a new account certificate of representation changing the CO_2 authorized account representative.

b. All emissions monitoring information, in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part and 40 CFR 75.57.

c. Copies of all reports, compliance certifications, and other submissions and all records made or required under the CO_2 Budget Trading Program.

d. Copies of all documents used to complete a CO_2 budget permit application and any other submission under the CO_2 Budget Trading Program or to demonstrate compliance with the requirements of the CO_2 Budget Trading Program.

2. The CO_2 authorized account representative of a CO_2 budget source and each CO_2 budget unit at the source shall submit the reports and compliance certifications required under the CO_2 Budget Trading Program, including those under Article 4 (9VAC5-140-6170 et seq.) of this part.

F. Liability requirements shall be as follows.

1. No permit revision shall excuse any violation of the requirements of the CO_2 Budget Trading Program that occurs prior to the date that the revision takes effect.

2. Any provision of the CO_2 Budget Trading Program that applies to a CO_2 budget source, including a provision applicable to the CO_2 authorized account representative of a CO_2 budget source, shall also apply to the owners and operators of such source and of the CO_2 budget units at the source.

3. Any provision of the CO_2 Budget Trading Program that applies to a CO_2 budget unit, including a provision applicable to the CO_2 authorized account representative of a CO_2 budget unit, shall also apply to the owners and operators of such unit.

G. No provision of the CO_2 Budget Trading Program, a CO_2 budget permit application, or a CO_2 budget permit shall be construed as exempting or excluding the owners and operators and, to the extent applicable, the CO_2 authorized account representative of the CO_2 budget source or CO_2 budget unit from compliance with any other provisions of applicable state and federal law or regulations.

9VAC5-140-6060. Computation of time.

A. Unless otherwise stated, any time period scheduled, under the CO_2 Budget Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

B. Unless otherwise stated, any time period scheduled, under the CO_2 Budget Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

C. Unless otherwise stated, if the final day of any time period, under the CO_2 Budget Trading Program, falls on a weekend or a state or federal holiday, the time period shall be extended to the next business day.

9VAC5-140-6070. Severability.

If any provision of this part, or its application to any particular person or circumstances, is held invalid, the remainder of this part, and the application thereof to other persons or circumstances, shall not be affected thereby.

Article 2. CO_2 Authorized Account Representative for CO_2 Budget Sources

9VAC5-140-6080. Authorization and responsibilities of the CO_2 authorized account representative.

A. Except as provided under 9VAC5-140-6090, each CO_2 budget source, including all CO_2 budget units at the source, shall have one and only one CO_2 authorized account representative, with regard to all matters under the CO_2 Budget Trading Program concerning the source or any CO_2 budget unit at the source.

B. The CO_2 authorized account representative of the CO_2 budget source shall be selected by an agreement binding on the owners and operators of the source and all CO_2 budget units at the source and must act in accordance with the account certificate of representation under 9VAC5-140-6110.

C. Upon receipt by the department or its agent of a complete account certificate of representation under 9VAC5-140-6110 , the CO_2 authorized account representative of the source shall represent and, by his representations, actions, inactions, or submissions, legally bind each owner and operator of the CO_2 budget source represented and each CO_2 budget unit at the source in all matters pertaining to the CO_2 Budget Trading Program, notwithstanding any agreement between the CO_2 authorized account representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the CO_2 authorized account representative by the department or a court regarding the source or unit.

D. No CO_2 budget permit shall be issued, and no COATS account shall be established for a CO_2 budget source, until the department or its agent has received a complete account certificate of representation under 9VAC5-140-6110 for a CO_2 authorized account representative of the source and the CO_2 budget units at the source.

E. Each submission under the CO_2 Budget Trading Program shall be submitted, signed, and certified by the CO_2 authorized account representative for each CO_2 budget source on behalf of which the submission is made. Each such submission shall include the following certification statement by the CO_2 authorized account representative: "I am authorized to make this submission on behalf of the owners and operators of the CO_2 budget sources or CO_2 budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting

false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

F. The department or its agent will accept or act on a submission made on behalf of owners or operators of a CO_2 budget source or a CO_2 budget unit only if the submission has been made, signed, and certified in accordance with subsection E of this section.

9VAC5-140-6090. CO_2 authorized alternate account representative.

A. An account certificate of representation may designate one and only one CO_2 authorized alternate account representative who may act on behalf of the CO_2 authorized account representative. The agreement by which the CO_2 authorized alternate account representative is selected shall include a procedure for authorizing the CO_2 authorized alternate account representative to act in lieu of the CO_2 authorized account representative.

B. Upon receipt by the department or its agent of a complete account certificate of representation under 9VAC5-140-6110, any representation, action, inaction, or submission by the CO_2 authorized alternate account representative shall be deemed to be a representation, action, inaction, or submission by the CO_2 authorized account representative.

C. Except in this section and 9VAC5-140-6080 A, 9VAC5-140-6100, 9VAC5-140-6110, and 9VAC5-140-6230, whenever the term "CO_2 authorized account representative" is used in this part, the term shall be construed to include the CO_2 authorized alternate account representative.

9VAC5-140-6100. Changing the CO_2 authorized account representatives and the CO_2 authorized alternate account representative; changes in the owners and operators.

A. The CO_2 authorized account representative may be changed at any time upon receipt by the department or its agent of a superseding complete account certificate of representation under 9VAC5-140-6110. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative or CO_2 authorized alternate account representative prior to the time and date when the department or its agent receives the superseding account certificate of representation shall be binding on the new CO_2 authorized account representative and the owners and operators of the CO_2 budget source and the CO_2 budget units at the source.

B. The CO_2 authorized alternate account representative may be changed at any time upon receipt by the department or its agent of a superseding complete account certificate of representation under 9VAC5-140-6110. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized

alternate account representative or CO_2 authorized alternate account representative prior to the time and date when the department or its agent receives the superseding account certificate of representation shall be binding on the new CO_2 authorized alternate account representative and the owners and operators of the CO_2 budget source and the CO_2 budget units at the source.

C. Changes in the owners and operators shall be addressed as follows.

1. In the event a new owner or operator of a CO_2 budget source or a CO_2 budget unit is not included in the list of owners and operators submitted in the account certificate of representation, such new owner or operator shall be deemed to be subject to and bound by the account certificate of representation, the representations, actions, inactions, and submissions of the CO_2 authorized account representative and any CO_2 authorized alternate account representative of the source or unit, and the decisions, orders, actions, and inactions of the department, as if the new owner or operator were included in such list.

2. Within 30 days following any change in the owners and operators of a CO_2 budget source or a CO_2 budget unit, including the addition of a new owner or operator, the CO_2 authorized account representative or CO_2 authorized alternate account representative shall submit a revision to the account certificate of representation amending the list of owners and operators to include the change.

9VAC5-140-6110. Account certificate of representation.

A. A complete account certificate of representation for a CO_2 authorized account representative or a CO_2 authorized alternate account representative shall include the following elements in a format prescribed by the department or its agent:

1. Identification of the CO_2 budget source and each CO_2 budget unit at the source for which the account certificate of representation is submitted;

2. The name, address, email address, telephone number, and facsimile transmission number of the CO_2 authorized account representative and any CO_2 authorized alternate account representative;

3. A list of the owners and operators of the CO_2 budget source and of each CO_2 budget unit at the source;

4. The following certification statement by the CO_2 authorized account representative and any CO_2 authorized alternate account representative: "I certify that I was selected as the CO_2 authorized account representative or CO_2 authorized alternate account representative, as applicable, by an agreement binding on the owners and operators of the CO_2 budget source and each CO_2 budget unit at the source. I certify that I have all the necessary authority to carry out my duties and responsibilities under

the CO_2 Budget Trading Program on behalf of the owners and operators of the CO_2 budget source and of each CO_2 budget unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the department or a court regarding the source or unit."; and

5. The signature of the CO_2 authorized account representative and any CO_2 authorized alternate account representative and the dates signed.

B. Unless otherwise required by the department or its agent, documents of agreement referred to in the account certificate of representation shall not be submitted to the department or its agent. Neither the department nor its agent shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

9VAC5-140-6120. Objections concerning the CO_2 authorized account representative.

A. Once a complete account certificate of representation under 9VAC5-140-6110 has been submitted and received, the department and its agent will rely on the account certificate of representation unless and until the department or its agent receives a superseding complete account certificate of representation under 9VAC5-140-6110.

B. Except as provided in 9VAC5-140-6100 A or B, no objection or other communication submitted to the department or its agent concerning the authorization, or any representation, action, inaction, or submission of the CO_2 authorized account representative shall affect any representation, action, inaction, or submission of the CO_2 authorized account representative or the finality of any decision or order by the department or its agent under the CO_2 Budget Trading Program.

C. Neither the department nor its agent will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any CO_2 authorized account representative, including private legal disputes concerning the proceeds of CO_2 allowance transfers.

9VAC5-140-6130. Delegation by CO_2 authorized account representative and CO_2 authorized alternate account representative.

A. A CO_2 authorized account representative may delegate, to one or more natural persons, his authority to make an electronic submission to the department or its agent under this part.

B. A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his authority to make an electronic submission to the department or its agent under this part.

C. To delegate authority to make an electronic submission to the department or its agent in accordance with subsections A and B of this section, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, shall submit to the department or its agent a notice of delegation, in a format prescribed by the department that includes the following elements:

1. The name, address, email address, telephone number, and facsimile transmission number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;

2. The name, address, email address, telephone number, and facsimile transmission number of each such natural person, referred to as the "electronic submission agent";

3. For each such natural person, a list of the type of electronic submissions under subsection A or B of this section for which authority is delegated to him; and

4. The following certification statement by such CO_2 authorized account representative or CO_2 authorized alternate account representative: "I agree that any electronic submission to the department or its agent that is by a natural person identified in this notice of delegation and of a type listed for such electronic submission agent in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 9VAC5-140-6130 D shall be deemed to be an electronic submission by me. Until this notice of delegation is superseded by another notice of delegation under 9VAC5-140-6130 D, I agree to maintain an email account and to notify the department or its agent immediately of any change in my email address unless all delegation authority by me under 9VAC5-140-6130 is terminated."

D. A notice of delegation submitted under subsection C of this section shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the department or its agent and until receipt by the department or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of delegation may replace any previously identified electronic submission agent, add a new electronic submission agent, or eliminate entirely any delegation of authority.

E. Any electronic submission covered by the certification in subdivision C 4 of this section and made in accordance with a notice of delegation effective under subsection D of this section shall be deemed to be an electronic submission by the CO_2 authorized account representative or CO_2 authorized alternate account representative submitting such notice of delegation.

F. A CO_2 authorized account representative may delegate, to one or more natural persons, his authority to review information in the CO_2 allowance tracking system under this part.

G. A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his authority to review information in the CO_2 allowance tracking system under this part.

H. To delegate authority to review information in the CO_2 allowance tracking system in accordance with subsections F and G of this section, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, shall submit to the department or its agent a notice of delegation, in a format prescribed by the department that includes the following elements:

1. The name, address, email address, telephone number, and facsimile transmission number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;

2. The name, address, email address, telephone number, and facsimile transmission number of each such natural person, referred to as the "reviewer";

3. For each such natural person, a list of the type of information under subsection F or G of this section for which authority is delegated to him; and

4. The following certification statement by such CO_2 authorized account representative or CO_2 authorized alternate account representative: "I agree that any information that is reviewed by a natural person identified in this notice of delegation and of a type listed for such information accessible by the reviewer in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under subsection I of this section shall be deemed to be a reviewer by me. Until this notice of delegation is superseded by another notice of delegation under subsection I of this section, I agree to maintain an email account and to notify the department or its agent immediately of any change in my email address unless all delegation authority by me under this section is terminated."

I. A notice of delegation submitted under subsection H of this section shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the department or its agent and until receipt by the department or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of

delegation may replace any previously identified reviewer, add a new reviewer, or eliminate entirely any delegation of authority.

Article 3. Permits

9VAC5-140-6140. CO_2 budget permit requirements.

A. Each CO_2 budget source shall have a permit issued by the department pursuant to 9VAC5-85 (Permits for Stationary Sources of Pollutants Subject to Regulation).

B. Each CO_2 budget permit shall contain all applicable CO_2 Budget Trading Program requirements and shall be a complete and distinguishable portion of the permit under subsection A of this section.

9VAC5-140-6150. Submission of CO_2 budget permit applications.

For any CO_2 budget source, the CO_2 authorized account representative shall submit a complete CO_2 budget permit application under 9VAC5-140-6160 covering such CO_2 budget source to the department by the later of January 1, ~~2020~~ 2021, or 12 months before the date on which the CO_2 budget source, or a new unit at the source, commences operation.

9VAC5-140-6160. Information requirements for CO_2 budget permit applications.

A complete CO_2 budget permit application shall include the following elements concerning the CO_2 budget source for which the application is submitted, in a format prescribed by the department:

1. Identification of the CO_2 budget source, including plant name and the ORIS (Office of Regulatory Information Systems) or facility code assigned to the source by the Energy Information Administration of the U.S. Department of Energy if applicable;

2. Identification of each CO_2 budget unit at the CO_2 budget source; and

3. The standard requirements under 9VAC5-140-6050.

Article 4. Compliance Certification

9VAC5-140-6170. Compliance certification report.

A. For ~~the initial control period and~~ each control period in which a CO_2 budget source is subject to the CO_2 requirements of 9VAC5-140-6050 C, the CO_2 authorized account representative of the source shall submit to the department by March 1 following the relevant control period, a compliance certification report. A compliance

certification report is not required as part of the compliance obligation during an interim control period.

B. The CO_2 authorized account representative shall include in the compliance certification report under subsection A of this section the following elements, in a format prescribed by the department:

1. Identification of the source and each CO_2 budget unit at the source;

2. At the CO_2 authorized account representative's option, the serial numbers of the CO_2 allowances that are to be deducted from the source's compliance account under 9VAC5-140-6260 for the control period; and

3. The compliance certification under subsection C of this section.

C. In the compliance certification report under subsection A of this section, the CO_2 authorized account representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the source and the CO_2 budget units at the source in compliance with the CO_2 Budget Trading Program, whether the source and each CO_2 budget unit at the source for which the compliance certification is submitted was operated during the calendar years covered by the report in compliance with the requirements of the CO_2 Budget Trading Program, including:

1. Whether the source was operated in compliance with the CO_2 requirements of 9VAC5-140-6050 C;

2. Whether the monitoring plan applicable to each unit at the source has been maintained to reflect the actual operation and monitoring of the unit, and contains all information necessary to attribute CO_2 emissions to the unit, in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part;

3. Whether all the CO_2 emissions from the units at the source were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports, including whether conditional data were reported in the quarterly reports in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part. If conditional data were reported, the owner or operator shall indicate whether the status of all conditional data has been resolved and all necessary quarterly report resubmissions have been made;

4. Whether the facts that form the basis for certification under Article 8 (9VAC5-140-6330 et seq.) of this part of each monitor at each unit at the source, or for using an excepted monitoring method or alternative monitoring method approved under Article 8 (9VAC5-140-6330 et seq.) of this part, if any, have changed; and

5. If a change is required to be reported under subdivision 4 of this subsection, specify the nature of the change, the reason for the change, when the change occurred, and how the unit's compliance status was determined subsequent to the change, including what method was used to determine emissions when a change mandated the need for monitor recertification.

9VAC5-140-6180. Action on compliance certifications.

A. The department or its agent may review and conduct independent audits concerning any compliance certification or any other submission under the CO_2 Budget Trading Program and make appropriate adjustments of the information in the compliance certifications or other submissions.

B. The department or its agent may deduct CO_2 allowances from or transfer CO_2 allowances to a source's compliance account based on the information in the compliance certifications or other submissions, as adjusted under subsection A of this section.

Article 5. CO_2 Allowance Allocations

9VAC5-140-6190. Base budgets.

A. The Virginia CO_2 Budget Trading Program base budget shall be as follows:

1. ~~For 2020, the Virginia CO_2 Budget Trading Program base budget is 28 million tons.~~

~~2.~~ For 2021, the Virginia CO_2 Budget Trading Program base budget is 27.16 million tons.

~~3.~~ 2. For 2022, the Virginia CO_2 Budget Trading Program base budget is 26.32 million tons.

~~4.~~ 3. For 2023, the Virginia CO_2 Budget Trading Program base budget is 25.48 million tons.

~~5.~~ 4. For 2024, the Virginia CO_2 Budget Trading Program base budget is 24.64 million tons.

~~6.~~ 5. For 2025, the Virginia CO_2 Budget Trading Program base budget is 23.80 million tons.

~~7.~~ 6. For 2026, the Virginia CO_2 Budget Trading Program base budget is 22.96 million tons.

~~8.~~ 7. For 2027, the Virginia CO_2 Budget Trading Program base budget is 22.12 million tons.

~~9.~~ 8. For 2028, the Virginia CO_2 Budget Trading Program base budget is 21.28 million tons.

~~10.~~ 9. For 2029, the Virginia CO_2 Budget Trading Program base budget is 20.44 million tons.

~~11.~~ 10. For 2030, the Virginia CO_2 Budget Trading Program base budget is 19.60 million tons.

B. ~~The department will allocate conditional allowances to CO_2 budget units and to DMME. After a conditional allowance has been consigned in an auction by a CO_2 budget unit or the holder of a public contract with DMME as specified under Article 9 (9VAC5-140-6410 et seq.) of this part, the conditional allowance becomes a CO_2 allowance once it is sold to an auction participant.~~

~~C.~~ For 2031 and each succeeding calendar year, the Virginia CO_2 Budget Trading Program base budget is 19.60 million tons unless modified as a result of a program review and future regulatory action.

9VAC5-140-6200. Undistributed and unsold ~~conditional~~ CO_2 allowances.

A. The department will retire undistributed ~~conditional~~ CO_2 allowances at the end of ~~the initial control period and~~ each ~~subsequent~~ control period.

B. The department will retire unsold ~~conditional~~ CO_2 allowances at the end of ~~the initial control period and~~ each ~~subsequent~~ control period.

9VAC5-140-6210. ~~Conditional~~ CO_2 allowance allocations.

A. The department will allocate the Virginia CO_2 Budget Trading Program base budget ~~conditional~~ CO_2 allowances ~~to CO_2 budget sources to be consigned to auction~~ to the Virginia ~~Consignment~~ Auction Account.

B. For allocation years ~~2020~~ 2021 through ~~2031~~ 2030, the Virginia CO_2 Budget Trading Program adjusted budget shall be the maximum number of allowances available for allocation in a given allocation year, except for ~~conditional~~ CO_2 CCR allowances.

C. ~~Conditional allowances allocated for a calendar year will be automatically transferred to the Virginia Consignment Auction Account to be consigned to auction. Following each auction, all conditional allowances sold at the auction will be transferred~~

~~from the Virginia Consignment Auction Account to winning bidders' accounts as CO_2 allowances.~~

~~D. The cost containment reserve (CCR) allocation shall be managed as follows.~~ ~~The~~ In the event that the CCR is triggered during an auction, the department will allocate ~~conditional~~ CO_2 CCR allowances, separate from and additional to the Virginia CO_2 Budget Trading Program base budget set forth in 9VAC5-140-6190 to the Virginia ~~Consignment~~ Auction Account. The CCR allocation is for the purpose of containing the cost of CO_2 allowances. The department will allocate ~~conditional~~ CO_2 CCR allowances as follows:

1. ~~Beginning in calendar year 2020, the department will initially allocate, on a pro rata basis to CO2 budget sources, 2.8 million conditional CO2 CCR allowances.~~

~~2.~~ On or before January 1, 2021, and each year thereafter, the department will allocate~~, on a pro rata basis to CO2 budget sources, current vintage year conditional~~ CO_2 CCR allowances equal to the quantity in Table 140-5A.

Table 140-5A
~~Conditional~~ CO_2 CCR Allowances from 2021 Forward

2021	2.716 million tons
2022	2.632 million tons
2023	2.548 million tons
2024	2.464 million tons
2025	2.380 million tons
2026	2.296 million tons
2027	2.212 million tons
2028	2.128 million tons
2029	2.044 million tons
2030 and each year thereafter	1.960 million tons

~~3. The pro rata calculation to be used for the distribution of conditional CO2 CCR allowances is as follows:~~

~~$SAA/TAA * CCR = SCCR$~~

~~Where:~~

~~SAA = source adjusted allocation~~
~~TAA = total adjusted allocation~~
~~SCCR = source CCR~~

~~4.~~ 2. ~~Conditional~~ CCR allowances allocated for a calendar year will be automatically transferred to the Virginia ~~Consignment~~ Auction Account to be ~~consigned to auction~~ auctioned. Following each auction, all ~~conditional~~ CO_2 CCR allowances sold at auction will be transferred to winning bidders' accounts as CO_2 CCR allowances.

~~5.~~ 3. Unsold ~~conditional~~ CO_2 CCR allowances will remain in the Virginia ~~Consignment~~ Auction Account to be re-offered for sale at auction within the same calendar year. ~~Conditional~~ CO_2 CCR allowances remaining unsold at the end of the calendar year in which they were originated will be made unavailable for sale at future auctions.

~~E.~~ D. In the event that the ECR is triggered during an auction, the department will authorize its agent to withhold ~~conditional~~ CO_2 allowances as needed. The department will further authorize its agent to convert and transfer any ~~conditional~~ CO_2 allowances that have been withheld from any auction into the Virginia ECR account. The ECR withholding is for the purpose of additional emission reduction in the event of lower than anticipated emission reduction costs. The department's agent will withhold CO_2 ECR allowances as follows:

1. If the condition in 9VAC5-140-6420 ~~D 1~~ C 1 is met at an auction, then the maximum number of CO_2 ECR allowances that will be withheld from that auction will be equal to the quantity shown in Table 140-5B minus the total quantity of CO_2 ECR allowances that have been withheld from any prior auction in that calendar year. Any CO_2 ECR allowances withheld from an auction will be transferred into the Virginia ECR account.

Table 140-5B
ECR Allowances from 2021 Forward

2021	2.716 million tons
2022	2.632 million tons
2023	2.548 million tons
2024	2.464 million tons
2025	2.380 million tons
2026	2.296 million tons
2027	2.212 million tons
2028	2.128 million tons
2019	2.044 million tons
2030 and each year thereafter	1.960 million tons

2. Allowances that have been transferred into the Virginia ECR account shall not be withdrawn.

~~F.~~ E. The adjustment for banked allowances will be as follows. On March 15, 2021, the department may determine the adjustment for banked allowances quantity for allocation years 2021 through 2025 through the application of the following formula:

$$TABA = ((TA - TAE)/5) \times RS\%$$

Where:

TABA is the adjustment for banked allowances quantity in tons.

TA, adjustment, is the total quantity of allowances of vintage years prior to 2021 held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program but not including accounts opened by participating states, as reflected in the CO_2 Allowance Tracking System on March 15, 2021.

TAE, adjustment emissions, is the total quantity of 2018, 2019, and 2020 emissions from all CO_2 budget sources in all participating states, reported pursuant to CO_2 Budget Trading Program as reflected in the CO_2 Allowance Tracking System on March 15, 2021.

RS% is Virginia budget divided by the regional budget.

~~G.~~ F. CO_2 Budget Trading Program adjusted budgets for 2021 through 2025 shall be determined as follows: on April 15, 2021, the department will determine the Virginia CO_2 Budget Trading Program adjusted budgets for the 2021 through 2025 allocation years by the following formula:

$$AB = BB - TABA$$

Where:

AB is the Virginia CO_2 Budget Trading Program adjusted budget.

BB is the Virginia CO_2 Budget Trading Program base budget.

TABA is the adjustment for banked allowances quantity in tons.

~~H.~~ G. The department or its agent will publish the CO_2 trading program adjusted budgets for the 2021 through 2025 allocation years.

~~I. Timing requirements for conditional allowance allocations shall be as follows:~~

~~1. By August 25, 2019, the department will submit to its agent the conditional allowance allocations in accordance with 9VAC5-140-6215 A and B, for the initial control period, 2020.~~

~~2. By the month and day established by subdivision 1 of this subsection, 2020, the department will submit to its agent 50% of the conditional allowance allocations in accordance with 9VAC5-140-6215 A and B, for the 2021 control period.~~

~~By the month and day one month before the date established by subdivision 1 of this subsection, 2021, the department will submit to its agent the remainder of the conditional allowance allocations in accordance with 9VAC5-140-6215 A and B, for 2021.~~

~~3. By the month and day established by subdivision 1 of this subsection, 2021, and the month and day established by subdivision 1 of this subsection of every subsequent year thereafter, the department will submit to its agent the conditional allowance allocations for the applicable control period in accordance with 9VAC5-140-6215 A and B.~~

~~J. Implementation of the CCR (subsection C of this section), the ECR (subsection D of this section) and the banking adjustment (subsection E of this section) shall be determined based on the extent of the CO2 trading program.~~

~~K. Conditional allowances and conditional CCR allowances allocated for a calendar year will be automatically transferred to the Virginia Consignment Auction Account to be consigned to auction. Following each auction, all conditional allowances sold at the auction will be transferred from the Virginia Consignment Auction Account to winning bidders' accounts as CO_2 allowances. Conditional CCR allowances sold at auction will be transferred to winning bidders' accounts as CO_2 CCR allowances. Unsold conditional CCR allowances will remain in the Virginia Consignment Auction Account to be re-offered for sale at auction within the same calendar year. Conditional CCR allowances remaining unsold at the end of the calendar year in which they were originated will be made unavailable for sale at future auctions.~~

9VAC5-140-6211. ~~Conditional allowance allocations, DMME allowances.~~ (Repealed.)

~~Notwithstanding 9VAC5-140-6210, the department will allocate 5.0% of the Virginia CO_2 Budget Trading Program base or adjusted budget allowances, as applicable, to DMME to be consigned to auction by the holder of a public contract with DMME to assist the department for the abatement and control of air pollution, specifically CO_2, by the implementation of programs that lower base and peak electricity demand and reduce the cost of the program to consumers and budget sources.~~

9VAC5-140-6215. ~~Conditional allocation methodology.~~ (Repealed.)

~~A. The net electric output in MWh used with respect to conditional allowance allocations under subsection B of this section for each CO_2 budget unit shall be:~~

~~1. For units operating on or before January 1, 2020, the average of the three amounts of the unit's net electric output during 2016, 2017, and 2018 to determine allocations for the initial control period.~~

~~2. For all units operating in each control period after 2020, the average of the three amounts of the unit's total net-electric output during the three most recent years for which data are available prior to the start of the control period.~~

~~B. 1. For each control period beginning in 2020 and thereafter, the department will allocate to all CO_2 budget units that have a net-electric output, as determined under subsection A of this section, a total amount of conditional allowances equal to the CO2 base budget.~~

~~2. The department will allocate conditional allowances to each conditional budget unit under subdivision 1 of this subsection in an amount determined by multiplying the total amount of CO_2 allowances allocated under subdivision 1 of this subsection by the ratio of the baseline electrical output of such CO_2 budget unit to the total amount of baseline electrical output of all such CO_2 budget units and rounding to the nearest whole allowance as appropriate.~~

~~3. New CO_2 budget units will be allocated conditional allowances once they have established electrical output data to be used in the conditional allowance allocation process.~~

~~C. For the purpose of the allocation process as described in subsections A and B of this section, CO_2 budget units shall report the unit's net-electric output to the department on a yearly basis as follows:~~

~~1. By August 25, 2019, each CO_2 budget unit shall report yearly net-electric output data during 2016, 2017, and 2018.~~

~~2. By the month and day established by subdivision 1 of this subsection, 2020, and each year thereafter, each CO_2 budget unit shall report yearly net-electric output data for the previous year.~~

Article 6. CO_2 Allowance Tracking System

9VAC5-140-6220. CO_2 allowance tracking system accounts.

A. Consistent with 9VAC5-140-6230 A, the department or its agent will establish one compliance account for each CO_2 budget source. Allocations of ~~conditional~~ CO_2 allowances pursuant to Article 5 (9VAC5-140-6190 et seq.) of this part and deductions or transfers of ~~conditional~~ CO_2 allowances pursuant to 9VAC5-140-6180, 9VAC5-140-6260, 9VAC5-140-6280, or Article 7 (9VAC5-140-6300 et seq.) of this part will be recorded in the compliance accounts in accordance with this section.

B. Consistent with 9VAC5-140-6230 B, the department or its agent will establish, upon request, a general account for any person. Transfers of CO_2 allowances pursuant

to Article 7 (9VAC5-140-6300 et seq.) of this part will be recorded in the general account in accordance with this article.

9VAC5-140-6230. Establishment of accounts.

A. Upon receipt of a complete account certificate of representation under 9VAC5-140-6110, the department or its agent will establish ~~a conditional~~ an allowance account and a compliance account for each CO_2 budget source for which an account certificate of representation was submitted ~~and a conditional allowance account for DMME~~.

B. General accounts shall operate as follows.

1. Any person may apply to open a general account for the purpose of holding and transferring CO_2 allowances. An application for a general account may designate one and only one CO_2 authorized account representative and one and only one CO_2 authorized alternate account representative who may act on behalf of the CO_2 authorized account representative. The agreement by which the CO_2 authorized alternate account representative is selected shall include a procedure for authorizing the CO_2 authorized alternate account representative to act in lieu of the CO_2 authorized account representative. A complete application for a general account shall be submitted to the department or its agent and shall include the following elements in a format prescribed by the department or its agent:

a. Name, address, email address, telephone number, and facsimile transmission number of the CO_2 authorized account representative and any CO_2 authorized alternate account representative;

b. At the option of the CO_2 authorized account representative, organization name and type of organization;

c. A list of all persons subject to a binding agreement for the CO_2 authorized account representative or any CO_2 authorized alternate account representative to represent their ownership interest with respect to the CO_2 allowances held in the general account;

d. The following certification statement by the CO_2 authorized account representative and any CO_2 authorized alternate account representative: "I certify that I was selected as the CO_2 authorized account representative or the CO_2 authorized alternate account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CO_2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Budget Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the department or its agent or a court regarding the general account.";

e. The signature of the CO_2 authorized account representative and any CO_2 authorized alternate account representative and the dates signed; and

f. Unless otherwise required by the department or its agent, documents of agreement referred to in the application for a general account shall not be submitted to the department or its agent. Neither the department nor its agent shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

2. Authorization of the CO_2 authorized account representative shall be as follows:

a. Upon receipt by the department or its agent of a complete application for a general account under subdivision 1 of this subsection:

(1) The department or its agent will establish a general account for the person for whom the application is submitted.

(2) The CO_2 authorized account representative and any CO_2 authorized alternate account representative for the general account shall represent and, by his representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CO_2 allowances held in the general account in all matters pertaining to the CO_2 Budget Trading Program, notwithstanding any agreement between the CO_2 authorized account representative or any CO_2 authorized alternate account representative and such person. Any such person shall be bound by any order or decision issued to the CO_2 authorized account representative or any CO_2 authorized alternate account representative by the department or its agent or a court regarding the general account.

(3) Any representation, action, inaction, or submission by any CO_2 authorized alternate account representative shall be deemed to be a representation, action, inaction, or submission by the CO_2 authorized account representative.

b. Each submission concerning the general account shall be submitted, signed, and certified by the CO_2 authorized account representative or any CO_2 authorized alternate account representative for the persons having an ownership interest with respect to CO_2 allowances held in the general account. Each such submission shall include the following certification statement by the CO_2 authorized account representative or any CO_2 authorized alternate account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CO_2 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry

of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

c. The department or its agent will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with subdivision 2 b of this subsection.

3. Changing CO_2 authorized account representative and CO_2 authorized alternate account representative, and changes in persons with ownership interest, shall be accomplished as follows:

a. The CO_2 authorized account representative for a general account may be changed at any time upon receipt by the department or its agent of a superseding complete application for a general account under subdivision 1 of this subsection. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative, or the previous CO_2 authorized alternate account representative, prior to the time and date when the department or its agent receives the superseding application for a general account shall be binding on the new CO_2 authorized account representative and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

b. The CO_2 authorized alternate account representative for a general account may be changed at any time upon receipt by the department or its agent of a superseding complete application for a general account under subdivision 1 of this subsection. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CO_2 authorized account representative, or the previous CO_2 authorized alternate account representative, prior to the time and date when the department or its agent receives the superseding application for a general account shall be binding on the new alternate CO_2 authorized account representative and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

c. In the event a new person having an ownership interest with respect to CO_2 allowances in the general account is not included in the list of such persons in the application for a general account, such new person shall be deemed to be subject to and bound by the application for a general account, the representations, actions, inactions, and submissions of the CO_2 authorized account representative and any CO_2 authorized alternate account representative, and the decisions, orders, actions, and inactions of the department or its agent, as if the new person were included in such list.

d. Within 30 days following any change in the persons having an ownership interest with respect to CO_2 allowances in the general account, including the addition or deletion of persons, the CO_2 authorized account representative or any CO_2 authorized alternate account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CO_2 allowances in the general account to include the change.

4. Objections concerning CO_2 authorized account representative shall be governed as follows:

a. Once a complete application for a general account under subdivision 1 of this subsection has been submitted and received, the department or its agent will rely on the application unless and until a superseding complete application for a general account under subdivision 1 of this subsection is received by the department or its agent.

b. Except as provided in subdivisions 3 a and 3 b of this subsection, no objection or other communication submitted to the department or its agent concerning the authorization, or any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative for a general account shall affect any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative or the finality of any decision or order by the department or its agent under the CO_2 Budget Trading Program.

c. Neither the department nor its agent will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CO_2 authorized account representative or any CO_2 authorized alternate account representative for a general account, including private legal disputes concerning the proceeds of CO_2 allowance transfers.

5. Delegation by CO_2 authorized account representative and CO_2 authorized alternate account representative shall be accomplished as follows:

a. A CO_2 authorized account representative may delegate, to one or more natural persons, his authority to make an electronic submission to the department or its agent provided for under this article and Article 7 (9VAC5-140-6300 et seq.) of this part.

b. A CO_2 authorized alternate account representative may delegate, to one or more natural persons, his authority to make an electronic submission to the department or its agent provided for under this article and Article 7 (9VAC5-140-6300 et seq.) of this part.

c. To delegate authority to make an electronic submission to the department or its agent in accordance with subdivisions 5 a and 5 b of this subsection, the CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, shall submit to the department or its agent a notice of delegation, in a format prescribed by the department that includes the following elements:

(1) The name, address, email address, telephone number, and facsimile transmission number of such CO_2 authorized account representative or CO_2 authorized alternate account representative;

(2) The name, address, email address, telephone number, and facsimile transmission number of each such natural person, referred to as "electronic submission agent";

(3) For each such natural person, a list of the type of electronic submissions under subdivision 5 c (1) or 5 c (2) of this subsection for which authority is delegated to him; and

(4) The following certification statement by such CO_2 authorized account representative or CO_2 authorized alternate account representative: "I agree that any electronic submission to the department or its agent that is by a natural person identified in this notice of delegation and of a type listed for such electronic submission agent in this notice of delegation and that is made when I am a CO_2 authorized account representative or CO_2 authorized alternate account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 9VAC5-140-6230 B 5 d shall be deemed to be an electronic submission by me. Until this notice of delegation is superseded by another notice of delegation under 9VAC5-140-6230 B 5 d, I agree to maintain an email account and to notify the department or its agent immediately of any change in my email address unless all delegation authority by me under 9VAC5-140-6230 B 5 is terminated."

d. A notice of delegation submitted under subdivision 5 c of this subsection shall be effective, with regard to the CO_2 authorized account representative or CO_2 authorized alternate account representative identified in such notice, upon receipt of such notice by the department or its agent and until receipt by the department or its agent of a superseding notice of delegation by such CO_2 authorized account representative or CO_2 authorized alternate account representative as appropriate. The superseding notice of delegation may replace any previously identified electronic submission agent, add a new electronic submission agent, or eliminate entirely any delegation of authority.

e. Any electronic submission covered by the certification in subdivision 5 c (4) of this subsection and made in accordance with a notice of delegation effective under subdivision 5 d of this subsection shall be deemed to be an

electronic submission by the CO_2 authorized account representative or CO_2 authorized alternate account representative submitting such notice of delegation.

C. The department or its agent will assign a unique identifying number to each account established under subsection A or B of this section.

9VAC5-140-6240. CO_2 allowance tracking system responsibilities of CO_2 authorized account representative.

Following the establishment of a COATS account, all submissions to the department or its agent pertaining to the account, including submissions concerning the deduction or transfer of CO_2 allowances in the account, shall be made only by the CO_2 authorized account representative for the account.

9VAC5-140-6250. Recordation of ~~conditional~~ CO_2 allowance allocations.

A. By January 1 of each calendar year, the department or its agent will record in the following accounts:

1. In each CO_2 budget source's ~~and DMME's conditional~~ allowance account, the ~~conditional~~ CO_2 allowances allocated to those sources ~~and DMME~~ by the department prior to being ~~consigned to auction~~ auctioned; and

2. In each CO_2 budget source's compliance account, the ~~CO_2~~ allowances purchased at auction by CO_2 budget units at the source under 9VAC5-140-6210 A.

B. Each year the department or its agent will record ~~conditional~~ CO_2 allowances, as allocated to the unit under Article 5 (9VAC5-140-6190 et seq.) of this part, in the compliance account for the year after the last year for which ~~conditional~~ CO_2 allowances were previously allocated to the compliance account. Each year, the department or its agent will also record ~~conditional~~ CO_2 allowances, as allocated under Article 5 (9VAC5-140-6190 et seq.) of this part, in an allocation set-aside for the year after the last year for which ~~conditional~~ CO_2 allowances were previously allocated to an allocation set-aside.

C. Serial numbers for allocated ~~conditional~~ CO_2 allowances shall be managed as follows. When allocating ~~conditional~~ CO_2 allowances to and recording them in an account, the department or its agent will assign each ~~conditional~~ CO_2 allowance a unique identification number that will include digits identifying the year for which the ~~conditional~~ CO_2 allowance is allocated.

9VAC5-140-6260. Compliance.

A. CO_2 allowances that meet the following criteria are available to be deducted for a CO_2 budget source to comply with the CO_2 requirements of 9VAC5-140-6050 C for ~~the initial control period,~~ a control period ~~,~~ or an interim control period.

1. The CO_2 allowances are of allocation years that fall within ~~an initial control period,~~ a prior control period, the same control period, or the same interim control period for which the allowances will be deducted.

2. The CO_2 allowances are held in the CO_2 budget source's compliance account as of the CO_2 allowance transfer deadline for that ~~initial control period,~~ control period ~~,~~ or interim control period or are transferred into the compliance account by a CO_2 allowance transfer correctly submitted for recordation under 9VAC5-140-6300 by the CO_2 allowance transfer deadline for that ~~initial control period,~~ control period ~~,~~ or interim control period.

3. For CO_2 offset allowances generated by other participating states, the number of CO_2 offset allowances that are available to be deducted in order for a CO_2 budget source to comply with the CO_2 requirements of 9VAC5-140-6050 C for a control period or an ~~initial~~ interim control period shall not exceed 3.3% of the CO_2 budget source's CO_2 emissions for that control period, or may not exceed 3.3% of 0.50 times the CO_2 budget source's CO_2 emissions for an interim control period, as determined in accordance with this article and Article 8 (9VAC5-140-6330 et seq.) of this part.

4. The CO_2 allowances are not necessary for deductions for excess emissions for a prior ~~initial control period or a~~ control period under subsection D of this section.

B. Following the recordation, in accordance with 9VAC5-140-6310, of CO_2 allowance transfers submitted for recordation in the CO_2 budget source's compliance account by the CO_2 allowance transfer deadline for ~~the initial control period,~~ a control period ~~,~~ or an interim control period, the department or its agent will deduct CO_2 allowances available under subsection A of this section to cover the source's CO_2 emissions, as determined in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part, for the ~~initial control period,~~ control period ~~,~~ or interim control period, as follows:

1. Until the amount of CO_2 allowances deducted equals the number of tons of total CO_2 emissions, or 0.50 times the number of tons of total CO_2 emissions for an interim control period, determined in accordance with Article 8 (9VAC5-140-6330 et seq.) of this part, from all CO_2 budget units at the CO_2 budget source for the ~~initial control period,~~ control period ~~,~~ or interim control period; or

2. If there are insufficient CO_2 allowances to complete the deductions in subdivision 1 of this subsection, until no more CO_2 allowances available under subsection A of this section remain in the compliance account.

C. Identification of available CO_2 allowances by serial number and default compliance deductions shall be managed as follows:

1. The CO_2 authorized account representative for a source's compliance account may request that specific CO_2 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for ~~the initial control period,~~ a control period ~~,~~ or interim control period in accordance with subsection B or D of this section. Such identification shall be made in the compliance certification report submitted in accordance with 9VAC5-140-6170.

2. The department or its agent will deduct CO_2 allowances for ~~the initial control period,~~ an interim control period ~~,~~ or a control period from the CO_2 budget source's compliance account, in the absence of an identification or in the case of a partial identification of available CO_2 allowances by serial number under subdivision 1 of this subsection, as follows: Any CO_2 allowances that are available for deduction under subdivision 1 of this subsection. CO_2 allowances shall be deducted in chronological order (i.e., CO_2 allowances from earlier allocation years shall be deducted before CO_2 allowances from later allocation years). In the event that some, but not all, CO_2 allowances from a particular allocation year are to be deducted, CO_2 allowances shall be deducted by serial number, with lower serial number allowances deducted before higher serial number allowances.

D. Deductions for excess emissions shall be managed as follows.

1. After making the deductions for compliance under subsection B of this section, the department or its agent will deduct from the CO_2 budget source's compliance account a number of CO_2 allowances equal to three times the number of the source's excess emissions. In the event that a source has insufficient CO_2 allowances to cover three times the number of the source's excess emissions, the source shall be required to immediately transfer sufficient allowances into its compliance account.

2. Any CO_2 allowance deduction required under subdivision 1 of this subsection shall not affect the liability of the owners and operators of the CO_2 budget source or the CO_2 budget units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under applicable state law. The following guidelines will be followed in assessing fines, penalties, or other obligations:

a. For purposes of determining the number of days of violation, if a CO_2 budget source has excess emissions for a control period, each day in the control period constitutes a day in violation unless the owners and operators of the unit demonstrate that a lesser number of days should be considered.

b. Each ton of excess emissions is a separate violation.

c. For purposes of determining the number of days of violation, if a CO_2 budget source has excess interim emissions for an interim control period, each day in the interim control period constitutes a day in violation unless the owners and operators of the unit demonstrate that a lesser number of days should be considered.

d. Each ton of excess interim emissions is a separate violation.

3. The propriety of the department's determination that a CO_2 budget source had excess emissions and the concomitant deduction of CO_2 allowances from that CO_2 budget source's account may be later challenged in the context of the initial administrative enforcement, or any civil or criminal judicial action arising from or encompassing that excess emissions violation. The commencement or pendency of any administrative enforcement, or civil or criminal judicial action arising from or encompassing that excess emissions violation will not act to prevent the department or its agent from initially deducting the CO_2 allowances resulting from the department's original determination that the relevant CO_2 budget source has had excess emissions. Should the department's determination of the existence or extent of the CO_2 budget source's excess emissions be revised either by a settlement or final conclusion of any administrative or judicial action, the department will act as follows:

a. In any instance where the department's determination of the extent of excess emissions was too low, the department will take further action under subdivisions 1 and 2 of this subsection to address the expanded violation.

b. In any instance where the department's determination of the extent of excess emissions was too high, the department will distribute to the relevant CO_2 budget source a number of CO_2 allowances equaling the number of CO_2 allowances deducted which are attributable to the difference between the original and final quantity of excess emissions. Should such CO_2 budget source's compliance account no longer exist, the CO_2 allowances will be provided to a general account selected by the owner or operator of the CO_2 budget source from which they were originally deducted.

E. The department or its agent will record in the appropriate compliance account all deductions from such an account pursuant to subsections B and D of this section.

F. Action by the department on submissions shall be as follows:

1. The department may review and conduct independent audits concerning any submission under the CO_2 Budget Trading Program and make appropriate adjustments of the information in the submissions.

2. The department may deduct CO_2 allowances from or transfer CO_2 allowances to a source's compliance account based on information in the submissions, as adjusted under subdivision 1 of this subsection.

9VAC5-140-6270. Banking.

Each CO_2 allowance that is held in a compliance account or a general account will remain in such account unless and until the CO_2 allowance is deducted or transferred under 9VAC5-140-6180, 9VAC5-140-6260, 9VAC5-140-6280, or Article 7 (9VAC5-140-6300 et seq.) of this part.

9VAC5-140-6280. Account error.

The department or its agent may, at its sole discretion and on its own motion, correct any error in any COATS account. Within 10 business days of making such correction, the department or its agent will notify the CO_2 authorized account representative for the account.

9VAC5-140-6290. Closing of general accounts.

A. A CO_2 authorized account representative of a general account may instruct the department or its agent to close the account by submitting a statement requesting deletion of the account from the COATS and by correctly submitting for recordation under 9VAC5-140-6300 a CO_2 allowance transfer of all CO_2 allowances in the account to one or more other COATS accounts.

B. If a general account shows no activity for a period of one year or more and does not contain any CO_2 allowances, the department or its agent may notify the CO_2 authorized account representative for the account that the account will be closed in the COATS 30 business days after the notice is sent. The account will be closed after the 30-day period unless before the end of the 30-day period the department or its agent receives a correctly submitted transfer of CO_2 allowances into the account under 9VAC5-140-6300 or a statement submitted by the CO_2 authorized account representative demonstrating to the satisfaction of the department or its agent good cause as to why the account should not be closed. The department or its agent will have sole discretion to determine if the owner or operator of the unit demonstrated that the account should not be closed.

Article 7. CO_2 Allowance Transfers

9VAC5-140-6300. Submission of CO_2 Allowance Transfers.

The CO_2 authorized account representatives seeking recordation of a CO_2 allowance transfer shall submit the transfer to the department or its agent. To be

considered correctly submitted, the CO_2 allowance transfer shall include the following elements in a format specified by the department or its agent:

1. The numbers identifying both the transferor and transferee accounts;

2. A specification by serial number of each CO_2 allowance to be transferred;

3. The printed name and signature of the CO_2 authorized account representative of the transferor account and the date signed;

4. The date of the completion of the last sale or purchase transaction for the allowance, if any; and

5. The purchase or sale price of the allowance that is the subject of a sale or purchase transaction under subdivision 4 of this section.

9VAC5-140-6310. Recordation.

A. Within five business days of receiving a CO_2 allowance transfer, except as provided in subsection B of this section, the department or its agent will record a CO_2 allowance transfer by moving each CO_2 allowance from the transferor account to the transferee account as specified by the request, provided that:

1. The transfer is correctly submitted under 9VAC5-140-6300; and

2. The transferor account includes each CO_2 allowance identified by serial number in the transfer.

B. A CO_2 allowance transfer into or out of a compliance account that is submitted for recordation following the CO_2 allowance transfer deadline and that includes any CO_2 allowances that are of allocation years that fall within a control period prior to or the same as the control period to which the CO_2 allowance transfer deadline applies will not be recorded until after completion of the process pursuant to 9VAC5-140-6260 B.

C. Where a CO_2 allowance transfer submitted for recordation fails to meet the requirements of subsection A of this section, the department or its agent will not record such transfer.

9VAC5-140-6320. Notification.

A. Within five business days of recordation of a CO_2 allowance transfer under 9VAC5-140-6310 , the department or its agent will notify each party to the transfer. Notice will be given to the CO_2 authorized account representatives of both the transferor and transferee accounts.

B. Within 10 business days of receipt of a CO_2 allowance transfer that fails to meet the requirements of 9VAC5-140-6310 A, the department or its agent will notify the CO_2 authorized account representatives of both accounts subject to the transfer of (i) a decision not to record the transfer and (ii) the reasons for such nonrecordation.

C. Nothing in this section shall preclude the submission of a CO_2 allowance transfer for recordation following notification of nonrecordation.

9VAC5-140-6325. Life-of-the-unit contractual arrangements.

A. A power purchaser entered into a life-of-the-unit contractual arrangement as described in subdivision b of the definition of "life-of-the-unit contractual arrangement" with a CO_2 budget source or unit shall be responsible for acquiring and transferring all allowances to the CO_2 budget source or unit that are necessary for demonstrating compliance with the CO_2 budget trading program.

B. The CO_2 budget source or unit shall provide a copy of the energy conversion or energy tolling agreement to the department within six months of the effective date of this part. If such agreement is subject to third-party disclosure restrictions, the CO_2 budget source or unit shall provide purchaser with 10 days prior written notice of its intention to disclose the agreement to the department and request confidential treatment from the public disclosure of such agreement. The department will grant a request for confidential treatment pursuant to applicable statutory and regulatory requirements addressing confidential information.

C. The CO_2 budget source or unit shall be responsible for compliance with and otherwise be subject to all other requirements of this part and the CO_2 budget trading program.

Article 8. Monitoring, Reporting, and Recordkeeping

9VAC5-140-6330. General requirements.

A. The owners and operators, and to the extent applicable, the CO_2 authorized account representative of a CO_2 budget unit shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this section and all applicable sections of 40 CFR Part 75. Where referenced in this article, the monitoring requirements of 40 CFR Part 75 shall be adhered to in a manner consistent with the purpose of monitoring and reporting CO_2 mass emissions pursuant to this part. For purposes of complying with such requirements, the definitions in 9VAC5-140-6020 and in 40 CFR 72.2 shall apply, and the terms "affected unit," "designated representative," and "CEMS" in 40 CFR Part 75 shall be replaced by the terms "CO_2 budget unit," "CO_2 authorized account representative," and "CEMS," respectively, as defined in 9VAC5-140-6020. For units not subject to an ~~acid rain~~ Acid Rain emissions limitation, the term

"administrator" in 40 CFR Part 75 shall be replaced with "the department or its agent." Owners or operators of a CO_2 budget unit who monitor a non-CO_2 budget unit pursuant to the common, multiple, or bypass stack procedures in 40 CFR 75.72(b)(2)(ii), or 40 CFR 75.16 (b)(2)(ii)(B) pursuant to 40 CFR 75.13, for purposes of complying with this part, shall monitor and report CO_2 mass emissions from such non-CO_2 budget units according to the procedures for CO_2 budget units established in this article.

B. The owner or operator of each CO_2 budget unit shall meet the following general requirements for installation, certification, and data accounting.

1. Install all monitoring systems necessary to monitor CO_2 mass emissions in accordance with 40 CFR Part 75, except for equation G-1. Equation G-1 in Appendix G shall not be used to determine CO_2 emissions under this part. This may require systems to monitor CO_2 concentration, stack gas flow rate, O_2 concentration, heat input, and fuel flow rate.

2. Successfully complete all certification tests required under 9VAC5-140-6340 and meet all other requirements of this section and 40 CFR Part 75 applicable to the monitoring systems under subdivision 1 of this subsection.

3. Record, report, and quality-assure the data from the monitoring systems under subdivision 1 of this subsection.

C. The owner or operator shall meet the monitoring system certification and other requirements of subsection B of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under subdivision B 1 of this section on and after the following dates:

1. The owner or operator of a CO_2 budget unit, except for a CO_2 budget unit under subdivision 2 of this subsection, shall comply with the requirements of this section by January 1, ~~2020~~ 2021.

2. The owner or operator of a CO_2 budget unit that commences commercial operation July 1, ~~2020~~ 2021, shall comply with the requirements of this section by (i) January 1, ~~2021~~ 2022, or (ii) the earlier of 90 unit operating days after the date on which the unit commences commercial operation or 180 calendar days after the date on which the unit commences commercial operation.

3. For the owner or operator of a CO_2 budget unit for which construction of a new stack or flue installation is completed after the applicable deadline under subdivision 1 or 2 of this subsection by the earlier of (i) 90 unit operating days after the date on which emissions first exit to the atmosphere through the new stack or flue or (ii) 180 calendar days after the date on which emissions first exit to the atmosphere through the new stack or flue.

D. Data shall be reported as follows:

1. Except as provided in subdivision 2 of this subsection, the owner or operator of a CO_2 budget unit that does not meet the applicable compliance date set forth in subsection C of this section for any monitoring system under subdivision B 1 of this section shall, for each such monitoring system, determine, record, and report maximum potential, or as appropriate minimum potential, values for CO_2 concentration, CO_2 emissions rate, stack gas moisture content, fuel flow rate, heat input, and any other parameter required to determine CO_2 mass emissions in accordance with 40 CFR 75.31(b)(2) or (c)(3) or Section 2.4 of Appendix D of 40 CFR Part 75 as applicable.

2. The owner or operator of a CO_2 budget unit that does not meet the applicable compliance date set forth in subdivision C 3 of this section for any monitoring system under subdivision B 1 of this section shall, for each such monitoring system, determine, record, and report substitute data using the applicable missing data procedures in Subpart D, or Appendix D of 40 CFR Part 75, in lieu of the maximum potential, or as appropriate minimum potential, values for a parameter if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation under subdivision C 3 of this section.

a. CO_2 budget units subject to an ~~acid rain~~ Acid Rain emissions limitation or CSAPR NO_x Ozone Season Trading Program that qualify for the optional SO_2, NO_x, and CO_2 (for ~~acid rain~~ Acid Rain) or NO_x (for CSAPR NO_x Ozone Season Trading Program) emissions calculations for low mass emissions (LME) units under 40 CFR 75.19 and report emissions for such programs using the calculations under 40 CFR 75.19, shall also use the CO_2 emissions calculations for LME units under 40 CFR 75.19 for purposes of compliance with these regulations.

b. CO_2 budget units subject to an ~~acid rain~~ Acid Rain emissions limitation that do not qualify for the optional SO_2, NO_x, and CO_2 (for ~~acid rain~~ Acid Rain) or NO_x (for CSAPR NO_x Ozone Season Trading Program) emissions calculations for LME units under 40 CFR 75.19 shall not use the CO_2 emissions calculations for LME units under 40 CFR 75.19 for purposes of compliance with these regulations.

c. CO_2 budget units not subject to an ~~acid rain~~ Acid Rain emissions limitation shall qualify for the optional CO_2 emissions calculation for LME units under 40 CFR 75.19, provided that they emit less than 100 tons of NO_x annually and no more than 25 tons of SO_2 annually.

3. The owner or operator of a CO_2 budget unit shall report net-electric output data to the department as required by Article 5 (9VAC5-140-6190 et seq.) of this part.

E. Prohibitions shall be as follows.

1. No owner or operator of a CO_2 budget unit shall use any alternative monitoring system, alternative reference method, or any other alternative for the required CEMS without having obtained prior written approval in accordance with 9VAC5-140-6380.

2. No owner or operator of a CO_2 budget unit shall operate the unit so as to discharge, or allow to be discharged, CO_2 emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this article and 40 CFR Part 75.

3. No owner or operator of a CO_2 budget unit shall disrupt the CEMS, any portion thereof, or any other approved emissions monitoring method, and thereby avoid monitoring and recording CO_2 mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this article and 40 CFR Part 75.

4. No owner or operator of a CO_2 budget unit shall retire or permanently discontinue use of the CEMS, any component thereof, or any other approved emissions monitoring system under this article, except under any one of the following circumstances:

a. The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this article and 40 CFR Part 75, by the department for use at that unit that provides emissions data for the same pollutant or parameter as the retired or discontinued monitoring system; or

b. The CO_2 authorized account representative submits notification of the date of certification testing of a replacement monitoring system in accordance with 9VAC5-140-6340 D 3 a.

9VAC5-140-6340. Initial certification and recertification procedures.

A. The owner or operator of a CO_2 budget unit shall be exempt from the initial certification requirements of this section for a monitoring system under 9VAC5-140-6330 B 1 if the following conditions are met:

1. The monitoring system has been previously certified in accordance with 40 CFR Part 75; and

2. The applicable quality-assurance and quality-control requirements of 40 CFR 75.21 and Appendix B and Appendix D of 40 CFR Part 75 are fully met for the certified monitoring system described in subdivision 1 of this subsection.

B. The recertification provisions of this section shall apply to a monitoring system under 9VAC5-140-6330 B 1 exempt from initial certification requirements under subsection A of this section.

C. Notwithstanding subsection A of this section, if the administrator has previously approved a petition under 40 CFR 75.72(b)(2)(ii), or 40 CFR 75.16(b)(2)(ii)(B) as pursuant to 40 CFR 75.13 for apportioning the CO_2 emissions rate measured in a common stack or a petition under 40 CFR 75.66 for an alternative requirement in 40 CFR Part 75, the CO_2 authorized account representative shall submit the petition to the department under 9VAC5-140-6380 A to determine whether the approval applies under this program.

D. Except as provided in subsection A of this section, the owner or operator of a CO_2 budget unit shall comply with the following initial certification and recertification procedures for a CEMS and an excepted monitoring system under Appendix D of 40 CFR Part 75 and under 9VAC5-140-6330 B 1. The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology in 40 CFR 75.19 or that qualifies to use an alternative monitoring system under Subpart E of 40 CFR Part 75 shall comply with the procedures in subsection E or F of this section, respectively.

1. For initial certification, the owner or operator shall ensure that each CEMS required under 9VAC5-140-6330 B 1, which includes the automated DAHS, successfully completes all of the initial certification testing required under 40 CFR 75.20 by the applicable deadlines specified in 9VAC5-140-6330 C. In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this article in a location where no such monitoring system was previously installed, initial certification in accordance with 40 CFR 75.20 is required.

2. For recertification, the following requirements shall apply.

a. Whenever the owner or operator makes a replacement, modification, or change in a certified CEMS under 9VAC5-140-6330 B 1 that the administrator or the department determines significantly affects the ability of the system to accurately measure or record CO_2 mass emissions or to meet the quality-assurance and quality-control requirements of 40 CFR 75.21 or Appendix B to 40 CFR Part 75, the owner or operator shall recertify the monitoring system according to 40 CFR 75.20(b).

b. For systems using stack measurements such as stack flow, stack moisture content, CO_2 or O_2 monitors, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that the administrator or the department determines to significantly change the flow or concentration profile, the owner or operator shall recertify the CEMS according to 40 CFR 75.20(b). Examples of changes that require recertification include

replacement of the analyzer, change in location or orientation of the sampling probe or site, or change of flow rate monitor polynomial coefficients.

3. The approval process for initial certifications and recertification shall be as follows: subdivisions 3 a through 3 d of this subsection apply to both initial certification and recertification of a monitoring system under 9VAC5-140-6330 B 1. For recertifications, replace the words "certification" and "initial certification" with the word "recertification," replace the word "certified" with "recertified," and proceed in the manner prescribed in 40 CFR 75.20(b)(5) and (g)(7) in lieu of subdivision 3 e of this subsection.

a. The CO_2 authorized account representative shall submit to the department or its agent, the appropriate EPA Regional Office and the administrator a written notice of the dates of certification in accordance with 9VAC5-140-6360.

b. The CO_2 authorized account representative shall submit to the department or its agent a certification application for each monitoring system. A complete certification application shall include the information specified in 40 CFR 75.63.

c. The provisional certification date for a monitor shall be determined in accordance with 40 CFR 75.20(a)(3). A provisionally certified monitor may be used under the CO_2 Budget Trading Program for a period not to exceed 120 days after receipt by the department of the complete certification application for the monitoring system or component thereof under subdivision 3 b of this subsection. Data measured and recorded by the provisionally certified monitoring system or component thereof, in accordance with the requirements of 40 CFR Part 75, will be considered valid quality assured data, retroactive to the date and time of provisional certification, provided that the department does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of receipt of the complete certification application by the department.

d. The department will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under subdivision 3 b of this subsection. In the event the department does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of 40 CFR Part 75 and is included in the certification application will be deemed certified for use under the CO_2 Budget Trading Program.

(1) If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of 40 CFR Part 75, then the department will issue a written notice of approval of the certification application within 120 days of receipt.

(2) If the certification application is incomplete, then the department will issue a written notice of incompleteness that sets a reasonable date by which the CO_2 authorized account representative shall submit the additional information required to complete the certification application. If the CO_2 authorized account representative does not comply with the notice of incompleteness by the specified date, then the department may issue a notice of disapproval under subdivision 3 d (3) of this subsection. The 120-day review period shall not begin before receipt of a complete certification application.

(3) If the certification application shows that any monitoring system or component thereof does not meet the performance requirements of 40 CFR Part 75, or if the certification application is incomplete and the requirement for disapproval under subdivision 3 d (2) of this subsection is met, then the department will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the department and the data measured and recorded by each uncertified monitoring system or component thereof shall not be considered valid quality assured data beginning with the date and hour of provisional certification. The owner or operator shall follow the procedures for loss of certification in subdivision 3 e of this subsection for each monitoring system or component thereof, which is disapproved for initial certification.

(4) The department may issue a notice of disapproval of the certification status of a monitor in accordance with 9VAC5-140-6350 B.

e. If the department issues a notice of disapproval of a certification application under subdivision 3 d (3) of this subsection or a notice of disapproval of certification status under subdivision 3 d (3) of this subsection, then:

(1) The owner or operator shall substitute the following values for each disapproved monitoring system, for each hour of unit operation during the period of invalid data beginning with the date and hour of provisional certification and continuing until the time, date, and hour specified under 40 CFR 75.20(a)(5)(i) or 40 CFR 75.20(g)(7): (i) for units using or intending to monitor for CO_2 mass emissions using heat input or for units sing the low mass emissions excepted methodology under 40 CFR 75.19, the maximum potential hourly heat input of the unit; or (ii) for units intending to monitor for CO_2 mass emissions using a CO_2 pollutant concentration monitor and a flow monitor, the maximum potential concentration of CO_2 and the maximum potential flow rate of the unit under Section 2.1 of Appendix A of 40 CFR Part 75;

(2) The CO_2 authorized account representative shall submit a notification of certification retest dates and a new certification application in accordance with subdivisions 3 a and 3 b of this subsection; and

(3) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the department's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

E. The owner or operator of a unit qualified to use the low mass emissions excepted methodology under 9VAC5-140-6330 D 3 shall meet the applicable certification and recertification requirements of 40 CFR 75.19(a)(2), 40 CFR 75.20(h), and this section. If the owner or operator of such a unit elects to certify a fuel flow meter system for heat input determinations, the owner or operator shall also meet the certification and recertification requirements in 40 CFR 75.20(g).

F. The CO_2 authorized account of each unit for which the owner or operator intends to use an alternative monitoring system approved by the administrator and, if applicable, the department under Subpart E of 40 CFR Part 75 shall comply with the applicable notification and application procedures of 40 CFR 75.20(f).

9VAC5-140-6350. Out-of-control periods.

A. Whenever any monitoring system fails to meet the quality assurance/quality control (QA/QC) requirements or data validation requirements of 40 CFR Part 75, data shall be substituted using the applicable procedures in Subpart D or Appendix D of 40 CFR Part 75.

B. Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under 9VAC5-140-6340 or the applicable provisions of 40 CFR Part 75, both at the time of the initial certification or recertification application submission and at the time of the audit, the department or administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this subsection, an audit shall be either a field audit or an audit of any information submitted to the department or the administrator. By issuing the notice of disapproval, the department or administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the initial certification or recertification procedures in 9VAC5-140-6340 for each disapproved monitoring system.

9VAC5-140-6360. Notifications.

The CO_2 authorized account representative for a CO_2 budget unit shall submit written notice to the department and the administrator in accordance with 40 CFR 75.61.

9VAC5-140-6370. Recordkeeping and reporting.

A. The CO_2 authorized account representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements under 40 CFR 75.73, and the requirements of 9VAC5-140-6080 E.

B. The owner or operator of a CO_2 budget unit shall submit a monitoring plan in the manner prescribed in 40 CFR 75.62.

C. The CO_2 authorized account representative shall submit an application to the department within 45 days after completing all CO_2 monitoring system initial certification or recertification tests required under 9VAC5-140-6340 , including the information required under 40 CFR 75.63 and 40 CFR 75.53(e) and (f).

D. The CO_2 authorized account representative shall submit quarterly reports, as follows:

1. The CO_2 authorized account representative shall report the CO_2 mass emissions data for the CO_2 budget unit, in an electronic format prescribed by the department unless otherwise prescribed by the department for each calendar quarter.

2. The CO_2 authorized account representative shall submit each quarterly report to the department or its agent within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in Subpart H of 40 CFR Part 75 and 40 CFR 75.64. Quarterly reports shall be submitted for each CO_2 budget unit, or group of units using a common stack, and shall include all of the data and information required in Subpart G of 40 CFR Part 75, except for opacity, heat input, NO_x, and SO_2 provisions.

3. The CO_2 authorized account representative shall submit to the department or its agent a compliance certification in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

a. The monitoring data submitted were recorded in accordance with the applicable requirements of this article and 40 CFR Part 75, including the quality assurance procedures and specifications;

b. For a unit with add-on CO_2 emissions controls and for all hours where data are substituted in accordance with 40 CFR 75.34(a)(1), the add-on emissions controls were operating within the range of parameters listed in the QA/QC program under Appendix B of 40 CFR Part 75 and the substitute values do not systematically underestimate CO_2 emissions; and

c. The CO_2 concentration values substituted for missing data under Subpart D of 40 CFR Part 75 do not systematically underestimate CO_2 emissions.

9VAC5-140-6380. Petitions.

A. Except as provided in subsection C of this section, the CO_2 authorized account representative of a CO_2 budget unit that is subject to an ~~acid rain~~ Acid Rain emissions limitation may submit a petition to the administrator under 40 CFR 75.66 and to the department requesting approval to apply an alternative to any requirement of 40 CFR Part 75. Application of an alternative to any requirement of 40 CFR Part 75 is in accordance with this article only to the extent that the petition is approved in writing by the administrator, and subsequently approved in writing by the department.

B. Petitions for a CO_2 budget unit that is not subject to an ~~acid rain~~ Acid Rain emissions limitation shall meet the following requirements.

1. The CO_2 authorized account representative of a CO_2 budget unit that is not subject to an ~~acid rain~~ Acid Rain emissions limitation may submit a petition to the administrator under 40 CFR 75.66 and to the department requesting approval to apply an alternative to any requirement of 40 CFR Part 75. Application of an alternative to any requirement of 40 CFR Part 75 is in accordance with this article only to the extent that the petition is approved in writing by the administrator and subsequently approved in writing by the department.

2. In the event that the administrator declines to review a petition under subdivision 1 of this subsection, the CO_2 authorized account representative of a CO_2 budget unit that is not subject to an ~~acid rain~~ Acid Rain emissions limitation may submit a petition to the department requesting approval to apply an alternative to any requirement of this article. That petition shall contain all of the relevant information specified in 40 CFR 75.66. Application of an alternative to any requirement of this article is in accordance with this article only to the extent that the petition is approved in writing by the department.

C. The CO_2 authorized account representative of a CO_2 budget unit that is subject to an ~~acid rain~~ Acid Rain emissions limitation may submit a petition to the administrator under 40 CFR 75.66 and to the department requesting approval to apply an alternative to a requirement concerning any additional CEMS required under the common stack provisions of 40 CFR 75.72 or a CO_2 concentration CEMS used under 40 CFR 75.71(a)(2). Application of an alternative to any such requirement is in

accordance with this article only to the extent the petition is approved in writing by the administrator and subsequently approved in writing by the department.

9VAC5-140-6390. (Reserved.)

9VAC5-140-6400. (Reserved.)

Article 9. Auction of CO_2 CCR and ECR Allowances

9VAC5-140-6410. Purpose.

The following requirements shall apply to each allowance auction. The department or its agent may specify additional information in the auction notice for each auction. Such additional information may include the time and location of the auction, auction rules, registration deadlines, and any additional information deemed necessary or useful.

9VAC5-140-6420. General requirements.

A. The department's agent will include the following information in the auction notice for each auction:

1. The number of ~~conditional~~ CO_2 allowances offered for sale at the auction, not including any ~~conditional~~ CO_2 CCR allowances;

2. The number of ~~conditional~~ CO_2 CCR allowances that will be offered for sale at the auction if the condition of subdivision B 1 of this section is met;

3. The minimum reserve price for the auction;

4. The CCR trigger price for the auction;

5. The maximum number of ~~conditional~~ CO_2 allowances that may be withheld from sale at the auction if the condition of subdivision D 1 of this section is met; and

6. The ECR trigger price for the auction.

B. The department's agent will follow these rules for the sale of ~~conditional~~ CO_2 CCR allowances.

1. ~~Conditional~~ CO_2 CCR allowances shall only be sold at an auction in which total demand for allowances, above the CCR trigger price, exceeds the number of ~~conditional~~ CO_2 allowances available for purchase at the auction, not including any ~~conditional~~ CO_2 CCR allowances.

2. If the condition of subdivision 1 of this subsection is met at an auction, then the number of ~~conditional~~ CO_2 CCR allowances offered for sale by the department or its agent at the auction shall be equal to the number of ~~conditional~~ CO_2 CCR allowances in the Virginia ~~Consignment~~ Auction Account at the time of the auction.

3. After all of the ~~conditional~~ CO_2 CCR allowances in the Virginia ~~Consignment~~ Auction Account have been sold in a given calendar year, no additional ~~conditional~~ CO_2 CCR allowances will be sold at any auction for the remainder of that calendar year, even if the condition of subdivision 1 of this subsection is met at an auction.

4. At an auction in which ~~conditional~~ CO_2 CCR allowances are sold, the reserve price for the auction shall be the CCR trigger price.

5. If the condition of subdivision 1 of this subsection is not satisfied, no ~~conditional~~ CO_2 CCR allowances shall be offered for sale at the auction, and the reserve price for the auction shall be equal to the minimum reserve price.

C. The department's agent shall implement the reserve price as follows: (i) no allowances shall be sold at any auction for a price below the reserve price for that auction and (ii) if the total demand for allowances at an auction is less than or equal to the total number of allowances made available for sale in that auction, then the auction clearing price for the auction shall be the reserve price.

D. The department's agent will meet the following rules for the withholding of CO_2 ECR allowances from an auction.

1. CO_2 ECR allowances shall only be withheld from an auction if the demand for allowances would result in an auction clearing price that is less than the ECR trigger price prior to the withholding from the auction of any ECR allowances.

2. If the condition in subdivision 1 of this subsection is met at an auction, then the maximum number of CO_2 ECR allowances that may be withheld from that auction will be equal to the quantity shown in Table 140-5B of 9VAC5-140-6210 E minus the total quantity of CO_2 ECR allowances that have been withheld from any prior auction in that calendar year. Any CO_2 ECR allowances withheld from an auction will be transferred into the Virginia ECR Account.

9VAC5-140-6430. ~~Consignment auction.~~ (Repealed.)

~~In accordance with Article 5 (9VAC5-140-6190 et seq.) of this part, one quarter of the annual conditional allowance allocation shall be consigned by the CO_2 budget source to whom they are allocated or the holder of a public contract with DMME to each auction in accordance with procedures specified by the department. At the~~

~~completion of the consignment auction, a conditional allowance sold at auction shall become a CO_2 allowance.~~

9VAC5-140-6435. ~~Other auction~~. (Repealed.)

~~Notwithstanding the requirements of 9VAC5-140-6430 , the department may participate in a direct auction of allowances without consignment in accordance with requirements established by the Virginia General Assembly. A "direct auction" means a CO_2 auction conducted by a CO_2 Budget Trading Program in which Virginia is a participating state.~~

Article 10. Program Monitoring and Review

9VAC5-140-6440. Program monitoring and review.

In conjunction with the CO_2 Budget Trading Program program monitoring and review process, the department will evaluate impacts of the program specific to Virginia, including economic, energy, and environmental impacts and impacts on vulnerable and environmental justice and underserved communities. The department will, in evaluating the impacts on environmental justice communities, including low income, minority, and tribal communities, develop and implement a plan to ensure increased participation of environmental justice communities in the review.

Form: TH-09
April 2020

townhall.virginia.gov

Exempt Action: Final Regulation
Agency Background Document

Agency name	Department of Environmental Quality for State Air Pollution Control Board
Virginia Administrative Code (VAC) Chapter citation(s)	Part VII of 9VAC5-140
VAC Chapter title(s)	Regulation for Emissions Trading
Action title	Amend CO_2 Budget Trading Program to comport with RGGI Model Rule as required by Chapter 1219, 2020 Acts of Assembly (Revision A20).
Final agency action date	
Date this document prepared	

Although a regulatory action may be exempt from executive branch review pursuant to § 2.2-4002 or § 2.2-4006 of the *Code of Virginia*, the agency is still encouraged to provide information to the public on the Regulatory Town Hall using this form. However, the agency may still be required to comply with the Virginia Register Act, Executive Order 14 (as amended, July 16, 2018), the Regulations for Filing and Publishing Agency Regulations (1VAC7-10), and the *Form and Style Requirements for the Virginia Register of Regulations and Virginia Administrative Code.*

Brief Summary

Provide a brief summary (preferably no more than 2 or 3 paragraphs) of this regulatory change (i.e., new regulation, amendments to an existing regulation, or repeal of an existing regulation). Alert the reader to all substantive matters. If applicable, generally describe the existing regulation.

Chapter 1219 of the 2020 Acts of Assembly amends the Air Pollution Control Law to add a new Article 4, the Clean Energy and Community Flood Preparedness Act. Under § 10.1-1330 A, Clean Energy and Community Flood Preparedness, "[T]he provisions of this article shall be incorporated by the Department, without further action by the Board, into the final regulation adopted by the Board on April 19, 2019, and published in the Virginia Register on May 27, 2019. Such incorporation by the Department shall be exempt from the provisions of the Virginia Administrative Process Act (§ 2.2-4000 et seq.)."

Accordingly, Part VII of 9VAC5-140, Regulation for Emissions Trading, has been amended such that it comports with the full Regional Greenhouse Gas Initiative (RGGI) CO_2 emissions trading program and associated auction as mandated by Chapter 1219.

Mandate and Impetus

Identify the mandate for this regulatory change and any other impetus that specifically prompted its initiation (e.g., new or modified mandate, internal staff review, petition for rulemaking, periodic review, or board decision). "Mandate" is defined as "a directive from the General Assembly, the federal government, or a court that requires that a regulation be promulgated, amended, or repealed in whole or part."

The mandate for this regulatory action is a directive from the General Assembly (Chapter 1219, 2020 Acts of Assembly).

Statement of Final Agency Action

Provide a statement of the final action taken by the agency including: 1) the date the action was taken; 2) the name of the agency taking the action; and 3) the title of the regulation.

On #[date], the Director of the Virginia Department of Environmental Quality (DEQ) incorporated the provisions of Chapter 1219 of the 2020 Acts of Assembly, without further action by the State Air Pollution Control Board, into the final regulation adopted by the board on April 19, 2019, and published in the Virginia Register on May 27, 2019, by amending the Regulation for Emissions Trading, specifically, the CO_2 Budget Trading Program (Part VII of 9VAC5-140). The regulatory action is to be effective on #[date].

The regulation amendments are exempt from the state administrative procedures for adoption of regulations contained in the Administrative Process Act by the provisions of Chapter 1219 of the 2020 Acts of Assembly

REG\DEV\A20-09TF

NOTE

The preceding Director's Package document references an Attachment 3 on page 2. That attachment is protected from disclosure by attorney-client privilege, and is therefore not included. The memorandum following this page from the Office of Attorney General is that publically available.

MEMORANDUM

FROM: Gray O'Dwyer
Assistant Attorney General

DATE: July 09, 2020

RE: Proposed Exempt Regulations - 9 Va. Admin. Code §§ 5-140 *et seq.*

Please note that this memorandum does not constitute an opinion, formal or informal, of the Attorney General. Rather, this memorandum contains the legal analysis of the individual staff member providing it.

It is my view that the Department of Environmental Quality ("Department") on behalf of the Virginia Air Pollution Control Board ("Board") has the authority to promulgate these proposed amendments to its regulations in 9 Va. Admin. Code §§ 5-140 *et seq.*

It is also my view that this regulation is exempted from the Virginia Administrative Process Act, §§ 2.2-4000 *et seq.*, by its enabling legislation. Chapter 1219 of the 2020 Acts of Assembly amended the Air Pollution Control Law to add a new Article 4, the Clean Energy and Community Flood Preparedness Act. Under § 10.1-1330 A, Clean Energy and Community Flood Preparedness, "[T]he provisions of this article shall be incorporated by the Department, without further action by the Board, into the final regulation adopted by the Board on April 19, 2019, and published in the Virginia Register on May 27, 2019. Such incorporation by the Department shall be exempt from the provisions of the Virginia Administrative Process Act (§ 2.2-4000 et seq.)."

The foregoing conclusion is my own. It does not constitute an opinion, formal or informal, of the Attorney General.

COMMONWEALTH OF VIRGINIA

BEFORE THE STATE AIR POLLUTION CONTROL BOARD

IN RE: State Air Pollution Control Board
Final Regulation 9 VAC §§ 5-140 *et seq.*
Regulation for Emissions Trading Programs
Amending 9 VAC § 5-140-6010 through 9 VAC § 5-140-6440

NOTICE OF APPEAL

In accordance with Rule 2A:2 of the Rules of the Supreme Court of Virginia, the Virginia Manufacturers Association ("Appellant" or "VMA") hereby files this notice of appeal with David K. Paylor, Executive Secretary of the Virginia State Air Pollution Control Board, for judicial review of the Virginia Department of Environmental Quality's amendments of the Regulation for Emissions Trading Programs (9 VAC §§ 5-140 *et seq.*) as a final regulation, effective on July 10, 2020.

The appeal of this case decision will be taken to the Circuit Court for the City of Richmond, 13th Judicial Circuit of Virginia, located at 400 North Ninth Street, Richmond, Virginia 23219. Under Rule 2A:3 of the Rules of the Supreme Court of Virginia, the agency record should be forwarded to the Clerk of the Circuit Court for the City of Richmond as soon as possible.

As required by Rule 2A:2(b) of the Rules of the Supreme Court of Virginia, the Appellant provides the following information:

1. The Appellant is:

   Virginia Manufacturers Association
   2108 W. Laburnam Ave, Suite 230
   Richmond, VA 23227

2. Counsel for the Appellant is:

Elizabeth C. Williamson, Esq.
John M. Holloway, Esq.
Williams Mullen
200 South 10th Street
Richmond, VA 23219

3. The Appellee is:

Virginia State Air Pollution Control Board
Virginia Department of Environmental Quality
c/o David K. Paylor, Executive Secretary and Director
1111 East Main Street St., Suite 1400
Richmond, VA 23219

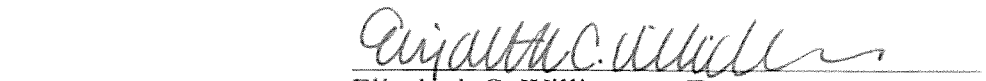
4. Counsel for the Appellee is:

Mark R. Herring, Attorney General of Virginia
Gray O'Dwyer, Assistant Attorney General
Office of the Attorney General of Virginia
202 North Ninth Street
Richmond, VA 23219

Dated: September 2, 2020

Respectfully submitted,

Virginia Manufacturers Association

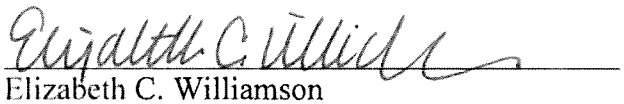


Elizabeth C. Williamson, Esq.
John M. Holloway, Esq.

Williams Mullen
200 South 10th Street
Richmond, VA 23219
ewilliamson@williamsmullen.com
jholloway@williamsmullen.com
Tel: 804-420-6050
804-420-6054

CERTIFICATE OF SERVICE

I hereby certify that on September 2, 2020, I have hand-delivered a complete copy of the foregoing Notice of Appeal to Appellee and its counsel identified above.



Elizabeth C. Williamson

43296978_1

VIRGINIA:

IN THE CIRCUIT COURT OF THE CITY OF RICHMOND

Virginia Manufacturers Association,

Appellant,

v. Case No.: CL20004918-00

Virginia Department of Environmental Quality, et al.

Appellees.

CERTIFICATE OF SERVICE

I certify that on this 18th of March, 2021, I mailed by first class mail, postage prepaid, a true copy of the foregoing Agency Record to

Elizabeth C. Williamson, Esq.
John M. Holloway, III, Esq.
Harold E. Johnson, Esq.
Williams Mullen
200 South 10th Street
Suite 1600
Richmond, Virginia 23219
Counsel for Appellant

Michael G. Dowd, on behalf of Appellees,
Virginia Department of Environmental Quality, et al.

Attachment 17

Perma.cc record

Captured September 27, 2022 2:26 pm

View: Standard (/8RRX-7PRB) Screenshot (/8RRX-7PRB?type=image)

Show record details

SERVICE FINDER (https://www.deq.virginia.gov/air/greenhouse-gases)

View the live page

Greenhouse Gases

Gases that trap heat in the atmosphere are called greenhouse gases (GHGs). These include carbon dioxide, methane, nitrous oxide and fluorinated gases. Solar radiation in the lower atmosphere acts like a “greenhouse” – thus the name – preventing heat from escaping. Emissions of greenhouse gases into the atmosphere is the main cause of climate change.

Virginia is committed to addressing the pollutants that contribute to climate change. The Virginia Clean Economy Act establishes renewable portfolio and energy efficiency standards, and advances offshore wind and solar generation, and the Clean Energy and Community Flood Preparedness Act requires Virginia to join the Regional Greenhouse Gas Initiative (RGGI).

Additionally, DEQ implements several programs to reduce methane DEQ also coordinates Virginia's participation in RGGI and the Transportation Climate Initiative (TCI).

GHG Inventories

DEQ has conducted economy-wide GHG inventories for 2005, 2010 and 2018. The following reports and accompanying Excel files provide more information on these inventories.

Baseline Inventory Report - 2005 and 2010

Baseline Inventory Tables and Figures Data

2018 Inventory Report

2018 Inventory Tables and Figures Data

Attachment 18

https://richmond.com/news/state-and-regional/govt-and-politics/61-dems-say-virginias-participation-in-rggi-is-up-to-legislature/article_86e0f575-2dc6-5e30-9b39-fa056de7a9f2.html

ALERT FEATURED

61 Dems say Virginia's participation in RGGI is up to legislature

Charlotte Rene Woods
Sep 8, 2022

Air Pollution Control Board Member Hope Cupit tells Virginia DEQ Director Mike Rolband that the Virginia attorney general's office gave her a document in March saying Virginia's participation in the Regional Greenhouse Gas Initiative is up to the General Assembly, not the Air Board.

On Thursday, 61 Virginia Democrats — more than a third of the General Assembly — signed onto a letter addressed to the state's **Air Pollution Control Board** opposing Gov. Glenn Youngkin's proposed regulatory route to remove Virginia from the Regional Greenhouse Gas Initiative.

On Aug. 31, **Travis Voyles**, the acting secretary of natural and historic resources, outlined the administration's plans to remove Virginia from RGGI through the Administrative Process Act — which entails a period of public comment and eventually a vote by the air board.

Download PDF

SENATE OF VIRGINIA

LYNWOOD W. LEWIS, JR.
6TH SENATORIAL DISTRICT
ALL OF ACCOMACK, NORTHAMPTON, AND MATHEWS COUNTIES; AND PART OF THE CITIES OF NORFOLK AND VIRGINIA BEACH

P. O. BOX 760
ACCOMAC, VIRGINIA 23301

COMMITTEE ASSIGNMENTS:
LOCAL GOVERNMENT, CHAIR
AGRICULTURE, CONSERVATION AND NATURAL RESOURCES
COMMERCE AND LABOR
EDUCATION AND HEALTH
RULES

September 8, 2022

Members of the Virginia Air Pollution Control Board
c/o Office of Regulatory Affairs
Department of Environmental Quality
P.O. Box 1105
Richmond, Virginia 23218

Sent via email: CitizenBoards@DEQ.Virginia.gov

Dear Members of the Air Pollution Control Board:

As current members of the Virginia General Assembly who voted for the Clean Energy and Community Flood Preparedness Act in 2020 or voted against changes to that same law in 2022, we write to express our continued support for Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI). Further, we write to articulate the reality that Virginia's participation in RGGI is mandated by *law*. Therefore, ultimately only a change in the *law* that passes both chambers of the General Assembly and is signed by the Governor can remove Virginia's participation. No proposed regulation, emergency regulation, regulatory act, or any subsequent administrative process can do so.

In addition to the Commonwealth's participation being mandated, RGGI is already delivering benefits to the residents of Virginia. As legislators, we believe it is important that you consider and understand the following benefits to Virginians from our participation in RGGI:

- RGGI has generated $378 million to support low-income energy efficiency programs and flood resilience infrastructure in Virginia.[1]
    - Energy efficiency upgrades are the best way to lower electricity bills, and Virginia's funds are directed to helping those households most in need.[2]
    - Flood resilience infrastructure protects Virginians against increased flooding and extreme weather events.
- RGGI has demonstrated Energy Cost Savings.
    - Electricity prices in RGGI states dropped by almost 6% while they went up by almost 9% throughout the rest of the country.[3] RGGI is a proven tool to reduce utilities'

[1] https://www.rggi.org/sites/default/files/Uploads/Auction-Materials/Cumulative-State-Charts/VA_Proceeds_by_Auction.xlsx
[2] https://vaeec.org/rggi/
[3] https://acadiacenter.org/wp-content/uploads/2019/09/Acadia-Center_RGGI_10-Years-in-Review_2019-09-17.pdf

But the 61 legislators who have signed onto the letter say that's "improper and illegal" and that it's a decision for the General Assembly.

People are also reading...

1. **Parent sues Hanover schools over new transgender policy**
2. **As catalytic converter thefts rise in the Richmond area, local police promote new deterrence measure**
3. **Thousands of terrified fish throw themselves onto Outer Banks beach, videos show**
4. **Williams: John V. Moeser, a scholar and a gentleman, pushed for a more inclusive and equitable Richmond region.**

RGGI is a carbon market composed of 11 states where energy producers trade emission reductions for credits or buy credits to emit carbon dioxide past a capped amount. Proponents of the initiative say it can incentivize producers to use fewer fossil fuels over time, and the funding generated through quarterly auctions is used for environmental projects. In 2021, Virginia raked in $228 million in funding for flood protection and energy efficiency programs.

Legislators mull ways to keep power bills down amid Regional Greenhouse Gas Initiative debate

The letter comes amid debates surrounding whose authority it is to pull Virginia out of RGGI. Environmental advocates, legal groups — and now many Democrats in the General Assembly — say that it's the legislative body's purview to remove Virginia from RGGI, that lawmakers put Virginia into the initiative.

"We write to articulate the reality that Virginia's participation in RGGI is mandated by law," the letter reads. "Therefore ultimately only a change in the law that passes both chambers of the General Assembly and is signed into law by the governor can remove Virginia's participation."

It seems that the attorney general's office might share that view. At an air board meeting this spring, member Hope Cupit said she received correspondence from the office reiterating the point.

Environmental advocacy group Appalachian Voices has a **pending lawsuit** in which it seeks to obtain a copy of the correspondence after it unsuccessfully requested the document under the Freedom of Information Act.

Environmental group sues to get AG document on withdrawal from RGGI

The letter, spearheaded by Sen. Lynwood Lewis, D-Accomack, added that the air board is limited in its abilities because it was created by the General Assembly.

"You only have the powers that the General Assembly grants you," the letter said.

The Democrats' letter also notes the law that enables participation in RGGI — the Clean Energy and Community Flood Preparedness Act — adding, "it is clear our intent for Virginia to participate in RGGI."

With Youngkin's proposed regulatory route, his goal is for Virginia to withdraw from the initiative by the end of 2023. The air board is composed of gubernatorial appointees on staggered terms, and with new appointees who could vote in Youngkin's favor, legal groups argue that this may trigger legal challenges.

Youngkin report calls carbon program too expensive; its supporters push back

Some members of the legislature have worked on a withdrawal, but efforts failed in the 2022 session. House Majority Leader Terry Kilgore, R-Scott, and Sen. Richard Stuart, R-Stafford, carried bills that would have repealed the Clean Energy and Community Flood Preparedness Act.

All General Assembly seats are up for election in 2023. Should the legislative body change its mind about RGGI, lawmakers would present such measures during the 2024 session.

Richmond fall festival guide: Pumpkin picking, Harvest Fest & fall festivities

ARMENIAN FOOD FESTIVAL

Sept. 9-10

It's the 62nd year for the Armenian Food Festival, an area favorite dishing up shish kebabs, stuffed grape leaves, hummus and fresh baked items. Two days only this year: 11:30 a.m.-9:30 p.m. Friday and Saturday. St. James Armenian Church, 834 Pepper Ave. Free entry; pay as you go. **armenianfoodfestival.com**

2018, SHELBY LUM/TIMES-DISPATCH

43RD STREET FESTIVAL OF THE ARTS

Attachment 19

VIRGINIA:

IN THE CIRCUIT COURT FOR THE CITY OF RICHMOND
JOHN MARSHALL COURTS BUILDING

RECEIVED AND FILED
CIRCUIT COURT
MAY 07 2021
EDWARD F. JEWETT, CLERK
BY_____D.C.

VIRGINIA MANUFACTURERS ASSOCIATION,	:	
Petitioner,	:	
v.	:	Case No.: CL20-4918
VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY, ET AL.,	:	Hon. Judge Beverly W. Snukals
Respondents.	:	

Respondents' Brief in Opposition

Respondents, the Virginia Department of Environmental Quality ("DEQ"), the State Air Pollution Control Board, and Director David Paylor, the Director of DEQ, by counsel, respectfully submit this brief in Opposition to the Petitioner's appeal.

This case is important, but not complex. The General Assembly passed legislation mandating that DEQ amend regulations for the CO_2 Budget Trading Program. The legislation expressly exempted the amended regulations from the Virginia Administrative Process Act ("APA"). DEQ followed the General Assembly's mandate and promulgated amended regulations.

Petitioner, Virginia Manufacturers Association ("VMA") has appealed the amended regulations but not challenged the legislation that required them. As discussed below, VMA's arguments are incorrect: the amended regulations follow the General Assembly's mandate, indeed at times, incorporating *verbatim* the language from the legislation; the amended regulations are exempt from the APA; they are not vague; and there is no illegal tax on electricity ratepayers. VMA is asking this Court to set aside a program that controls CO_2 pollution and provides millions of dollars to help low-income households and vulnerable shoreline communities. This Court should not be persuaded to undermine these efforts in contravention of the law.

Table of Contents

Relevant Factual History....1

I. The Act mandated that DEQ establish a CO2 auction trading program and then sell 100% of Virginia's CO2 allowances through that program. 1

A. Before the Act, Virginia could only participate in CO_2 auctions on a limited, "consignment" basis....1

B. The General Assembly mandated that DEQ establish a CO_2 direct auction and "sell 100 percent" of all annual CO_2 allowances in the auction. 2

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Relevant Factual History

The relevant facts in this case are not in dispute.[1] As discussed below, before 2020, DEQ had a CO_2 budget trading program that was limited to utilizing a conditional allowance / consignment model. In 2020, the General Assembly passed legislation that mandated DEQ to implement a CO_2 direct auction program and then to sell all CO_2 allowances through such auctions. The General Assembly further required that DEQ implement these changes by amending its existing regulations and then expressly exempted those amendments from the APA. It is those Amended Regulations that VMA challenges in this case.

I. The Act mandated that DEQ establish a CO_2 auction trading program and then sell 100% of Virginia's CO_2 allowances through that program.

A. Before the Act, Virginia could only participate in CO_2 auctions on a limited, "consignment" basis.

The State Air Pollution Control Board, with the support of DEQ, adopted regulations establishing a CO_2 Budget Trading Program on April 19, 2019 and published those regulations on May 27, 2019 (hereafter referred to as the "Original Regulations"). VMA Pet. at ¶ 35.[2]

[1] VMA filed over 450 pages of attachments to its Brief in Support; most of these documents were not included in the Certified Agency Record. VMA never objected to the Certified Agency Record nor moved to supplement the record. Thus, this Court need not consider any of these documents as they are not part of the record in this case. *See* Va. Sup. Ct. R. 2A:3(c) (2020). Moreover, most of these documents are irrelevant to the issue in this case, which is whether DEQ's Amended Regulations are *lawful*. VMA's attachments address whether it is a good *policy* to establish a CO_2 trading program. *See, e.g.*, VMA Attachment E (2017 article on RGGI); Attachment J (cost study of Virginia's CO_2 trading program). The General Assembly answered that policy question in 2020. Thus, these attachments are largely irrelevant to this case.

[2] The dates of adoption and publication for the Original Regulations are significant because, as discussed below, it is by those dates that the General Assembly refers to the Original Regulations in the Clean Energy and Community Flood Preparedness Act.

Prior to adoption, the Original Regulations went through a full notice and comment process pursuant to the APA. *Id.* at ¶ 33. VMA participated in that process and submitted "extensive written comments." *Id.*

The Original Regulations were limited because DEQ lacked legislative authority to either directly sell CO_2 allowances in an auction or spend or receive proceeds from an auction. *Id.* at ¶ 31. The Original Regulations worked around these limitations by utilizing a consignment model. Under the Original Regulations, DEQ granted "conditional allowances" to power plants and other CO_2 sources, those sources then "consigned" those allowances over to the CO_2 auction program where they were sold at a consignment auction. *Id.* At the same time, CO_2 sources were required to obtain CO_2 allowances that equaled their CO_2 emissions. *Id.* In this way, DEQ neither participated directly in the auctions nor spent or received revenue from the auction. *Id.*

B. The General Assembly mandated that DEQ establish a CO_2 direct auction and "sell 100 percent" of all annual CO_2 allowances in the auction.

In the 2020 legislative session, the General Assembly passed two historic pieces of environmental legislation. The first was the Virginia Clean Economy Act, which is not subject to this lawsuit. The second was the Virginia Clean Energy and Community Flood Preparedness Act (hereafter referred to as the "Act.").[3]

[3] Both the media and trade publications immediately recognized the significance of both pieces of legislation. As one commenter described the importance of the Act:

> The Act directs DEQ to revise the Rule without notice and comment through the Virginia Administrative Process Act by incorporating the statute into the existing Rule. Now, Virginia will be sprinting toward RGGI membership by the end of this year. Direct RGGI membership is a significant shift from the prior consignment membership….

Liz Williamson, *Virginia Regional Carbon Trading: Ready, Set, Join RGGI!*, JD Supra, July 15, 2020) (available at https://www.jdsupra.com/legalnews/virginia-regional-carbon-trading-ready-77904/ (last visited Apr. 14, 2021). *See also Virginia Enacts Aggressive Clean Energy Laws*, The National Law Review (Apr. 17, 2020) (available at

The Act created a new Virginia Code provision: Section 10.1-1330, which requires DEQ to take two actions. First, Section 1330.B. authorizes the Director of DEQ to "establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program and this article." Va. Code § 10.1-1330.B (2020). Second, the section mandates that the "Director shall seek to sell 100 percent of all allowances issued each year through the allowance auction." *Id.*[4]

C. The Act explicitly exempted the Amended Regulations from the APA.

Subsection A of Section 1330 of the Act requires DEQ to incorporate the provisions of the Act "into the final regulation adopted by the Board on April 19, 2019, and published in the Virginia Register on May 27, 2019." Va. Code § 10.1-1330.A. The dates referenced in this provision refer to the dates of adoption and publication of the Original Regulations; *i.e.*, the regulations that developed the conditional allowance / consignment model described above.

Section 1330.A. then states: "Such incorporation by the Department shall be exempt from the provisions of the Virginia Administrative Process Act (§ 2.2-4000 *et seq.*)." *Id.*

Thus, Section 1330 is clear. Whereas before, DEQ was not allowed to directly participate in a CO_2 auction and could not directly receive proceeds from auction sales, now:

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https://www.natlawreview.com/article/virginia-enacts-aggressive-clean-energy-laws (last visited Apr. 14, 2021); *Virginia Gov. Ralph Northam signs clean energy legislation*, WJHL News (Apr. 12, 2020) (available at https://www.wjhl.com/news/regional/virginia/virginia-gov-ralph-northam-signs-clean-energy-legislation/ (last visited Apr. 14, 2021).

[4] The legislation also contains several provisions that are not directly relevant to this case, but which demonstrate the General Assembly's purpose and intent. For example, the General Assembly revised Virginia Code 10.1-603.25 by converting the Virginia Shoreline Resiliency Fund into the Virginia Community Flood Preparedness Fund. Pursuant to the revisions, the fund "shall be used solely for the purpose of enhancing flood prevention or protection and coastal resilience as required by this article." Va. Code § 10.1-603.25.B. The General Assembly also required that "[n]o less than 25 percent of the moneys disbursed from the Fund each year shall be used for projects in low-income geographic areas." Va. Code § 10.1-603.25.E.

- DEQ must implement and manage a CO_2 auction program;
- DEQ must sell 100% of all CO_2 allowances through an allowance auction; and
- DEQ must do these tasks by amending the Original Regulations; however, those amendments are exempt from the APA.

II. DEQ followed the Act's mandate by revising its CO_2 Trading Regulations so that Virginia could directly participate in CO_2 auctions.

Consistent with the Act, on July 10, 2020, DEQ issued amendments to the Original Regulations (hereafter referred to as the "Amended Regulations"). VMA Pet. at ¶ 43. These Amended Regulations comprise the majority of the Certified Agency Record that DEQ filed in this case. Specifically, the Amended Regulations begin on the third page of the Certified Agency Record and consist of 57 pages of regulations that are now codified as 9 VAC5-140-6010 through 9 VAC5-140-6440. The Amended Regulations, as filed as part of the Certified Agency Record in this case, are paginated 1 through 57, with the page number appearing on the top right corner of each page. For ease of reference, this Opposition Brief will refer to this pagination system when citing to the Amended Regulations.

The Amended Regulations, as filed in this case, show both the Original Regulations and the amendments. The Original Regulations appear as regular typeface. Where DEQ deleted words, those words appear with a line through them. Where DEQ added words, those words are underlined. *See, e.g.*, Amended Regulations at 2 ("Allocate" or "allocation" means the determination by the department of the number of ~~conditional~~ $\underline{CO_2}$ allowances recorded in the ~~conditional~~ allowance account of a CO_2 budget unit…"). In other words, the Amended Regulations DEQ has filed with this Court are a blackline, edited version of the Original Regulations that show both the Original Regulations and the Amended Regulations.

As the Amended Regulations demonstrate, most of the Original Regulations remain unchanged. For example, two of the regulations that VMA challenge as impermissibly vague, 9 VAC5-140-6050.C and 9 VAC5-140-6260 (*see* VMA Brief at 22), are unchanged and only contain minor edits that update dates and remove obsolete terminology. *See* Amended Regulations at 16 (showing the only amendments to 9 VAC5-140-6050.C are to remove the phrase "initial control period" and to update dates); at 39 – 43 (showing minimal changes to 9 VAC5-140-6260).

Most of the changes in the Amended Regulations, as required by the Act, change the CO_2 trading program from a conditional allowance / consignment model to a direct auction model. For example, the Amended Regulations add language stating that CO_2 allowances would now be sold "by the Department or its agent" through an auction. *Id.* at 5. The Amended Regulation also delete references to conditional allowances and consignment auctions. *Id.* at 6-7; 28; 32-33; 56-57.[5]

III. Virginia received $43 million in net revenue from its first auction.

On March 5, 2021, Virginia participated in its first quarterly auction of CO_2 allowances. As reported, Virginia earned more than $43 million in net proceeds from the auction.[6] Pursuant to the Act, 45% of this revenue will assist localities affected by flooding and sea level rise. Va. Code § 10.1-1330.C. 50% of this revenue will be spent on low-income energy efficiency programs. *Id.* The next RGGI auction is scheduled for June 2, 2021.[7]

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[5] The Amended Regulations also add to the definition of the term "life-of-the-unit contractual arrangement" and then have a new regulation specifying the parties' obligations for CO_2 allowances under such an arrangement. *Id.* at 9-10; 45. These new regulations were explicitly required by Section 1331 of the Act. *See* Va. Code § 10.1-1331.

[6] *See* Sarah Vogelsong, *Virginia Nets More than $43 Million in First Carbon Allowance Auction*, The Virginia Mercury (Mar. 9, 2021) (available at https://www.virginiamercury.com/blog-va/virginia-nets-more-than-43-million-in-first-carbon-allowance-auction/) (last visited Apr. 13, 2021).

[7] https://www.rggi.org/auctions/upcoming-auctions.

Standard of Review and Burden of Proof

I. Standard of review when comparing regulations to enabling legislation.

At its core, VMA's Brief argues that the Amended Regulations are inconsistent with the Act. As the Virginia Court of Appeals has explained: "[w]hen [a] [c]ourt reviews whether a regulation is inconsistent with its enabling legislation, it must take into account the text as well as the context in the underlying statute, viewing it as a symmetrical and coherent regulatory scheme." *Karr v. Dep't of Envtl. Quality*, 66 Va. App. 507, 526 (2016) (internal citations and quotation marks omitted). Further, a court "is duty bound to interpret the several parts of a statute as a consistent and harmonious whole so as to effectuate the legislative goal." *Id.* at 527 (citing *Virginia Elec. & Power Co. v. Citizens for Safe Power*, 222 Va. 866, 869 (1981)).

Finally, although "pure questions of statutory interpretation" are subject to *de novo* review, if the statute in question "falls within the agency's specialized competence, the agency decision is entitled to special weight and will be overturned only if it constitutes a clear abuse of the delegated discretion." *Dorman v. Commonwealth*, 2019 Va. App. LEXIS 209, *6 (2019) (unpublished) (internal citations omitted); *see also Thormac, LLC v. Dep't of Alcoholic Bev. Control*, 68 Va. App. 216, 223 (Va. Ct. App. 2017) ("where the question involves an interpretation which is within the specialized competence of the agency and the agency has been entrusted with wide discretion by the General Assembly, the agency's decision is entitled to special weight in the court.").

II. Burden of proof

The APA places the burden upon VMA to demonstrate an error of law. Va. Code § 2.2-4027. "[T]he agency action is presumed valid on review and the burden rests upon the party complaining to overcome this presumption." *Strawbridge v. Cnty. of Chesterfield*, 23 Va. App. 493, 503 (1996).

Argument

VMA's Brief asserts four arguments for why the Amended Regulations should be declared void. These four arguments relate to VMA's six assignments of error that it has listed in its Petition for Appeal. For ease of reference, this Opposition Brief will address each of VMA's arguments in the order they were presented.

I. The Amended Regulations satisfy the Act's mandate of implementing a "market-based trading program consistent with the RGGI program" and of selling "100 percent of all allowances each year through the allowance auction."

VMA's first argument is that DEQ violated the Act when it issued the Amended Regulations. VMA Brief at 17. As discussed below, this argument fails because DEQ satisfied the Act's mandate that it establish a CO_2 auction program and then sell all CO_2 allowances through those auctions. Furthermore, VMA's assertion that DEQ "failed to incorporate" certain portions of the Act fails because those portions of the Act either had no relevance to the CO_2 auction program or were implemented in the Amended Regulations *verbatim*.

A. DEQ's Amended Regulations follow the General Assembly's Mandate.

Section 1330.B of the Act (codified at Virginia Code Section 10.1-1330.B) contains two sentences, each of which directs DEQ to take certain action. First, the Act authorizes DEQ to "establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program and this article." Va. Code § 10.1330.B. Second, the Director of DEQ "shall seek to sell 100 percent of all allowances issued each year through the allowance auction." *Id.*

DEQ did exactly as the General Assembly instructed. Through the Amended Regulations, DEQ struck all language referencing the former consignment model and replaced it with the direct auction model the Act requires. For example, the Amended Regulations:

- Added language stating that CO_2 allowances would now be sold "by the Department or its agent" through a direct auction (Amended Regulations at 5);
- Deleted reference to conditional allowances and consignment auctions (*id.* at 6 – 7);
- Deleted "conditional allowances" and replaced them with "CO_2 allowances" (*id.* at 28);
- Repealed the methodology for conditional allocations (*id.* at 32 – 33); and
- Repealed the consignment auctions (*id.* at 56 – 57).

VMA does not, and cannot, dispute that the Amended Regulations repealed consignment auctions, removed references to conditional allowances, and removed other transitional provisions that are not compatible with a direct auction program. *See* VMA Brief at 17 (alleging that the Amended Regulations "*implement*" the Act but still violate it) (emphasis in original). Simply put, the Act mandated that DEQ take two significant steps: implement and manage a direct auction CO_2 program, and sell 100% of Virginia's CO_2 allowances in that program. Through the Amended Regulations, DEQ has done exactly what the General Assembly mandated. DEQ did not violate the Act, it followed it.

B. VMA's argument that DEQ "failed to incorporate" certain provisions of the Act fails because those provisions are either unrelated to DEQ's mandate or explicitly incorporated in the Amended Regulations.

Rather than argue that the Amended Regulations fail to satisfy the Act's mandate, VMA argues that DEQ did not go far enough and that, allegedly, DEQ "failed to incorporate" certain provisions of the Act. VMA Brief at 17. As discussed below, VMA is incorrect.

1. VMA's allegation that DEQ failed to incorporate the definitions section of the Act is both illogical, because that section did not require DEQ to do anything, and undermined by the 13 pages of definitions in the Amended Regulations.

First, VMA alleges that DEQ "failed to incorporate" Section 10.1-1329 of the Act. VMA Brief at 17. Section 1329 is titled "Definitions" and is a list of nine defined terms that are used in

the Act, including "DMME," "Energy efficiency program, and "Fund." Va. Code § 10.1-1329. ("As used in this article, unless the context requires a different meaning: [followed by nine defined terms]").

VMA's argument seems to be that DEQ was required to define terms such as "DMME" or "Fund" in the Amended Regulations. There are two problems with this argument. First, definitions prescribed by the General Assembly are already incorporated into the Board's regulations. The very first section in the Board's Regulations, 9 VAC5-10-10, provides that "[u]nless specifically defined in the Virginia Air Pollution Control Law . . . terms used [in the Air Board's regulations] shall have the meanings given them by 9VAC5-170-20, or commonly ascribed to them by recognized authorities." 9 VAC5-10-10(B). Thus, the regulations, by operation of 9 VAC5-10-10(B), defer to and adopt definitions provided by the General Assembly. *Id.* DEQ has already incorporated the definitions contained in the Act by virtue of existing regulations. Repeating this incorporation in the Amended Regulations would be redundant.

Second, the fact that the General Assembly included a list of defined terms in the Act does not require DEQ to do anything in its Amended Regulations. Indeed, those Amended Regulations contain 13 pages of definitions, many of which were unchanged by the amendments. *See* Amended Regulations at 1-13. DEQ did not "fail to incorporate" Section 10.1-1329 because there was nothing in that section for DEQ to incorporate. And, VMA has not shown a single instance where the definitions in the Amended Regulations contradict or undermine the Act's defined terms. Thus, VMA is incorrect: DEQ did not violate the Act by "failing to incorporate" the definitions listed in the Act. The Board's existing regulations already incorporate by reference definitions passed by the General Assembly, the Original Regulations already had a lengthy definitions section, and DEQ amended those definitions where necessary to comply with the Act. *Id.*

2. VMA's allegation that DEQ failed to incorporate Section 1331 is incorrect: The Amended Regulations contain a nearly *verbatim* inclusion of that section.

Second, VMA alleges that DEQ "failed to incorporate" Section 10.1-1331. *See* VMA Brief at 17 (listing Section 10.1-1331 as one of the provisions DEQ "failed to incorporate") and at 18 (alleging that the Amended Regulations "also has not incorporated . . . Section 1331.").

This argument is demonstrably false: not only do the Amended Regulations incorporate this section, they do so nearly *verbatim*. Section 1331 of the Act (codified at Virginia Code Section 10.1-1331) is titled "Energy conversion or energy tolling agreements." The section states that if Virginia becomes a "full participant in RGGI," then two items must be included in DEQ's Amended Regulations. Va. Code § 10.1-1331. First, the Amended Regulations must include within its definition of the phrase "life-of-the-unit contractual arrangement" the following phrase: "any energy conversion or energy tolling agreement that has a primary term of 20 years or more and pursuant to which the purchaser is required to deliver fuel to the CO2 budget source or CO2 budget unit and is entitled to receive all of the nameplate capacity" from that source. *Id.* Second, the Act requires the Amended Regulations include a provision stating that under such an agreement, the purchaser is responsible for acquiring the associated CO_2 allowances. *Id.*[8]

The Amended Regulations include both requirements. The Original Regulations already contained a definition of "life-of-the-unit contractual arrangement." *See* Amended Regulations at 9-10 (showing the original definition in subsection "a"). Thus, the Amended Regulations added

[8] A "life-of-the-unit contractual arrangement" in the electricity utility industry is essentially a dedicated power plant: a situation where a power plant commits, by long-term contract, to provide all or most of its produced electricity to a single purchaser. *See, e.g.* 42 U.S.C. § 7651a(27) (2020) (defining the term under federal law). Section 1331 of the Act clarifies that under such a contractual arrangement, it is the power purchaser who must obtain the CO_2 allowances. *See* Va. Code § 10.1-1331 ("any purchaser under an energy conversion or energy tolling agreement shall be responsible for acquiring any CO2 allowances"); Amended Regulations at 45 (adding a new section, 9 VAC5-140-6325, that includes this same clarification).

the word "either" to the definition, made the original definition subsection "a." and then added a new "b." *Id.* Subsection b of that definition is, *verbatim*, the definition from Section 1331. *Id.*

Then, the Amended Regulations added a new provision, 9 VAC 5-140-6325, that clarifies that the purchaser under such an arrangement is responsible for obtaining the necessary CO_2 allowances. *Id.* at 45.

So that there is no doubt as to whether the Amended Regulations incorporate Section 1331, here is the exact language from both the Act and the Amended Regulations:

Section 1331 of the Act	**Relevant Amended Regulations**
If the Governor seeks to include the Commonwealth as a full participant in RGGI or another carbon trading program… then	
(i) the definition of the term "life-of-the-unit contractual arrangement" under the Final Regulation shall include any energy conversion or energy tolling agreement that has a primary term of 20 years or more and pursuant to which the purchaser is required to deliver fuel to the CO2 budget source or CO2 budget unit and is entitled to receive all of the nameplate capacity and associated energy generated by such source or unit for the entire contractual period and	"Life-of-the-unit contractual arrangement" means either… (b) For any energy conversion or energy tolling agreement that has a primary term of 20 years or more and pursuant to which the purchaser is required to deliver fuel to the CO_2 budget source or CO_2 budget unit and is entitled to receive all of the nameplate capacity and associated energy generated by such source or unit for the entire contractual period. (Amended Regulations at pp. 9-10.)
(ii) any purchaser under an energy conversion or energy tolling agreement shall be responsible for acquiring any CO2 allowances required under the Final Regulation in relation to a CO2 budget source or CO2 budget agreement that is subject to such agreement.	A power purchaser entered into a life-of-the-unit contractual arrangement… shall be responsible for acquiring and transferring all allowances to the CO_2 budget source or unit that are necessary for demonstrating compliance with the CO_2 budget trading program. (Amended Regulations at p. 45.)

VMA never mentions the Amended Regulations' new definition of "life-of-the-unit contractual arrangement." VMA Brief at 17-18. Nor does VMA ever mention the new

requirement, codified in 9 VAC5-140-6325, that the purchaser under such an arrangement acquire the requisite CO_2 allowances. *Id.* Instead, VMA ignores these provisions and claims that the Amended Regulations "fail to incorporate" Section 1331. *Id.* This is simply false: the Amended Regulations incorporate, on a nearly *verbatim* basis, Section 1331.[9]

3. VMA's allegation that the Amended Regulations "fail to incorporate" Section 10.1-1330(C) is a red herring: that provision addresses how the *proceeds* from direct auctions will be spent; there is nothing in that provision for DEQ to include in its regulations implementing and managing a direct auction program.

Third, VMA alleges in its Petition for Appeal that DEQ failed to incorporate Section 10.1-1330.C, which VMA describes as "the most substantive and impactful part" of the Act. VMA Pet. at ¶ 51. Curiously, VMA never makes this argument in its Brief in Support. *See* VMA Brief at 17-18 (listing the three provisions of the Act it alleges that DEQ "failed to incorporate" but not including Section 10.1-1330.C). Nonetheless, because VMA made this assertion in its Petition for Appeal, the Respondents will address it here.

Section 1330.C of the Act (codified at Virginia Code Section 10.1-1330.C) specifically provides for how the proceeds from the CO_2 direct auctions shall be allocated:

1. 45% of the revenue shall go to the Virginia Community Flood Preparedness Fund;

[9] In support of its argument that DEQ failed to incorporate Section 1331, VMA cites *Jackson v. Marshall*, 454 S.E.2d 23 (Va. Ct. App. 1995). VMA Brief at 18. VMA cites *Jackson* for the proposition that "no deference can be given to an agency when compliance with a statute is at issue." *Id.* The word "deference" is only used once in in the *Jackson* opinion: "On review, the interpretation which an administrative agency gives its law must be accorded great deference." *Jackson*, 454 S.E.2d at 26. Not only is VMA's characterization of *Jackson* incorrect, it is also irrelevant. *Jackson* involved a Department of Social Services administrative hearing over allegations of sexual abuse where the hearing officer issued a ruling finding "Reason to Suspect Sexual Abuse," yet the statute at issue only allowed for findings of either "Founded" or "Unfounded." *Id.* at 24-25. The *Jackson* court then reasoned that, even though agency interpretation of its law "must be accorded great deference," where a statute "is clear and unambiguous, a court will give the statute its plain meaning." *Id.* at 26. Here, Section 1331 is clear and DEQ inserted its provisions directly into the Amended Regulations. Thus, *Jackson* is inapplicable.

2. 50% of the revenue shall go to the Department of Housing and Community Development to support low-income energy efficiency programs;
3. 3% of the revenue shall go to DEQ to cover administrative expenses of managing the auction and related activities; and
4. 2% of the revenue shall go to the Department of Housing and Community Development, in partnership with the Department of Mines, Minerals, and Energy, to administer and implement the low-income efficiency programs funded above.

Va. Code § 10.1-1330.C.

There is nothing in this provision related to how DEQ shall "establish, implement, and manage" the CO_2 direct auction program. Va. Code § 10.1-1330.B. Nor is there anything in this provision related to how the Director of DEQ shall "seek to sell 100 percent of all allowances issued each year." *Id.* Thus, there was nothing for DEQ to incorporate from Section 1330.C into the Amended Regulations. Indeed, it would be nonsensical for DEQ, through regulations that implement the auction program, to prescribe rules for how other state agencies, such as the Department of Housing and Community Development, are to administer separate programs. DEQ did not "fail to incorporate" Section 1330.C as VMA alleges; rather, there is nothing in that provision for DEQ to incorporate in the Amended Regulations.[10]

[10] VMA included a fourth "failure to incorporate" allegation in its brief. In two separate places, VMA alleges that DEQ failed to incorporate "Section 10.1-1300." *See* VMA Brief at 17 (listing among the sections DEQ allegedly "failed to incorporate" "Section 10.1-1300"); at 18 ("Revision A20 also has not incorporated Section 10.1-1300 . . . ."). This could be a typographical error as Virginia Code Section 10.1-1300 is not part of the Act, is unrelated to the CO_2 trading program, and is not mentioned in VMA's Petition for Appeal.

Since VMA makes this assertion twice in its brief; however, the Respondents will briefly address it here. This allegation should be rejected for three reasons. First, VMA did not identify this provision as an assignment of error in its Petition for Appeal; and therefore, has waived its right to raise this new issue now. *See* Va. Sup. Ct. R. 2A:4(a) (requiring a petition for appeal to "specify the errors assigned") (2020). Second, this code provision was not changed by the Act.

II. VMA's APA-based assignments of error fail because: (A) the Act exempted the Amended Regulations from the APA; and (B) the Act authorized each of the changes VMA identifies in its brief.

VMA's first three assignments of error (Claims I, II, and III) in its Petition for Appeal allege that DEQ violated the APA by issuing the Amended Regulations without going through APA's notice-and-comment process. VMA Pet. at ¶¶ 58-78. VMA supports these claims through the second argument in its brief. *See* VMA Brief at 18-21. As discussed below, VMA's argument is incorrect because the Act expressly exempts the Amended Regulations from the APA and because the Act authorizes each of the changes VMA complains of.

A. The Act expressly exempts the Amended Regulations from the APA.

Section 1330.A of the Act (codified at Virginia Code Section 10.1-1330.A) states:

> The provisions of this article shall be incorporated by the Department, without further action by the Board, into the final regulation adopted by the Board on April 19, 2019, and published in the Virginia Register on May 27, 2019. Such incorporation by the Department *shall be exempt from the provisions of the Virginia Administrative Process Act (§ 2.2-4000 et. seq.*).

Va. Code § 10.1-1330.A (emphasis added). Thus, the Act expressly exempts DEQ's Amended Regulations from the requirements of the APA. This Court's analysis need go no further.

VMA incorrectly alleges that DEQ claims that the Amended Regulations qualify for one of the exemptions listed in the APA. VMA Brief at 19 (asserting that DEQ was invoking Virginia Code 2.2-4006(A)(4)(a) to justify avoiding the APA). In support of this assertion, VMA cites "Attachment A (Agency Record) at 3." *Id.* But nowhere on that page, nor anywhere else in the

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Virginia Code Section 10.1-1300 is the definitions section for the chapter of the Virginia Code that establishes the State Air Pollution Control Board. It was last amended in 2015, well before the Original Regulations or the Act. *See* Va. Code § 10.1-1300 (legislative history section showing the last amendment in 2015). Thus, VMA's argument that DEQ somehow violated "the Act" by failing to incorporate this section is internally inconsistent: this section is not part of the Act so failing to incorporate it cannot be a violation of the Act. Finally, VMA has not identified any definition or provision in the Amended Regulations that is inconsistent with Section 10.1-1300. Thus, VMA's contention that DEQ "failed to incorporate" this code provision is without merit.

record, does DEQ ever claim this APA exemption. There is no reason to claim such an exemption: the Act exempts the Amended Regulations from the APA. [11]

VMA relies upon a strawman fallacy: after misrepresenting DEQ's justification for not going through the APA process, VMA spends the remainder of its second argument refuting DEQ's supposed position. *See* VMA Brief at 19-22. There was no reason for DEQ to resort to one of the APA's exemptions when the Act exempted the Amended Regulations from the APA.[12]

B. The Act authorized each of the changes VMA identifies in its brief.

VMA concedes that the Act exempts the Amended Regulations from the APA. VMA Brief at 19. But according to VMA, DEQ went "far beyond the scope of the exemption" and included

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[11] Recently, VMA made the same APA argument in a case before the Honorable Judge W. Reilly Marchant. In *VMA v. Northam*, Case No. CL20-4521, VMA asserted that emergency temporary standards for workplace safety, passed in response to the COVID-19 pandemic, were illegal because they did not go through the APA process. VMA also asserted that Governor Northam's emergency executive orders, also passed in response to the COVID-19 pandemic, had to go through the APA process. This Court dismissed VMA's APA claim reasoning:

> Count I is an allegation that there are violations to the Administrative Process Act. The Court finds that the VAPA doesn't apply to executive orders. In regard to the Emergency Temporary Standards, the Court also agrees with the Defense that 40.1 exempts the ETS, the Emergency Temporary Standards, from the VAPA. They exempt it. So the Court grants the Defense motion to dismiss Count I for those reasons.

VMA v. Northam, Case No. CL20-4521, Hearing Transcript at 60:6-15 (Feb. 16, 2021). *See also* Order Granting Motion to Dismiss at ¶ 1 ("Count I… is **HEREBY DISMISSED** for the reasons stated on the record at the February 16, 2021 hearing and because the VAPA does not apply to Emergency Executive Orders and because Virginia Code Section 40.1-22(6a) expressly exempts the Emergency Temporary Standard from the VAPA."). VMA has now filed a notice of appeal. *See* Notice of Appeal (Mar. 31, 2021).

While VMA may prefer to have the Amended Regulations go through the APA, just like they wanted the Emergency Temporary Standards at issue before the Honorable Judge Marchant to go through the APA, in both instances the General Assembly expressly exempted the regulations from the APA. In both instances, VMA's reliance on the APA is mistaken.

[12] VMA also asserts, without explanation, that the Act's APA exemption "is very narrow." VMA Brief at 20. Yet VMA does not point to any limiting language in the exemption.

"abundant substantive changes" in the Amended Regulations. *Id.* VMA then lists, in bullet-point format, six such changes.

Yet each of these changes are amendments that move Virginia from the previous consignment model (where DEQ granted "conditional allowances" to the regulated community who then consigned them over to the RGGI market) to the current direct auction model that the Act requires. Specifically, the first and third of VMA's examples are provisions where DEQ removed the concept of conditional allowances. *Compare* VMA Brief at 20 *with* Amended Regulations at 2 (replacing "conditional allowances" with "CO_2 allowances"). Similarly, the fourth, fifth, and sixth examples are provisions where DEQ removed the concept of a consignment auction and replaced it with a direct auction. *Compare* VMA Brief at 20 *with* Amended Regulations at 32-33 (repealing conditional allocation methodology regulations and removing reference to consignment auctions); at 56-57 (repealing consignment auction regulations).

These changes are expressly required by Section 1330.B of the Act, which requires DEQ to "establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program," and which requires the Director to "sell 100 percent of all allowances issued each year." Va. Code § 10.1-1330.B. Put differently, because the General Assembly mandated that DEQ move from the consignment/conditional allowance model to a direct auction model, DEQ amended its regulations to remove all references to consignment auctions and conditional allowances.

VMA characterizes its second example as an amendment that "strikes language in the definition for 'adjustment for banked allowances.'" VMA Brief at 20. This change, found on page 1 of the Amended Regulations, simply deletes the last phrase from the definition of the term "Adjustment for banked allowances." Specifically:

> "Adjustment for banked allowances" means an adjustment applied to the Virginia CO_2 Budget Trading Program base budget for allocation years 2021 through 2025 to address allowances held in general and compliance accounts, including compliance accounts established pursuant to the CO_2 Budget Trading Program, but not including accounts opened by participating states~~, that are in addition to the aggregate quantity of emissions from all CO_2 budget sources in all of the participating states at the end of the initial control period in 2020 and as reflected in the CO_2 Allowance Tracking System on March 15, 2021~~.

Amended Regulations at 1. DEQ made this change because, by moving from the consignment model to being a "full participant in RGGI" (Act at Section 1331), DEQ was now in sync with RGGI's time schedule—not its own—and it no longer needed an "initial control period in 2020." *See* Amended Regulations at 9 (deleting the term "Initial Control Period.") In other words, the Original Regulations included both an "Initial Control Period" and an "Interim Control Period." *Id.* (including both terms in the Original Regulations). After the Act, DEQ no longer needed both concepts so it deleted the term "Initial Control Period" from the Amended Regulations. *Id.* For consistency, it then deleted the last phrase in the definition of "adjustment for banked allowances" that referenced this now obsolete term. *Id.* at 1. VMA incorrectly characterizes this change as more than it is by describing it as changing "how the adjustment shall be aggregated with other participating states." VMA Brief at 20. This is incorrect. The only revision, as shown on the record, is removing reference to an obsolete term, *i.e.*, allowances from the "Initial Control Period."[13]

[13] After listing six examples of "abundant substantive changes" that VMA contends are illegal, VMA includes another example. VMA claims that "DEQ opted to further exceed its authority" by imposing a new provision requiring manufacturing facilities that generate some of their own electricity to apply for a permit exemption. VMA Brief at 20. According to VMA, this requirement is not in the Act; and is therefore, not exempt from the APA. *Id.* This is another red herring. The manufacturing facility exemption already existed in the Original Regulations; thus, it already went through the APA process. *See* Amended Regulations at 14 (showing the Original Regulations and showing that the exemption found in 9 VAC5-140-6040 is not one of the new amendments). Thus, this exemption already went through the APA process and VMA's opportunity to appeal these regulations has passed.

III. Contrary to VMA's assertion, the Amended Regulations are not vague.

The third argument in VMA's Brief (and its sixth assignment of error in its Petition for Appeal) is that the Amended Regulations are "void as a vague regulation." VMA Brief at 21. As discussed below, VMA's argument is incorrect. First, to establish that a regulation is unlawfully void, VMA faces an incredibly high burden, yet VMA points to no language in the Amended Regulations that comes anywhere close to meeting that burden Second, each of the specific arguments VMA advances in support of its vagueness theory is flawed.

A. The Amended Regulations are not void under Virginia law.

VMA cites two Virginia Supreme Court cases in support of its unlawfully void argument: *Tanner v. City of Va. Beach*, 277 Va. 432 (2009), and *Volkswagon of Am., Inc. v. Smit*, 279 Va. 327 (2010). *See* VMA Brief at 22. In each opinion, the court begins its analysis by stating that setting aside a statute or regulation on voidness grounds, which is rooted in due process concerns, is an extreme remedy that should be avoided if possible. In *Tanner*, the court stated:

> We are required to resolve any reasonable doubt concerning the constitutionality of a law in favor of its validity. Thus, if a statute or ordinance can be construed reasonably in a manner that will render its terms definite and sufficient, *such an interpretation is required*.

Moreover, these facilities were already required to apply for a permit. *See generally* 9 VAC5 Chapter 85 (permits for stationary sources of pollutants subject to regulation). Thus, the permit requirement is not new either. The only new revision DEQ made to this exemption is to provide a new application deadline of January 1, 2022. *See* Amended Regulations at 14. There are other updated deadlines throughout the Amended Regulations. *See, e.g. id.* at 5 (updating calendar year trigger price definitions); at 10 (similar update for the definition of "minimum reserve price"); at 25 (new deadline for submission of CO_2 budget permit applications); at 27 (revising Virginia's base budget to begin in 2021 rather than 2020); at 46 (replacing certain 2020 deadlines with new 2021 deadlines). According to VMA's argument, anytime the General Assembly mandates that a state agency make changes to an existing regulatory regime, the General Assembly must also explicitly empower the agency to make necessary deadline changes that go with those revisions.

Tanner, 277 Va. at 438-39 (emphasis added) (citations omitted). In *Volkswagon*, the court began its analysis by citing *Tanner*, and adding, "a court should not declare a statute to be wholly unconstitutional unless such a determination *is absolutely necessary* to decide the merits of the case. *Volkswagon*, 279 Va. at 337 (emphasis added) (citations and internal quotations omitted).

Thus, VMA as the moving party, has the burden to demonstrate that there is no "reasonable doubt" that the Amended Regulations are so vague that they are incapable of being "construed reasonably in a manner that will render [them] definite and sufficient." *Tanner*, 277 Va. at 439.

VMA cannot meet this burden. The key obligation that the Amended Regulations place on owners and operators of fossil-fuel burning power plants is to acquire CO_2 allowances that are equal or greater than the amount of the plant's CO_2 emissions. This obligation is codified in 9 VAC5-140-6050.C. *See* Amended Regulations at 16. That provision states:

> 1. The owners and operators of each CO_2 budget source and each CO_2 budget unit at the source *shall hold CO_2 allowances* available for compliance deductions under 9 VAC5-140-6260, as of the CO_2 allowance transfer deadline, in the source's compliance account *in an amount not less than the total CO_2 emissions* that have been generated as a result of combusting fossil fuel for an interim control period or control period from all CO_2 budget units at the source….

Id. There is nothing vague about this obligation. Indeed, each of the key terms in this regulation is specifically defined in the Amended Regulations. *See, e.g.*, Amended Regulations at 4 (defining "CO_2 budget source" and "CO_2 budget unit"); at 6 (defining "compliance account"); at 12 (defining "source" and "unit"). VMA fails to explain how any of this is vague; much less, incapable of being "construed reasonably in a manner that will render its terms definite and sufficient," which is the legal standard articulated in *Tanner*. 277 Va. at 438-39.

The Amended Regulations stand in stark contrast to the ordinance at issue in *Tanner*. There, Virginia Beach imposed a city ordinance that made it unlawful "for any person to create, or allow to be created any unreasonably loud, disturbing and unnecessary noise in the city." *Id.* at

435. The ordinance failed to define "unreasonably loud" and the trial court heard testimony from police officers that they interpreted the ordinance using a "reasonable person standard" that "depends on an individual officer's assessment." *Id.* at 437. The Virginia Supreme Court ruled that the ordinance was unlawfully vague because persons subject to the ordinance could not determine in advance whether activity was unlawful. *Id.* at 439-40.

Here, there is no reasonable person test. Indeed, the phrase "reasonable person" does not appear anywhere in the Amended Regulations. VMA fails to demonstrate how any CO_2 unit or budget source, subject to these Amended Regulations, is unable to determine whether activity is unlawful. The Amended Regulations are clear: such a regulated entity must acquire CO_2 allowances that are "not less than" its CO_2 emissions.[14]

There is one final point worth noting about VMA's vagueness claim. Challenges to statutes or regulations on vagueness grounds are due process claims. *See Volkswagon*, 279 Va. at 337. Yet most of the obligations the Amended Regulations place on power plants, such as the obligation to acquire CO_2 allowances, are not new: they are obligations that existed in the Original Regulations. *See, e.g.*, Amended Regulations at 16 (showing only one minor change to 9VAC-140-6050.C). The Original Regulations went through a full APA notice and comment process that VMA participated in. VMA elected not to appeal the Original Regulations. Thus, even if the obligations were somehow vague, VMA has had due process and waived its right to now challenge the specificity of these obligations.

B. Each of VMA's voidness arguments is flawed.

In support of its "unlawfully void" argument, VMA makes three arguments; each is flawed.

[14] Also, *Tanner* involved a city ordinance that applied to the general population. The Amended Regulations, by contrast, apply to fossil-fuel burning electric utilities and other large, sophisticated entities who already comply with a myriad of federal, state, and local regulations.

1. VMA's argument that the Amended Regulations "do not even mention" RGGI ignores the Act's mandate and how the Amended Regulations work.

First, VMA argues that "[w]ithout RGGI, the [Amended Regulations] cannot operate; however, the RGGI program is not even mentioned." VMA Brief at 22. There are two flaws in this argument. First, the Act does not require DEQ to join RGGI or mention RGGI in its amendments; rather, it very specifically mandates that DEQ "establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program." Va. Code § 10.1-1330.B. In other words, the General Assembly gave DEQ flexibility: it could join RGGI, create its own auction "consistent with the RGGI program," or should a new auction be created in the future, join it. *See also* Va. Code § 10.1-1331 ("If the Governor seeks to include the Commonwealth as a full participant in RGGI…."). DEQ followed the Act's mandate by fashioning Amended Regulations that are "consistent with RGGI" but would also be consistent with one of these other options. Thus, rather than being an unlawful ambiguity, the lack of the word "RGGI" in the Amended Regulations is intentional and consistent with the Act.

The second flaw with this argument is that other states' regulations do not mention RGGI either; yet there is no evidence that their auctions, which have been occurring for years, impose vague or uncertain obligations on participants.[15] If VMA's argument that regulations that fail to mention RGGI are so vague that they cannot be complied with, then one would not expect over a

[15] For example, Massachusetts' CO2 Budget Trading Program regulations are nearly identical to Virginia's Amended Regulations, yet Massachusetts has been successfully participating in RGGI auctions for years. *See* 310 Code of Mass. Regulations 7.70 (creating the "Massachusetts CO2 Budget Trading Program," requiring utilities to purchase allowances through that trading program, and only using the word "RGGI" when discussing the "RGGI CO_2 Allowance Tracking System"). *See also* 26 Code of Maryland Regulations Subtitle 9 (establishing the "Maryland CO2 Budget Trading Program" without using the word "RGGI"); 6 New York Code of Rules and Regulations Subpart 242-1 (establishing the New York CO2 Budget Trading Program but not using the word "RGGI"); Code of Vermont Regulations 12-031-002 (establishing the Vermont CO 2 Budget Trading Program but not using the word "RGGI").

decade of successful auctions by other states that have regulations that do not mention RGGI. *See, e.g.,* RGGI Auction Results (showing cumulative auction proceeds since RGGI's inception of $3,953,834,280.29) (available at https://www.rggi.org/auctions/auction-results) (last visited Apr. 14, 2021); RGGI Fourth Compliance Report (Apr. 2, 2021) (finding that "99.1% of covered power section emissions were in compliance" with auction requirements) (available at https://www.rggi.org/sites/default/files/Uploads/PressReleases/2021_04_02_FoCP_Compliance.pdf) (last visited Apr. 14, 2021).

2. VMA's argument that RGGI requirements are de facto rules is internally inconsistent, misapplies caselaw, and is a challenge to the Original Regulations, not the Amended Regulations.

VMA's second argument is that "RGGI requirements are de facto rules neatly eluding public notice or engagement in Virginia." VMA Brief at 24. There are three flaws with this argument. First, it is inconsistent with VMA's prior argument that the regulations are vague for failing to mention RGGI. Both statements cannot be true: regulations cannot be simultaneously vague for not using the word "RGGI" and vague for imposing RGGI.

The second flaw is that it misconstrues the concept of "de facto rules." VMA cites a single case regarding "de facto rules" — *Virginia Bd. Of Med. v. Virginia Physical Therapy Ass'n.*, 413 S.E.2d 59 (Va. Ct. App. 1991). *Id.* That case involved a determination of whether an informal "rule" adopted by the Board of Medicine constituted a "rule or regulation" under the APA. *Virginia Bd. of Medicine*, 413 S.E.2d at 64-65. In that context, the Court of Appeals discussed the concept of a "de facto rule," meaning, an agency action that the agency characterizes as something short of a final rule or regulation, but nonetheless, may constitute a rule or regulation under the APA. *Id.* That concept has no application here. The Amended Regulations are regulations. There

is no dispute. The Amended Regulations did not go through the APA process because the General Assembly expressly exempted them. Va. Code § 10.1-1330.A.

The third flaw in this argument, mentioned in Section A above, is that the *Original Regulations* imposed the requirements VMA now complains of. For example, VMA complains that the Amended Regulations require participants to comply with the requirements for RGGI COATS accounts. VMA Brief at 22. Yet the regulation VMA cites to make this argument, 9VAC5-140-6260, is substantially unchanged by the Amended Regulations. *See* Amended Regulations at 39-41 (showing the only change the Amended Regulations made to this provision is to remove reference to an "initial control period"). In other words, the Original Regulations imposed the same requirements VMA now claims to be unlawfully vague. Yet, the Original Regulations went through a full notice and comment process that VMA participated in and VMA chose not to pursue an APA appeal. Thus, VMA cannot now claim some sort of due process violation for a requirement that is not new. Moreover, the Original Regulations are not before the Court; thus, any alleged ambiguity is not at issue here.

3. VMA offers no evidence to support its claim that a "person of ordinary intelligence" could not comply with the Amended Regulations and the results of Virginia's first CO_2 auction demonstrate that VMA's claim is false.

VMA's third argument is that a "person of ordinary intelligence, in the Revision A20 program could not decipher the program requirements in general." VMA Brief at 23-24. This argument is flawed for two reasons. First, VMA has the burden of proof and, as discussed above, it is a very high burden for a vagueness claim. VMA points to no evidence in the record to substantiate this claim.

Second, this Court can take judicial notice[16] of media accounts of Virginia's first CO_2 auction which occurred earlier this year. As reported, Virginia generated over $43 million in revenue from the first auction and there were no reports of widespread confusion by participants.[17]

IV. VMA's tax claims fail because: (A) they are challenges to the Act, not the Amended Regulations; and (B) the revenue collected is not an illegal tax.

The fourth argument in VMA's Brief (and its fourth and fifth assignments of error in its Petition for Appeal) is that "requiring utilities to buy CO2 allowances to offset 100% of their annual tons of CO2 emissions" is an "illegal carbon tax on Virginia electricity ratepayers." VMA Brief at 25. There are two flaws with this argument. First, it is a challenge to the Act (and other statutes), not a challenge to the Amended Regulations. Second, utilities charging their customers for CO_2 allowances is not an illegal tax under Virginia law.

A. VMA's tax arguments are challenges to the Act, not the Amended Regulations; yet, VMA did not challenge the Act in this case.

According to VMA, "[t]he trading market, as structured under Revision A20, creates a carbon tax outside of the required taxation process." *Id.* Yet, "the trading market," that VMA describes was explicitly mandated by the General Assembly through the Act:

> The Director is hereby authorized to establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program and this article. The Director shall seek to sell 100 percent of all allowances issued each year through the allowance auction. . . .

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[16] Pursuant to Virginia Supreme Court Rule 2:201, this Court may take judicial notice of "a factual matter not subject to reasonable dispute in that it is either (1) common knowledge or (2) capable of accurate and ready determination by resort to sources whose accuracy cannot reasonably be questioned." Va. Sup. R. 2:201(a) (2020).

[17] *See* Sarah Vogelsong, *Virginia Nets More than $43 Million in First Carbon Allowance Auction*, The Virginia Mercury (Mar. 9, 2021) (available at https://www.virginiamercury.com/blog-va/virginia-nets-more-than-43-million-in-first-carbon-allowance-auction/) (last visited Apr. 13, 2021). VMA has provided no evidence of widespread confusion in any of the other RGGI states since their adoption of similar regulations.

Va. Code § 10.1-1330.B. Thus, the General Assembly — not DEQ — created "the trading program" that VMA asserts is an illegal tax and the General Assembly mandated that the DEQ Director sell "100 percent" of all allowances through that program. Yet VMA did not challenge the Act.

VMA similarly argues that "the CECFPA directs the state treasury to hold the proceeds recovered from the allowance auction in an interest-bearing account," and by doing so, "the CECFPA specifically evades the general treasury." VMA Brief at 26. According to VMA, this evasion of the general treasury is unconstitutional. *Id.* But as VMA's own brief demonstrates, this is an argument against the Act, not the Amended Regulations. *Id.* ("the CECFPA specifically evades the general treasury…").

VMA did not challenge the constitutionality of the Act. Instead, VMA is asking this Court to set aside the Amended Regulations. But even if this Court did so, the Act would remain in place; thus, the "illegal tax" VMA claims exists would remain.

B. Even if the Act was before this Court, the General Assembly's authorization for utilities to include the costs of allowances in their rates is not an illegal tax.

VMA argues that "Revision A20 effectively *imposes a tax on electricity ratepayers* because the CECFPA provides for recovery of these costs through rates as environmental compliance project costs." VMA Brief at 25 (emphasis added). Not only is this argument, as discussed above, a challenge to the Act rather than to the Amended Regulations, this argument suffers from two additional defects: this provision is neither a tax nor illegal.

First, the Act mandates the creation of a CO_2 direct auction program. Va. Code § 10.1-1330.B. The potential added costs of electricity that ratepayers may pay utilities to comply with that program is not a tax under Virginia law. As the United States Court of Appeals for the Fourth Circuit reasoned in *Corr v. Metro. Wash. Airports Auth.*, 740 F.3d 295, 300 (4th Cir. 2013), in

assessing an illegal tax claim, "Virginia courts ask whether a given exaction is a bona fide fee-for-service or an invalid revenue-generating device." For example, tolls "are user fees and not taxes when they are nothing more than an authorized charge for the use of a special facility." *Id.* (quoting *Elizabeth River Crossings OpCo., LLC v. Meeks*, 749 S.E.2d 176, 183 (Va. 2013) (internal quotation marks omitted)). The rate that electricity customers pay an electricity utility is the "authorized charge" the customer pays in exchange for receiving the electricity. *Id.* The fact that the General Assembly, through the Act, has allowed utilities to include within that fee the costs of purchasing CO_2 allowances necessary to produce that electricity does not transform a customer's electricity bill into a tax.[18]

The second defect with VMA's argument is that even if passing on the costs of purchasing CO_2 allowances to ratepayers did constitute a tax, the General Assembly has the legal authority to levy taxes. *See* Va. Cont. Art. VII, § 7. *See also Wise Cty Bd. of Supervisors v. Wilson*, 250 Va. 482, 484 (1995) ("no entity other than an elected governing body may levy taxes"). The constitutional limitation on the General Assembly's taxing power is found in Article X, Section 7 of the Virginia Constitution, which states that "[n]o money shall be paid out of the State treasury except in pursuance of appropriations made by law." Va. Const. Art X, § 7. The Virginia Supreme Court has interpreted the term "appropriation" to mean "payment out of the state treasury." *Button v. Day*, 203 Va. 687, 695 (1962). Thus, taxes collected in Virginia can only be paid out of the state

[18] If VMA's argument were correct, every "environmental compliance project cost" that a utility includes in its costs of service would constitute an illegal tax on rate payers. For example, the General Assembly allows a utility to charge all its customers for the costs of projects that replace existing overhead powerlines with underground power lines. *See* Va. Code § 56-585.1.A.6. According to VMA, this cost sharing would be an illegal tax because it is a project cost that is paid for by all customers for a public need. Similarly, the General Assembly allows utilities to include the "cost of compliance" with renewable energy portfolio standards as part of its cost of service. Va. Code § 56-585.1.A.5.d. These costs, according to VMA's logic, would also constitute illegal taxes on electricity customers.

treasury if authorized by the General Assembly through the passage of a law. Here, the General Assembly did just that: it passed the Act. Specifically, Section 10.1-1330.C of the Act, begins with, "[t]o the extent permitted by Article X, Section 7 of the Constitution of Virginia," and then articulates exactly how proceeds from direct auctions are to be distributed. Thus, even if the Act were challenged in this case (which it is not), and even if requiring electricity customers to pay through electricity rates for the purchase of CO_2 allowances necessary to produce their electricity constituted a tax (which it does not), it is not an unconstitutional or illegal tax because the General Assembly explicitly directed how the proceeds should be distributed through a law.

V. VMA is not entitled to attorneys' fees under the APA or otherwise.

In its petition, VMA requests that this Court award it attorneys' fees that VMA incurred in bringing this action. VMA Pet. at 26. Pursuant to Virginia Code Section 2.2-4030, a party is only entitled to attorneys' fees in an APA appeal if "(i) the agency's position is not substantially justified, (ii) the agency action was in violation of law, or (iii) the agency action was for an improper purpose." Va. Code § 2.2-4030.A.

Here, none of these elements have been satisfied. As discussed above, DEQ's issuance of the Amended Regulations was mandated by the General Assembly through the Act and the Act expressly exempted the Amended Regulations from the APA. Thus, DEQ neither violated the law nor acted "for an improper purpose." *Id.* For all the reasons stated above, DEQ respectfully requests that this Court deny VMA's request for attorneys' fees.

Conclusion

This case is important. In 2020, the Virginia General Assembly passed historic environmental legislation that addresses both the causes of climate change and its impact on vulnerable communities in Virginia. Part of that legislation required that DEQ amend the existing CO_2 budget trading program by moving to a direct auction model and then selling 100% of Virginia's CO_2 allowances in those auctions. The General Assembly expressly exempted these amendments from the APA. DEQ followed the General Assembly's mandate: it issued the Amended Regulations that made all necessary changes to the existing CO_2 Budget Trading Program. Now, DEQ is directly auctioning CO_2 allowances and the proceeds, which were over $43 million in the first auction, are going to support programs for low-income communities and vulnerable shorelines. This is exactly what the General Assembly legislated.

Yet this case is not complicated. VMA has challenged the Amended Regulations, but not the Act. Contrary to VMA's assertions, the Amended Regulations expressly follow the Act, they do not violate it. There can be no APA violation because the Act exempts the Amended Regulations from the APA. The Amended Regulations are not unlawfully vague. Finally, allowing utilities to charge their customers for the costs of CO_2 allowances is not an issue before this Court (because it is an issue that goes to the Act, not the Amended Regulations), and even if it was, doing so is not an illegal tax.

The Virginia General Assembly acted to address climate change and vulnerable communities in Virginia are receiving the benefit of these actions. This Court should not be persuaded to undermine this progress.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the above Brief in Opposition was served via certified mail and by electronic mail on May 7, 2021, on the following:

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Attachment 20

Virginia:

In the Circuit Court of the City of Richmond, John Marshall Courts Building

VIRGINIA MANUFACTURERS ASSOCIATION	)	
Petitioner,	)	
v.	)	**Case No.: CL20-4918**
VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY, DAVID PAYLOR DIRECTOR, VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY, AND THE VIRGINIA STATE AIR POLLUTION CONTROL BOARD;	)	
Respondents.	)	

OPINION ORDER

Virginia Manufacturers Association (hereinafter, "VMA") came before the Court on June 30, 2021, to be heard on its Petition for Appeal which named the Virginia Department of Environmental Quality, David Paylor, and the Virginia State Air Pollution Control Board (hereinafter, "Respondents" or "DEQ") as Respondents. The Court took the matter under advisement and denies VMA's petition for the reasons set forth below.

I. Procedural History

VMA filed a Petition for Appeal on October 2, 2020 asserting six Assignments of Error, four of which outline how DEQ allegedly violated the Virginia Administrative Process Act ("VAPA") when it amended the regulation governing Virginia's CO_2 Budget Trading Program. The remaining Assignments of Error allege that the amended regulation is constitutionally infirm because it is both void for vagueness and levies a tax in violation of Article X, Section 7 of the Virginia Constitution. To remedy the alleged violations, VMA asks the Court to invalidate, vacate, and declare the amended regulation null and void.

On October 20, 2020, Virginia Interfaith Power & Light, Wetlands Watch, and Appalachian Voices (collectively, the "Conservation Organizations") filed a Motion to Intervene as Respondents. The Court denied the Motion to Intervene on February 9, 2021 for the reasons stated in the Court's Letter Opinion.

On October 28, 2020, DEQ filed a Motion to Dismiss the Petition for Appeal. The Court denied the Motion to Dismiss on January 29, 2021.

The Court entered a briefing schedule Order on April 1, 2021, and the parties' briefs were submitted in compliance with the deadlines established therein. On May 7, 2021, the Conservation Organizations filed a Motion for Leave to File an *Amicus Curiae* Brief in Support of Respondents. The *amicus* brief was filed contemporaneously with the motion.[1] The *amicus* brief assists the Court in deciding the issues presented in this appeal and therefore, the Court will take it into consideration. 4 Am. Jur. 2d *Amicus Curiae* §§ 1, 5 (2021); *Jones v. Caldwell*, 61 Va. Cir. 408 (2003).

II. Factual Background

As a preliminary matter, the issue on appeal is whether the amendment of the CO_2 Budget Trading Program was lawful. VMA devoted a considerable amount of time arguing that the amended trading program imposes significant financial burdens on the entities required to participate and that similar programs have failed to effectively reduce carbon emissions. On the other hand, DEQ argues that the trading program reduces CO_2 emissions, improves public health, and helps keep electricity costs down. The parties' dispute whether the CO_2 Budget Trading Program is "good" for the Commonwealth or "successful" in accomplishing the goal of reducing CO_2 emissions is irrelevant to the questions presented. However, the history of the CO_2 Budget Trading Program and the events preceding this appeal must be discussed to better understand the legal issues presented.

a. The Original Regulation

In June of 2016, former Governor McAuliffe issued Executive Order 57 which directed the Secretary of Natural Resources to convene a study and recommend ways in which the Commonwealth could attempt to reduce the amount of carbon dioxide emitted by utilities that produce electricity. The study group recommended, among other things, the need to promulgate a regulation "limiting the total amount of carbon dioxide emitted from electric power facilities." Va. Exec. Directive No. 11 (May 16, 2017). Governor McAuliffe agreed, directed DEQ to promulgate a regulation, and specified that it should:

a. Include[] provisions to ensure that Virginia's regulation is 'trading-ready' to allow for the use of market-based mechanisms and the trading of carbon dioxide allowances through a multi-state trading program; and

b. Establish[] abatement mechanisms providing for a corresponding level of stringency to limits on carbon dioxide emissions imposed in other states with such limits.

Id. DEQ published the proposed regulation in January of 2018 and presented it to the State Air Pollution Control Board for consideration for approval for public comment. *Id.* The regulation was re-proposed in February of 2019 to address feedback received from the VAPA notice and comment

[1] Although the Conservation Organizations were not subject to the filing deadlines set forth in the Court's briefing schedule Order, the *amicus* brief was filed in accordance with the deadlines applicable to DEQ.

process, and more public comment was received. Pet. for Appeal ¶ 33. The Air Board adopted the regulation (hereinafter, the "Original Regulation") on April 19, 2019, and it was published as a new chapter of the Air Board's regulations on May 27, 2019. *Id.* ¶ 35. Neither party disputes that the Original Regulation was fully vetted through the VAPA. *Id.* ¶ 33.

The Original Regulation established the Virginia component of the CO_2 Budget Trading Program. Designed to operate as a consignment-based, conditional allowance program, it proscribed that CO_2 allowances would be allocated to electricity manufacturers, sold by the manufacturers into an auction market, and thereafter repurchased by the manufacturers at auction. Pet. for Appeal ¶ 30-31. The auction market into which the CO_2 allowances were to be sold and purchased was that created by the Regional Greenhouse Gas Initiative ("RGGI"). *Id.* ¶ 31. At oral argument, the parties conceded that RGGI is the only currently existing auction house for trading CO_2 allowances.

Although properly adopted and intended to go into effect in 2020, the General Assembly passed a budget provision preventing DEQ from implementing the program and joining RGGI as a consignment member. H.B. 1700, CH. 854, Item 4-5.11, Reg. Sess. (Va. 2019).

b. The Clean Energy and Flood Preparedness Act

In 2020, the General Assembly struck the budgetary restriction. H.B. 29, Ch. 1283, Item 4-5.11, Reg. Sess. (Va. 2020). With the Original Regulation still intact, Virginia was permitted to join or participate in RGGI as a consignment member. Instead, the General Assembly enacted the Clean Energy and Flood Preparedness Act (the "Act"), Virginia Code § 10.1-1329 *et seq.*, which authorized DEQ to move away from the consignment-based model and establish a direct auction trading system.

The Act authorized the Director of DEQ "to establish, implement, and manage an auction program to sell allowances into a market-based trading program consistent with the RGGI program and this article." Va. Code § 10.1-1330(B). The Act also directed DEQ to incorporate "[t]he provisions of this article" into the Original Regulation "without further action by the [Air Pollution Control] Board," and provided that "[s]uch incorporation . . . shall be exempt from the" VAPA. Va. Code § 10.1-1330(A).

On July 10, 2020, DEQ issued Revision A20 (hereinafter, the "Amended Regulation") which amended the Original Regulation by converting the CO_2 Budget Trading Program from the prior consignment-based model to a direct auction trading system. VMA argues that DEQ acted beyond the scope of the Act's exemption in doing so and that no other VAPA exemptions save its actions. VMA additionally argues that the Amended Regulation is both unlawfully vague and imposes a tax which DEQ is not authorized to levy.

III. Standard of Review

As VMA is the "the party complaining of agency action," it carries the burden "to designate and demonstrate an error of law subject to review." Va. Code § 2.2-4027.

> Such issues of law include: (i) accordance with constitutional right, power, privilege, or immunity, (ii) compliance with statutory authority, jurisdiction

> limitations, or right as provided in the basic laws as to subject matter, the stated objectives for which regulations may be made, and the factual showing respecting violations or entitlement in connection with case decisions, (iii) observance of required procedure where any failure therein is not mere harmless error, and (iv) the substantiality of the evidentiary support for findings of fact.

Id. The issues in this appeal concern matters of statutory interpretation. "A question of statutory interpretation is subject to review *de novo* on appeal." *Karr v. Va. Dep't of Envtl. Quality*, 66 Va. App 507, 513 (2016) (internal quotation and citations omitted). The parties do not dispute that the issues raised in VMA's Petition for Appeal present questions of statutory and constitutional interpretation. Accordingly, the Court must analyze the Act and DEQ's actions in accordance with well-settled principles of statutory interpretation to determine whether DEQ had "statutory authorization" to issue the Amended Regulation and whether "it did so within the statutory limits of its discretion and with the intent of the statute in mind[.]" *Va. Jockey Club, Inc. v. Va. Racing Comm'n*, 22 Va. App. 275, 286 (1996) (internal quotations and citation omitted). In doing so, the Court does not construe the statue "by singling out a particular phrase." *Va. Electric & Power Co. v. Citizens for Safe Power*, 222 Va. 866, 869 (1981).

IV. Discussion

a. Whether Amending the Regulation Was Exempt from the VAPA

VMA asserts the Act did not grant the Director of DEQ an unbridled VAPA exemption to substantively amend the Original Regulation. According to VMA, the General Assembly permitted the Director to incorporate or, in essence, lift the language from the Act and place it into the Original Regulation. It argues that any further action was subject to the requirements of the VAPA. Because DEQ allegedly acted outside the scope of the Act's VAPA exemption, VMA requests the Court to declare the Amended Regulation null and void.

As an initial matter, VMA claims that DEQ cannot invoke the VAPA exemption contained in Virginia Code § 2.2-4006(A)(4)(a). DEQ has conceded that it does not attempt to claim that exemption. Pursuant to Virginia Code § 2.2-4006(A)(4)(a), DEQ is permitted to bypass the VAPA when issuing regulations "[n]ecessary to conform to changes in Virginia statutory law or the appropriation act where no agency discretion is involved." The Court agrees with DEQ that it never intended to, nor needed to, invoke this exemption. The Act contains a specific VAPA exemption rendering it unnecessary for DEQ to seek to comply with one which is broader and more generalized. Va. Code § 10.1-1330(A).

VMA concedes that "DEQ was permitted to avoid [V]APA procedural requirements for a revision" but argues that the exemption only permitted DEQ to copy the language of the Act and paste into the Original Regulation verbatim. Pet'r Br. in Supp. 19. Converting the CO_2 Budget Trading Program to a direct auction trading system, it argues, fell outside the scope of the Act's VAPA exemption and therefore, the Amended Regulation must be nullified because it was not vetted through the VAPA.

When the language of a statute is "clear and unambiguous," the Court is to "assign the statute its plain meaning." *Browning-Ferris Indus. v. Residents Involved in Saving the Env't, Inc.*, 254 Va. 278, 284 (1997). "The plain, obvious, and rational meaning of [the] statute is preferred

over any curious, narrow, or strained construction." *Karr*, 66 Va. App. at 527 (quoting *Commonwealth v. Zamani*, 256 Va. 391, 395 (1998)).

The Act directs DEQ to incorporate its provisions into the Original Regulation. "Incorporate," as that word is commonly used, means "to unite or work into something already existent so as to form an indistinguishable whole." *Incorporate*, Merriam-Webster.com, https://www.merriam-webster.com/dictionary/incorporate (last visited July 12, 2021). In context, DEQ was directed to take the provisions of the Act and unite them into the Original Regulation to create an indistinguishable regulation applicable to electricity manufacturers that emit CO_2. The incorporation language specifically identifies the already existent regulation into which the Act is to be incorporated – the Original Regulation – and expressly provides that the Air Board need not approve, and the VAPA shall not apply to, such incorporation. Va. Code § 10.1-1330(A).

It is well-settled "that every part of a statute is presumed to have some effect and no part will be considered meaningless unless absolutely necessary." *Hubbard v. Henrico Ltd. P'ship*, 255 Va. 335, 340 (1998). VMA argues that the General Assembly directed DEQ to take the language of the Act and add it to the Original Regulation verbatim. In other words, the General Assembly directed DEQ to recite what the General Assembly had already stated. Doing so, however, would have produced no change. The Original Regulation would proscribe the particulars of a consignment-based trading program but state that DEQ is authorized to "establish, implement, and manage" one that operates differently. If VMA were correct in arguing that DEQ had to comply with the VAPA before converting the Original Regulation to a direct auction program, the trading program would remain unchanged, and the Amended Regulation would have provided nothing more than what was stated in the Act itself. The amendment contemplated by VMA would have been wholly ineffectual.

When interpreting the plain language of a statute, the Court is to construe it "so as to avoid an absurd result." *Eastlack v. Commonwealth*, 282 Va. 120, 126 (2011) (citing *Commonwealth v. Doe*, 278 Va. 223, 230 (2009)). Here, however, VMA singles out the language of incorporation without reading the Act in context. If its cut and paste argument were correct, DEQ would have produced a convoluted and confusing regulatory scheme. The Original Regulation would specify how the consignment-based trading program shall operate and define terms such as "conditional allowances" and "consignment auctions." It would simultaneously state that the Director of DEQ is "authorized to establish, implement, and manage" a direct auction trading program under which CO_2 allowances are not consigned and consignment auctions are not held.

Further confusion would result from a verbatim transfer of language because certain language in the Act has no application to manufacturers required to participate in the CO_2 Budget Trading Program. For instance, VMA claims that DEQ failed to include a provision of the Act stating that the revenues generated by DEQ's sale of CO_2 allowances will be held by the state treasury and spent for enumerated purposes. Va. Code § 10.1-1330(C). It would be nonsensical to include such language in a regulation governing electricity manufacturers. The enacted language was not a directive to DEQ. Instead, its inclusion was necessitated by the fact the General Assembly authorized DEQ to sell CO_2 allowances directly into the auction market rather than

consign them to participants.[2] Determining what to do with the revenue generated from those sales was a question for the General Assembly which it answered in the Act.

Furthermore, VMA believes the General Assembly directed DEQ to add to the Original Regulation an entirely new set of definitions – those set forth in Virginia Code § 10.1-1329 – effectively creating two sets of definitions in a single regulation. Not only would doing so have been duplicative of certain definitions included in the Original Regulation, the newly defined terms would be meaningless. The newly added set of definitions would clarify that "'DHCD' means the Department of Housing and Community Development" and define what an "energy efficiency program" is, yet neither the abbreviation nor the phrase are used in the regulation itself. Va. Code § 10.1-1329. The newly added definitions would also be prefaced with the phrase, "[a]s used in this article, unless the context requires a different meaning[,]" yet appear in a regulation. *Id.*

The General Assembly did not direct DEQ to amend the Original Regulation in a manner which would only confuse those required to participate and substantively amend nothing. Rather, it authorized DEQ to convert the trading program to a direct auction trading system and directed DEQ to sell, not consign, CO_2 allowances. The General Assembly not only authorized this change, but it also exempted DEQ from requirements which would otherwise apply in the absence of language to the contrary.

It is worth noting that when DEQ issued the Original Regulation in response to the Governor's directive, it had to both comply with the VAPA and receive Air Board approval. If the General Assembly had not included the exemption in this new Act, the Amended Regulation would have been subject to the same requirements and the amendment process would have been prolonged.

VMA attempts to distinguish the VAPA exemption language from other instances in which the General Assembly granted exemptions, yet the examples they provided either applied to the enactment of wholly new regulations or contained differing exemption language for different mandates. The exemption language here applies to the amendment of a preexisting regulation and does not differentiate between exempt and non-exempt actions. "Courts assume that the General Assembly chose, with care, the words it used in enacting the statute." *Kalergis v. Comm'r of Highways*, 294 Va. 260, 266 (1017). If the General Assembly intended for the VAPA to apply, it would have stated so. In fact, in the same session in which the Act was enacted, the General Assembly did so expressly when it added a new subsection E to Virginia Code § 10.1-1308 which states: "Regulations adopted by the [Air Pollution Control] Board under this subsection shall be subject to the requirements set out in" specific provisions of the VAPA.[3]

The Court recognizes that bypassing the VAPA may have prevented interested parties from providing important input into the rulemaking process, but DEQ did what the General Assembly

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[2] Under the Original Regulation, DEQ was to consign the allocated number of CO_2 allowances to manufacturers. However, the Act stated that DEQ "shall seek to *sell* 100 percent of all allowances issued each year through the allowance auction[.]" Va. Code § 10.1-1330(B) (emphasis added). The revenue generated from the sale of allowances is to be held by the state treasury and used for environmental mitigation purposes. Va. Code § 10.1-1330(C).

[3] Other state statutes that authorize the issuance of regulations establishing the state's CO_2 Budget Trading Program expressly require compliance with that state's version of the APA, yet the General Assembly in this case provided the exact opposite. *See* Conn. Gen. Stat. § 22a-200c (requiring that adoption of such regulations be "in accordance with" Connecticut's Uniform Administrative Procedure Act).

required it to do. Therefore, the Court **FINDS** that DEQ did not violate the VAPA in issuing the Amended Regulation.

b. Whether DEQ Impermissibly Added a Permitting Requirement

VMA argues that the Amended Regulation impermissibly added a permitting requirement which was neither found in the Original Regulation nor authorized by the Act. DEQ argues that the Original Regulation contained the same permitting requirement and therefore, this provision of the Amended Regulation remains unchanged.

Subsection A of the "Applicability" provision specifies which manufacturers are required to participate in the CO_2 Budget Trading Program. 9 VAC 5-140-6040(A). Subsection B of the "Applicability" provision previously stated:

> *Exempt* from the requirements of this part is *any* fossil fuel *CO_2 budget source* located at or adjacent to and physically interconnected with a manufacturing facility that, prior to January 1, 2019, and in every subsequent calendar year, *met either of the following requirements*:
>
> . . .
>
> "Such CO_2 *budget source* shall have an operating permit containing the applicable restrictions *under this subsection*."

9 VAC 5-140-6040(B) (2019) (emphasis added) (amended 2020). The Amended Regulation merely added the word "exempt" to say: "Such exempt CO_2 budget source shall have an operating permit containing the applicable restrictions under this subsection." 9 VAC 5-140-6040(B). The permit requirement in the Original Regulation clearly applied to exempt budget sources. The word "exempt" only clarified, but did not change, what was previously required.

The other change VMA takes issue with is a provision clarifying that exempt budget sources must file an application permit by January 1, 2022. 9 VAC 5-140-6040(B). The Original Regulation required all CO_2 budget sources to file an application permit by January 1, 2020; however, that deadline was rendered obsolete as the Amended Regulation was issued on July 10, 2020. If DEQ had not changed the permitting deadline, the Amended Regulation would require budget sources to submit permit applications after the deadline for doing so had expired. DEQ simply extended the generally applicable permitting deadline to January 1, 2021 and provided exempt budget sources with a further extended deadline of January 1, 2022. *Compare* 9 VAC 5-140-6040(B), *with* 9 VAC 5-140-6150.

Exempt and non-exempt manufacturers are subject to the same permitting requirements that were set forth in the Original Regulation. The other change only extends the deadline by which exempt budget sources must submit permitting applications. For these reasons, the Court **FINDS** that the Amended Regulation did not add a new permitting requirement and that DEQ did not otherwise act outside the scope of the VAPA exemption.

c. Whether the Amended Regulation is Void for Vagueness

VMA argues that the Amended Regulation is so vague that no participant of ordinary intelligence can discern what is necessary for compliance. Specifically, VMA alleges that the Amended Regulation fails to define key operational aspects of the CO_2 Budget Trading Program such as how CO_2 allowances are to be obtained. It also asserts that the Amended Regulation does not mention "Regional Greenhouse Gas Initiative" or "RGGI" but participants must comply with RGGI's internal rules, which are "de facto" rules subject to the VAPA.

First, VMA has not pointed to any case in which the void for vagueness doctrine has been applied in the regulatory context. It cites to *Tanner v. City of Va. Beach*, 227 Va. 431 (2009) (analyzing whether a city noise ordinance was facially vague or vague as applied to plaintiffs) and *Volkswagen of Am., Inc. v. Smit*, 279 Va. 327 (2010) (analyzing whether a statute was impermissibly vague as applied), but neither case contains a claim similar to the one asserted here. Furthermore, *Tanner* and *Volkswagen* establish that VMA carries a high burden to prevail on this assertion.

Second, VMA has not pointed to any vague or incomprehensible provision within the Amended Regulation. To comply with the CO_2 Budget Trading Program, electricity manufacturers must hold CO_2 allowances in an amount equal to or greater than the amount of CO_2 they emit. 9 VAC 5-140-6050(C). VMA participated in the development of the Original Regulation, and all material aspects of this provision remain identical. A statute, and perhaps also a regulation, is not vague if it can be "construed reasonably in a manner that will render its terms definite and sufficient[.]" *Tanner*, 227 Va. at 438-39. The Amended Regulation sets forth what the manufacturers need to do for compliance purposes – hold a certain amount of CO_2 allowances relative to the amount of CO_2 they emit – using explicit and definite terms. It specifies which entities must participate, the requirements for permitting and monitoring, where the allowances are to be held, how compliance is measured, penalties for non-compliance, recordkeeping requirements, and how Virginia's budget for allowances will change over time. The Amended Regulation sufficiently details what manufacturers are required to do for compliance purposes, and Virginia has since held two successful auctions with no reported confusion.

VMA next asserts that the rules governing the actual trading market are "de facto" rules created by RGGI which may change in the future and potentially deprive participants of their due process rights. However, the Original Regulation also required participants to use the RGGI auction house for trading allowances. *See* Pet. for Appeal ¶¶ 34, 36. VMA's concern that RGGI rules may change in the future are merely hypothetical and not ripe for review. Furthermore, the cases VMA cites for this proposition are inapposite because they involve an agency's interpretation of a regulation. *See Va. Bd. of Med. v. Va. Physical Therapy Ass'n*, 13 Va. App. 458 (1991); *Jerri's Ceramic Arts, Inc. v. Consumer Prod. Safety Comm'n*, 874 F.2d 205 (4th Cir. 1989). Lastly, manufacturers are only required to comply with RGGI rules if they choose to acquire allowances through the RGGI auction market. They are free to acquire the required amount of allowances on a secondary market.

For the foregoing reasons, the Court **FINDS** that VMA's vagueness claims fail.

d. Whether the Amended Regulation Imposes an Unconstitutional Tax

VMA alleges that the Amended Regulation imposes an illegal tax DEQ is not authorized to levy. It claims that participants will incur costs in complying with the Amended Regulation which will then be passed down to consumers under the guise of an "environmental compliance cost" which is a tax. Because the General Assembly possesses the authority to impose taxes and has not delegated such authority to DEQ, the Amended Regulation must be declared null and void.

This taxation argument focuses on the revenues the CO_2 Budget Trading Program will generate. DEQ argues that it only sells the CO_2 allowances into the market and enforces the Amended Regulation. While the revenue is generated from the sale by DEQ, it argues that it does nothing with respect to such revenues after the sale has been made. The Court agrees. The General Assembly directed DEQ to establish, implement, and manage the CO_2 Budget Trading Program. Va. Code § 10.1-1330(B). It also authorized DEQ to sell rather than consign CO_2 allowances. *Id.* As VMA notes, DEQ did not copy and paste Virginia Code § 10.1-1330(C) into the Amended Regulation, but it did not need to do so as discussed above. Aside from the requirements set forth in Amended Regulation, DEQ has no role.

VMA conceded at oral argument that the Amended Regulation does not cloak DEQ with authority to decide where the revenue is to be held or how it is to be spent. The operational aspects concerning revenues generated is controlled by the statute itself. Va. Code § 10.1-1330(C). As part of the Act, the General Assembly directed the state treasury to hold and allocate the auction proceeds. *Id.* The General Assembly also declared that the state treasury shall distribute the proceeds "without further appropriation." *Id.*

Because VMA's constitutional challenge is directed at the Act itself, the Court **FINDS** that the Amended Regulation is not violative of the Virginia Constitution.

V. Conclusion

Upon consideration of the pleadings, briefs, argument of counsel, and for the reasons discussed above, the Court **FINDS** that DEQ did not violate the VAPA or the Virginia Constitution when it issued the Revised Regulation. Therefore, VMA's Petition for Appeal is hereby **DISMISSED**.

Pursuant to Rule 1:13 of the Supreme Court of Virginia, the Court dispenses with the Parties' endorsement of this Order.

The Clerk is directed to forward a copy of this Order to all parties.

It is so **ORDERED**.

ENTER: 7/14/21

Beverly W Snukals

Judge

Attachment 21

https://richmond.com/news/state-and-regional/govt-and-politics/the-mystery-of-the-secret-virginia-air-board-document/article_4bc77dff-7562-53c8-a65b-eabb1af3c34d.html

FEATURED

The mystery of the secret Virginia air board document

Patrick Wilson
May 13, 2022

DEQ Director Mike Rolband addressed the Virginia State Air Pollution Control Board during its meeting at the Parha on April 20.

SHABAN ATHUMAN/TIMES-DISPATCH

Patrick Wilson

Air Pollution Control Board Member Hope Cupit tells Virginia DEQ Director Mike Rolband that the Virginia attorney general's office gave her a document in March saying Virginia's participation in the Regional Greenhouse Gas Initiative is up to the General Assembly, not the Air Board.

State officials are refusing to release a document that purportedly undercuts Gov. Glenn Youngkin's desire to remove Virginia from a greenhouse gas reduction program.

Youngkin wants the Virginia State Air Pollution Control Board to consider an emergency regulation that would remove Virginia from the **Regional Greenhouse Gas Initiative**, a multistate program in which energy producers charge their customers to cover the costs of reducing pollution.

But a member of the air board said at the panel's April 20 meeting that the attorney general's office believes only the General Assembly can remove Virginia from the program.

Hope Cupit said she received an "opinion" in March from the attorney general's office. But she and the attorney general's office declined to release it. A staffer with the Virginia Department of Environmental Quality said someone there had the document "at one point."

People are also reading...

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DEQ's Natalie Womack declined to explain how someone at DEQ had the document "at one point" but supposedly no longer has it.

In any event, the mysterious document — which would undercut Youngkin's goal — remains secret.

After he was elected, Youngkin **gave a speech in December** saying he would remove Virginia from the greenhouse program, known as RGGI, by executive action. But the General Assembly passed a law in 2020 requiring Virginia to join the program, and a governor doesn't have the power to overturn a law.

Under RGGI, energy producers in a number of states trade emission reductions for credits, or buy credits to emit carbon dioxide past a cap. The states in the program are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont and Virginia.

Youngkin **backed off his plan**, and instead issued an **executive order** calling on the air board to consider a regulation removing Virginia from RGGI. Environmental groups say even that would be illegal because a regulatory board can't overturn a state law.

Cupit, the air board member, asked DEQ Director Mike Rolband at the April 20 board meeting about the administration's plan for an emergency regulation for the air board to consider. (Air board members are appointed by the governor, and DEQ

acts as staff to the air board.)

DEQ staff in March **issued a report** — as requested by Youngkin's executive order — about how the agency believes Virginia could remove itself from the program.

Rolband told her the process was "complicated" and is being "vetted by a lot of different people."

He said the emergency regulation would need review and approval by the air board, and that would begin the process of removing the state from RGGI, which DEQ's report said was an "emergency" because of the costs. Rolband said the attorney general's office would review everything first.

That's when Cupit introduced an issue that seemed to surprise Rolband.

"I did reach out to the attorney general's office and was told that this is not an action of the board, it actually is an action of the General Assembly," Cupit said at the meeting.

She added: "I got an opinion from the attorney general's office back in March saying that it's not the responsibility of the board, that it's the responsibility of the General Assembly."

Rolband asked Cupit to provide him with a copy of it, and she said she would.

The Richmond Times-Dispatch asked Cupit after the meeting for a copy of what the attorney general sent her; she said she'd check to see if she could release it, but never responded.

Victoria LaCivita, a spokeswoman for the attorney general, said by email for this story that there had been "no official or unofficial AG's opinion on RGGI issued by this administration."

But pressed as to whether the attorney general's office provided Cupit with anything in writing, a special counsel in the office, Stephanie Hamlett, said there was a document. She said the attorney general declined to release it, and she cited a discretionary FOIA exemption for written advice of legal counsel.

Womack, the DEQ staffer, declined to explain the circumstances under which someone at DEQ had the document "at one point" but no longer did.

Womack also responded last week on behalf of Cupit, the air board member, saying Cupit was opting not to release the document. Womack cited the discretionary FOIA exemption for legal advice.

Nothing in the Freedom of Information Act stops the attorney general's office or Cupit from releasing the document, but FOIA allows them to withhold it, at their discretion.

So for now, the mystery of the secret air board document remains unsolved.

Under RGGI, the revenue Virginia gets is directed to programs that help low-income people reduce energy usage — thereby lowering their cost of electricity — and for programs combating sea level rise in coastal areas and inland flooding across the state.

Under the initial RGGI cost recovery request from Dominion Energy, the state's largest electric utility, a typical customer's bill increased $2.39 a month because of the program.

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By Patrick Wilson

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Attachment 22

Table 3. 2020 State energy-related carbon dioxide emissions by sector

State	million metric tons of energy-related carbon dioxide						shares				
	Commercial	Electric Power	Residential	Industrial	Transportation	Total	Commercial	Electric Power	Residential	Industrial	Transportation
Alabama	2.1	42.7	1.9	18.0	33.6	98.3	2.1%	43.4%	1.9%	18.3%	34.2%
Alaska	2.1	2.7	1.7	17.6	11.9	36.0	5.9%	7.6%	4.6%	48.9%	33.0%
Arizona	2.8	35.6	2.6	4.7	34.4	80.1	3.6%	44.4%	3.2%	5.9%	43.0%
Arkansas	3.3	22.6	1.9	8.4	18.6	54.7	6.1%	41.2%	3.5%	15.3%	34.0%
California	18.4	33.6	26.6	64.3	160.4	303.4	6.1%	11.1%	8.8%	21.2%	52.9%
Colorado	4.3	28.6	8.5	12.9	25.6	79.9	5.4%	35.8%	10.6%	16.2%	32.0%
Connecticut	3.8	8.7	6.6	1.7	13.0	33.8	11.3%	25.6%	19.5%	4.9%	38.6%
Delaware	1.0	1.8	0.9	3.9	4.9	12.5	8.1%	14.5%	7.0%	31.1%	39.4%
District of Columbia	0.9	0.0	0.6	0.0	0.9	2.4	36.4%	0.0%	25.7%	1.0%	36.9%
Florida	6.5	92.3	1.4	11.2	96.3	207.6	3.2%	44.4%	0.7%	5.4%	46.4%
Georgia	4.4	37.3	7.1	11.7	56.1	116.6	3.8%	32.0%	6.0%	10.1%	48.1%
Hawaii	0.5	5.9	0.1	0.9	7.6	14.9	3.2%	39.3%	0.4%	5.9%	51.1%
Idaho	1.6	1.6	2.0	3.4	10.8	19.4	8.1%	8.5%	10.2%	17.5%	55.7%
Illinois	13.7	42.6	23.4	35.5	54.6	169.9	8.1%	25.1%	13.8%	20.9%	32.1%
Indiana	5.6	63.1	8.3	41.4	35.9	154.3	3.6%	40.9%	5.4%	26.9%	23.3%
Iowa	4.0	16.2	5.2	21.4	18.9	65.7	6.1%	24.7%	7.9%	32.5%	28.7%
Kansas	2.7	19.8	4.0	13.8	17.5	57.8	4.6%	34.3%	6.8%	23.9%	30.3%
Kentucky	2.6	50.5	3.0	14.1	31.8	101.9	2.6%	49.5%	2.9%	13.8%	31.2%
Louisiana	2.3	27.5	1.9	112.5	39.1	183.3	1.2%	15.0%	1.0%	61.4%	21.3%
Maine	1.6	0.7	2.9	1.7	6.6	13.5	12.0%	5.2%	21.2%	12.4%	49.2%
Maryland	5.2	9.2	5.5	2.7	25.5	48.1	10.8%	19.2%	11.5%	5.5%	53.1%
Massachusetts	7.3	5.7	12.2	3.1	24.0	52.3	13.9%	11.0%	23.3%	6.0%	45.8%
Michigan	10.7	47.0	19.6	15.9	43.6	136.8	7.8%	34.3%	14.3%	11.7%	31.9%
Minnesota	6.7	19.2	9.2	16.2	27.1	78.4	8.5%	24.5%	11.8%	20.6%	34.6%
Mississippi	1.6	26.3	1.4	11.5	22.4	63.1	2.5%	41.6%	2.3%	18.1%	35.5%
Missouri	4.4	54.8	6.4	8.3	34.9	108.7	4.0%	50.4%	5.9%	7.6%	32.1%
Montana	1.7	10.1	1.8	4.7	8.0	26.2	6.4%	38.5%	6.8%	17.8%	30.5%
Nebraska	2.2	19.6	2.5	9.0	13.2	46.5	4.7%	42.2%	5.4%	19.3%	28.4%
Nevada	2.0	13.3	2.7	2.8	15.5	36.2	5.5%	36.6%	7.4%	7.6%	42.8%
New Hampshire	1.3	1.6	2.8	0.8	6.0	12.4	10.7%	12.8%	22.3%	6.0%	48.1%
New Jersey	9.0	13.6	14.0	8.1	39.1	83.8	10.7%	16.2%	16.7%	9.7%	46.6%
New Mexico	1.7	18.6	2.3	7.7	14.9	45.2	3.8%	41.1%	5.1%	17.0%	33.0%
New York	20.3	23.4	31.5	8.0	60.1	143.4	14.2%	16.4%	22.0%	5.6%	41.9%
North Carolina	4.9	37.1	4.8	9.6	50.1	106.5	4.6%	34.8%	4.5%	9.0%	47.0%
North Dakota	1.3	27.4	1.0	16.0	8.5	54.3	2.4%	50.6%	1.9%	29.5%	15.6%
Ohio	11.6	67.0	17.1	34.9	55.0	185.6	6.3%	36.1%	9.2%	18.8%	29.7%
Oklahoma	3.1	24.7	3.8	23.2	28.8	83.7	3.7%	29.5%	4.6%	27.7%	34.4%
Oregon	2.4	8.9	2.8	4.4	19.1	37.5	6.3%	23.7%	7.5%	11.6%	50.8%
Pennsylvania	10.7	70.1	17.8	42.0	52.6	193.2	5.6%	36.3%	9.2%	21.8%	27.2%
Rhode Island	0.8	3.2	1.9	0.6	3.3	9.8	8.2%	32.4%	19.2%	6.2%	34.0%
South Carolina	2.2	22.8	1.9	7.1	29.5	63.5	3.4%	36.0%	3.0%	11.2%	46.4%
South Dakota	0.9	2.3	1.1	4.1	6.6	14.9	5.9%	15.3%	7.1%	27.6%	44.3%
Tennessee	3.9	19.7	4.0	13.8	41.9	83.3	4.7%	23.7%	4.8%	16.5%	50.3%
Texas	13.1	176.9	12.1	229.2	192.7	624.0	2.1%	28.3%	1.9%	36.7%	30.9%
Utah	2.9	26.4	4.2	6.6	17.2	57.4	5.1%	46.1%	7.4%	11.6%	29.9%
Vermont	0.9	0.0	1.4	0.5	2.6	5.4	16.3%	0.1%	26.2%	8.8%	48.7%
Virginia	5.7	28.8	5.8	10.8	47.1	98.2	5.8%	29.3%	5.9%	11.0%	48.0%
Washington	4.6	11.0	5.8	12.3	34.6	68.4	6.8%	16.1%	8.5%	18.0%	50.6%
West Virginia	1.6	50.4	1.7	12.0	11.2	76.9	2.1%	65.5%	2.2%	15.6%	14.6%
Wisconsin	6.1	31.5	9.8	12.2	27.4	87.0	7.0%	36.2%	11.2%	14.0%	31.5%
Wyoming	0.9	35.2	0.9	11.2	7.3	55.6	1.7%	63.4%	1.7%	20.2%	13.1%
Total[1]	235.8	1,439.8	320.1	948.3	1,648.5	4,592.4	5.1%	31.4%	7.0%	20.6%	35.9%

Data source: U.S. Energy Information Administration (EIA), State Energy Data System and EIA calculations made for this analysis.

[1]For the United States as a whole see, EIA, Monthly Energy Review, Section 11: Environment. Differing methodologies between the two data series causes the total for all states to be different from the national-level estimate.

Attachment 23

Photo by Katherine Hafner

Flooding in the Hague area of Norfolk in May 2022.

Unchecked sea level rise would cost Virginia $79 billion this century, ODU says

Written by Katherine Hafner (/staff/katherine)Published: 15 September 2022
Category: Local News (/news/local-news)

(https://www.facebook.com/sharer/sharer.php?u=https://whro.org/news/local-news/32263-unchecked-sea-level-rise-would-cost-virginia-79-billion-this-century-odu-says&caption=whro.org&title=Unchecked sea level rise would cost Virginia $79 billion this century, ODU says&text=Unchecked sea level rise would cost Virginia $79 billion this century, ODU says) (https://twitter.com/intent/tweet?via=WHRO&url=https://whro.org/news/local-news/32263-unchecked-sea-level-rise-would-cost-virginia-79-billion-this-century-odu-says&text=Unchecked sea level rise would cost Virginia $79 billion this century, ODU says)

PLAY

The impacts of large natural disasters — think fires and hurricanes — are pretty easy to demonstrate.

But the injury from sea level rise can be harder to illustrate, said Bob McNab, director of Old Dominion University's Dragas Center for Economic Analysis and Policy.

Changes happen over months and years rather than all at once.

"You just kind of adjust slowly as the climate changes," McNab said. "And that's why it's harder to combat."

So how to grab people's attention on the issue? Follow the money.

That's what a new ODU analysis tries to do. Researchers estimated exactly how much coastal Virginia could lose if nothing changes to confront sea level rise and flooding.

They came up with some massive figures, expressed in 2021 dollars.

Unmitigated flooding from 2020 to 2099 would result in about $56 billion in financial damages — about 85% of which is in Hampton Roads, according to the new report.

That would lead to a roughly $79 billion decline in economic output across the Commonwealth's coast.

"Imagine a hurricane hitting Virginia last year and wiping out more than 13% of economic activity in Virginia," McNab said. "That's the cost we project in sea level rise and recurrent flooding over the remainder of the century."

To reach those numbers, the researchers looked at eight planning districts that comprise coastal Virginia, including Hampton Roads.

George McLeod, director of the Center for Geospatial Science, Education and Analytics said his team used modeling that builds upon their existing work.

They have spent years projecting (https://www.pilotonline.com/news/environment/vp-nw-odu-flood-map-20211221-ll2ikzcwfzfrvdi2cgm6bq3c2y-

story.html) how much flooding the region will see by 2040, 2060 and 2080 – down to the street level (https://odu-geosea.maps.arcgis.com/home/webmap/viewer.html?webmap=36e758f7e2b544a980962faef1faaeb4#).

According to data from the National Oceanic and Atmospheric Administration, average sea levels in Virginia could rise by almost 5 feet by the end of the century – even more in certain spots around the region.

One difference for this project is it includes projections for storm surge in addition to regular nuisance flooding, McLeod said.

His team used the models combined with basic economic numbers from various categories including agriculture, government and education.

“The way I look at it is, because of the complexity and magnitude and inevitability of this issue of sea level rise, it’s really our job to look at the problem at all scales,” McLeod said.

“It’s really incumbent upon us to look at every one of those scales and to try to provide as much information to decision-makers as possible.”

McNab then did further economic analysis, which does not take into account future mitigation efforts like a planned floodwall in Norfolk.

The Hampton Roads region would suffer the most economic consequences: $47 billion in direct losses leading to $67 billion in lost output.

That’s a conservative estimate, McNab said.

McNab and McLeod said they hope people will use the report to jumpstart both policy and grassroots efforts.

“This should be another part of the wake-up call for not only Virginia but coastal areas in the United States, because sea level rise is occurring,” McNab said. “These

are all the conversations that will become part and parcel of local, state and national politics over the coming decades."

(https://www.facebook.com/sharer/sharer.php?u=https://whro.org/news/local-news/32263-unchecked-sea-level-rise-would-cost-virginia-79-billion-this-century-odu-says&caption=whro.org&title=Unchecked sea level rise would cost Virginia $79 billion this century, ODU says&text=Unchecked sea level rise would cost Virginia $79 billion this century, ODU says)

(https://twitter.com/intent/tweet?via=WHRO&url=https://whro.org/news/local-news/32263-unchecked-sea-level-rise-would-cost-virginia-79-billion-this-century-odu-says&text=Unchecked sea level rise would cost Virginia $79 billion this century, ODU says)

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Attachment 24

The Regional Greenhouse Gas Initiative

An Initiative of Eastern States of the United States

The Investment of RGGI Proceeds in 2020

Published May 2022

www.rggi.org

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Executive Summary

Proceeds from the Regional Greenhouse Gas Initiative (RGGI) have powered significant investment in the energy future of participating Eastern states. This report reviews the benefits of programs funded in 2020 by $196 million in RGGI investments, which have reduced harmful carbon dioxide (CO_2) emissions while spurring local economic growth. The lifetime effects of 2020 RGGI investments are projected to avoid the release of 6.6 million short tons of carbon emissions. RGGI-funded programs also save consumers and businesses money, create jobs, and provide targeted assistance to low-income communities throughout the RGGI region. RGGI investments in 2020 are estimated to return $1.9 billion in lifetime energy bill savings to 65,000 households and 800 businesses that participated in programs funded by RGGI proceeds, while over 720,000 households and 38,000 businesses received direct bill assistance in 2020. As a whole, the RGGI states have reduced power sector CO_2 emissions over 50% since 2008, while the region's gross domestic product has continued to grow.

The benefits tracked in this report arise from RGGI investments in energy efficiency, clean and renewable energy, beneficial electrification, direct bill assistance, and greenhouse gas abatement. Any benefits associated with other funds (such as transfers to general funds) are outside the scope of this report.

RGGI states have individual discretion as to how they invest proceeds. Investments fall into five major categories:

Energy efficiency makes up 35% of 2020 RGGI investments and 53% of cumulative investments. Programs funded by these investments in 2020 are expected to return about $1.2 billion in lifetime energy bill savings to more than 56,000 participating households and over 700 businesses in the region and avoid the release of 4.6 million short tons of CO_2.

Clean and renewable energy makes up 18% of 2020 RGGI investments and 14% of cumulative investments. RGGI investments in these technologies in 2020 are expected to return over $600 million in lifetime energy bill savings and avoid the release of more than 1.7 million short tons of CO_2.

Beneficial electrification makes up 11% of 2020 RGGI investments and 3% of cumulative investments. RGGI investments in beneficial electrification in 2020 are expected to avoid the release of 177,000 short tons of CO_2 and return nearly $90 million in lifetime savings.

Greenhouse gas abatement makes up 5% of 2020 RGGI investments and 8% of cumulative investments. RGGI investments in greenhouse gas (GHG) abatement in 2020 are expected to avoid the release of more than 160,000 short tons of CO_2 and to return over $51 million in lifetime savings.

Direct bill assistance makes up 19% of 2020 RGGI investments and 16% of cumulative investments. Direct bill assistance programs funded through RGGI in 2020 have returned over $37 million in credits or assistance to consumers.

This is the first version of this report which includes beneficial electrification as its own investment category. In previous versions of this report, investments in beneficial electrification programs were included within the other major investment categories.

These investments, in concert with the broader energy policies in each RGGI state, have enabled the region to continue to set a national example in driving decarbonization while strengthening economic resilience.

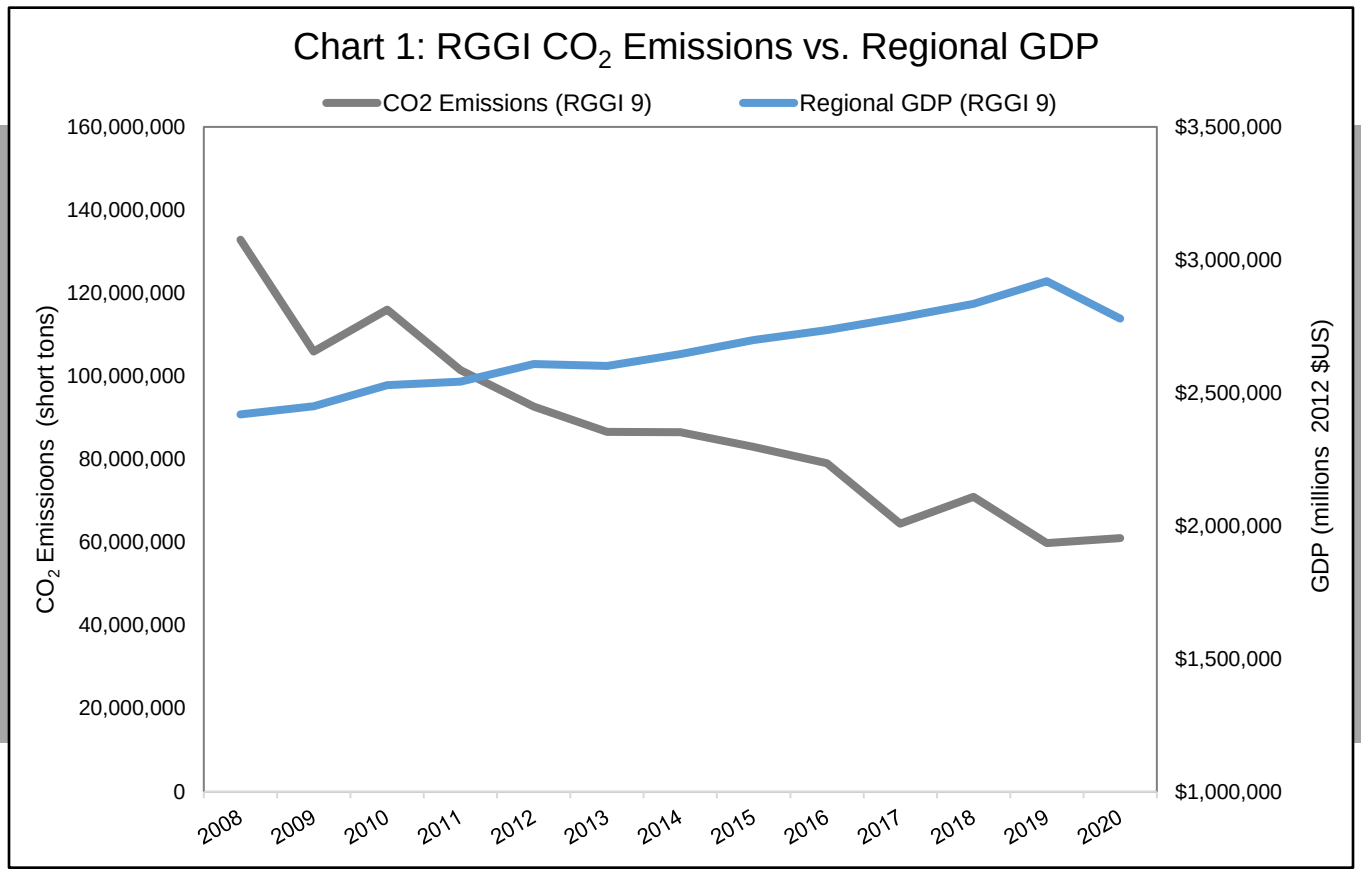
Introduction

The Regional Greenhouse Gas Initiative

RGGI is the nation's first multi-state initiative to reduce power sector CO_2 emissions. The RGGI states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia) establish a regional cap on the amount of CO_2 emissions that power plants can emit by issuing a limited number of tradable CO_2 allowances. Each allowance represents an authorization for a regulated power plant to emit one short ton of CO_2. Individual CO_2 budget trading programs in each RGGI state together create a regional market for CO_2 allowances. This allows market forces to determine the most cost-effective means of reducing emissions, and creates market certainty to drive long-term investments in clean energy. Each state's independent regulations are based on the RGGI Model Rule. New Jersey participated in RGGI from 2009 to 2011, and resumed its participation starting in 2020. RGGI investments in this report include the ten participating RGGI states in 2020.

The RGGI states have distributed 90% of CO_2 allowances through quarterly regional auctions, generating proceeds for reinvestment. The remaining allowances are allocated to state set-aside accounts, from which allowances may be distributed according to state-specific regulations or auctioned in future years. Each RGGI state has full discretion over the investment of RGGI proceeds and the administration of RGGI-funded programs.

The nine RGGI states that participated from 2009-2020 experienced a reduction of over 90 million short tons of annual power sector carbon emissions, even as the regional economy grew (see **Chart 1**).[1] This represents a reduction in power sector carbon emissions of over 50%.



[1] The nine RGGI states that participated for the entire 2009-2020 time period are CT, DE, ME, MD, MA, NH, NY, RI, and VT. The reduction in regional GDP in 2020 coincides with the onset of the COVID-19 pandemic.

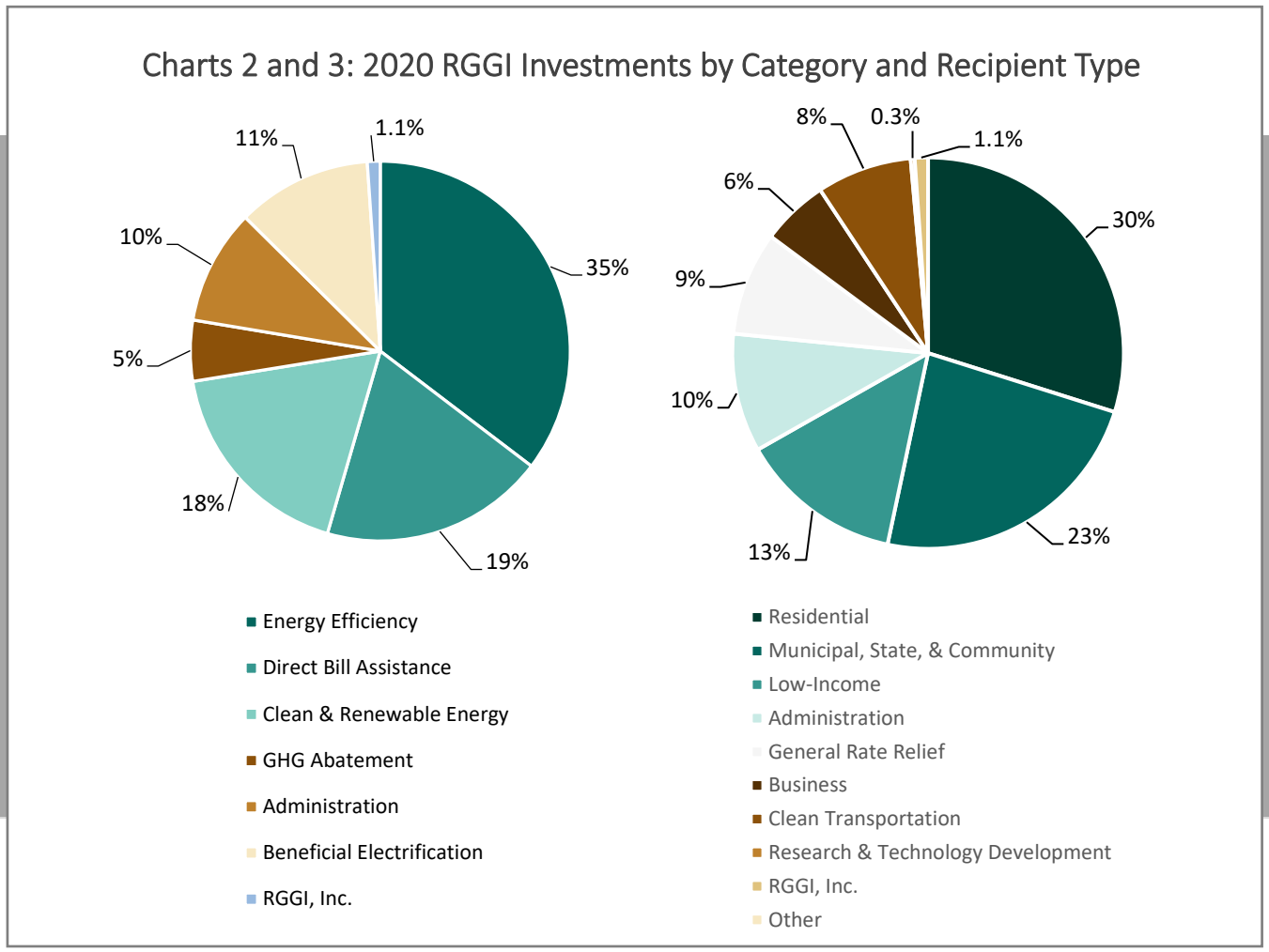
2020 RGGI Investments

This report estimates the benefits, such as energy bill savings and avoided CO_2 emissions, that arise from $196 million in 2020 RGGI investments. RGGI investments as defined within this report include investments in energy efficiency, clean and renewable energy, beneficial electrification, greenhouse gas abatement, and direct bill assistance, as well as administrative costs associated with these programs. This is the first version of this report which includes beneficial electrification as a separate category for the investment of proceeds. In previous reports, investments into beneficial electrification programs were included within the other major investment categories. This report focuses on 2020 annual investments. RGGI investments throughout the region cover a wide variety of programs.

Chart 2 shows 2020 RGGI investments divided among major program categories. **Chart 3** illustrates the same 2020 funds divided according to the type of end-user who benefits from the program or ultimately receives funding.

Many of the categories in Chart 3 can be seen as subcategories of those in Chart 2. Direct Bill Assistance is split between assistance for low-income consumers, and general rate relief for all consumers. GHG Abatement includes a wide variety of program types, including research funding and clean transportation programs. The Energy Efficiency and Clean Energy program categories mainly flow to residential, business, and municipal, state, & community recipients, with a substantial number of programs specifically serving low-income households.

Due to rounding, pie charts may not sum to exactly 100%.



In 2020, RGGI investments have saved participants money on their energy bills, created jobs, and reduced carbon emissions. Over their lifetime they will save participants an estimated $2 billion on energy bills, and avoid the emission of 6.7 million short tons of harmful CO_2 emissions. For details see **Table 1**.

RGGI investments benefit more than just those who directly participate in RGGI-funded programs. for example, money not spent on energy by families and businesses can be used in other ways that boost the economy. Reduced demand for energy also keeps power prices lower for everyone, and avoids investments in costly infrastructure to meet peak demand.

RGGI states have long been and continue to be leaders in energy efficiency, with millions of MWh saved. As the region's generation becomes cleaner, many states are also investing in beneficial electrification programs, which reduce carbon emissions by replacing direct fossil fuel use with electric power. Often, these programs result in an increases in MWh, but do reduce carbon emissions overall. As the grid becomes cleaner, the emissions from electrified appliances become cleaner, as opposed to the fixed emissions intensity of fossil-powered appliances.

Avoided MWh continues to be a relevant metric for energy efficiency and clean and renewable energy programs, and will be reported in the tables associated with these respective investment categories.

Table 1: Benefits of 2020 RGGI Investments

Category	Annual Benefits of 2020 Investments	Lifetime Benefits of 2020 Investments
Short Tons CO_2 Avoided	399,493	6,665,490
Energy Bill Savings	$143,819,935	$1,957,732,399

One of RGGI's strengths is the discretion held by each state to invest RGGI auction proceeds according to state-specific goals. This can present challenges for data collection; for example, a program offering discounts on efficient lightbulbs will collect quite different data from a program helping businesses to install large-scale equipment, or funding the installation of electric car charging stations. The data in this report are compiled using the output of state-based and program-based estimates for actual and projected savings and benefits. Methods for estimating program benefits differ across states and across programs. The appendix at the end of this report contains more details on how each metric is estimated for different types of programs.

States may also combine RGGI funds with funds from other sources. In many cases, the reported benefits from the program are adjusted based on the percentage of the program's funding that comes from RGGI. In cases where states determine a program could not have gone forward without RGGI funds, states will report the full benefits associated with that program.

Energy Efficiency

Energy efficiency remains the largest portion of 2020 RGGI investments, at 35%. Over the lifetime of the installed measures, 2020 RGGI investments in energy efficiency are projected to save participants nearly $1.2 billion on energy bills, providing benefits to more than 56,000 participating households and over 700 participating businesses. They are also projected to avoid the release of 4.6 million short tons of CO_2 (see **Table 2**).

Table 2: Benefits of 2020 RGGI Investments in Energy Efficiency

Category	Annual Benefits of 2020 Investments	Lifetime Benefits of 2020 Investments
Participating Households	56,412	n/a
Participating Businesses	737	n/a
Increased Employment	n/a	1400-1500*
Short Tons CO_2 Avoided	275,304	4,591,753
Energy Bill Savings	66,037,494	1,178,557,556
MMBtu Saved	1,869,047	31,427,411
MWh Saved	597,736	3,420,325

*Estimated job-years created.

Energy efficiency improvements can be achieved cost-effectively by upgrading appliances and lighting, weatherizing and insulating buildings, upgrading HVAC at offices, and improving industrial processes. For example, occupancy sensors automatically turn lights off when a room or building is not in use, saving significant amounts of energy. These programs allow consumers and businesses to take full advantage of modern appliances, heating, and cooling, increasing the comfort of homes, offices, and businesses while using less energy and saving on their energy bills.

Energy efficiency also creates jobs. Programs such as home retrofits directly spur employment gains in housing and construction, with 2020 RGGI investments projected to create an estimated additional 1400-1500 job-years across participating states. Lower energy costs also create numerous benefits across the economy, allowing businesses to expand and families to save and invest in other priorities.

Ultimately, all electricity consumers, not only those who make upgrades, benefit from energy efficiency programs. Lower overall demand for electricity results in lower wholesale electricity rates, as power plants with the highest costs do not run as often, and expensive transmission upgrades can be deferred in some cases. The full economy-wide benefits of energy efficiency are not modeled in this report. However, a range of other independent reports

have affirmed these widespread benefits of energy efficiency, including work by the Analysis Group, the Regulatory Assistance Project, and others.

RGGI-funded investments in energy efficiency, in concert with the broader energy policies in each RGGI state, have made the region a leader in this field. Six RGGI states once again ranked among 2020's top ten states for energy efficiency, according to the American Council for an Energy Efficient Economy.

Clean and Renewable Energy

Clean and renewable energy represents 18% of 2020 RGGI investments in the region. Over the lifetime of the projects installed in 2020, these investments are projected to offset $602 million in energy expenses. They are also projected to avoid the release of over 1.7 million short tons of CO_2 emissions (see **Table 3**).

Table 3: Benefits of 2020 RGGI Investments in Clean Energy

Category	Annual Benefits of 2020 Investments	Lifetime Benefits of 2020 Investments
Short Tons CO_2 Avoided	96,092	1,735,768
MWh Avoided*	192,903	3,473,936
MMBtu Avoided	25,965	576,144
Energy Bill Savings	$31,394,795	$601,955,014

*RGGI investments in clean and renewable energy decrease the electricity generated from marginal generating units, which are typically more expensive and carbon-intensive.

Clean energy systems require labor to install, which creates jobs and boosts local economic activity. Energy expenditures that might otherwise flow to out-of-state fossil fuel resources stay within the region. As with energy efficiency, “behind-the-meter” programs also contribute to lowering wholesale electricity prices by lowering the demand for electricity at the wholesale level. As demand for electricity decreases, the most expensive power plants run less often, driving long-term prices down for all consumers. Households and businesses both with and without clean energy systems save money on bills.

While RGGI investments are just a small part of widespread clean and renewable energy investments in the region, together these actions are having a measurable impact on the energy mix. Since 2008, RGGI states have increased their non-hydro renewable generation by 73%. In 2020 the RGGI states derived 50% of total generation from clean or renewable sources.

Beneficial Electrification

Beneficial electrification refers to programs that reduce carbon emissions by displacing direct fossil fuel use with electric power. In contrast to energy efficiency programs, which reduce electricity or fuels usage, beneficial electrification programs can increase MWh consumption, but result in a net reduction in carbon emissions. Examples include programs that promote the use of electric vehicles, reducing oil consumption, or the installation of electric heat pumps, reducing heating fuel and natural gas consumption.

Beneficial electrification represents 11% of 2020 RGGI investments in the region. Over their lifetime, the investments in beneficial electrification made in 2020 are expected to avoid 177,000 short tons of CO2 emissions and result in $90 million in customer bill savings. Beneficial electrification investments will yield even greater emissions reduction benefits over time, as renewables take up a larger portion of the electric grid composition. Investments in beneficial electrification programs, and the resulting bill savings, also lead to job creation and spur local economic activity.

In addition, some programs reported as energy efficiency, clean and renewable energy, or greenhouse gas abatement may include beneficial electrification components, but the outcomes of these projects are not reported under beneficial electrification.

Table 4: Benefits of 2020 RGGI Investments in Beneficial Electrification

Category	Annual Benefits of 2020 Investments	Lifetime Benefits of 2020 Investments*
Short Tons CO_2 Avoided	12,187	176,877
Energy Cost Savings**	$5,420,796	$89,589,982
MMBtu Saved	150,038	2,179,101
MWh Increased	10,089	151,330

*Although Beneficial Electrification is a new addition to the RGGI Proceeds report, Lifetime Benefits are calculated the same as other categories in the report. States use assumptions about the lifespan of their Beneficial Electrification investments in terms of years, and calculate lifetime benefits based on assumptions about their ISO's carbon intensity, energy cost, etc. over the lifespan of an investment to estimate Lifetime Benefits.

**Energy cost savings is the net result of increased MWh costs from beneficial electrification combined with the decrease in avoided fuel costs (i.e. heating oil, gasoline).

Greenhouse Gas Abatement

Greenhouse gas abatement (GHG abatement) is a broad category encompassing other ways of reducing greenhouse gases, apart from energy efficiency and clean and renewable energy. Approximately 5% of 2020 RGGI investments supported GHG abatement programs. Over their lifetime, the investments made in 2020 are expected to avoid the release of over 160,000 short tons of CO_2 (see **Table 5**).

Programs in the GHG abatement category may vary significantly, and may drive GHG emission reductions in multiple sectors. For example, technology, research, and development programs are tracked as GHG abatement, as they may lead to advancements resulting in the reduction of greenhouse gases. Climate change policy research is also tracked as GHG abatement.

GHG abatement programs vary in the types of benefits they provide. Some projects reduce electricity and fossil fuel use as part of their efforts to reduce overall emissions, generating economic benefits similar to those realized through energy efficiency and clean and renewable energy programs. Other projects may not return immediately trackable benefits within the scope of this report, but still provide important long-term benefits in climate preparedness and mitigation.

Table 5: Benefits of 2020 RGGI Investments in GHG Abatement

Category	Annual Benefits of 2020 Investments	Lifetime Benefits of 2020 Investments
Participating Households	2,999	n/a
Participating Businesses	28	n/a
Short Tons CO_2 Avoided	15,888	160,881
MMBtu Saved	222,821	2,228,214
Energy Bill Savings	$5,184,777	$51,847,774

Direct Bill Assistance

Direct bill assistance returns money to consumers as a rebate on their energy bills. Approximately 19% of 2020 RGGI investments have funded direct bill assistance. RGGI investments in direct bill assistance in 2020 returned $37 million in bill savings to energy consumers (see **Table 6**).

These programs provide rate relief to electricity consumers in the RGGI region. Some programs provide assistance specifically to low-income families, while other programs provide small on-bill credits to all consumers.

Direct bill assistance typically appears as a credit on a consumer's electricity bill. Direct bill assistance programs support economic activity by providing funds directly to consumers, who can then spend those funds on other priorities. Unlike energy efficiency or clean energy programs (which generate benefits for the lifetime of the installed measures), direct bill assistance programs provide benefits only for the length of the bill-assistance program. Direct bill assistance programs also do not reduce or affect wholesale electricity prices.

RGGI proceeds provide a small percentage of low-income direct bill assistance programs across the states. Other sources of funds come from on-bill system benefit charges, and federal funds in the case of LIHEAP programs.

Table 6: 2020 RGGI Investments in Direct Bill Assistance

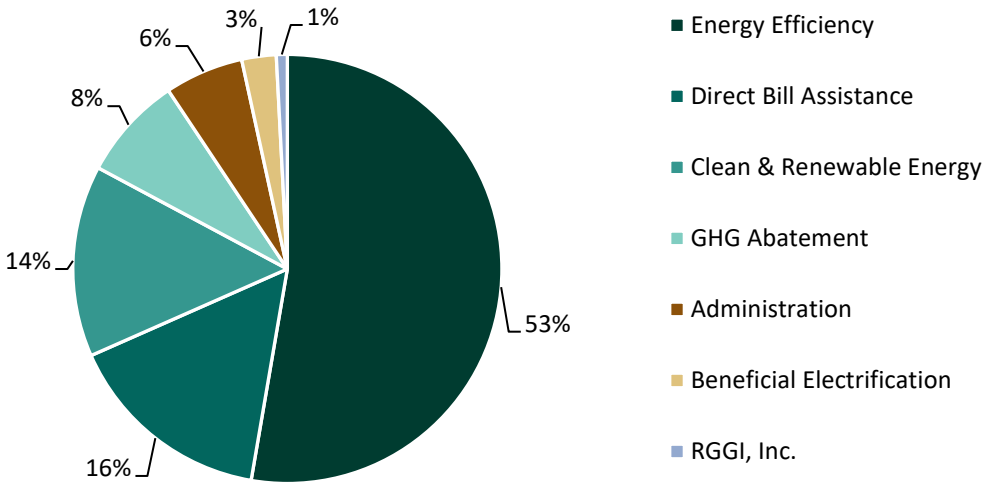
Category	Annual Benefits of 2020 Investments
Participating Households	722,874
Participating Businesses	38,580
Energy Bill Savings	$37,586,252

Cumulative Uses of Auction Proceeds

While this report focuses primarily on 2020 data, information on cumulative RGGI investments is provided in this section as an overview of RGGI's track record. **Chart 4**, below, shows the percentage of all-time RGGI investments directed to each of the major program categories.

This pie chart shows each program category as a percentage of all-time RGGI investments.

Chart 4: Cumulative RGGI Investments by Category



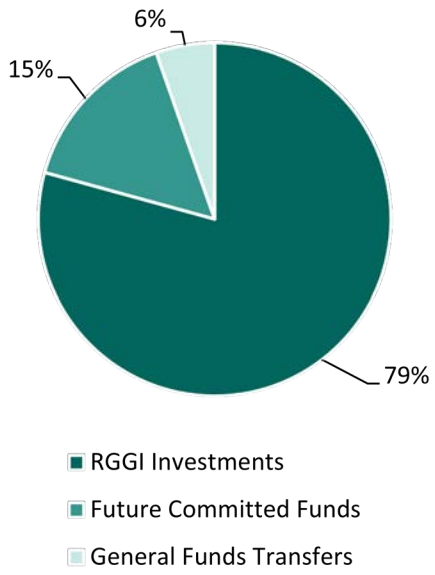
The states participating in RGGI invested $2.99B as of 2020.

RGGI investments are themselves a subset of total proceeds. Most RGGI proceeds through 2020 are defined as RGGI investments. Other uses of funds, such as transfers to state general funds, are outside the scope of this report. See **Chart 5**, below, for more details on total RGGI proceeds.

Two states report program data according to the fiscal year (July 1-June 30) rather than the calendar year. A fiscal year adjustment is used to compare numbers between fiscal-year and calendar-year states.

Chart 5: RGGI Investments as a Subset of Total Proceeds

Description	Funds
All Proceeds through Dec. 31, 2020	$3,801,985,568
Adjustment for Fiscal Year Reporting	-$39,673,943
General Funds Transfers	$199,700,000
Future Committed Funds	$571,395,708
RGGI Investments	**$2,991,215,917**



The pie chart shows three categories of funds, as a percentage of all proceeds **after** the fiscal year adjustment. The participating RGGI states invested $2.99B in the period covered by this report. This leaves $571M in funds that are yet to be invested.

All-time benefits metrics may be best understood as a general indication of the cumulative benefits of RGGI-funded investments since the program's inception. **Table 7** shows that the track record from all RGGI investments includes benefits on the order of billions in customer bill savings, and tens of millions of short tons of CO_2 avoided. Note that as the program's track record grows longer, all-time numbers may include changes in states' methodologies from year to year.

Table 7: All-Time Benefits of RGGI Investments

Category	Lifetime Benefits of All RGGI Investments
Participating Households	7,237,334
Participating Businesses	293,137
Short Tons CO_2 Avoided	49,523,308
Megawatt-Hours Saved	74,527,807
MMBtu Saved	255,317,388
Energy Bill Savings	$14,816,129,607

Previously reported cumulative data plus 2020 data may not sum exactly to updated cumulative data. This is due to state adjustments or corrections to prior cumulative calculations.

Connecticut

Connecticut primarily invests RGGI auction proceeds towards programs dedicated to the deployment of energy efficiency measures and improvements, and financing options for renewable energy projects. Connecticut allocates 69.5% of its auction proceeds to support the energy efficiency programs overseen by the Connecticut Energy Efficiency Board (CEEB) and administered by Eversource Energy and The United Illuminating Company, as well as those of the Connecticut Municipal Electric Energy Collective (CMEEC) and the Town of Wallingford – Electric Division (WED). Connecticut further allocates 23% to the Connecticut Green Bank to support the development of Class I renewable energy sources. The Department of Energy and Environmental Protection retains the remaining 7.5% for administrative purposes.

During 2020, Connecticut invested RGGI auction proceeds in the following programs:

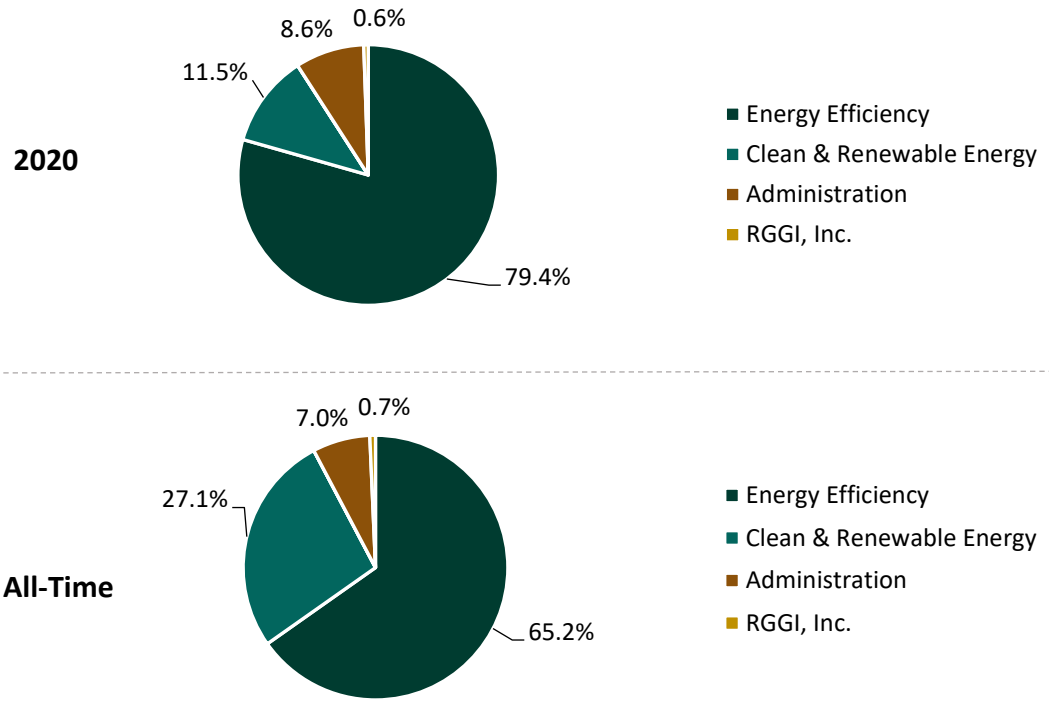
- Home Energy Solutions^{SM} Program: Under this program, Eversource Energy and The United Illuminating Company invested RGGI funds to conduct residential energy audits and install weatherization measures. Due to the investment of RGGI funds, Eversource and UI were able to extend participation to more than 8,000 homes in 2020 and avoid more than 12,000 tons of CO_2 emissions and conserve over 154,000 MMBtus of fossil fuel use.
- Home Energy Savings Program: Under this program, WED leveraged RGGI funds to perform residential energy audits and deploy weatherization measures. In 2020, WED served 198 homes and provided weatherization services to 108.
- Commercial Property Assessed Clean Energy (C-PACE) Program: Under this program, the Connecticut Green Bank offers low interest, zero-down payment financing for clean and renewable energy projects. In 2020, the Connecticut Green Bank invested RGGI proceeds in C-PACE to help finance eleven projects, four of which were completed in 2020. The remaining seven projects were completed in 2021. Since the inception of the C-PACE program, 111 projects have been completed.
- Various energy efficiency projects: CMEEC used RGGI funds toward the deployment of residential and commercial energy efficiency projects, ranging from the installation of heat pumps and mini splits to street lighting upgrades including the retrofit of street lighting on University of Connecticut's (UCONN) Avery Point campus.

Connecticut has cumulatively invested nearly $214 million in RGGI allowance proceeds toward programs and services dedicated to the deployment of energy efficiency measures and renewable energy technologies.

The American Council for an Energy-Efficient Economy (ACEEE) nationally ranked Connecticut seventh in its 2021 State Energy Efficiency Scorecard, which evaluated 2020 state energy efficiency efforts. Connecticut's continued Top Ten ranking is attributed to a range of energy-saving policies across the entire economy including:

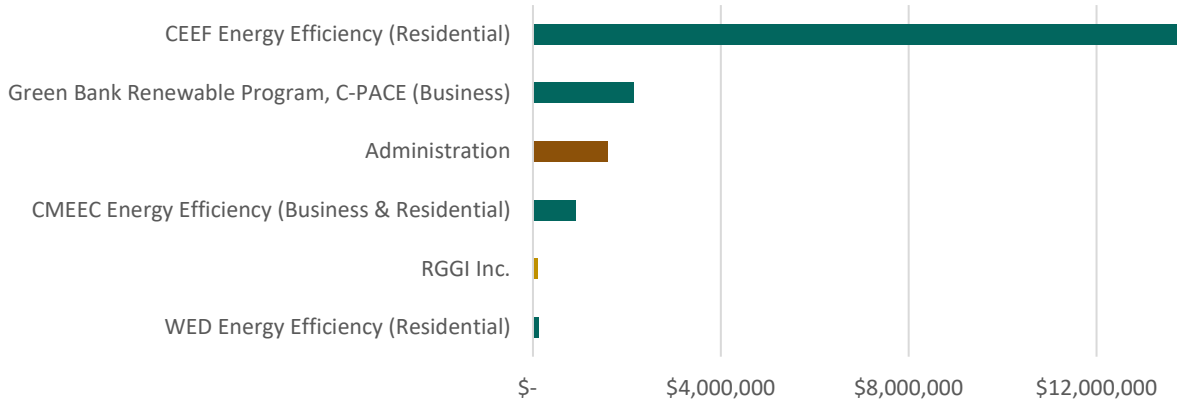
- Incentives for high-efficiency vehicles and adoption of California's ZEV program.
- Waivers of co-pays for certain energy efficiency programs to mitigate impacts from the COVID-19 pandemic.
- Launch of the Equitable Energy Efficiency Proceeding in order to increase participation in energy efficiency programs by members of communities that have traditionally been underrepresented.

Chart 6: 2020 Connecticut RGGI Investments by Category



Connecticut received $246M in proceeds from 2008-2020. RGGI investments represent $18.6M in 2020, and $214M cumulatively. $4M is committed to 2021 and future investments.

Chart 7: 2020 Connecticut RGGI Investments by Recipient



Connecticut RGGI investments represent $18.6M in 2020.

Program Highlight: Home Energy Solutions℠

The Home Energy Solutions℠ (HES) program is a home energy efficiency audit and energy conservation program, primarily funded by mandated conservation charges collected from electric and natural gas ratepayers, who in turn can receive its services. Connecticut's investment of RGGI proceeds in this program has provided funding for the deployment of services under the program to families who heat their homes with fuel oil or propane.

The HES program enables evaluation of a home's energy performance and installation of core weatherization and energy-saving measures such as sealing air leaks, installing energy-efficient lighting such as LEDs, faucet aerators, low-flow showerheads, and weather stripping. Participation in the HES program requires a co-pay, however, for much of 2020, the co-pay was waived in response to the emergence of the COVID-19 pandemic.

The HES program also provides families with customized reports highlighting additional opportunities and estimated cost savings for implementing deeper energy-saving measures. Participants may also receive rebates on these interventions such as improving insulation and installing energy-efficient mechanical equipment. HES participants may also be provided with the Department of Energy's Home Energy Score for their home, a standardized comparison of the home's energy usage to similar buildings, and recommendations for energy upgrades along with the estimated annual savings from those upgrades. HES participants can be provided with up to $7,500 in rebates to perform energy efficiency and equipment upgrades such as installation of ENERGY STAR rated appliances and improved home insulation. Low-interest rate financing options are also available. The average home in Connecticut receives about $1,000 in services and realizes $200-$250 in savings on their annual energy bills.

Success Story: UCONN at Avery Point

The UCONN at Avery Point campus, located on Long Island Sound at the mouth of the Thames River in Groton, CT is a public campus of the University of Connecticut offering liberal arts programs of study for approximately 564 enrolled students.

Groton Utilities (GU), a member of CMEEC, provides and maintains streetlights to this 72-acre campus. The recognition of the need to upgrade the pole top lighting fixtures was the catalyst for GU to embark on the replacement of the 121 high pressure sodium fixtures (175W each) with LED fixtures (99W each). The expenditure of $242,675 of RGGI funds for the UCONN at Avery Point project is anticipated to realize an annual energy savings and reduction in monthly peak demand of 53 MWh and 13 kW, respectively, and an estimated reduction of GHG emissions equivalent to 25 tons of CO_2.

Resources:

- ACEE State Energy Efficiency Scorecard
- C-PACE
- CMEEC
- Energy Efficiency Board 2020 Programs and Operations Report
- Energize Connecticut℠
- Home Energy Solutions℠ Core Services
- Town of Wallingford – Electric Division

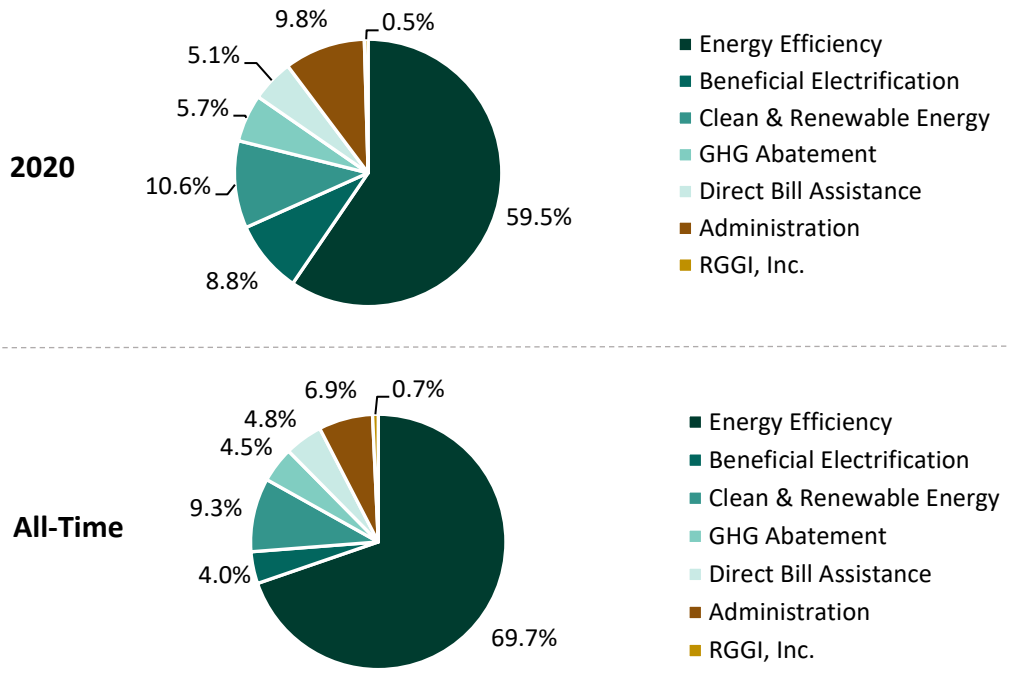
Delaware

Delaware invests RGGI allowance proceeds in a variety of programs that reduce energy use, reduce greenhouse gas emissions, and assist low-income families with energy bill payments. The suite of programs funded with RGGI allowance proceeds provides Delaware families and businesses with valuable assistance with energy efficiency improvements while providing opportunities for innovation in greenhouse gas reductions.

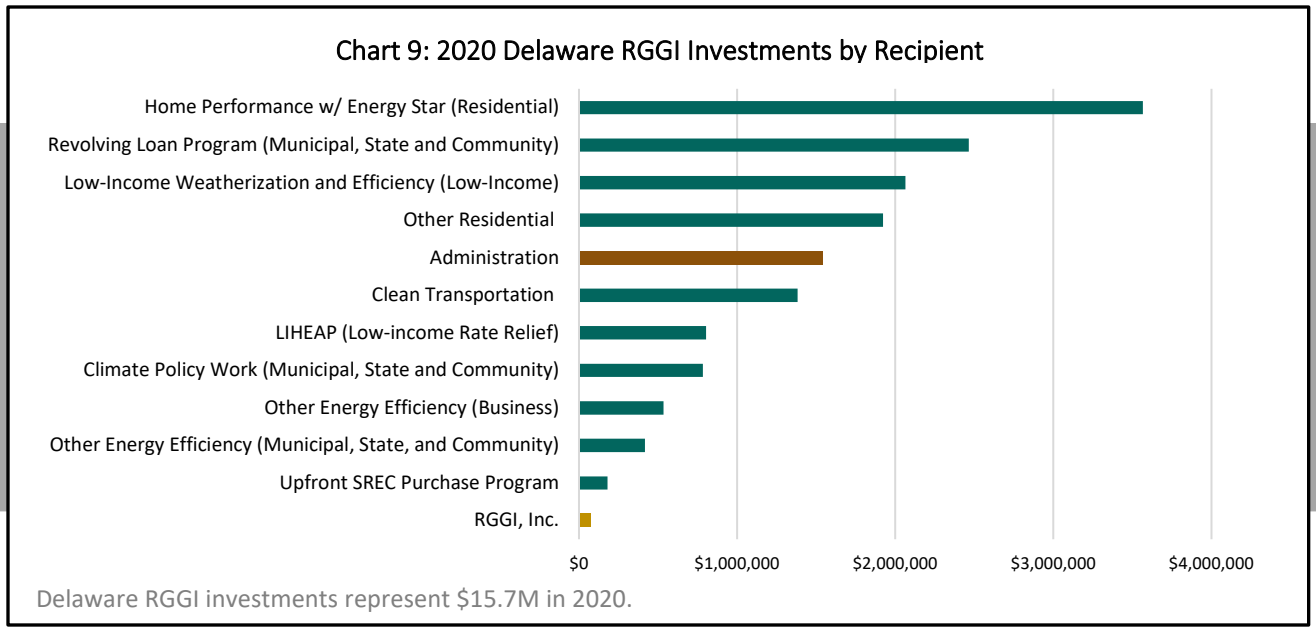
Delaware directs 65% of its allowance proceeds to the Delaware Sustainable Energy Utility (SEU). The SEU serves Delawareans by promoting the use of affordable, reliable, clean energy, and providing a variety of incentives for energy efficiency improvements.

In addition, Delaware directs ten percent of its allowance proceeds to the Delaware Department of Natural Resources and Environmental Control (DNREC) for development of innovative programs to reduce greenhouse gas emissions such as the Clean Transportation incentive program and infrastructure grants. Ten percent of proceeds is also directed to DNREC to implement the state's Weatherization Assistance Program which provides no-cost upgrades to homes to decrease energy use and decrease bills. Five percent of proceeds is also directed to a program to reduce energy bills for low-income customers. The remaining ten percent is reserved for administration of programs.

Chart 8: 2020 Delaware RGGI Investments by Category



Delaware received $149.8M in proceeds from 2008-2020. RGGI investments represent $15.7M in 2020, and $148.8M cumulatively. $1.3M is committed to 2021 and future programs.



Program Highlight: DESEU-Energize Delaware Home Performance with ENERGY STAR

The SEU flagship Home Performance with ENERGY STAR® program is going into its eighth year. This program offers a "whole house" approach to improving comfort and safety in the home and provides homeowners significant savings on their utility costs. Delaware homeowners learn ways to improve the energy efficiency of their homes through completion of a subsidized, comprehensive home energy assessment performed by certified contractors, and they also receive up to $200 of energy saving items such as LED light bulbs and pipe insulation.

After the assessment, homeowners making recommended energy-saving improvements can take advantage of rebates that make their home projects affordable. Reduced assessment costs and increased rebates are available to income-qualified Delawareans and also to property owners residing in Delaware's designated "Downtown Development Districts." Of the 1,749 home assessments completed in 2020, 1,196 homeowners received rebates. In total, SEU leveraged $3.5M in RGGI funds for the Home Performance with ENERGY STAR Program in calendar year 2020, resulting in about $490,000 in energy bill savings and over 2,000 metric tons CO_2 emissions avoided.

Success Story: Delivering Savings through Home Performance with ENERGY STAR

Delawareans and families across the country are experiencing higher utility costs and more strain on their budgets due to the COVID-19 pandemic. Even during the pandemic, SEU was able to keep the Home Performance with ENERGY STAR program operating and participating contractors working in a safe and efficient manner to provide home energy assessments and rebates for energy efficiency heating and cooling equipment, air sealing and insulation, and other water heating and weatherization measures. SEU provided reduced costs for the energy assessments, increased rebate amounts, and provided incentives for completed applications to keep contractors working and making projects more affordable during the pandemic. Rob and Cami Seward provided the following testimonial of their experience as 2020 participants in SEU's Home Performance with ENERGY STAR program:

"We were running an alternate A/C unit in the dining room and it was still 90 degrees in the house. This year is different! Because of your work evaluating our house and sealing and insulating the attic, it has been cool and comfortable all summer. No extra A/C unit needed! Our electric bill last July was $349 and this July it was $201. What a dramatic improvement! We are so happy with the house now that the work has been completed. Great Job sealing us up and cooling us down—We are so grateful to the Energize Delaware Team!"

Maine

The Efficiency Maine Trust (Efficiency Maine) is the independent administrator for programs to improve the efficiency of energy use and reduce greenhouse gases in Maine. The Trust does this primarily by delivering financial incentives on the purchase of high-efficiency equipment or changes to operations that help customers save electricity, natural gas, and other fuels throughout the Maine economy. The organization's purposes include the following:

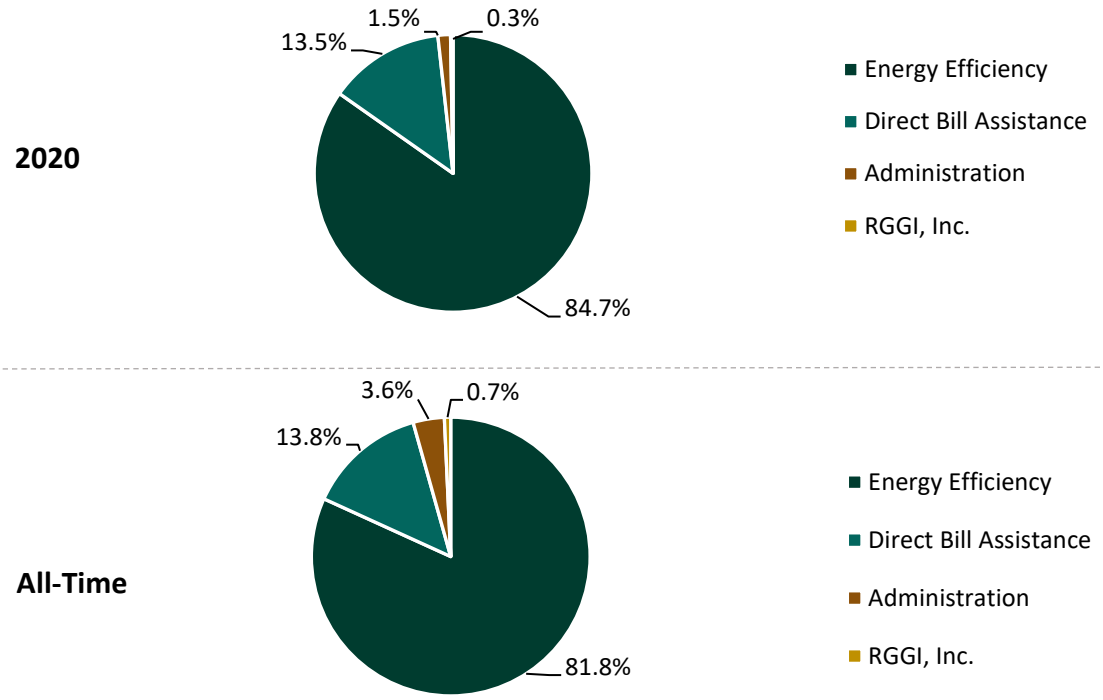
- Consolidating under one roof the funds for Maine's consumer-focused efficiency and alternative energy programs for all fuel types, including electric, natural gas, and unregulated fuels;
- Procuring distributed energy resources (such as efficiency and alternative energy) that cost less than traditional energy to help individuals and businesses meet their energy needs at the lowest cost; and
- Helping transform the energy market in Maine so that energy-efficient products, alternative energy equipment, and related energy services are more accessible and affordable to end-use customers.

Efficiency Maine's programs are funded primarily by a combination of electric and natural gas system benefit charges, Forward Capacity Market proceeds, and RGGI proceeds. During its 2020 fiscal year (FY2020), Efficiency Maine invested over $7.4 million in RGGI proceeds, directing approximately 98% towards a combination of energy efficiency programs and rate relief for large manufacturers; the remaining 2% went towards general administration. Though nearly all of Efficiency Maine's programs leveraged RGGI funding to some degree in FY2020, the bulk of funds were invested through the following five programs:

- *Home Energy Savings Program:* Drove market-based home weatherization and heating demand reduction by offering rebates and loans, providing customer education, and developing a vendor network.
- *Distributor Initiatives:* Rebated high efficiency boilers and furnaces to homes and businesses through the distributor channel
- *Retail Initiatives:* Rebated efficient wood stoves and pellet stoves in retail stores to heat the homes of Mainers
- *Commercial and Industrial (C&I) Prescriptive Program:* Provided fixed-price incentives for a prescriptive suite of "off-the-shelf" energy efficiency measures for C&I customers.
- *C&I Custom Program:* Targeted larger C&I customers by offering incentives for custom, site-specific energy efficiency projects that require unique engineering analyses.

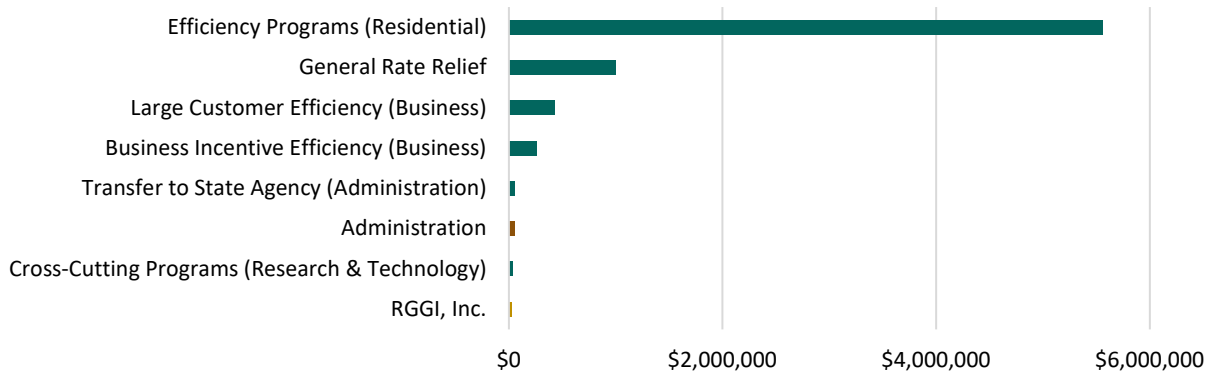
Over the lifetime of the investments made in FY2020, Maine's RGGI-funded efficiency measures are estimated to generate savings of over 2.15 million MMBtu in avoided consumption of natural gas and other heating or process fuels. These investments will lower participants' energy bills by more than $41 million.

Chart 10: 2020 Maine RGGI Investments by Category



Maine received $122.8M in proceeds from FY08-FY20. RGGI investments represent $7.4M in FY20, and $103M cumulatively. $13.4M is committed to 2021 and future programs.

Chart 11: 2020 Maine RGGI Investments by Recipient



Maine RGGI investments represent $7.4M in 2020.

Program Highlight: Home Energy Savings Program

Efficiency Maine's Home Energy Savings Program (HESP) serves as the framework for market-based residential weatherization and heating system improvements achieved through a combination of rebates, financing, and customer education. HESP raises awareness about the benefits of home weatherization and encourages Maine homeowners to make energy efficiency upgrades. Efficiency Maine's Low-Income Initiatives leverage this market-

based channel to target low- and moderate-income (LMI) customers by providing enhanced incentives for home weatherization (with an energy assessment) and high-performance heat pumps.

In the past, Efficiency Maine's ability to promote these tailored offerings to low-income households was limited; it required that participants be enrolled in the federally funded Low-Income Home Energy Assistance Program (LIHEAP). In 2017, the Maine State Housing Authority estimated that there were up to 176,000 low-income homes in Maine, yet only 40,000 were enrolled in LIHEAP. In FY2017, Efficiency Maine expanded eligibility criteria for this initiative to include LMI customers enrolled in any state or federal income-based program, as well as owners living in mobile homes and those living in homes with assessed property values below a certain threshold.

These eligibility changes, along with enhanced incentives, have helped drive dramatic growth in activity in Efficiency Maine's market-based LMI initiative. Indeed, overall participation rose from 40 homes in FY2016 to 1,444 homes in FY2021. (Though the COVID-19 pandemic initially dampened this growth trend in FY2020, data from FY2021 showed a strong rebound.) Rebates for heat pumps covered 1,213 units over the course of FY2021, up from 144 units in FY2017. The larger pool of potential customers and simplified criteria made this approach significantly easier for staff, contractors, and community organizations to promote Efficiency Maine's LMI offerings, and for participants to access it.

Overall, Efficiency Maine's market-based LMI offerings leveraged $15,000 in RGGI funds in FY2020. Low-income Mainers save an estimated 172 MMBtu annually in avoided energy consumption associated with heating oil and other fuels.

Success Story: Bath Iron Works

Bath Iron Works (BIW) is a major shipyard that has been building U.S. Navy warships in Bath, ME for over 100 years. The primary structural assembly building is nearly 170,000 square feet with 80-foot ceilings. It houses the majority of the facility's welding operations.

Originally, the assembly building's heat was provided by 19 Modine unit heaters equipped with steam coils. The building operated at a significant negative pressure; exhaust fans pulled air out of the building, and uncontrolled make-up air came in through infiltration. In these conditions, the building experienced fume accumulation, cold temperatures, and considerable energy loss. BIW therefore launched an effort to upgrade the building with the goals of improving air quality, increasing winter space temperature, reducing the negative pressure, and saving energy.

BIW's new high-efficiency air filtration units.

BIW received two separate proposals for new air filtration and make-up air systems – one high-efficiency, more expensive option, and one lower-efficiency, cheaper option. Both systems would accomplish the company's general goals for the project. By offering a financial incentive to defray the upfront incremental cost differential, Efficiency Maine was able to encourage BIW to select the high-efficiency alternative.

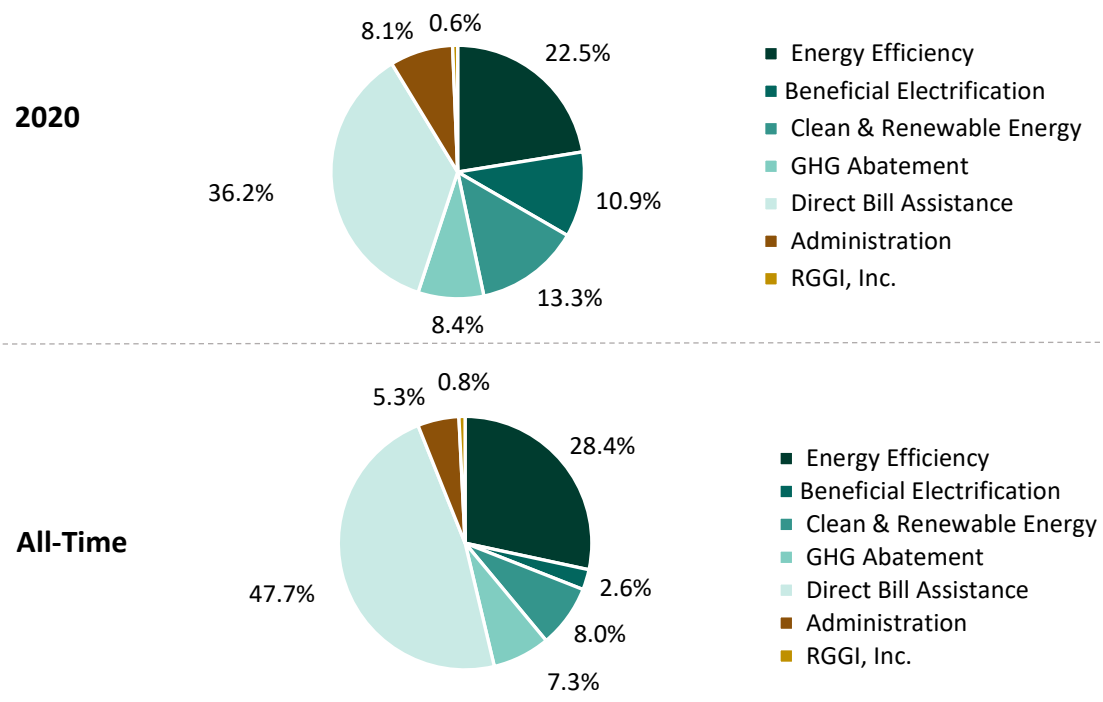
Given the relatively complex, site-specific nature of the project, BIW worked with Efficiency Maine's Commercial and Industrial (C&I) Custom Program. The program was able to validate the predicted energy impacts and offer a $752,000 incentive, funded partially with RGGI dollars. These investments will save BIW approximately 2.7 million kWh of electricity and 7,900 MMBtu of natural gas annually, reducing the company's operating costs for years to come.

Maryland

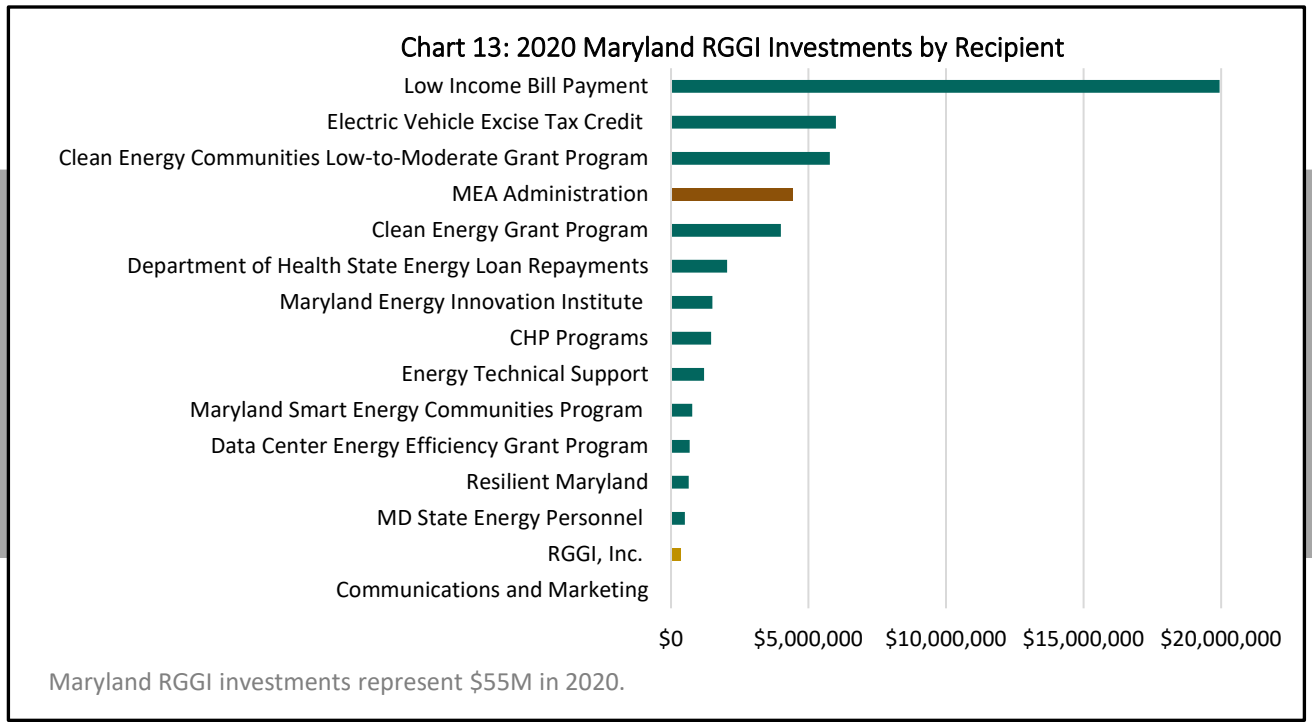
Maryland allocates proceeds from the sale of CO_2 allowances into the State's Strategic Energy Investment Fund (SEIF)—a special, non-lapsing fund administered by the Maryland Energy Administration (MEA). MEA deploys SEIF funds to promote affordable, reliable, and clean energy across Maryland's diverse regions and communities.

These programs are intended to reduce energy bills, create jobs in growing industries, help reduce greenhouse gas emissions, increase resiliency, and promote energy independence.

Chart 12: 2020 Maryland RGGI Investments by Category



Maryland received $736.8M in proceeds from 2008-2020. RGGI investments represent $55.0M in 2020, and $711.3M cumulatively. $25.5M is committed to 2021 and future programs.



Success Story: Public School Data Center Team Puts Energy Efficiency Lessons into Action

The Maryland Energy Administration (MEA) continues to develop innovative energy programs that drive economic development, energy resilience and recovery for Marylanders. Maryland was the first in the nation to offer a targeted energy efficiency program for data centers with the Data Center Energy Efficiency grant. Data centers use 100 – 200 times more energy than a typical office building, running 24 / 7 / 365. MEA provides Clean Energy Rebates to businesses, nonprofits, local governments, and State of Maryland government agencies and departments that install clean energy systems on facilities located in the state.

Data centers provide round-the-clock sensors to monitor power, temperature, humidity, fire, and other mechanical functionals for critical IT infrastructure. In 2017, US data centers required more than 90 billion kilowatt-hours of electricity, equal to the energy generated from 34 massive coal-powered plants. Energy efficiency at data centers has never been more important. Montgomery County Public Schools (MCPS) received a $127,000 Maryland's Data Center Energy Efficiency Grant (DCEEG) in 2018, to install more energy efficient technology in their data center. MCPS's data center operates, monitors, and provides technical support for central servers and related equipment allowing 24-hour access to essential student and administrative databases as well as payroll, student attendance and enrollment, retirement, asset management, financial management, report cards, and online ordering. MCPS implement numerous upgrades including server virtualization, replacement, and migration of storage area networks to reduce energy consumption of servers. Air flow optimization measures such as rack enclosure cooling blanking panels were also implemented, all as part of a multiphase data center improvement project. These upgrades are expected to save MCPS over $21,000 annually or 180,695 kilowatt hours, which is enough to power roughly 600 laptop computers for 8 hours. This project was co-sponsored by MCPS' Office of Technology and Innovation (OTI) and Department of Facilities Management's (DFM) Energy Resource Team. MCPS hopes to reinvest the grant funding to procure software that will give insight into actual server energy usage that is not presently available. This would facilitate and encourage informed decisions in prioritizing and pursuing larger ticket/cost items where greater energy savings and efficiencies could be realized. Before this project, MCPS did not consider energy efficiency or ENERGY STAR™ ratings when purchasing equipment.

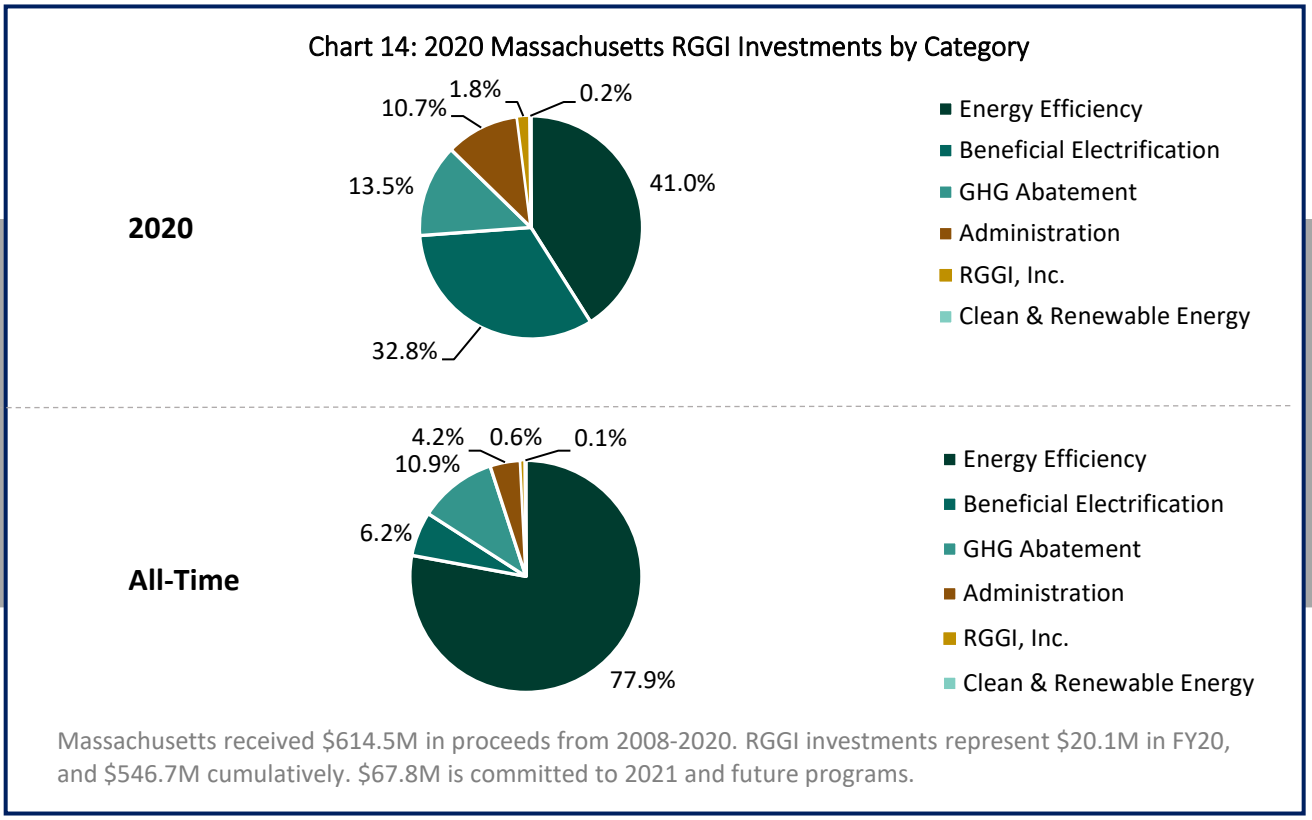
Massachusetts

Massachusetts leads the nation with bold and transformative policies and practices to address climate change. Signed into law in 2008, the *Global Warming Solutions Act (GWSA)* established a statewide limit on greenhouse gas (GHG) emissions of 25 percent below 1990 levels for 2020 and 80 percent below 1990 levels by 2050.[2] In 2020, Governor Baker signed *An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy*, further committing the Commonwealth to net zero emissions in 2050.[3]

Massachusetts was one of the first states in the nation to set aggressive economy-wide goals to reduce GHG emissions across the electricity, thermal, and transportation sectors and enact a suite of policies and practices to reach those goals. However, emissions from the transportation sector remain the states' foremost challenge in reaching its goal of net zero emissions in 2050. Transportation is the largest source of GHG emissions, and it continues to grow.

The aggregate emissions of the light-duty fleet of vehicles on Massachusetts roads is determined by a combination of the makeup of registered vehicles and the number of miles driven. The overall composition of the state's registered vehicles changes over time as new vehicles are purchased, old vehicles that no longer function or pass inspection are removed, and vehicles move in and out of state. Persuading new vehicle buyers to purchase an electric vehicle (EV) instead of a gasoline vehicle reduces future emissions from the transportation sector as vehicle purchases today determine the composition of the fleet for the vehicle's lifetime.

Chart 14: 2020 Massachusetts RGGI Investments by Category

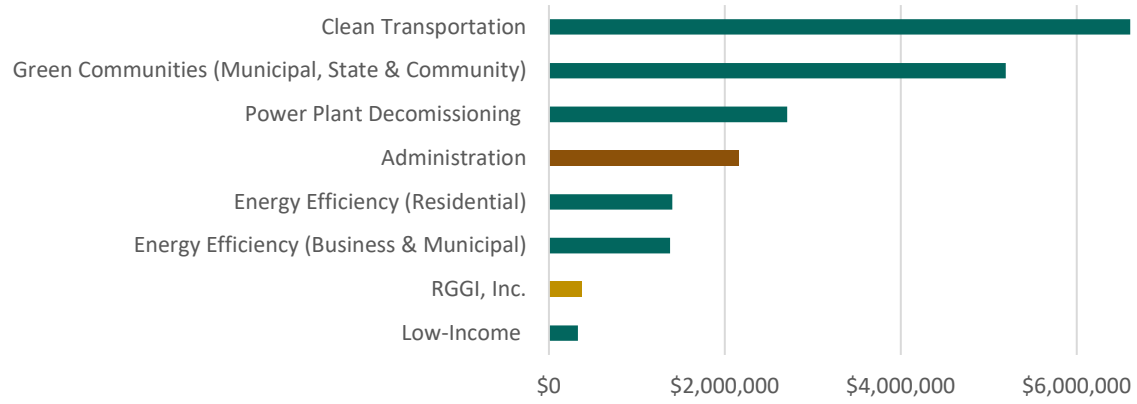


Massachusetts received $614.5M in proceeds from 2008-2020. RGGI investments represent $20.1M in FY20, and $546.7M cumulatively. $67.8M is committed to 2021 and future programs.

[2] An Act Establishing the Global Warming Solutions Act. Chapter 298 of the Acts of 2008, and as codified at M.G.L. c. 21N (Chapter 21N). Available at: https://malegislature.gov/laws/sessionlaws/acts/2008/chapter298

[3] Mass.gov. Press Release. Governor Baker Signs Climate Legislation to Reduce Greenhouse Gas Emissions, Protect Environmental Justice Communities. March 26, 2021. Available at: Governor Baker Signs Climate Legislation to Reduce Greenhouse Gas Emissions, Protect Environmental Justice Communities | Mass.gov

Chart 15: 2020 Massachusetts RGGI Investments by Recipient



Massachusetts RGGI investments represent $20.1M in 2020.

Program Highlight: MOR-EV

Launched in 2014, the *Massachusetts Offers Rebates for Electric Vehicles* (MOR-EV) program is an education and rebate program funded by the Executive Office of Energy and Environmental Affairs (EEA) and Department of Energy Resources (DOER) and is administered by the Center for Sustainable Energy (CSE) to increase the number of zero-emission vehicles (ZEVs) on roadways and reduce Massachusetts transportation sector GHG emissions. The MOR-EV program is designed to reduce GHG emissions in the transportation sector by influencing buyers to purchase an EV rather than a traditional gasoline-powered vehicle.

The program objective is to provide air pollution emission reductions for the Commonwealth by increasing the use of ZEVs MOR-EV offers rebates of up to $2,500 per electric vehicle and educates consumers and dealers about ZEV rebates and benefits. In 2020, more than 2,700 rebates were approved.

MOR-EV supports the Commonwealth's goals to reach 300,000 ZEVs on the roads by 2025. The program is designed to accelerate deployment of ZEVs in the Commonwealth by incentivizing residents to purchase or lease vehicles that will help:

- Reduce GHG emissions that contribute to climate change
- Protect public health and air quality by reducing transportation-related air pollution that contributes to smog formation and related health effects such as asthma and heart attacks
- Enhance energy diversity and security
- Save drivers money
- Promote economic growth in the Commonwealth

In 2020, the MOR-EV program avoided the use of nearly 23,000 barrels of oil used by light duty vehicles. The Commonwealth's program succeeded in avoiding more than 127,000 MMBtu and reducing GHG emissions by 10,317 short tons.

From its inception in 2014, the program has gone through several iterations, with an eye for changes towards improvement. A cost effectiveness report is currently being undertaken to examine the role of such changes within the program scope.

MOR-EV was one of the first programs of its kind in the United States and the performance of the program to date offers many lessons learned. As with any new initiative, there are successful aspects of the program as well as opportunities for improvement. Three challenges of the current program are financial sustainability, cost-effectiveness, and equity. These issues are high priorities for the next phase of the program, and the opportunities presented are focused on achieving these three priorities.

Success Story: Green Communities

The city of Methuen used its $268,640 Green Community Designation Grant to install three energy efficiency measures at its public library, new pumps and motors at a sewer pumping station, efficiency upgrades at the water treatment plant, new heating equipment at fire stations, and to replace insulation and vapor barriers on rooftop ductwork at an elementary school. These projects will save the city an estimated $31,000 a year in energy costs and reduce annual emissions due to municipal operations by 89 tons.

Three projects at the Nevins Library were designed to improve energy efficiency of the historic municipal building's heating and ventilation systems.

- Project #1 - Installation of demand controls to enable central programming and automation of heating, ventilation, and cooling.
- Project #2 - Installation of variable frequency drive controls for more efficient timing operation of air handling unit fan motors.
- Project #3 - Replacement of two outdated, inefficient fan motors of air handling unit pumps. This project was added as project team made a determination that two of the four air handling unit motors needed to be replaced to maximize energy efficiency benefits.

The sewer Pump and motor replacement involved replacing two obsolete pumps & motors at the Bolduc Street sewer pumping station in West Methuen.

The Bolduc Street station is the city's second largest sewer pump station. The two old 25-horsepower 3-phase motors, in addition to inefficient energy usage, required extensive maintenance for operation, including frequent cleaning and regular reassembly of both pumps. The new pumps have significantly reduced clogging of materials and maintenance costs at the station.

At the water treatment plant, grant funds supported the installation of two variable frequency drives to enable more efficient timing operation at the plant's hot water secondary pumps and the installation of an air source heat pump at the plant's backup generator facility. This will provide for more efficient pre-heating of the back-up generator system's engine block.

Two fire stations received heating equipment upgrades. An outdated, inefficient furnace heating office and living space on the second floor of the Central Fire Station was replaced with a more efficient gas-fired unit. Garage bay unit heaters at the North Fire station were replaced with more efficient models.

The final project replaced aging insulation and vapor barriers supporting a rooftop unit on an elementary school.

New Hampshire

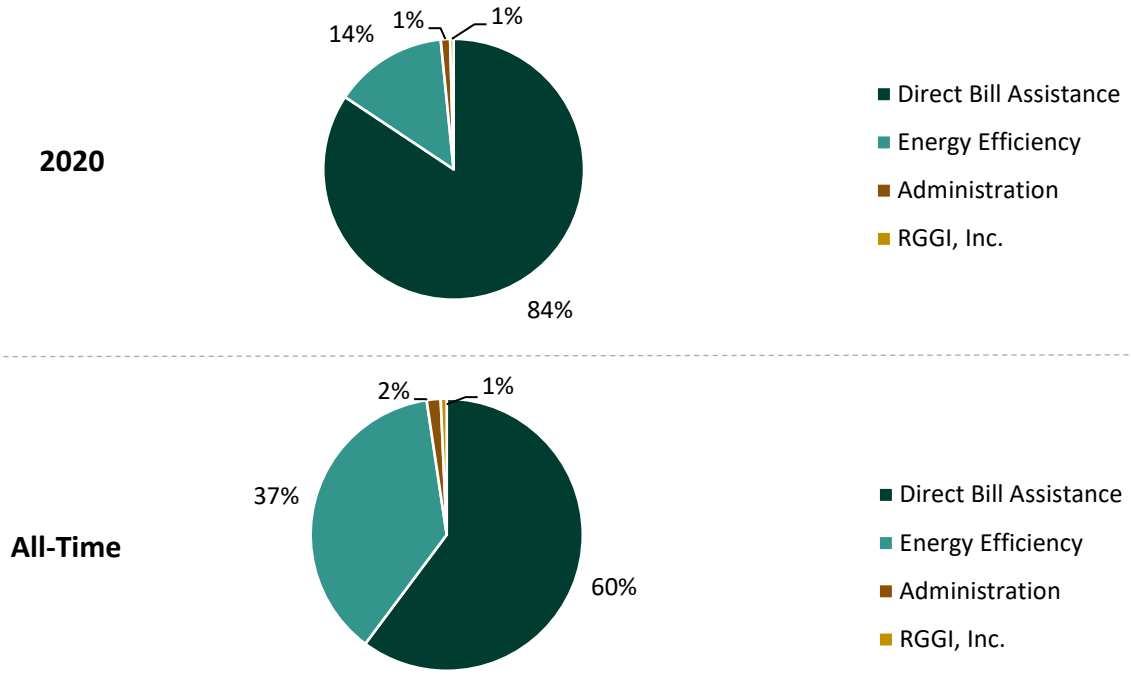
New Hampshire invests RGGI allowance proceeds in a variety of programs that reduce energy use in municipal and retail buildings, commercial and industrial facilities, and low-income households. RGGI allowance proceeds also provide direct bill assistance to reduce electric bills.

In 2020, New Hampshire received approximately $18.8 million in RGGI allowance proceeds, of which approximately $2.5 million was allocated to the Energy Efficiency Fund (EEF). The state's four electric utility companies administer energy efficiency fund programs through the EEF in combination with funds collected through the System Benefits Charge. Approximately $15.8 million was used to provide direct bill assistance to New Hampshire electric consumers, $0.1 million was allocated to an energy efficiency program focusing on moderate-income households, and the remaining RGGI auction proceeds of approximately $0.3 million covered RGGI-related administrative expenses.

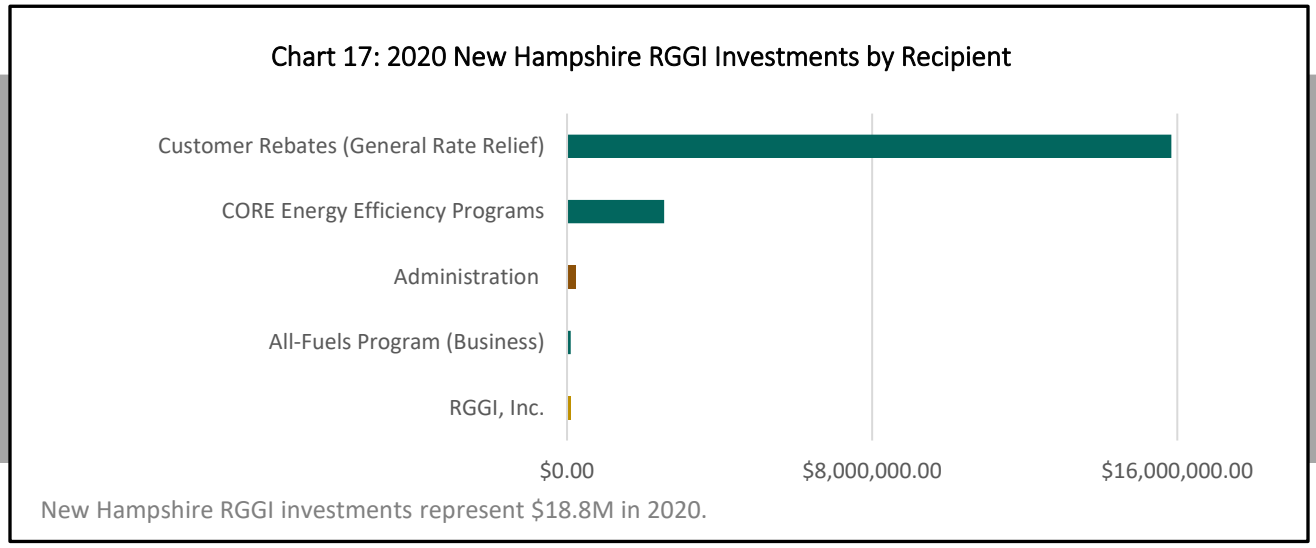
The state's electric utility companies' energy efficiency programs supported by RGGI funds include: a Municipal program; an income-eligible Home Energy Assistance program; and an All-Fuels weatherization program targeting moderate-income households. In 2020, EEF funds were used to accomplish the following:

- Installed energy efficiency measures in 163 municipal buildings;
- Weatherized and/or provided weatherization self-install "kits" to 476 income-eligible homes; and
- Worked closely with Community Action Agencies to develop moderate-income program details, outreach methods, and to identify eligible households for targeted outreach.

Chart 16: New Hampshire RGGI Investments by Category



New Hampshire received $176M in proceeds from 2008-2020. RGGI investments represent $18.8M in 2020, and $172M cumulatively.



Program Highlight: Efficiency Programs

For the measures installed in 2020, the Home Energy Assistance and Municipal programs will save approximately 53,712 MWh of electricity and 129,400 MMBtu over the expected life of the energy efficient equipment improvements. Associated bill savings over the lifetime of these improvements is estimated to be $10.5 million. The All-Fuels program will save approximately 23 MWh of electricity and 310 MMBtu over the expected life of the energy efficient equipment improvements made in 2020.

The All-Fuels program was launched in 2016. From 2016 through 2018 the program received $1.2 million of RGGI funding to support energy efficiency measures for retail businesses, and large commercial and industrial energy users. Beginning in 2019, the All-Fuels program supports energy efficiency measures for moderate-income residential energy users with household income of 200% to 300% of Federal Poverty Guidelines. Working with Community Action Agencies, the New Hampshire electric utilities will provide energy audits, and offer financial incentives for installation of energy efficiency measures. Beginning In 2019, this program will receive a total of $690 thousand of RGGI funding over a three-year period.

Success Story: Town of Carroll Public Safety Building and Town Hall

At their 2019 Town Meeting, Carroll voters overwhelmingly approved the proposal for a new Town Hall and Safety Building to be erected at a single, convenient location. The ultimate plan was to construct two separate buildings at the site of the now former, and since removed, town hall. This project presented an ideal opportunity for energy efficiency measures to be incorporated into the new structures through the RGGI-funded NHSaves Municipal Program and partner utility Eversource Energy (“Eversource”). Eversource worked with the project architects and contractors to include multiple energy efficiency measures in the project, resulting in structures that exceed building code efficiency requirements and containing multiple efficient measures, including above code insulation, double glazed windows with argon fill, LED lighting, and efficient heating and water systems.

The town formerly leased a building for its police headquarters and to house its Fire and Rescue departments at another, separate location. With the new 13,000 square foot Safety Building, Carroll is able to house its police and emergency-operations center, and the Twin Mountain Fire and Rescue department, all under one roof. Building spaces include a large apparatus bay, a workshop, fire chief offices, EMS offices, police chief offices, a secure, controlled entry way, evidence rooms, booking/holding areas, a training room, a kitchen, storage, and mechanical/electrical areas. Adjacent to the Safety Building is the new Town Hall, which is a 6,500 square foot structure. Its building spaces include a 1,500 square foot community room, library, historical room, offices/conference rooms, store, and mechanical/electrical areas.

The RGGI-funded NHSaves Municipal program not only allowed the Town of Carroll to construct the buildings they voted for, it also allowed for enhanced versions of the buildings with a more appealing return on investment. These

structures, as built, ensure reduced energy use, carbon emissions and energy bills for the town for many years to come compared to baseline structures that simply meet codes and standards. Together, the buildings are estimated to produce annual savings of 53,591 kWh, 8.0 kW, and 1,493 gallons of propane for the Town of Carroll each year for the useful life of the measures incorporated.

Resources:

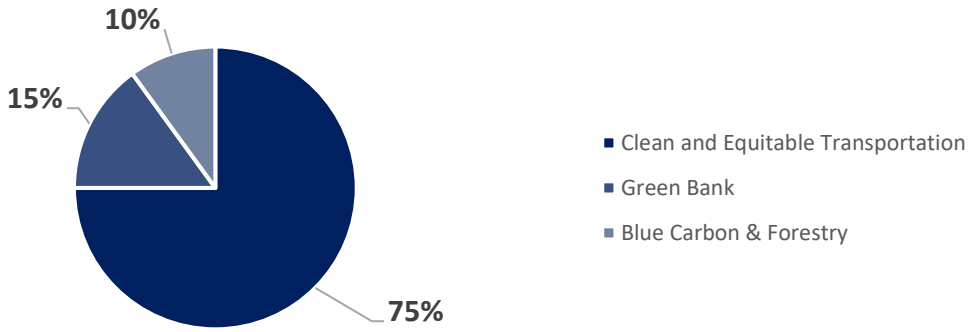
- Energy Efficiency Program Regulatory Webpage
- 2020 Systems Benefit Charge Report to New Hampshire Legislature inc. RGGI Grant Program
- Report to New Hampshire Legislature on 2020 RGGI Program

New Jersey

New Jersey formally rejoined RGGI in 2020, and as part of its onboarding process released its *RGGI Strategic Funding Plan: Years 2020 through 2022*. This plan guides the investment of the state's auction proceeds for its first three years of participation, ensuring cross-agency coordination. By law, New Jersey's RGGI funding is allocated by percentage to three state agencies (60% to the New Jersey Economic Development Authority, 20% to the New Jersey Board of Public Utilities and 20% to the New Jersey Department of Environmental Protection) and each agency is required to spend funds within specific programs areas. The plan identifies cross-agency initiatives that will be funded by RGGI auction proceeds and how these investments complement the state's emissions reductions, clean energy, and environmental justice priorities. Funds from 2020 through 2022 are devoted to programs and projects that fall within the scope of four initiatives:

1. Catalyzing Clean, Equitable Transportation
2. Promoting Blue Carbon in Coastal Habitats
3. Enhancing Forests and Urban Forests
4. Creating a New Jersey Green Bank

Chart 18: New Jersey 2020-2022 Planned RGGI Investments by Category

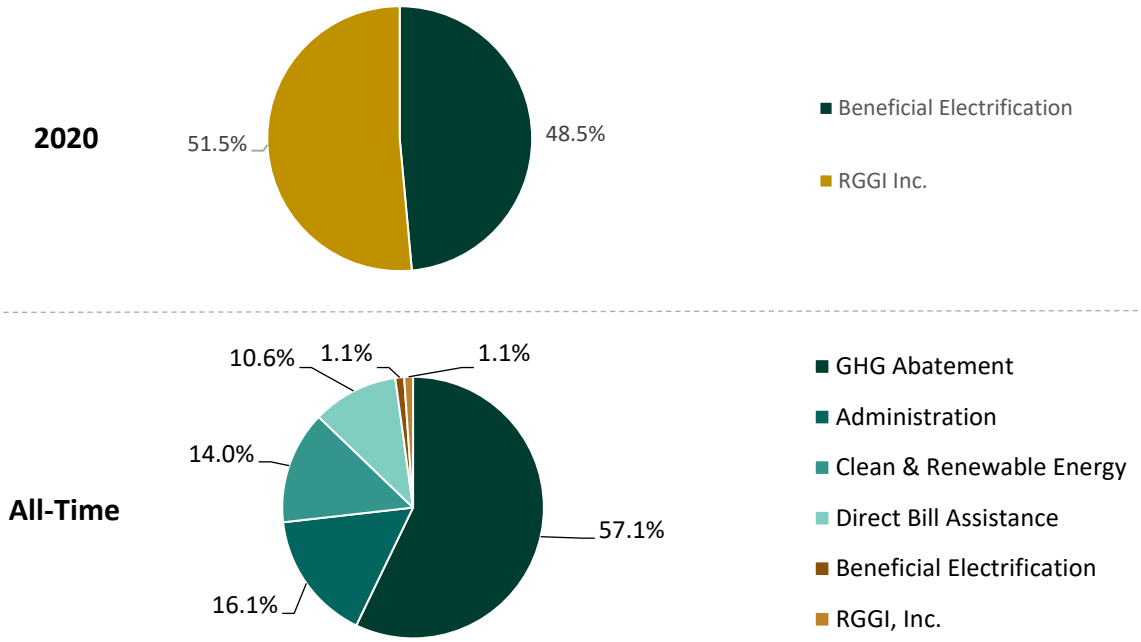


The majority of funding is dedicated to accelerating transportation electrification in the State, focusing on reducing emissions from transportation sources in communities disproportionately impacted by the effects of environmental degradation and climate change. Electrification of the transportation sector is essential for New Jersey to achieve its targets of a 50% reduction in greenhouse gas emissions by 2030 and an 80% reduction by 2050. Currently, transportation accounts for 41% of greenhouse gas emissions in the State, more than twice that of the second largest source, electric generation (19%).[4]

During 2020, the Economic Development Authority, in consultation with, the Board of Public Utilities and the Department of Environmental Protection worked closely with a consultant to develop a zero-emission medium and heavy-duty vehicle strategy, to guide its RGGI investments in clean and equitable transportation.

[4] New Jersey Greenhouse Gas Inventory, Mid-Cycle Update Report. NJ Department of Environmental Protection (NJDEP). 2021. https://www.nj.gov/dep/aqes/ghgarchive/MCU%20GHG%20Inventory_2021.pdf

Chart 19: New Jersey RGGI Investments by Category



New Jersey received $94M in proceeds in 2020. RGGI investments represent $1M in 2020, which are reflected in the 2020 chart above. New Jersey was an early participant in RGGI before withdrawing in 2012, and then resumed participation in 2020. New Jersey's first control period (2008-2012) proceeds investments total $43.6 million, which are included with 2020 investments in the All-Time investments chart.

Program Highlight: Supporting the Transition to Zero-Emission Commercial Transportation

New Jersey is uniquely situated along the Northeast corridor and has extensive transportation assets, including the nation's second busiest port and second densest road and rail network. Electrifying the State's transportation sector therefore requires a thoughtful approach to planning and implementation. To that end, the New Jersey Economic Development Authority, in consultation with the Department of Environmental Protection and the Board of Public Utilities, utilized RGGI funds to develop a strategic approach for establishing New Jersey as a zero-emission transportation hub with a focus on job creation and workforce development. This strategy works in concert with the State's Energy Master Plan and Global Warming Response Act 80x50 Report. As part of this effort, the zero-emission medium and heavy-duty market and supply chain were analyzed, a state strategy was proposed and a slate of new zero-emission medium- and heavy-duty vehicle programs and initiatives were conceptualized. Initial efforts focused on the development of the New Jersey Zero Emission Incentive Program (NJ ZIP), which was formally launched in April of 2021.

NJ ZIP is a voucher program for businesses and organizations purchasing new, electric, class 2b to class 6 vehicles. The program offsets the costs of purchasing electric medium-and heavy-duty vehicles by offering vouchers with base values ranging between $25,000 to $100,000. Additional bonuses are available for small businesses; women-, minority-, and veteran-owned businesses; vehicles that were manufactured in New Jersey; small businesses that scrapped their eligible gas- or diesel-powered medium- and heavy-duty vehicles; and vendors that invest in driver education and training. Funding is limited to companies operating in eligible communities, as defined as the greater Newark and Camden areas for NJ ZIP's inaugural round.

Resources:

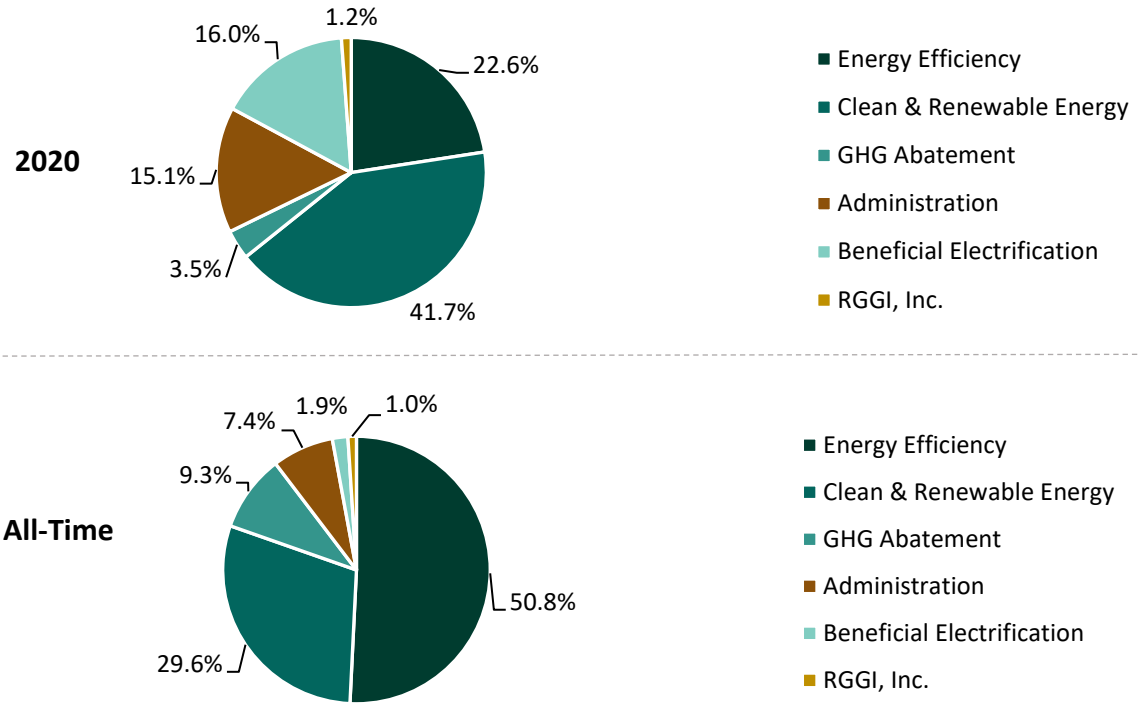
- New Jersey Zero Emission Incentive Program

New York

New York's robust record of climate action includes helping to establish RGGI as North America's first market-based program to reduce carbon emissions. The state affirmed its role as a climate leader with enactment of the Climate Leadership and Community Protection Act, one of the most aggressive climate polices of any major economy. The State has already reduced electricity emissions by 51% since 1990, with a 60% reduction from 2005 to 2019 in greenhouse gas emissions from sources covered by the RGGI program. Further reductions in electricity sector emissions will allow for needed shifts to electrify buildings and transportation. RGGI, alongside state policies such as the Clean Energy Standard, focused on renewable generation deployment, and the ten-year, $5 billion Clean Energy Fund, focused on buildings decarbonization, will continue to serve as a critical tool to reduce state-wide greenhouse gas emissions 40% from 1990 levels by 2030 and realize a zero-carbon electricity sector by 2040.

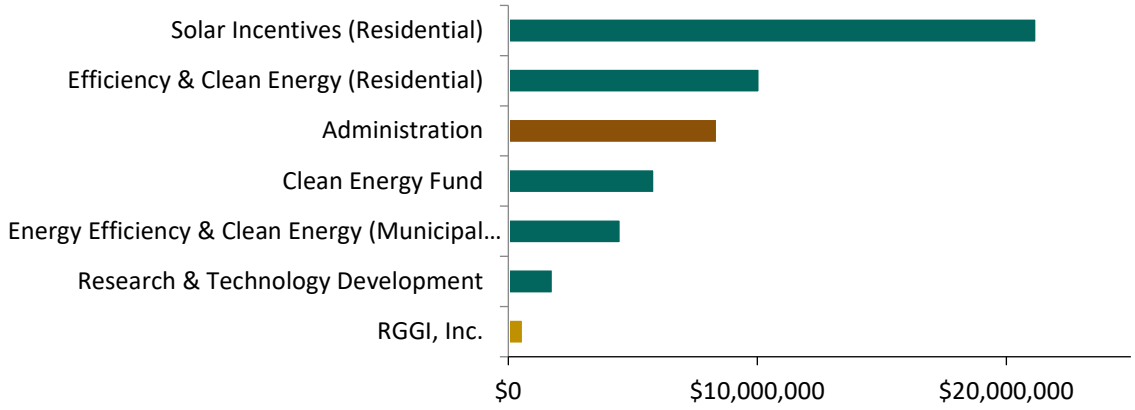
Proceeds generated through RGGI auctions allow New York to pursue opportunities for clean energy, energy efficiency, and carbon reduction that other state activities are not currently designed to reach. The demand for RGGI-supported programs underscores New Yorkers' desire for clean energy opportunities.

Chart 20: New York RGGI Investments by Category



New York received $1.4B in proceeds from 2008-2020. RGGI Investments represent $52.6M in 2020, and $1.1B cumulatively. $345.5M is committed to 2021 and future programs.

Chart 21: 2020 New York RGGI Investments by Recipient



New York RGGI investments represent $ 52.6M in 2020.

Program Highlight: REV Campus Challenge

The Energy to Lead Competition of NYSERDA's REV Campus Challenge initiative challenges colleges and universities across the State to develop and implement plans to advance building decarbonization and innovative, cost-effective clean energy solutions on their campuses and local communities. Institutions are encouraged to incorporate students, curriculum integration, and community engagement into their projects. Proposals with the best solutions to achieve deep energy savings and combat climate change through energy efficiency, renewables, or GHG emission reduction will win approximately $1 million each to help implement their plans. There were three rounds of the Energy to Lead Competition. The final round had proposals submitted in February 2020, and resulted in 18 proposals from 17 institutions. The latest updates from winning institutions of the first two rounds include:

- The State University of New York at Buffalo and its partners are close to finalizing advancement of an offsite solar venture that will enable the university to achieve their goal of 100% renewable purchased electricity. In addition, the university's sustainable living learning lab project, Garden, Relax, or Work (GRoW) Home, has been moved to the North Campus and interior/exterior construction is being finalized. The installation of 22,600 ground mount solar panels commenced in Q4 2020 and is expected to be completed by Q2 2021.
- Bard College filed an application with the Federal Regulatory Commission (FERC) on May 1, 2019 for an exemption from licensing for the Annandale micro hydropower project. FERC requested a stability analysis to also be completed while FERC continues to review the application. Bard College and Micro Hydro have submitted a response to FERC during Q4 2020 and FERC is finalizing their review of the full application package. Since the launch of their Micro Hydro New York website, Bard has released several blog posts about project status and FERC approval on a real-time basis.
- Suffolk County Community College (SCCC) completed the project design and construction documents for their Renewable Energy and STEM Center (RESC) to achieve Net Zero Energy (NZE) in Q3 2020. Following design completion, SCCC obtained a building permit for the RESC and issued an RFP to solicit a general contractor for the building's construction. SCCC selected and awarded a general contractor in Q4 2020 and construction began in Q2 2021.

Success Story: Workforce Development

The Green Jobs Green New York (GJGNY) Workforce Training and Development (WFD) initiative complements other NYSERDA and New York State Department of Labor (DOL) programs targeted at preparing individuals for energy efficiency, solar thermal, and solar electric careers in New York State. WFD programs help to build the State's capacity for long-term carbon reduction, facilitate energy education programs that will help build a clean

energy future, and provide long-term career opportunities for individuals seeking to work in clean energy. Specifically, GJGNY efforts are expanding the State Registered Apprenticeship Program and additional third-party accredited building trades programs by providing clean energy specific content in those training activities. Expectations are to increase access to technical training workshops for skill enhancement and certification. In addition, the GJGNY-supported programs are expected to bridge the gap between training and employment through on-the-job training incentives for businesses seeking to hire and train new workers while reaching out to low-income communities to expand training opportunities. From the program's inception a total of 4,184 New Yorkers were trained in a range of energy efficiency and renewable energy courses.

In 2020, NYSERDA advanced approximately $520,000 in GJGNY WFD funds that will be made available to eligible New York State employers. This program supports wages for new hires on a first-come, first-served basis for eligible clean energy businesses. The program includes higher wage subsidies for employers that hire workers with additional barriers to employment. On Long Island, GJGNY supported 51 total On the Job Training hires in 2019, and a total of 245 total for 2020 – which represents over 480% year-over-year growth in the program to support business hiring, even during the height of the COVID-19 pandemic.

Resources:

- 2020 RGGI Operating Plan
- Regional Greenhouse Gas Initiative (RGGI) Reports - NYSERDA
- GRoW History - UB Sustainability - University at Buffalo
- Blog Landing - Microhydro NY
- Clean Energy Industry reports

Rhode Island

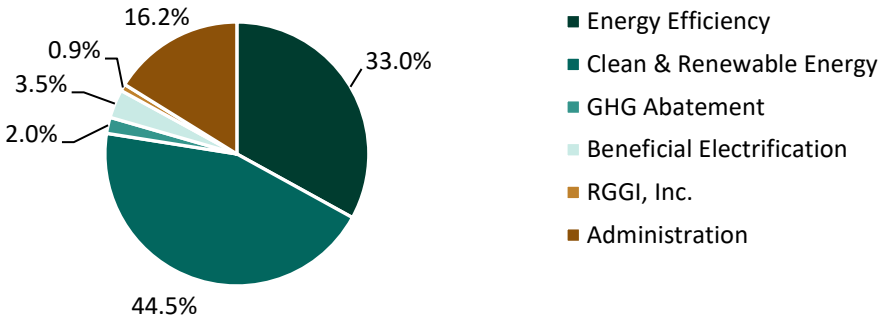
Rhode Island RGGI auction proceeds are allocated by the state's Office of Energy Resources (OER) to drive investment in – and expansion of – clean energy resources, including cost-effective energy efficiency and renewables. In doing so, OER seeks to support investment and job growth in Rhode Island's burgeoning clean energy sector; reduce barriers to consumer adoption of clean energy solutions; place downward pressure on long-term energy costs; and shrink the state's carbon footprint. RGGI auction proceeds are accelerating cleaner, more sustainable energy solutions across public and private sector institutions and in Ocean State communities. These investments are being made in a manner consistent with the Regional Greenhouse Gas Initiative Act, Rhode Island's State Energy Plan, its 2021 Act on Climate, and broader state energy and environmental policy goals.

In 2020, Rhode Island RGGI proceeds were allocated to support several important clean energy programs, including:

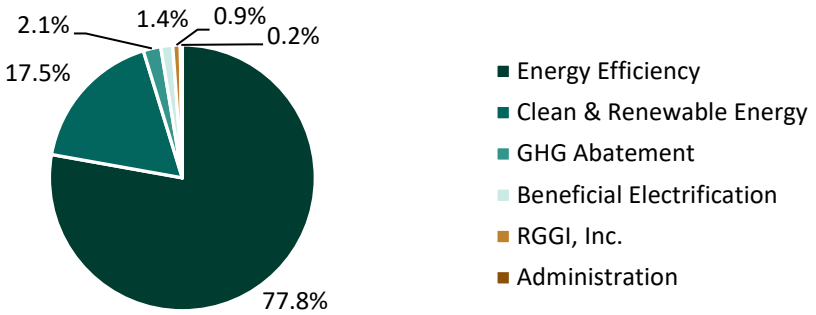
- Providing enhanced financial incentives to support Rhode Island municipalities with the conversion of local streetlights to high-efficiency LED technologies;
- Continued support for the Rhode Island Department of Environmental Management's Energy-Savings Trees program, which distributes trees to homeowners that can be strategically planted on their property and result in saving energy and lower utility bills;
- Advancement of the State Clean Energy Lead by Example program, which is supporting the adoption of energy efficiency and renewable energy projects at state government properties;
- Expanded cost-effective energy efficiency programs and incentives for utility customers located in the Pascoag Utility District;
- Support for the Rhode Island Infrastructure Bank's Efficient Buildings Fund (EBF). RIIB's EBF provides attractive, long-term financing to municipalities and quasi-public agencies for the completion of energy efficiency and renewable energy projects;
- Continued support for a Farm Energy Program that links local farms to energy efficiency and solar PV opportunities;
- Support for the Zero Energy for the Ocean State (ZEOS) program through collaboration with Rhode Island Housing and National Grid. This program is designed to help provide energy savings to low and moderate income (LMI) customers in Rhode Island;
- Support solar development on Brownfields through Rhode Island Commerce Corporation's Renewable Energy Fund; and
- Furthering solar PV adoption by Rhode Island homes and businesses through continued support of the state's Renewable Energy Fund.

Chart 22: Rhode Island RGGI Investments by Category

2020

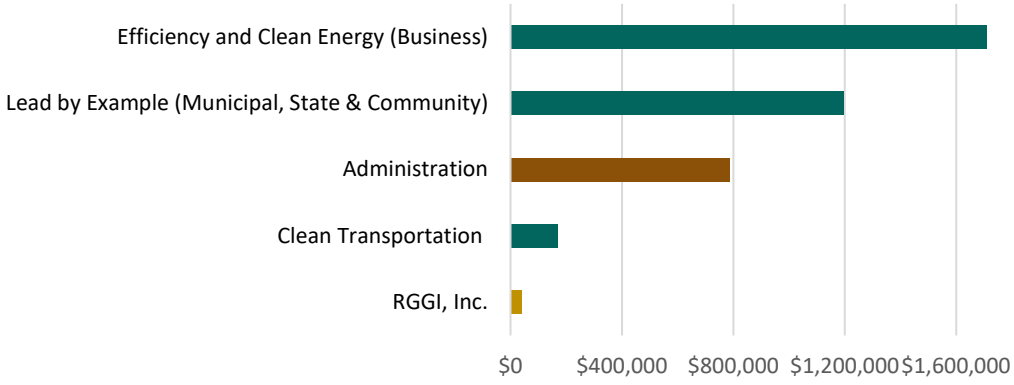


All-Time



Rhode Island received $81.9M in proceeds from 2008-2020. RGGI Investments represent $4.9M in 2020, and $55.7M cumulatively. $26.3M is committed to 2021 and future programs.

Chart 23: 2020 Rhode Island RGGI Investments by Recipient



Rhode Island RGGI investments represent $4.9M in 2020.

Success Story: Pascoag Utility District Battery Storage

The Pascoag Utility District (PUD) is a not-for-profit, quasi-municipal utility serving approximately 5,000 electric customers in the Pascoag and Harrisville sections of Burrillville, Rhode Island.

Their electric service territory is serviced by two feeder lines, one primary and one backup, which were meeting or exceeding maximum capacity during peak load conditions. After comparing options from a system impact study conducted to look for solutions to alleviate these grid concerns, PUD decided to undertake a "non-wires alternative" or NWA project to address this need rather than implement a traditional infrastructure upgrade to both feeder lines.

This NWA solution involved a substation expansion to allow both feeder lines to serve PUD's load simultaneously at peak conditions in combination with a 3 MW/9 MWh battery storage device that will allow PUD to dispatch stored power under contingency conditions or when one of the feeder lines is down.

This project is expected to cost approximately $2.3 million dollars, providing significant savings when compared to the estimated $6-$12 million cost of the traditional infrastructure upgrade. As a not-for-profit utility, maintaining low rates and reliable service are two of PUD's most important priorities, which this NWA solution advanced. In addition, this innovative project will better utilize clean energy resources in the Pascoag territory by charging during off-peak hours and deploy energy during high-load hours to reduce overall load on PUD's system. Having battery storage of this capacity also provides an important resiliency asset to this community that can be deployed during emergency situations or in response to extreme weather conditions to maintain critical services for their customers.

Further showcasing Pascoag Utility District's leadership and creativity was their pursuit of numerous funding channels to support this project. PUD was able to secure financing for some of the project costs through the Rhode Island Infrastructure Bank at well-below market interest rates while bringing on a strong institutional partner to support this project.

This project began construction in 2021 and is expected to be fully complete, interconnected, and operational in 2022 prior to the summer peak season. Once operational, it is anticipated that this clean energy project will deliver over 80 tons of CO2 reductions annually and provide significant reliability and grid optimization services to the community as well.

This project was funded with RGGI Proceeds.

Resources:

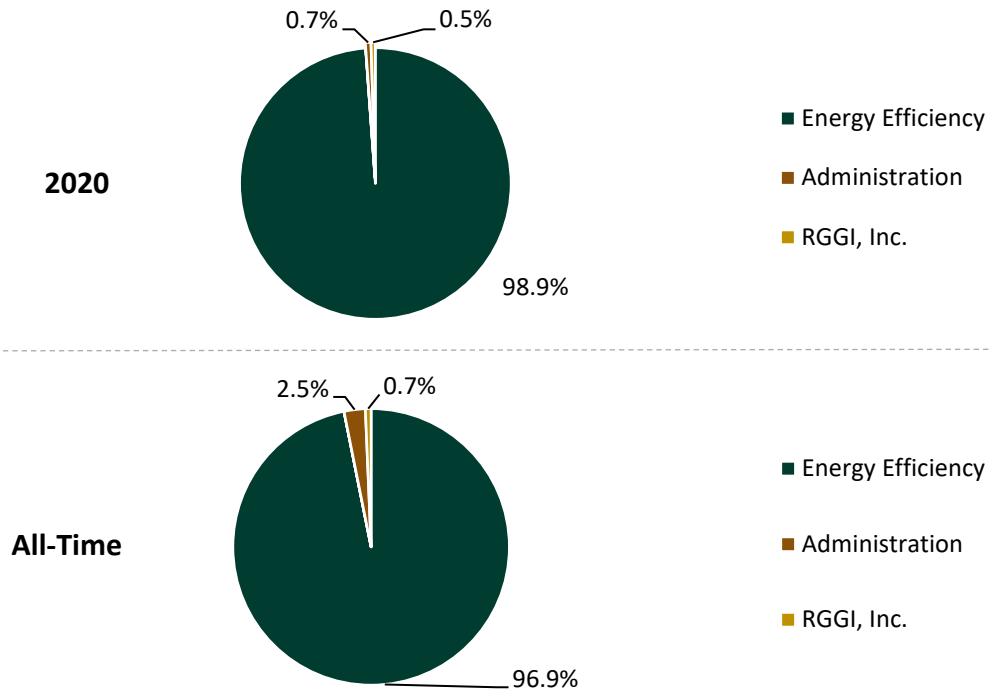
- Regional Greenhouse Gas Initiative (RGGI)- Rhode Island -Office of Energy Resources (ri.gov)

Vermont

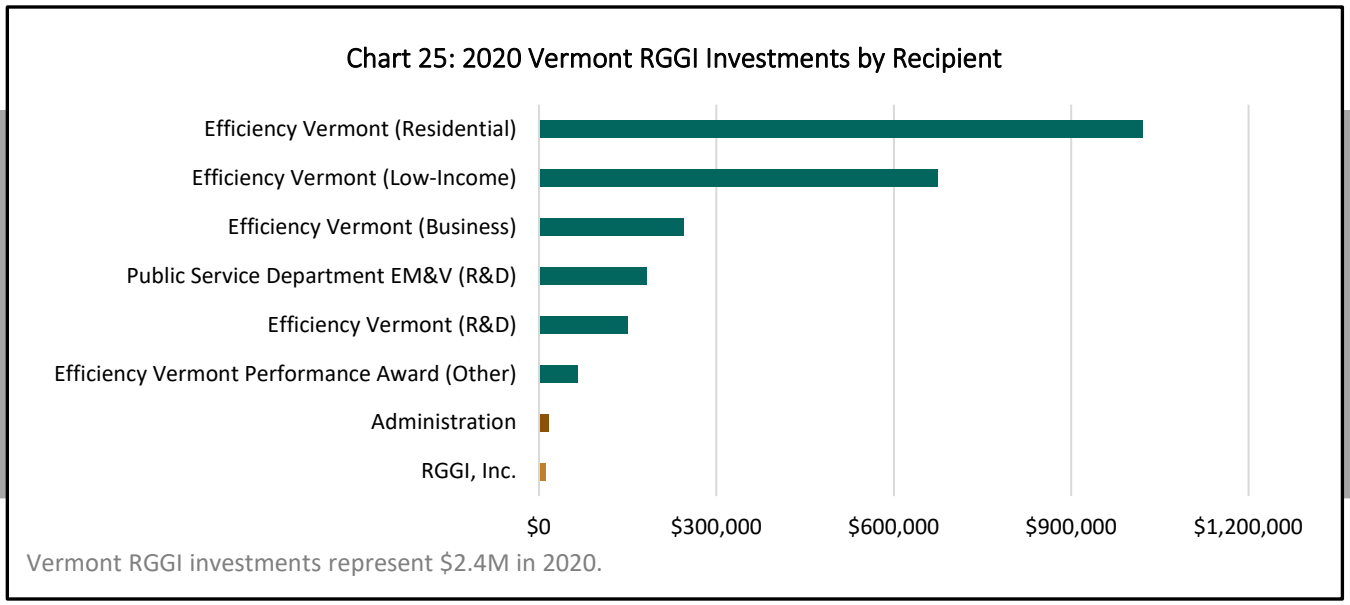
Vermont invests the majority of its CO_2 allowance proceeds in programs managed by Efficiency Vermont. RGGI funds allow Efficiency Vermont to expand its electrical energy efficiency programs to include thermal energy and process fuels efficiency programs. Efficiency Vermont's participation in the regional grid's forward capacity market also provides funds for this program expansion. Vermont's thermal energy and process fuels efficiency programs funded by RGGI through 2020 are estimated to result in lifetime energy savings of 4,672,229 MMBtu. These programs are estimated to avoid the emission of 278,837 short tons of CO_2, and to save participants $113,109,031 on their energy bills over the lifetime of those investments. Vermont's RGGI-funded programs have served approximately 12,326 households and 689 businesses. Programs currently supported by CO_2 allowance proceeds include the Home Performance with ENERGY STAR® service for residential customers, the Building Performance service providing incentives for efficiency services to small business customers, the Home Energy Loan for residential customers, low-income energy efficiency services through 3E Thermal project management, custom commercial thermal efficiency projects, and technologies including woodstoves and heat pumps.

Efficiency Vermont, the nation's first ratepayer-funded energy efficiency utility, is overseen by the Vermont Public Utility Commission, and implemented by VEIC. Efficiency Vermont's programs have a proven track record of saving energy and money for commercial, industrial, and residential consumers. These and other energy efficiency programs helped to rank Vermont third in the nation in 2020, according to the American Council for an Energy Efficient Economy (A CEEE) State Energy Efficiency Scorecard.

Chart 24: Vermont RGGI Investments by Category



Vermont received $28.2M in proceeds from 2008-2020. Vermont investments represent $25.8M cumulatively. In 2020, Vermont received $2.5M in proceeds, $176k of which is committed to 2021 and future programs.



Program Highlight: Home Performance with ENERGY STAR and Home Energy Loan

The Efficiency Vermont Home Performance with ENERGY STAR service is an incentive-based program for single-family Vermont residences to lower utility bills and increase home comfort and safety by installing insulation, air sealing, and ventilation (heating systems improvements are also recommended). Vermonters can access comprehensive thermal efficiency retrofits, incentives to offset project costs, and low-no interest rate financing. Customers hire a participating Efficiency Excellence Network, Building Performance Institute certified, contractor. This allows customers to receive incentives up to $5,500, requires the contractor to meet Vermont residential building energy codes and standards, health and safety and program requirements, and provides quality assurance for projects.

The Efficiency Vermont Home Performance with ENERGY STAR service officially launched in 2005. In 2008, when the Vermont Legislature set a statewide goal to weatherize 80,000 homes by the year 2020, the Home Performance with ENERGY STAR service was galvanized. The legislation sought to harness energy efficiency as a driver of savings for consumers and economic development in Vermont. Home Performance with ENERGY STAR is one of the primary programs contributing to these goals.

Home Performance with ENERGY STAR is a national brand managed by the U.S. Department of Energy (U.S. DOE). Across the US, 50 organizations sponsor local programs under this brand. Although local programs differ, they follow the same basic structure to ensure a comprehensive, whole-house approach to energy efficiency and maximize long-term savings for homeowners. The key components of the Home Performance with ENERGY STAR program approach are outlined by U.S. DOE and implemented in Vermont by Efficiency Vermont.

The RGGI funded portion of the Efficiency Vermont Home Energy Loan program provides residential customers financing for Home Performance with ENERGY STAR projects and other thermal efficiency projects, including woodstoves (pellet and cord wood), and central pellet heating systems with income-based interest-rate buydowns and loan loss reserve support for participating lenders.

Success Story: RGGI Funds Help VT Accelerate Moderate-Income Weatherization Support

Efficiency Vermont helps Vermonters who don't qualify for low-income assistance weatherize their homes by providing rebates that offset the project costs. A substantial portion of the funding for these incentives has come from RGGI revenues, which have helped Efficiency Vermont build its robust Home Performance with ENERGY STAR program.

Leading up to 2020, Efficiency Vermont was able to support between 800-1,100 households each year through the Home Performance with ENERGY STAR program. This strong annual participation allowed the weatherization market to develop over time and positioned the state to make significant enhancement when the opportunity presented itself.

Such an opportunity came in 2019, when the legislature passed, and Governor Scott enacted, Act 62, allowing Efficiency Vermont to repurpose existing budget dollars from its electric energy efficiency budget as a result of operational efficiency cost savings, to help more moderate-income Vermonters weatherize their homes. With a strong Home Performance with ENERGY STAR program already well established, thanks in part to the sustained investment of RGGI funds over time, Efficiency Vermont was able to rapidly deploy these funds as increased incentives for moderate income Vermonters in 2020.

Efficiency Vermont reinvigorated and expanded the existing weatherization offer to provide up to 75% off project costs, with 0% interest financing for 60 months, and the first six months of payments would be paid for by Efficiency Vermont. It was paired with a robust, multimedia campaign.

The impact was immediate. Once the cost came down through the upfront incentive, and homeowners could break the remaining cost into low monthly payments (about $50 a month), the demand for weatherization surged statewide.

Steve Dunn, Program Manager for the DOE Home Performance with ENERGY STAR program, said that Efficiency Vermont is leading the effort to improve energy efficiency in homes, which lowers energy costs and improves home comfort and safety for thousands of families across the state, including communities that are not able to afford the cost of energy efficiency improvements.

Jill Neitlich and husband Flynn of Wardsboro, VT joined thousands of other Vermonters in 2020 by taking advantage of weatherization incentives through Efficiency Vermont's Home Performance with ENERGY STAR program.

"By providing low-moderate income families access to weatherization programs, Efficiency Vermont has made sure that the energy savings and health benefits of weatherization improvements are available to the families who need it most," said Dunn.

Thanks to consistent funding for more than a decade through RGGI and other revenues, Efficiency Vermont was able to tap into a proven, fully developed Home Performance with ENERGY STAR program in 2020 to ramp up the program and extend its reach to thousands of Vermonters who most needed it.

As the Vermont Public Utility Commission stated in its Act 62 Final Report to the legislature, "Efficiency Vermont was able to quadruple the number of projects it completed by reducing up-front project costs. In August and September 2020, increased funding allowed Efficiency Vermont to complete four to five times the number of projects historically completed in those months."

Weatherization directly supports Vermonters, boosts a growing workforce, and reduces greenhouse gas emissions. The past decade has proved that our statewide system of delivering these benefits has been effective. 2020 proved that without a stable, long-term source of additional funding like RGGI, Vermont would have missed out on the opportunity to help thousands more Vermonters. Efficiency Vermont looks forward to continuing its successful partnerships to serve Vermonters and support our state's goals for many years to come.

Resources:

- Efficiency Vermont Rebates
- Efficiency Vermont Services
- Efficiency Vermont News

Glossary and Methodology

Program Categories

Administration
Funds directed to administrative overhead expense associated with all RGGI-funded programs, including outsourced and in-house overhead expenses.

Beneficial Electrification
Programs designed to reduce fossil fuel consumption by implementing or facilitating fuel-switching to replace direct fossil fuel use with electric power. Examples include incentives for electric vehicles and home appliances, and installation of electric vehicle infrastructure. Program costs include evaluation and measurement.

Clean and Renewable Energy
Programs directed at accelerating the deployment of renewable or other non-carbon emitting energy technologies. Program costs include evaluation and measurement. Examples include incentives for residential solar panels, financing of commercial renewable energy projects through green banking, research and development of new energy technologies.

Direct Bill Assistance
Programs providing energy bill payment assistance, including direct bill assistance to low-income ratepayers. Program costs include evaluation and measurement.

Energy Efficiency
Programs designed to improve energy efficiency by reducing overall energy use without degrading functionality. This includes programs directed at assisting low-income families and small businesses. Program costs include evaluation and measurement. Examples: home energy audit programs, home and building weatherization, energy efficient appliance or industrial equipment rebate programs, compact fluorescent light bulb programs, and energy efficiency workforce training programs.

Greenhouse Gas Abatement
Programs promoting the research and development of advanced energy technologies, the reduction of vehicle miles traveled, the reduction of emissions in the power generation sector, tree-planting projects designed to increase carbon sequestration, and other initiatives to reduce greenhouse gases. Program costs include evaluation and measurement.

RGGI, Inc.
Funds provided to RGGI, Inc. to support and implement state CO_2 Budget Trading programs.

General Terms

RGGI Investments
RGGI Investments are the proceeds generated by RGGI CO_2 allowance auctions that have been invested by the RGGI states in the energy efficiency, clean and renewable energy, GHG abatement, and direct bill assistance programs discussed in this report.

Future Committed
Future committed funds are the proceeds generated by RGGI CO_2 allowance auctions that have not yet been invested by the RGGI states. Future committed proceeds represent funds that could be invested by the state in 2020 and beyond.

Current Period
The twelve-month period covered by this report, which may be either the fiscal year or calendar year 2020, as defined by each state.

Benefits and Statistics

Annual (2020)
A measure of one year's worth of benefits from all measures installed in 2020. Note that actual realized benefits in the year 2020 may differ slightly from the 2020 annual benefits, since measures may be installed at different times during the year.

Lifetime (2020)
The full benefits of measures installed in 2020, including benefits to be realized in the future. The lifespan of installed measures varies by type of measure and by program, and is calculated and provided by program administrators. For example, an industrial boiler would likely be estimated to provide benefits over a longer lifespan than an LED lightbulb. Measure lifespans used in this report typically range between 5-25 years.

Lifetime (All-Time)
The total estimated lifetime benefits of all measures installed since the inception of the RGGI program. This includes the full lifetime benefits of measures installed in previous years, in addition to the lifetime benefits of 2020 measures.

Funds Invested
Total dollar amount of RGGI proceeds invested in a program or category over a given period. For programs that are partially funded by RGGI, only the amount provided by RGGI funds is included.

Participating Households: Programs
Number of households that have directly received assistance as a result of each program (e.g. number of homes weatherized, number of households receiving home energy audits, etc.). Households participating in more than one program may be counted under each program they have participated in (e.g. a completed home energy audit constitutes a participating household even if the household may elect to further participate in programs to install recommended measures). For multi-family dwellings, each unit within the multi-family home may be considered to be a household. For retail programs such as lightbulb distribution, households may be extrapolated from the number of items distributed.

Participating Households: Direct Bill Assistance
Number of households receiving direct bill assistance or energy bill rebates funded through RGGI proceeds. Bill assistance programs vary by state; in some cases rebates may be returned to all customers, while in other cases they may be targeted to low-income customers or to specific customer types.

Participating Businesses: Programs
Number of "end-user" businesses who have directly received assistance as a result of the program (e.g. number of businesses whose offices were weatherized, number of businesses receiving grant assistance to install energy efficiency measures, etc… via a grant, loan, or rebate). Businesses participating in more than one program will be counted under each program they have participated in (e.g. a completed audit constitutes a Participating Business even if the business may elect to further participate in programs to install recommended measures).

Participating Businesses: Direct Bill Assistance
Number of businesses receiving direct bill assistance or energy bill rebates funded through RGGI proceeds.

Increased Employment
Total estimated job-years created as a result of RGGI funds invested, estimated on a regional basis based on literature review.

MWh Avoided
Estimated total MWh projected to be avoided as a result of RGGI funds invested, calculated using program-specific savings as defined by each state.

MMBtu Avoided
Estimated total MMBtu projected to be avoided as a result of RGGI funds invested, calculated using program-specific savings as defined by each state.

Energy Bill Savings
Estimated gross amount saved as a result of RGGI funds invested (initial investment in installed measures is not deducted). Calculated using program-specific savings, as defined by each state. Estimates of lifetime energy bill savings are given in current year dollars as of the start of the savings, and in most cases are not discounted into the future. Where discounts are applied, they are noted on state-specific pages.

CO_2 Emissions Avoided
Estimated total number of short tons of CO_2 avoided as a result of funds invested, calculated using a program-specific formula as defined by each state.

RGGI States Proceeds Contacts

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Attachment 25

Analysis of the Public Health Impacts of the Regional Greenhouse Gas Initiative, 2009–2014

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Acronyms and Abbreviations

BenMAP	Benefits Mapping and Analysis Program
CAA	Clean Air Act Amendments of 1990
CAMD	Clean Air Markets Division
CO_2	Carbon dioxide
COBRA	Co-Benefits Risk Assessment
EE	Energy efficiency
eGRID	Emissions and Generation Resources Integrated Database
EGU	Electric generating unit
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
ER	Emergency room
GHG	Greenhouse gas
Hg	Mercury
IPCC	Intergovernmental Panel on Climate Change
MAPS	Multi-Area Production Simulation
MW	Megawatt
MWh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NARSTO	North American Research Strategy for Tropospheric Ozone
NEI	National Emissions Inventory
NESCAUM	Northeast States for Coordinated Air Use Management
NO_x	Nitrogen oxides
PM	Particulate matter
$PM_{2.5}$	Fine particulate matter
RE	Renewable energy
RFF	Resources for the Future
RGGI	Regional Greenhouse Gas Initiative
S-R	Source-Receptor
SO_2	Sulfur dioxide
TAG	Technical Advisory Group
WTP	Willingness-to-pay
ZEV	Zero emission vehicle

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The findings of this independent study are based solely on the analysis and judgment of Abt Associates and do not necessarily reflect the views of the TAG members, Laurie Burt, or our funders.

About Abt Associates

Abt Associates is a mission-driven, global leader in research, evaluation, and program implementation in the fields of health, social and environmental policy, and international development. Known for its rigorous approach to solving complex challenges, Abt is regularly ranked as one of the top 20 global research firms and one of the top 40 international development innovators. The company has multiple offices in the United States and program offices in more than 40 countries.

Abt's experts in climate change, clean energy, and public health include economists, public health experts, epidemiologists, natural scientists, data scientists, attorneys, and others. In addition, Abt economists and public health experts support the U.S. Environmental Protection Agency's (EPA's) efforts to develop, maintain, and update the Benefits Mapping and Analysis Program (BenMAP) and the Co-Benefits Risk Assessment (COBRA) tools, both of which are utilized in this analysis.

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Executive Summary

Purpose of this Study

This independent study provides an analysis of the public health impacts of the Regional Greenhouse Gas Initiative (RGGI) over its first six years of implementation (2009 to 2014). RGGI is the nation's first regional regulatory program designed to reduce greenhouse gas (GHG) emissions from large electric power plants, and builds from a long and successful tradition in the Northeast states of using market-based programs to cost-effectively reduce air pollution. Since RGGI started in 2009, the program has raised nearly $3 billion to support the RGGI states' investments in energy efficiency, renewable generation, and other public benefit programs, and these states are on track to achieve reductions of GHG emissions of 45 percent below 2005 levels by 2020.

Because "criteria" air pollutants[1] are co-produced along with GHG emissions from fossil-fuel power plants, RGGI is also expected to drive reductions in these air pollutants and their adverse effects on human health. The objective of this independent study is to provide a *retrospective* analysis of the impacts of an existing GHG reduction program—RGGI—on air quality and public health.

Using publicly available, peer-reviewed air quality and public health models and historical data characterizing RGGI's actual performance during the program's first two compliance periods (covering 2009 to 2014), we addressed the following questions in this analysis:

- Did RGGI result in measurable changes in emissions of criteria air pollutants and air quality?
- If so, how did changes in air quality resulting from RGGI affect public health and to what degree?
- What were the spatial and temporal patterns to changes in air quality and public health due to RGGI implementation?
- Will health benefits from RGGI's first two compliance periods be replicated in the future?

Key Results and Findings

The RGGI program improved air quality throughout the Northeast states and created major benefits to public health and productivity, including avoiding hundreds of premature deaths and tens of thousands of lost work days. RGGI's impact on electricity markets resulted in significant reductions in key air pollutants with adverse effects on human health. Over the first six years of the program, RGGI avoided hundreds of cases of premature deaths, heart attacks, hospitalizations, and emergency room (ER) visits; tens of thousands of lost work days, and hundreds of thousands of cases of restricted activity days due to poor air quality. Table 1 summarizes cumulative avoided health and productivity effects associated with RGGI's first two compliance periods.

[1] "Criteria air pollutants" refer to the six most common air pollutants in the United States: carbon monoxide (CO), lead, ground-level ozone (O_3), nitrogen oxides (NOx), particulate matter (PM), and sulfur dioxide (SO_2). The Clean Air Act requires EPA to set National Ambient Air Quality Standards (NAAQS), which are maximum allowable concentrations for these pollutants that are protective of public health.

Table 1. Summary of Cumulative RGGI Health Benefits, 2009 to 2014

Avoided Health Effects	**Avoided Mortality**		
	• 300–830 premature adult deaths		
	Avoided Morbidity		
	• 35–390 non-fatal heart attacks		
	• 420–510 cases of acute bronchitis		
	• 8,200–9,900 asthma exacerbations		
	• 13,000–16,000 respiratory symptoms		
	Other		
	• 180–220 hospital admissions		
	• 200–230 asthma ER visits		
	• 39,000–47,000 lost work days		
	• 240,000–280,000 days of minor restricted activity		
Value of Avoided Health Effects	**Low**	**Central**	**High**
	$3.0 billion	$5.7 billion	$8.3 billion

Source: Abt Associates analysis (2017).

Notes: The total value of avoided health effects is the sum of health benefits in states participating in RGGI and in neighboring northeastern states, based on a 3 percent rate of discount. Values are in 2015 dollars.

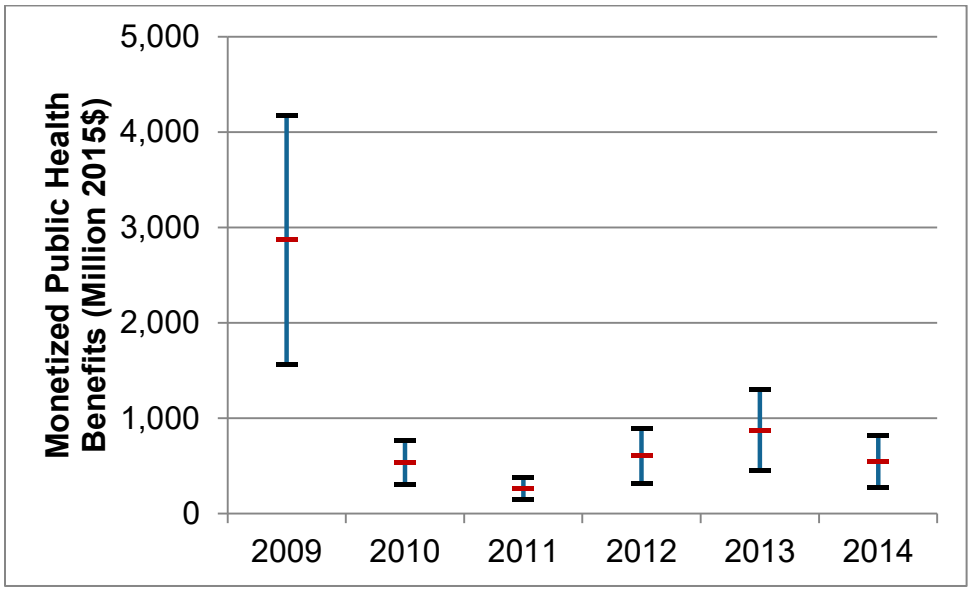
The economic value of RGGI's health and productivity benefits is estimated at a cumulative $5.7 billion ($3.0 billion low-end, $8.3 billion high-end). Avoided cases of premature deaths due to reduced levels of fine particulate matter $PM_{2.5}$ account for the majority of RGGI's monetized health benefits. However, other important benefits to the region's economic productivity and quality-of-life include more than 39,000 avoided lost work days and at least 240,000 avoided days with restricted activities (e.g., exercising outdoors) due to poor air quality.

Estimated benefits to health are positive in every state in the Northeast region (including RGGI and certain neighboring states)), and in almost every year of the study period. States with the highest total monetized health benefits over RGGI's first six years include: Delaware, Maryland, New Jersey, New York, and Pennsylvania. Sizeable benefits also occur in Massachusetts, Connecticut, and New Hampshire. Benefits in Rhode Island, Vermont, and Maine are smaller in magnitude compared to those in states with larger populations, but are relatively consistent over the study period. Overall, health benefits estimated for the first compliance period are higher than for the second period.

The largest annual improvements in air quality and health benefits from RGGI are in 2009 and 2013. The largest single-year benefits in health due to RGGI occur in 2009 (shown in Figure 1). This result is consistent with RGGI's two observed effects on wholesale power markets: 1) changes in power prices to absorb CO_2 allowance costs, which results in shifting electricity dispatch from higher- to lower-carbon sources, and 2) investments in energy efficiency that reduce electricity demand, fossil fuel-based generation, and emissions. There is also some evidence that power plant owners, anticipating the requirements of the program, may have taken early action to reduce CO_2 emissions immediately before and after the start of the program in 2009. Energy efficiency investments were comparatively high in this year as well. The combination of higher prices and energy efficiency investments, together with early action, likely account for the largest single-year emission reductions and health benefits across the six year period. Similarly, higher benefits in 2013 most likely correspond to higher relative investments in

energy efficiency and renewable energy in that year, and also reflect energy savings accruing from efficiency investments made in prior years.

Figure 1. Annual Health Benefits due to RGGI, 2009 to 2014

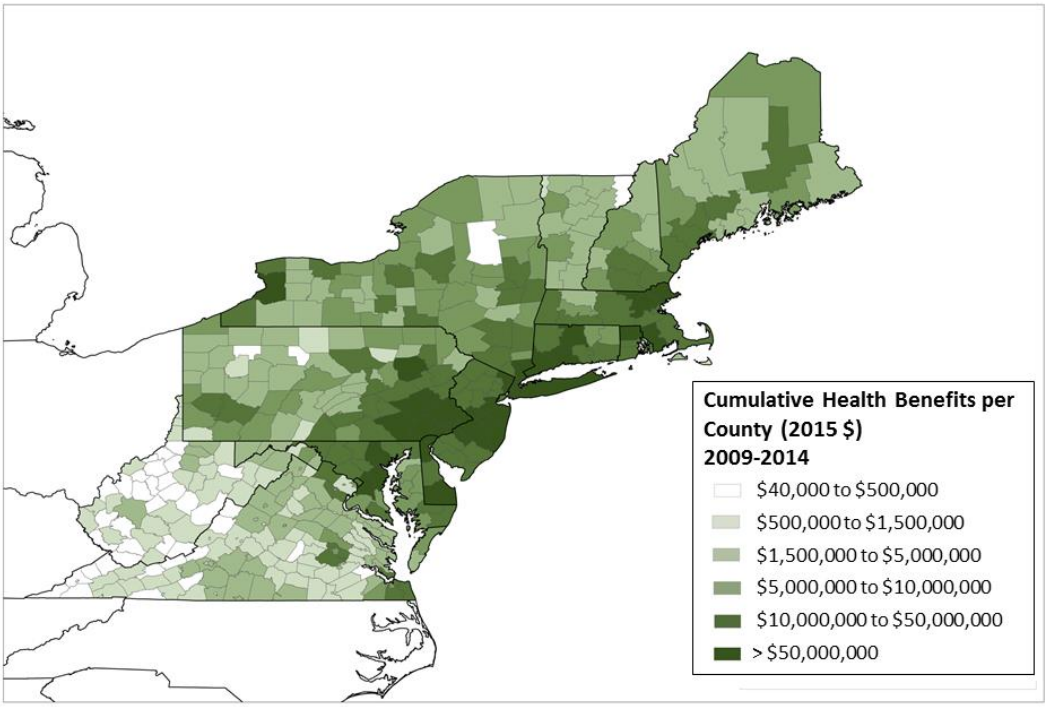


Source: Abt Associates analysis (2017).

Note: Value of annual health benefits is the sum of health benefits to RGGI states and neighboring northeastern states, based on a 3 percent rate of discount.

Multiple states in the mid-Atlantic and New England regions experienced significant health benefits from RGGI-induced changes to air quality which originate in the RGGI states. Due to regional transport of air pollutants, our modeling shows that states with densely populated areas located directly downwind of key coal-fired power plants experienced substantial health benefits, regardless of whether they participate in RGGI. As shown in Figure 2, Pennsylvania experienced the most significant benefits overall from RGGI due to reductions in emissions from Maryland's (and to a lesser extent Delaware's) large coal plants. The District of Columbia, Virginia and West Virginia also experienced modest health benefits from emissions reductions occurring in RGGI states. Similarly, emissions reductions due to RGGI from coal plants in western New York, Massachusetts, and New Hampshire create health benefits not only in those states, but also in Rhode Island, Vermont, and Maine.

Figure 2. Cumulative Health Effects of RGGI, 2009 to 2014



Source: Abt Associates analysis (2017).

A small number of legacy coal plants, particularly in the mid-Atlantic RGGI states, account for the majority of RGGI's health benefits. Coal-fired power plants have the highest emission rates of SO_2, which is the primary contributor to ambient $PM_{2.5}$ levels and risks to health. So, reductions in SO_2 emissions by coal plants account for the majority of health benefits. Of the RGGI states, Maryland has the most significant footprint of older coal-fired power plants and the largest inventory of SO_2 emissions. RGGI-induced changes in generation and emissions from five of Maryland's coal plants alone account for roughly 62 percent of SO_2 reductions in 2009, and 55 percent of cumulative SO_2 reductions from RGGI's first two compliance periods (2009 to 2014).

If coal plants in RGGI states retire as planned in the near future, reductions of air pollutants and annual health benefits resulting from the RGGI program will likely level off. However, additional health benefits will occur as energy demand from other sectors—transportation and buildings—shifts onto a cleaner grid in RGGI and neighboring states. As noted above, RGGI-induced changes at a relatively small number of coal plants drive a high proportion of RGGI's total reductions in key air pollutants and health benefits. However, a number of older coal-fired power plants in RGGI states driving many of the health benefits presented in this analysis are scheduled to retire within the next five years (e.g., Chalk Point in Maryland, Brayton Point in Massachusetts). As such, the fleet of power plants in RGGI states will on average be cleaner in the near future than the current fleet, so that future RGGI-induced reductions in generation are likely to result in less average annual health benefits going forward. However, states will be able to move energy use from other sectors, such as transportation and heating, to this cleaner grid. This process, known as "electrification," can further reduce air pollutants resulting in significant health benefits. For example, transitioning the light-duty vehicle fleet to about 65 percent zero-emission vehicles (ZEVs) by 2050 in eight northeastern states could result in emission reductions that generate nearly $12 billion in health benefits (American Lung Association of California 2016).

RGGI-funded investments in energy efficiency strategically targeted to address daily air quality goals during high-electricity demand periods can generate additional health benefits. The scope of this analysis addressed only annual changes in average $PM_{2.5}$ concentrations. However, air quality in a given location can be highly variable over the course of a year, and a single short-term exposure to high $PM_{2.5}$ concentrations can lead to more severe health outcomes than multiple exposures to low $PM_{2.5}$ concentrations. To the extent that RGGI states' future investments in energy efficiency programs can effectively target peak load on days with high electricity demand, RGGI can further reduce the number of low air quality days and thereby generate additional health benefits in the future.

Estimates of RGGI's health benefits presented in this study are likely conservative, and also do not include the value of other co-benefits associated with reductions in air pollution, such as improved ecosystem services. Health benefits resulting from energy savings associated with RGGI states' efficiency investments that persist beyond 2014 and from reductions in ozone were beyond the scope of this study, but could be significant. In addition, additional benefits to terrestrial and aquatic ecosystems resulting from reductions in sulfur and nitrogen deposition are not included in this analysis.

Approach

The analytic approach used in this study for estimating RGGI's impact on emissions, air quality, and public health consisted of three sequential steps described below:

1. **Estimate annual changes in electric generation and emissions of air pollutants at power plants as a result of RGGI implementation from 2009 to 2014.**

   The RGGI program created changes to annual electricity generation, the mix of power plants (and fuels) dispatched to meet electric demand, and associated changes in emission profiles through its two direct effects on the electricity market: 1) Owners of large fossil-fuel power plants purchase CO_2 allowances to meet RGGI's emissions cap, and then build the costs of these purchases into wholesale power prices. In this way, purchases of CO_2 allowances result in shifts in power production from higher- to lower-carbon generation sources; and 2) Participating RGGI states' investments of proceeds from allowance auctions into energy efficiency measures and renewable generation result in reductions in overall electricity demand and increase the capacity for low- or zero-carbon electricity, respectively.

   We used results from electricity dispatch modeling to determine annual changes in generation (in megawatt-hours (MWh), at the plant level) due to the RGGI program and also for a counterfactual scenario representing the world without RGGI. Using EPA historical data on actual power plant-level emissions (and emissions rates), we then used the incremental difference in plant-level output due to RGGI, calculated associated changes in SO_2 and NOx emissions, and aggregated these emission changes at the county level. These results became the inputs to the air quality modeling conducted in the second step of this analysis.

2. **Estimate annual changes in air quality at the county level associated with changes in sulfur dioxide (SO_2) and NO_x emissions from power plants, by year.**

   To estimate the air quality impacts of RGGI using annual county-level emission changes calculated under the first analytic step, we used EPA's Co-Benefits Risk Assessment (COBRA) model. COBRA is a free, screening-level tool that assists government agencies and others in assessing the benefits of clean energy and climate mitigation policies by estimating the effects of changes in air pollutant

emissions on ambient air concentrations of fine particulate matter ($PM_{2.5}$). Using the estimated incremental change in county-level emissions of NO_x and SO_2 due to RGGI that we calculated under Step 1, we performed a COBRA modeling run for each individual year from 2009 to 2014. Outputs from the COBRA modeling step consist of annual changes in ambient $PM_{2.5}$ levels in each county in RGGI and adjacent non-RGGI states, and become the inputs to the modeling of associated health impacts under Step 3.

3. **Assess public health impacts associated with changes in air quality due to RGGI implementation from 2009 to 2014.**

   To quantify and value the public health impacts associated with RGGI's first six years, we used EPA's BenMAP. The BenMAP model uses data describing population, background levels of health outcomes in populations, and economic values for health effects from literature to estimate the number and economic value of health impacts resulting from changes in air quality. We used the county-level changes in ambient $PM_{2.5}$ levels generated by COBRA as inputs to BenMAP. BenMAP then calculated annual health benefits from RGGI's relative effect on ambient $PM_{2.5}$ for 2009 to 2014.

In addition, we conducted sensitivity analysis to address uncertainties surrounding data, assumptions, and key modeling relationships. Specifically, we applied a sensitivity factor of 50 percent to discount estimates of health benefits for states not participating in the RGGI program, to account for a gap in information about changes in air emissions that may have occurred in these states as a result of RGGI. In addition, outputs from the BenMAP model also reflect uncertainties in the assumed relationship between reductions in exposures of human populations to key air pollutants and health outcomes, especially premature mortality. Finally, we did not quantify other benefits outside the scope of this analysis, such as health benefits associated with reductions in ozone and RGGI-induced energy savings occurring after 2014, or improved ecosystem health. As such, the benefits presented here can be considered a conservative representation of the co-benefits of the RGGI program to human health and ecosystems.

Overview of Analysis

The northeastern U.S. states have a long track record of implementing market-based environmental programs to improve air and water quality. The first of these programs—the Acid Rain Program[2]—was established under Title IV of the 1990 Clean Air Act Amendments (CAA) and required power plants to reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x), the primary contributors to acid rain formation. The Acid Rain Program also established a trading system that enabled regulated firms to exchange allowances or permits to meet emissions goals at the lowest possible total cost. The Acid Rain Program was an environmental success story: SO_2 emissions from electric power plants declined by more than one-third—from 15.9 million to 10.2 million tons—between 1990 and 2004 (U.S. EPA, 2016c), despite a 25 percent increase in electricity generation from coal-fired power plants over the same period (Schmalensee and Stavins, 2013). The program's cap of nearly 9 million tons of SO_2 emissions from the power sector was achieved by 2007, and declined further to 5 million tons by 2010.

Another important hallmark of the Acid Rain Program was that its environmental goals were achieved with low costs of implementation relative to net benefits. Electric utilities regulated under this program achieved the goals for emissions reductions at a significantly lower cost than was projected at the outset of the program. Costs projected before implementation of the Acid Rain Program were over $2.7 to $6.2 billion (U.S. EPA, 2011b). However, retrospective studies found that actual annual costs ranged from $0.5 billion to $2 billion, and total annual benefits ranged from $59 billion to $116 billion (Schmalensee and Stavins, 2013).

The Northeast region's second experience with implementing market-based trading to address air pollution from large power plants was the NO_x Budget Program, which was initiated by 12 states in order to attain compliance with National Ambient Air Quality Standards (NAAQS) for ozone. The NO_x Budget Program incorporated key "lessons learned" by regulators in state environmental agencies and utilities from implementing the Acid Rain Program and similar environmental trading programs. In particular, this program was the first time that a group of states worked together to establish their own multi-state program, in lieu of the U.S. Environmental Protection Agency (EPA) promulgating regulations to address summertime ozone exceedances in the region (Pew Center, 2003).[3] Another key feature of the NO_x Budget Program was that the states developed a "model rule," a set of core requirements that each state needed to adopt to ensure a well-functioning program.[4]

The Regional Greenhouse Gas Initiative (RGGI) built from and further leveraged the northeastern states' hands-on experience with implementing multi-state, market-based programs. RGGI is the nation's first regional market-based regulatory program designed to reduce greenhouse gas (GHG) emissions from the electric sector. Beginning in 2003, Governor Pataki of New York invited environmental and public utility

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2 40 CFR Parts 72 through 78.

3 The first example of a local regulator establishing a cap-and-trade program for meeting air quality goals was the RECLAIM program established by South Coast Air Quality Management District to reduce emissions of criteria air pollutants in the Los Angeles County basin.

4 The "model rule" was created by a task force that included representatives from all states in the Ozone Transport Commission and EPA.

staff from 10 northeastern states[5] to begin working together on the scope and design of a regional system to reduce carbon dioxide (CO_2) emissions from power plants. The program's scope includes new and existing fossil-fuel electric generating units (EGUs) with capacity of 25 megawatts (MW) or more.[6] In late 2008, the 10 RGGI states held the first allowance auctions in preparation for RGGI's January 2009 start date. As of this writing, the RGGI program has an eight-year track record (i.e., January 2009–December 2016) and the following achievements:

- Raised nearly $3 billion in auction proceeds for participating state investments in energy efficiency (EE), renewable energy (RE), and other public benefit programs;
- Is on track for reducing GHG emissions 45 percent below 2005 levels by 2020;[7]
- Generated net savings in consumers' electricity and energy bills through substantial investments in demand-side efficiency;
- Performed over 30 quarterly allowance auctions in a well-functioning marketplace.

For these reasons, RGGI has been held up as a blueprint for other programs and certainly helped to inform the EPA's proposal for the Clean Power Plan, a national-level GHG program for the electric power sector. However, the direct results of the RGGI program are only a part of the story—its influence in the northeastern United States extends beyond reductions in GHG emissions.

1.1 Objectives of Analysis

While the RGGI states' objectives for the program were primarily focused on reducing GHG emissions, increasing the role of renewable energy, and reducing imports of fossil fuels, RGGI and similar clean energy programs also have other, less direct effects on the economy, the environment, and public health. A broader evaluation of the full suite of RGGI's impacts will provide policymakers and the public with a more complete picture of the program's effectiveness.

Analysis Group conducted the first set of studies that analyzed other impacts of RGGI beyond its primary goal of reducing GHG emissions from large power plants. In 2011 and 2015, after RGGI's first three-year compliance periods ended, Analysis Group performed retrospective analysis of RGGI's impact on electricity markets, costs to power producers, impacts on electricity bills of consumers and businesses, and impacts on economic output of the RGGI states. Both of these studies demonstrated that RGGI implementation created positive and substantial benefits to the regional economy over the six years since its inception. This positive economic story resulted in part because the RGGI states opted to invest nearly all of the proceeds received from RGGI allowance auctions back into the economy. The RGGI states did

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5 At the outset of the program, Connecticut, Delaware, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, Rhode Island, and Vermont all participated in RGGI. New Jersey left the RGGI program in 2011; nine states currently participate in the RGGI program.

6 Owners of new and existing power plants regulated under RGGI must acquire a tradeable allowance for each short ton of CO_2 emitted. Owners of EGUs retire their allowances at the end of a three-year "control period" (also "compliance period").

7 New Jersey left the RGGI program in late 2011, and the emissions cap and goals were readjusted accordingly.

this through expansion of energy efficiency programs, new renewable power projects, assistance to low-income consumers of energy bills, and other programs designed to reduce GHG emissions.

Because Analysis Group's studies of RGGI economic impacts were retrospective, they used historical, real-world data on actual program performance and market outcomes to generate insights into net economic benefits of the program. Retrospective studies like these can provide especially useful inputs to RGGI's regular three-year program review process, during which policymakers in the RGGI states consider adjustments to fine-tune the program's effectiveness and net benefits.

The relationship between programs that improve air quality and public health is well-established: in numerous studies of the costs and benefits of CAA, EPA estimated that improved air quality results in public health benefits that exceed the costs of achieving air quality targets by a 30:1 ratio (U.S. EPA 2011c). Most of the economic value of CAA benefits (about 85 percent) are attributable to health benefits; specifically, reductions in premature deaths associated with reductions in ambient particulate matter (U.S. EPA 2011c). In 2020 alone, EPA estimates that the CAA will prevent over 230,000 early deaths.

Because air pollutants with adverse effects on human health are often co-produced with CO_2 when electric power is generated from fossil-fuel power plants, RGGI and similar GHG programs for the power sector are expected to drive some reductions in levels of these air pollutants. Numerous studies have explored the impact of *future* policies and programs aimed at reducing GHG emissions on air pollution and public health. To date, however, few studies have investigated public health impacts of *existing* GHG reduction programs such as RGGI.

To better understand the impacts of RGGI on public health, Abt Associates conducted an independent study of the program's effect on emissions and air quality during the first two compliance periods—2009 to 2014. The objective of our study is to apply credible, widely accepted tools, methods, and publicly available data to answer the following questions:

- Did the first six years of RGGI's implementation result in measurable changes in emissions of criteria air pollutants and air quality?
- If so, how did changes in air quality resulting from RGGI's implementation affect public health and to what degree?
- What spatial and temporal patterns are evident in changes in air quality and health outcomes resulting from RGGI?
- Will health benefits from RGGI's first two compliance periods be replicated in the future?

1.2 Scope of Analysis

Retrospective analysis. Many policy analyses are *prospective*, that is, they project incremental impacts that are anticipated to occur in the future as a result of policy, relative to a baseline or counterfactual case representing the world without the policy. However, our analysis is *retrospective*, i.e., it looks backward at incremental outcomes and impacts that occurred from 2009 to 2014 as a result of RGGI. Our analysis benefits from having actual historical data for many variables used in the analysis. Specifically, we used EPA datasets to describe actual annual NO_x and SO_2 emissions, annual generation levels, and emission rates at the individual plant level for all power plants located in the RGGI states. In addition, we rely upon

results from electricity market dispatch modeling runs conducted by Analysis Group in 2011 and 2015; these modeling runs also incorporated actual historical data for fuel prices, costs of emissions allowances, power plant retirements and additions, and other electricity market factors (e.g., transmission constraints).[8]

Scope. Below we provide additional detail on the scope of this analysis and how the analytic scope may influence results.

Timeframe: The timeframe addressed by this analysis encompasses the entirety of RGGI's first two compliance periods, i.e., 2009 to 2011, and 2012 to 2014, respectively. This is a somewhat limited picture of the incremental impacts of RGGI in one respect: proceeds invested by the states into energy efficiency programs during the 2009 to 2014 timeframe will continue to generate energy savings *after* 2014, because the incremental energy savings from high-efficiency devices funded through these programs typically persist for 10 to 15 years after installation. Our omission of these additional energy savings in this analysis was due to data and modeling limitations.[9] As such, our estimates likely *underestimate* reduced emissions associated with avoided electricity generation due to RGGI, and thus underestimate health benefits.

Air quality modeling: To estimate changes in air quality associated with RGGI implementation, we use EPA's Co–Benefits Risk Assessment model (COBRA) (U.S. EPA, 2015c). COBRA includes a reduced-form air quality model that estimates the effect of emission changes on formation of fine particulate matter (referred to as $PM_{2.5}$).[10] COBRA does not estimate changes in ozone, another air pollutant with adverse health effects. Thus, this analysis does not estimate benefits associated with ozone reductions, although they are expected to occur. Changes in levels of ambient particulate matter, however, are typically the largest factor driving human health benefits.[11] Therefore, we expect COBRA to capture a large share of RGGI's impacts on health in the region, although our estimates will be conservative.

Geographic scope: The geographic scope of this analysis includes changes in electricity market outcomes and associated emissions changes occurring in states participating in the RGGI program. Because changes in emissions that take place within RGGI states will affect air quality and public health in "downwind" states, we also report results for states within the region affected by the program but not currently participating in RGGI.

Other benefit categories: There are additional benefits associated with reducing emissions of CO_2 and other air pollutants that are outside of the scope of this study. First, this study does not cover the potential health benefits of mitigating climate change, such as fewer heat-related illnesses or cases of vector-borne disease.

The scope of this study also excludes reductions in regional haze, largely caused by $PM_{2.5}$ pollutants scattering the sunlight, which impairs visibility and also contributes to harmful respiratory impacts. EPA

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8 Descriptions of these dispatch models and results from Analysis Group's use of them in their analyses of RGGI's regional economic impacts can be found in Analysis Group (2011, 2015).

9 Additional detail on tools and methods used for air quality modeling is provided in Section 2.

10 Fine particulate matter is less than 2.5 micrometers in diameter.

11 Anenberg et al. (2010) estimated that in North America annual mortalities due to anthropogenic $PM_{2.5}$ are approximately three to four times greater than annual mortalities due to anthropogenic ozone.

requires reductions in haze through the Regional Haze Rule to improve visibility in federally protected national parks and wilderness areas (U.S. EPA, 1999).

Benefits to ecosystems and natural resources represent a final category of benefits not captured in this analysis. RGGI-related reductions in the deposition of sulfur and nitrogen compounds in the environment, which have adverse effects on terrestrial and aquatic ecosystems, would improve the health of these ecosystems (Miller, 2011). These environmental impacts can also affect human livelihoods and public health.

This remainder of this report is organized as follows:

- **Section 2:** This section provides additional context for changes in air quality and public health as co-benefits of climate mitigation and clean energy policies.
- **Section 3:** This section describes the analytic approach, data, and methods used to estimate changes in emissions, air quality, and public health associated with RGGI implementation from 2009 to 2014.
- **Section 4:** This section provides results of the analysis and discussion of key findings, policy implications, and uncertainties.
- **Appendices:** The appendices include additional background and technical detail describing the air quality and public health modeling tools used in this analysis. Detailed state-level results are available in Appendix E, which is available for download as a separate document. .

2. Co-Benefits of Climate Mitigation and Clean Energy Programs

In addition to reducing GHG emissions, climate mitigation and clean energy programs such as RGGI can create an array of other public benefits—often referred to as "co-benefits"—in the energy system, the environment, and the economy.[12] These co-benefits can figure importantly in the analysis of total benefits and overall policy effectiveness. For example, the Intergovernmental Panel on Climate Change (IPCC) finds that the near-term public health co-benefits from climate mitigation may offset a significant portion of total mitigation costs (IPCC, 2013).

Table 2 lists key categories of co-benefits resulting from climate and clean energy policies, which are described below:

- **Energy system co-benefits** result from investments that improve the overall performance and efficiency of electricity grid operations. Energy system co-benefits include reduction in electricity losses over transmission lines (typically up to 10 percent), and alleviating load at times of peak demand. In addition, a more efficient system featuring a higher level of distributed generation resources (in contrast to large centralized power plants connected by long-distance transmission lines) can increase the resilience of the grid to severe storms while also enhancing reliability.
- **Economic co-benefits** associated with a more efficient and decentralized electricity grid include: direct savings on energy bills by consumers and businesses; reductions in high costs of serving peak load; and reducing imports of fossil fuels and thereby retaining more capital in the region. Regional employment and economic development can benefit directly from the growth of clean energy industries. In 2016, the 9 RGGI states plus New Jersey ranked in the top 20 states in the United States for total capital investments in energy efficiency, renewables, clean technology ventures, and policies supporting energy efficiency and clean technology (Clean Edge 2016). In Massachusetts for example, clean energy employment grew more than eight times faster than the overall growth rate across all Massachusetts industries from 2011 to 2013 (Massachusetts Clean Energy Center, 2013).
- **Public health co-benefits** result from improvements to environmental endpoints—airsheds and watersheds—as pollutant loadings to air and water are reduced via lower energy demand and shifting of energy generation to cleaner sources. Emissions of fine particulate matter, which can be emitted directly from sources or formed secondarily through atmospheric chemical processes, can cause premature death, heart attacks, and strokes, as well as harmful effects on the respiratory system, including asthma attacks. This category of co-benefit is the primary focus of this report; however, as noted below, reductions in emissions of mercury (Hg) and ozone-forming NO_x can also result from policies targeting GHGs and are also beneficial to human health.
- **Environmental co-benefits** of climate and clean energy programs arise from reducing total energy demand and shifting generation to cleaner, more efficient sources of generation. Key environmental benefits from clean energy include reductions in emissions of air pollutants and their precursors (e.g.,

[12] These positive outcomes are often referred to as "co-benefits" because they are additional to the direct program objective of reducing carbon emissions and increasing efficiency and renewable energy. While this list of co-benefits associated with climate mitigation and clean energy programs is fairly comprehensive, more in-depth information can be found in the following sources: U.S. EPA (2011a) and Regulatory Assistance Project (2014).

particulate matter (PM), NO_x, SO_2, ozone, air toxics, and Hg), which results in reduced formation and deposition of these pollutants.

Ozone is formed by emissions of nitrogen oxides reacting in the presence of sunlight with volatile organic compounds in the air. Ozone's effects on human health include increased frequency of asthma attacks, shortness of breath, aggravated lung disease, damage to lungs through long-term exposure, additional hospitalizations and emergency room (ER) visits, and premature deaths. Coal-fired power plants and other stationary sources (e.g., incinerators) can also release mercury into the air. Airborne mercury emissions then settle into terrestrial and aquatic ecosystems and can be converted to methylmercury, a harmful neurotoxin. Methylmercury enters into the food chain, where it builds up ("bio-accumulates") in fish through their diet. As a result, the most common source of human exposure to methylmercury occurs through fish consumption.

Table 2. Benefits of Climate Mitigation and Clean Energy Policies

	Energy System	Economic	Public Health	Environmental
Direct benefits	Reduced electricity load and peak demand Increase in distributed generation Reductions in imports of fossil fuels	Energy savings from energy efficiency investments Increased economic activity for energy efficiency and renewable energy sectors	**Improved air quality from co-reductions in emissions of criteria air pollutants**	Reductions in CO_2 emissions and impacts of climate change Reductions of nitrogen, sulfur, mercury, and other air toxics in air and watersheds
Indirect benefits	Fuel diversification Increased energy security Improved grid resilience and reliability	Job creation in clean energy and energy efficiency sectors	Fewer incidences of respiratory and cardiovascular diseases and premature deaths from improved air quality Improved water quality	Improved terrestrial and aquatic ecosystem health Improved visibility Potential reductions in water intake by power plants

Sources: IPCC (2014); U.S. EPA (2011a); Union of Concerned Scientists (2013).

2.1 Regional Economic Impacts of RGGI

The RGGI program had a net positive impact on the regional economy of the Northeast over the initial six years of program implementation. This outcome reflects key policy decisions made regarding the sale of nearly $2 billion of CO_2 allowances to owners of fossil-fuel power plants. The decision by RGGI states to auction nearly all emission allowances, rather than distributing allowances directly to regulated entities for free, is a unique and defining feature of the RGGI program.[13] As a result of this key design feature, the states were able to use proceeds collected from allowance auctions during the 2009 to 2014 period for

[13] Emission allowances were allocated freely to regulated utilities under both the Acid Rain and NO_x Budget Programs.

public benefit purposes. Each state determined how to deploy its share of RGGI proceeds based on its own legislative and public policy priorities.[14] During the first two compliance periods of RGGI, states participating in the program invested a substantial portion of auction proceeds into energy efficiency programs, renewable energy generation, and other GHG reduction programs. By investing proceeds into programs that themselves generate additional reductions in GHG emissions and energy demand, the RGGI states essentially leveraged revenues from proceeds to amplify the magnitude of GHG emissions reductions achieved, beyond those that would have been achieved solely from placing a cost on the right to emit CO_2.

Analysis Group's empirical review of the RGGI states' strategic investments of proceeds from RGGI auctions into efficiency and clean energy programs showed that these programs generated economic benefits to consumers and business, and an increase in output and employment in the region. Using six years of actual data gathered from RGGI's first two compliance periods, Analysis Group conducted consecutive analyses (in 2011 and 2015, respectively) that tracked individual RGGI states' investments of proceeds on an annual basis, and then estimated direct and indirect impacts of the program on the regional economy. In its calculations, Analysis Group accounted for the effects of the RGGI program on power system dispatch, net energy costs to consumers, revenues to electric generators, and overall state economic performance (Analysis Group, 2011, 2015).

Both the 2011 and 2015 Analysis Group studies arrived at similar conclusions: RGGI states' investments of auction proceeds into energy efficiency, renewable energy, climate mitigation activities, and direct rebates resulted in positive impacts on the region's economic value-added and employment. Analysis Group found that in the period 2009–2011, economic value-added in the RGGI states totaled $1.6 billion, and found similarly that economic value added in the period 2012–2014 was $1.3 billion. These benefits were found to be due in part to the states' combined investments in energy efficiency and clean energy in both compliance periods (Analysis Group, 2011, 2015). Additional economic value-added translated to an average of $31 per capita in the region for the 2012 to 2014 compliance period alone (Analysis Group, 2015). In addition, employment in the RGGI states increased by more than 16,000 job-years in the period 2009–2011, and 14,000 job-years from 2012 to 2014. Table 3 summarizes these key findings from Analysis Group's studies.

Table 3. Summary of RGGI Economic Benefits, 2009 to 2014

Type of Economic Impact	First Compliance Period (2009-2011)[1]	Second Compliance Period (2012-2014)[2]
Total value-added to RGGI states	$1.6 billion	$1.3 billion
Net job creation[3]	16,000 job-years	14,200 job-years

Source: Analysis Group (2011, 2015).

1. Reported in 2011 dollars, on a net present value basis using a discount rate of 3 percent.

[14] The 2005 Memorandum of Understanding and the 2008 revised Model Rule designate a minimum of 25 percent of each state's allowance proceeds to go to a "consumer benefit or strategic energy purpose." In practice, states are vastly exceeding the required minimums for public benefit or energy purposes. Allowances are apportioned through state allowance budgets, which are largely based on historical power plant emissions in each state and an agreed-upon formula. The allotment of allowances then determines the magnitude of each state's proceeds from the allowance auction.

2. Reported in 2015 dollars, on a net present value basis using a discount rate of 3 percent and reflects adjustments for inflation.
3. A job-year is defined as providing full-time job for one year.

Analysis Group's studies confirm that investments in energy efficiency acted as an important economic multiplier. Adopting energy efficiency measures reduces the total demand for electricity generation, and reduces wholesale electricity prices through impacts on system dispatch. Consumers who reduce their electricity use by becoming more efficient save on monthly energy bills. On a macroeconomic scale, reduced demand through energy efficiency and expansion of renewables lowers the total amount paid to fossil-fuel generators located outside of the RGGI region. Overall, higher per-kilowatt costs passed on to electricity consumers to cover the costs of CO_2 allowance purchases in the short term are offset by energy bill savings resulting from RGGI proceeds investments within the region (Analysis Group, 2015).

In the next section, we provide additional context for this evaluation of RGGI's impact on air quality and public health.

2.2 Impacts of Climate and Clean Energy Programs on Air Quality and Public Health

Policies and programs that reduce GHG emissions from electric power plants and other fossil-fuel stationary sources (e.g., industrial boilers) can also achieve important public health benefits. Fossil-fuel power plants emit not only CO_2 but also other air pollutants with proven adverse effects on human health, including fine particulate matter ($PM_{2.5}$), NO_x, SO_2, Hg, and air toxics.

Power plant emissions of NO_x, SO_2, and other pollutants impact air quality at the local level to varying degrees, depending on characteristics of the source,[15] spatial distribution of emissions, and local meteorological conditions that dictate the formation of pollutants with adverse health effects. The burning of fossil fuels releases SO_2, which contributes to the formation of acid rain and $PM_{2.5}$ and can cause impact human respiratory and cardiovascular systems. NO_x emissions also form $PM_{2.5}$ and ground-level ozone, thereby exacerbating negative impacts of this air pollutant. Fine particulate matter composed of airborne solid particles and liquid droplets carries a mixture of soot, smoke, toxic metals, and many other harmful chemical pollutants; inhaling the fine particulate matter can lead to severe health effects. By entering the lungs and even the bloodstream, these air pollutants can cause or aggravate respiratory conditions and cardiovascular diseases and can lead to premature death.

Below we describe results of recent prospective analyses of the impacts of national- and regional-level climate mitigation and clean energy policies on air quality and public health.

Findings from Recent Studies

A number of recent studies have demonstrated the link between policies aimed at reducing GHG emissions, associated changes in levels of air pollutants, and resulting impacts on human health. Generally, these studies rely upon a multi-step analytic approach that is similar to the process employed

[15] For example, the height of the emissions stack affects dispersion and formation of air pollutants, particularly through wind patterns that contribute to interstate transport of air pollutants. While tall stacks may be designed to limit negative air quality impacts on the local community, the overall pollution does not diminish, it is only transported downwind.

in this analysis (described in Section 3). The first step is to estimate the impact of a proposed policy on emissions of criteria air pollutants. Then, air quality models are applied to estimate how changes in emissions of air pollutants resulting from the policy modify levels of air pollution in specific geographic locations. Finally, a public health model is used to estimate changes in public health outcomes associated with air quality changes to specific geographic locations and populations, and the associated economic value of health impacts.

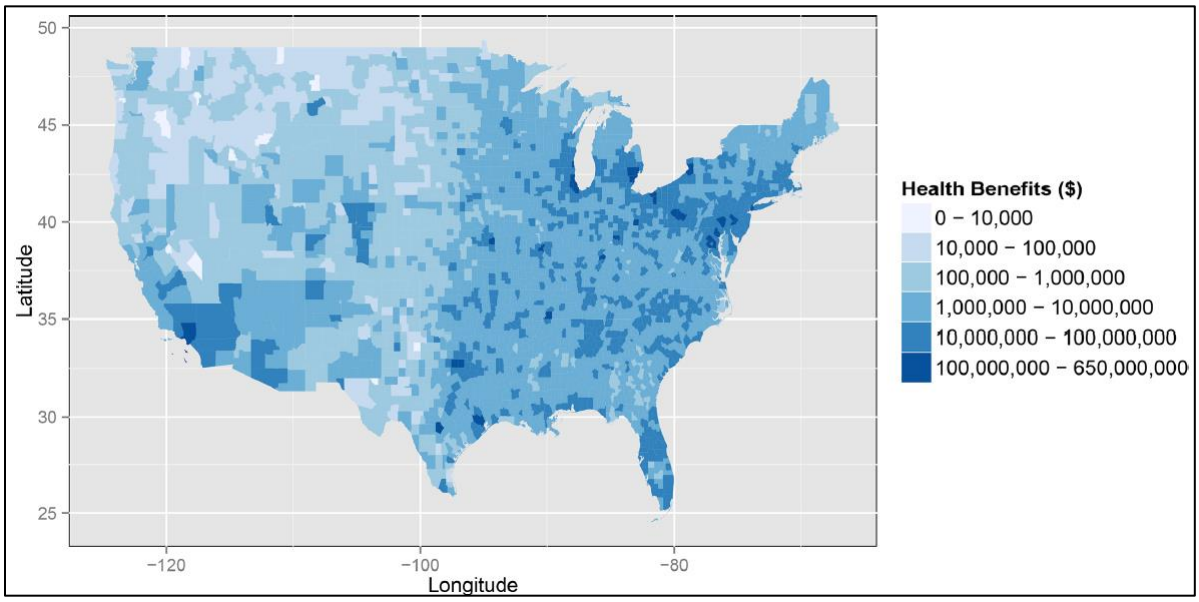
Based on an analysis of three national-level climate mitigation policies (for the electric sector, transportation sector, and an economy-wide trading system, respectively), a 2014 study by concluded that the health benefits associated with reduced $PM_{2.5}$ and ozone could offset some or all of the near-term costs of these policies (Thompson et al. 2014). Estimated public health benefits offset costs of mitigation by a range of 26 to 1,000 percent, with the economy-wide trading system offering the greatest flexibility and the largest potential net-benefits to health. Emission reductions occurring through a clean energy standard generated a median of nearly $40 billion in net benefits, accounting for nearly 120 percent of costs.

A 2015 study compared three national-level climate policies to determine which policy achieved the largest public health co-benefits, based on estimated changes in $PM_{2.5}$ and ozone (Driscoll et al., 2015). The authors found that limiting carbon emissions from power plants, while providing flexible compliance mechanisms and emphasizing energy efficiency investments, resulted in greater health co-benefits than a carbon tax of requiring heat-rate improvements at coal-fired plants. The energy efficiency investment scenario resulted in an estimated 3,500 premature deaths avoided nationally (with a range of 780 to 6,100) through changes in $PM_{2.5}$ and ozone. The study found that air quality improvements are maximized by shifting electric generation from coal plants to lower-carbon emitting sources and investing in demand-side efficiency measures.

A more recent study of a moderately stringent, highly flexible national policy scenario modeled after the final Clean Power Plan (EPA's proposed rule for power plants' GHG emissions nationally) estimates that public health benefits will exceed implementation costs by $12 billion per year in 2020 (Buonocore et al. 2016). The value of health benefits in RGGI states ranged from $10,000 to $100 million per county (see Figure 3). Under this scenario, the study estimates a total of $880 million in public health benefits in the New England states. Among New Jersey, Delaware, Maryland, and Virginia (a non-RGGI state[16]), the study estimates a total of $3 billion in public health benefits. For New York alone, the study estimates a total of $1.6 billion in health benefits.

[16] Throughout this report, we use the term "non-RGGI" to refer to states in the Northeast U.S. that are not participating in the RGGI program.

Figure 3. Total Annual Health Benefits in 2020 by County for Moderately Stringent, Highly Flexible Carbon Standards



Source: Buonocore et al. (2016).

Notably, the authors modeled investments in energy efficiency measures beginning in 2013 and increasing until 2025. Associated benefits from energy efficiency accrue years after initial investments are made; therefore, a comparison of costs in 2020 to benefits in 2020 does not take into account total benefits expected when the modeled regulation reaches its full effect in 2030. The authors conclude that not only are health benefits realized in the near term, they are also expected to extend past 2020 (Buonocore et al. 2016).

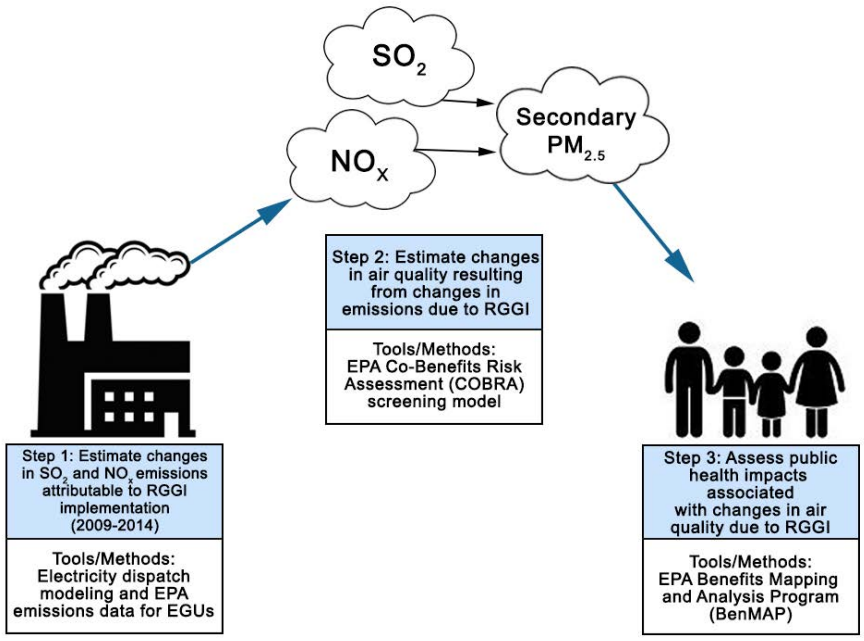
Despite the diversity and complexity of climate and energy scenarios modeled in these studies, they point to a consistent conclusion: there is potential for public health benefits to meet or exceed costs of mitigating GHG emissions by a significant degree. As Thompson et al. (2014) and Buonocore et al. (2016) both observe, estimates of overall net benefits are more sensitive to estimates of mitigation costs than to public health and other benefits.

3. Analytic Approach

We used a three-step analytic process to estimate the impacts on air quality and public health resulting from implementation of the RGGI program from 2009 to 2014. As shown in Figure 4, each of these steps relies upon a specific modeling tool (or tools) and datasets to estimate the incremental impacts of RGGI on the following variables: generation (in megawatt-hours (MWh)) by power plants, air pollution emissions, air quality, and public health.

This analysis was highly sequential—results from each analytic step were inputs to the next modeling tool in this process. At each stage of the analysis, we reviewed draft results at a highly disaggregated level and performed quality control before using results as an input to the next analytic step. In many cases, draft results were benchmarked to results from similar analyses and studies as another cross-check.

Figure 4. Overview of Analytic Steps and Tools



Source: Abt Associates analysis (2017).

Step 1: Estimate annual changes in electric generation and emissions of air pollutants at power plants as a result of RGGI implementation from 2009 to 2014.

To determine annual changes in emissions of air pollutants from electric power plants associated with RGGI implementation, we first estimated changes in electricity generation in participating RGGI states. For this step, we relied upon results from electricity dispatch modeling performed by Analysis Group in support of their studies of RGGI's regional economic impacts. These dispatch modeling runs were used to calculate incremental differences in electricity market outcomes between an "RGGI" scenario, and a counterfactual "No RGGI" scenario. Specifically, the difference in results of these two scenarios is the

incremental change in annual generation levels (in MWh) for power plants located in the RGGI states (including plants not regulated under RGGI).[17]

We then used actual, annual plant-level emissions and pollution control data from EPA to calculate changes in NO_x and SO_2 emissions associated with changes in generation at the power plant level due to RGGI.[18] Changes in plant-level NO_x and SO_2 emissions were aggregated at the county level for each year from 2009 to 2014, and then became the key inputs to the air quality modeling conducted in Step 2.

Step 2: Estimate annual changes in air quality at the county level associated with changes in SO_2 and NO_x emissions from power plants, by year.

For this step in the analysis, we used the COBRA model, developed by EPA to conduct screening-level analyses of the effect of changes in emissions on air quality. We ran COBRA using inputs of annual changes in SO_2 and NO_x emissions aggregated for each county in all RGGI participating states derived under Step 1 of the analysis.

COBRA's air quality model simulates chemical reactions in the atmosphere that transform NO_x and SO_2 into components of particulate matter. In the northeastern United States, these components constitute the majority of $PM_{2.5}$ resultant from power plant emissions and make up more than half of all ambient $PM_{2.5}$ (NARSTO, 2004). As noted earlier, as a simplified air quality model, COBRA does not model formation of ozone, although this is a major pollutant in the Northeast.

COBRA's outputs are changes in annual ambient $PM_{2.5}$ at the county level, which are the inputs to public health modeling conducted under Step 3.

Step 3: Assess public health impacts associated with changes in air quality due to RGGI implementation from 2009 to 2014.

We used the Benefits Mapping and Analysis Program (BenMAP) to translate county-level changes in annual ambient $PM_{2.5}$ from Step 2 into county-level changes in the frequency of various adverse health events among a population, referred to as incidences. BenMAP uses inputs of air quality changes, population, and baseline health incidences (i.e., the background frequency of a health impact in a population) to estimate the public health changes resulting from changes in air quality. BenMAP then estimates the economic value of health incidences avoided based on a synthesis of multiple economic valuation studies.

3.1 Estimating Changes in Emissions due to RGGI

Estimating changes in emissions due to RGGI requires isolating RGGI's incremental effect on the electricity market from that of the many other factors affecting the complex electric power system. Variations in weather and economic growth can influence electricity demand. And before RGGI's

[17] The scope of results from the dispatch modeling runs used in this analysis reflected changes in generation by power plants located in RGGI states, but did not include changes in other states and provinces adjacent to or with interconnection to RGGI. Results from dispatch modeling were also available for Pennsylvania but were not validated for plant additions, retirements, and other changes that occurred during the timeframe of this analysis.

[18] While power plants also emit other pollutants that affect air quality and health (such as mercury and air toxics), these pollutants' effects on air quality are not captured in the air quality modeling tool applied in this analysis.

inception in January 2009, major transformations in the market for natural gas, which is a key fuel used in electricity production, were underway. Advancements in shale gas extraction methods significantly increased the supply of domestic natural gas and resulted in substantial decreases in natural gas prices beginning in 2008.[19] Also in this timeframe, effects of the 2009 recession dampened demand for electricity.

In 2010, RGGI Inc. commissioned a study[20] to examine the role of factors that contributed to a 33 percent decrease in CO_2 emissions from the electric power sector across RGGI states, from 2005 to 2009 (RGGI Inc., 2010).[21] As shown in Figure 5, the study found that fuel-switching from oil and coal to lower-cost natural gas accounted for nearly one-third of the decline in CO_2 emissions from 2005 to 2009. An additional 25 percent of emissions reductions were due to weather, whereas the economic recession was responsible for a small fraction (about 4 percent) of emission reductions. Changes in available generation capacity (i.e., reduced coal capacity and increased nuclear, wind, and hydropower capacity) together accounted for nearly 21 percent of the reduction in emissions.

Finally, energy efficiency and customer-sited renewable generation accounted for approximately 12 percent of emissions reductions over this timeframe. While the study was not an analysis of the effect of the RGGI program, it showed that fuel-switching to natural gas and weather variations were more significant factors in the rapid decline of CO_2 emissions over the 2005 to 2009 timeframe than economic conditions or changes in the mix of available generation capacity.

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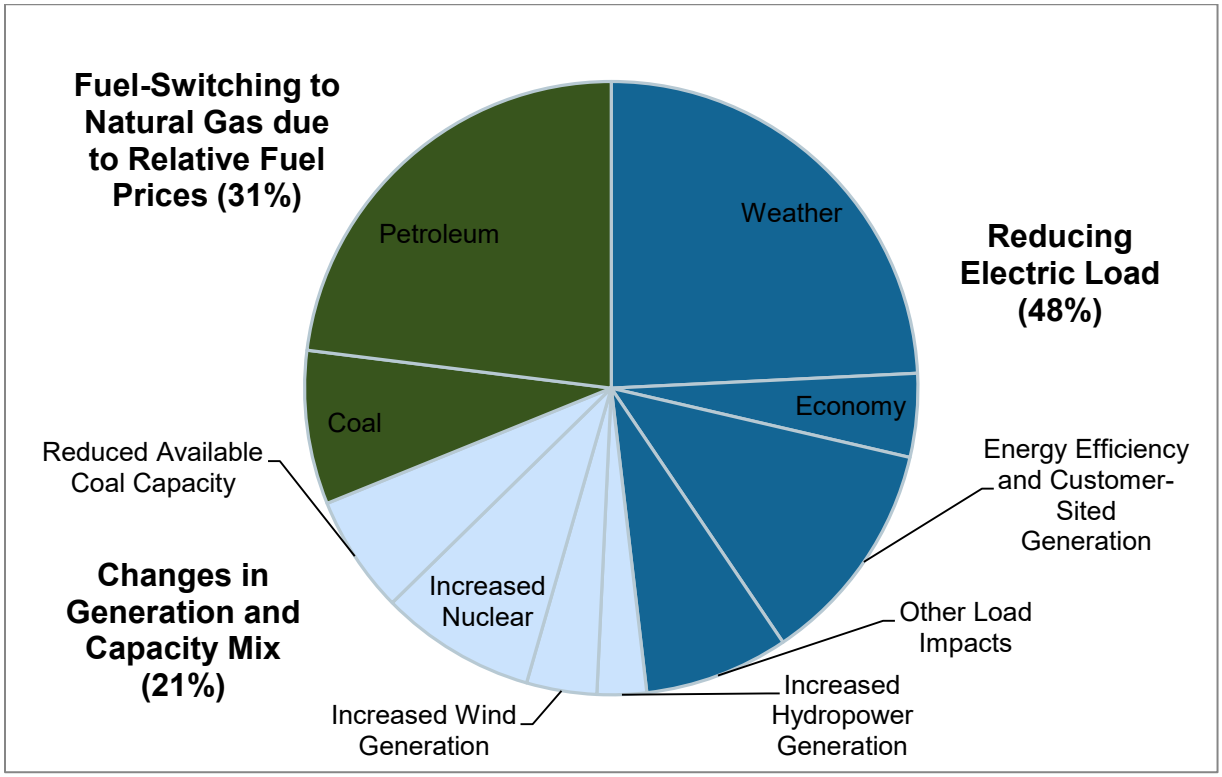
[19] The Henry Hub price for natural gas fell by nearly 70 percent between 2008 and 2015 (EIA, 2016).

[20] This study was conducted for RGGI Inc. in 2010 by the New York State Energy Research and Development Authority.

[21] Note that the timeframe of the RGGI Inc. study preceded RGGI program implementation and was focused on changes in emissions that pre-dated RGGI.

Figure 5. Factors Influencing CO_2 Emission Reductions in RGGI States, 2005-2009



Source: RGGI Inc. (2010).

Note: Connecticut, Delaware, Maryland, Massachusetts, Maine, New Hampshire, New Jersey, New York, Rhode Island, and Vermont are included in this analysis.

A more recent study focused specifically on RGGI's role in reducing regional CO_2 emissions during the first compliance period (2009 to 2011) (Murray and Maniloff 2015). Using econometric modeling, the study isolated the incremental effect of RGGI on emissions from that of other factors, including lower natural gas prices, the 2009 economic recession, and other environmental and energy programs, including states' minimum requirements for renewable energy generation (known as Renewable Portfolio Standards). Accounting for these factors, the study found that CO_2 emissions would have been 24 percent higher in the region over the first compliance period if the RGGI program did not exist (Murray and Maniloff 2015).[22]

[22] The study compared changes in CO_2 emissions from the electric sector from 1990-2008 to the 2009-2012 period and found that without low natural gas prices, the RGGI program, the recession, or state renewable goals, CO_2 emissions would have been 52 percent higher across the region. The same counterfactual scenario applied nationally found total CO_2 emissions would have only been 11 percent higher from 2009 to 2012. As such, the study concluded that nearly half of the actual CO_2 emissions reductions in RGGI states during this time period can be attributed to RGGI program implementation. The Murray and Maniloff study did not distinguish between the impact of RGGI's CO_2 allowance price from the effects of RGGI states' investments in energy efficiency and renewable energy on emissions, but noted that both are key aspects of RGGI's effect on generation and emissions.

For this analysis, we relied upon results from dispatch modeling of RGGI's first two compliance periods conducted by Analysis Group. These modeling runs estimated RGGI's incremental effect on overall electricity demand, the mix of generation sources and dispatch from power plants in the RGGI states, independent of changes in other variables over the 2009 to 2014 timeframe. These modeling runs provide an estimate of RGGI's incremental effect on the electricity market by simulating a "RGGI" scenario and a "No RGGI" counterfactual scenario. Modeling of the RGGI scenario depicted the two primary direct effects of the program on the wholesale power market, as described below:

- **Costs of CO_2 allowance purchases:** Owners of large fossil-fuel power plants purchase CO_2 allowances to meet RGGI's cap on emissions, and then build the costs of these purchases into the price at which they are willing to supply power to the wholesale market.[23] In this way, the cost of CO_2 allowances affects prices for power in many hours, which in turn can alter marginal generation (i.e., the last generator dispatched to meet hourly demand) from higher- to lower-carbon generation sources.
- **Investments of RGGI proceeds into energy efficiency (EE) and additional renewable generation (RE):** States' investments of RGGI proceeds into energy efficiency measures result in reductions in overall electricity demand and changes in the shape of annual electricity demand profiles.[24] Although much smaller than states' investments in energy efficiency, investments of RGGI proceeds in customer-sited renewables increase the capacity for low- or zero-carbon electricity. Demand-side efficiency investments and an increase in renewable capacity together shift demand for fossil-based electricity downward, resulting in changes to the mix of generation sources dispatched and associated emissions.

The No RGGI scenario is a counterfactual case of power market outcomes absent these two effects of RGGI. In this counterfactual scenario, all other variables affecting power markets except for RGGI (i.e., fuel prices, transmission constraints, NO_x and SO_2 allowance prices, state renewable energy requirements, plant retirements and additions) were held constant to the RGGI scenario. The difference between these two scenarios (i.e., RGGI and No RGGI) represents RGGI's incremental effect on the power system; specifically, changes in hourly generation by power plants located in RGGI states.

Because this analysis is retrospective, we had access to actual historical data depicting annual generation and emissions at individual power plants under RGGI. However, our retrospective approach also presented some analytical challenges in cases where results for the modeled RGGI scenario differ from

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[23] New England and many mid-Atlantic states have competitive markets for electric power, which means that prices bid into the market by power plant owners should be close to the marginal costs of producing the last unit needed to meet hourly electricity demand.

[24] Different energy efficiency programs tend to reduce hourly electricity demand in different ways, and thus affect the "shape" of customer demand over the course of the year in addition to reducing the total aggregate demand across the year. For example, energy efficiency programs that focus on replacing older, inefficient air conditioning units with newer, more efficient models generate reductions in electricity demand almost exclusively in summer daytime hours, when electricity demand peaks across the Northeast region. An air conditioning energy efficiency program thus alters the "shape" of electricity demand by generating reductions only in summer daytime hours. This, in turn, disproportionately reduces generation from the most expensive, least efficient, and most polluting generating resources during the highest-load hours of the year.

actual RGGI data. Such differences are typical because dispatch models simulate economically optimized outcomes that do not perfectly align with power producers' actual, real-world decisions.

To calibrate dispatch modeling results to actual, "real-world" outcomes, we based our analysis on the *relative* incremental effect of RGGI simulated by the dispatch modeling. Using actual data for RGGI, we constructed a new No RGGI scenario by applying the *percent difference* between emissions levels from the modeled results for the RGGI and No RGGI scenarios to actual emissions levels under RGGI. The difference between the RGGI emissions inventory and the No RGGI emissions estimate is the incremental change in emissions due to RGGI. These emissions changes then become the inputs to Step 2 of the analysis described below.

Appendix A includes descriptions of specific calculations and datasets used in our analysis of incremental emissions changes due to RGGI.

3.2 Air Quality Modeling

EPA developed the COBRA model to conduct screening-level analyses of the effect of emissions changes on air quality. COBRA models the ambient air quality changes that result from criteria pollutant emissions using a simplified air dispersion model, which quantifies the relationships between emissions from each source and air quality (average annual $PM_{2.5}$) in each county. As described earlier, the choice to apply the COBRA air quality modeling tool for this analysis results in a somewhat more limited picture of actual changes in air quality than could be developed with a more detailed air quality modeling tool.[25] To reiterate, COBRA estimates how changes in emissions of primary $PM_{2.5}$, SO_2, and NO_x result in changes in ambient levels of $PM_{2.5}$, but COBRA does not model changes in ozone formation.

We used the COBRA model in order to estimate changes in air quality due to RGGI implementation. To run the COBRA model, we input estimated annual changes in SO_2 and NO_x emissions derived under Step 1 of the analysis, aggregated at the county level, for all counties in RGGI participating states. We input these into COBRA for each modeling year 2009 through 2014 and then performed a COBRA run for each of these years. Outputs from each of these COBRA runs are changes in annual levels of ambient $PM_{2.5}$ for each county, and are expressed in micrograms per cubic meter ($\mu g/m^3$). Annual county-level changes in ambient $PM_{2.5}$ then became the inputs to Step 3, modeling of public health impacts.

The scope of our analysis of air quality excludes the effect of energy savings associated with RGGI states' investments in energy efficiency made in the 2009 to 2014 timeframe that persist past 2014. To include the effect of these energy savings on air quality and health would require a projection of emissions inventories for all sectors to support additional COBRA modeling runs for each year subsequent to 2014. Because projections for future baseline emissions are currently unavailable for this timeframe, however, the impact of these energy savings was excluded from this analysis.[26]

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[25] For example, the Community Multiscale Air Quality and CAMx models are often used to conduct cost-benefit studies of major proposed regulations—these models are capable of very detailed atmospheric modeling to estimate how emissions form ambient levels of ozone and ambient fine particles at very granular geographic levels.

[26] Specifically, the only annual emissions projection currently available from EPA is for the year 2025.

COBRA and underlying assumptions and data sources used for this step are described in more detail in Appendix B.

3.3 Public Health Modeling

To estimate the public health benefits resulting from RGGI, we used EPA's BenMAP, Version 4.0.67.[27] BenMAP uses data describing population, frequency of baseline health outcomes, and economic values to estimate the number and economic value of health impacts resulting from changes in air quality.

Abt Associates designed and implemented the original BenMAP model for EPA, which was the first publicly available model for valuing the health impacts of changes in air quality. EPA's current version of BenMAP[28] is being deployed around the world by government agencies and others for generating estimates of public health improvements resulting from reductions in air pollutants.

We used the county-level estimates of RGGI's effect on $PM_{2.5}$ relative to observed ambient $PM_{2.5}$, generated by COBRA under Step 2, as inputs to BenMAP. BenMAP used these estimated changes in ambient $PM_{2.5}$ to calculate the health benefits resulting from RGGI for 2009-2014.

BenMAP and underlying assumptions and data sources used for this step are described in more detail in Appendix C.

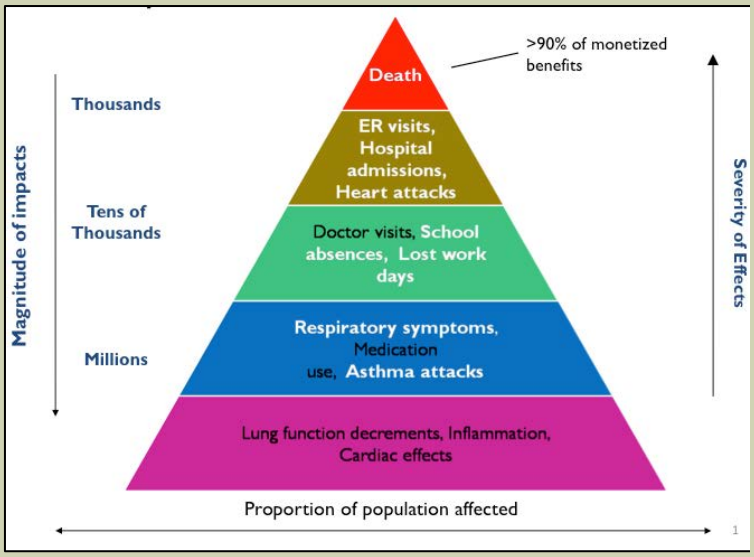
[27] COBRA also has functionality to estimate health benefits, but we selected BenMAP over COBRA for this step of the analysis because BenMAP allows us to capture changes in baseline population, incidence, and valuation over the entire study timeframe. While COBRA is an appropriate tool for estimating ambient air quality, the fact that its datasets are tied to a specific calendar year limits its representation of how air quality affects public health over time.

[28] This version is known as BenMAP-Community Edition.

How Does BenMAP Value Health Benefits?

As a society we value a clean, safe environment and a healthy population. Without an explicit value tied to a public good such as clean air,[1] it is challenging to evaluate the costs, benefits, and overall effectiveness of policies and programs that enhance or protect public goods. To estimate the value of public goods that are not traded in markets, economists rely upon a range of methods. One approach to quantifying the value of programs that benefit human health is to calculate the value of avoiding the "cost of illness," such as medical expenses and lost productivity. Another method is based on the value that individuals are willing to pay to avoid illness or reduce the risk of premature death.

Effects of Air Pollution on Health



Source: U.S. EPA (2016a).

To estimate a value for health benefits resulting from a reduction in air pollution, BenMAP estimates the value of total avoided health costs. BenMAP links air quality changes to public health outcomes by applying empirical relationships derived from epidemiological studies between air pollutants and 12 categories of human health effects (described in detail in U.S. EPA, 2015a). The economic value of improving air quality increases with the number of avoided premature deaths and illnesses, though the value of different avoided health effects can vary widely. For example, the economic, or "monetized" value for an avoided case of adult mortality is over $9 million, compared to the monetized value of an avoided case of respiratory symptoms ($22-$36); see Appendix C for a table of avoided health effects and their economic values.

As the "pyramid of effects" in the accompanying figure illustrates, the majority of monetized health benefits from reductions in air pollutants arise from a small number of avoided premature deaths (U.S. EPA, 2016a). The value of an avoided premature death is an estimate of how much people are willing to pay for small reductions in the risks of premature death (U.S. EPA, 2016b). This concept of avoided risk is commonly expressed as the "value per statistical life" (VSL), and is a commonly used value in economic and regulatory analysis of environmental and public health policies. It is important to note that the VSL concept represents the sum of many small risk reductions that are then aggregated, and does not represent the monetary value of an individual life.

4. Results and Discussion

In this section of the report, we discuss results from each analytic step used to determine RGGI's impact on public health. We then provide an overview of key findings, policy implications, and uncertainties for these results.

4.1 Changes in Generation due to RGGI

We calculated changes in electricity generation due to RGGI first on an absolute basis (in MWh per year), and then expressed them as a percentage relative to generation that would have occurred in the No RGGI scenario. These percentages are based on generation changes in RGGI-participating states only. Table 4 shows that the RGGI program resulted in a net reduction in electricity generation in every year of the first two compliance periods.[29]

Table 4. Annual Change in Generation due to RGGI

	2009	2010	2011	2012	2013	2014
Generation change in RGGI States	-5.8%	-2.9%	-2.0%	-3.4%	-7.0%	-6.9%

Source: Abt Associates analysis (2017).

Reductions in annual generation ranged from a low of 2.0 percent in 2011 to a high of 7.0 percent in 2013. Changes in generation as a result of RGGI were lowest overall in 2010 and 2011. The most significant RGGI-induced changes in generation occurred in 2009, 2013, and 2014.

In competitive electricity markets, changes in any number of variables, including fuel prices, weather, and plant and system operational changes, can cause variations in the level of electricity dispatched by a given power plant (or group of plants) from year to year. In this analysis, however, our modeling results account for all of these factors and thereby isolate the incremental effect of RGGI on electricity markets and dispatch. Thus, we interpret RGGI-induced changes in generation to be a result of the combination of (1) RGGI states' investments in energy efficiency and renewable energy and (2) the effect of CO_2 allowance prices on electricity dispatch. Our analysis does not quantify the individual contributions of these elements of the RGGI program to RGGI's overall net effect.

In addition to allowance prices and states' investments in EE and RE, the "announcement effect" is another factor that may have influenced the market response to RGGI. This effect describes the response by power plants owners to RGGI states' announcements of their intentions to join the RGGI system. If a plant owner believes an announcement to be credible, the prospect of future carbon prices can spur them to invest in lower-carbon generation options before the policy starts.[30] A 2015 study found that the

[29] Note that this analysis reflects modeling results only for those states that participated in RGGI at some point during the first two compliance periods. New Jersey participated in RGGI's first compliance period from 2009 to 2011, but did not participate in RGGI's second compliance period from 2012 to 2014. We modeled generation changes in New Jersey for 2009 to 2011, and assumed no generation changes from 2012 to 2014.

[30] Alternatively, if firm or plant owners do not view a policy announcement as credible, they might wait until a program takes effect to act. Murray and Maniloff (2015) noted literature which finds that the announcement effect was significant for policies addressing other air pollutants.

announcement of the RGGI program likely had a statistically significant effect on CO_2 emissions before and shortly after RGGI's start date (i.e., late 2008 and early 2009)—this suggests that owners of power plants in RGGI states did find states' policy announcements to be credible and took early actions to reduce CO_2 emissions (Murray and Maniloff 2015). The anticipation of pending CO_2 emissions limits may have affected plant owners' demand for CO_2 allowances and generation bids in 2009, the first year of the program.

Note that these results do not reflect changes in generation that may have occurred at power plants located in states or Canadian provinces (e.g., Quebec) adjacent (and with interconnection) to RGGI states, but not participating in RGGI. It is possible that changes in the marginal costs of electricity dispatch associated with pass-through of the cost of CO_2 allowance purchases by plant owners in RGGI states resulted in increases in electricity dispatch in non-RGGI states and provinces outside RGGI to some degree. Modeling by Resources for the Future (RFF) in 2004 projected that under RGGI, generation and CO_2 emissions in non-RGGI states would increase due to RGGI. Specifically, RFF estimated that that for every 100 tons of CO_2 reductions within the RGGI region, non-RGGI states and provinces adjacent to the RGGI region could emit an additional 37 tons of CO_2, a dynamic known as "leakage" (RFF, 2004).

RGGI Inc. (2013) examined patterns in generation in neighboring states over the first three years of RGGI implementation, and did not find conclusive evidence of substantial leakage to generators in non-RGGI states:[31] CO_2 emissions from non-RGGI electricity generators did not appreciably increase during 2009 to 2011 relative to a base period of 2006 to 2008, and total electric generation from all non-RGGI electric generation sources serving load in the RGGI region increased by only 1.2 percent, or 3.3 million MWh, over the same timeframe. A later RGGI Inc. study (2016) found that generation from all generators in non-RGGI states increased by nearly 12 percent in 2012 to 2014 compared to the 2006 to 2008 base period. However, neither RGGI Inc. study estimated RGGI's incremental effect on changes in generation in non-RGGI states and provinces relative to a counterfactual scenario, and thus are inconclusive with respect to the program's incremental impact on CO_2 emissions from these jurisdictions.

To account for the uncertainty in RGGI's effect on generation and emissions from fossil-fuel generators located in neighboring non-RGGI states and provinces, we applied a sensitivity factor that discounts benefits in non-RGGI states by 50 percent to represent a low-end estimate. Our high-end estimate of our range of estimates assumes 100 percent of benefits for non-RGGI states were realized.

4.2 Changes in Criteria Pollutant Emissions due to RGGI

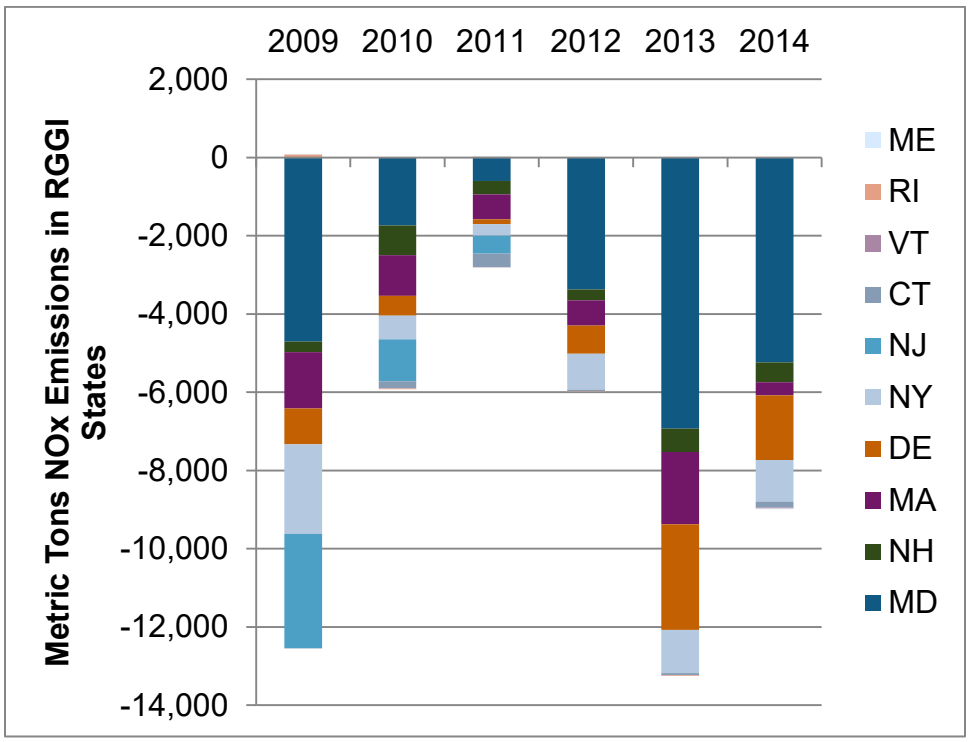
As described earlier, this analysis tracks changes in emissions of SO_2 and NO_x resulting from RGGI implementation. Annual changes in levels of these pollutants are the primary inputs to modeling of RGGI's impacts on air quality and public health.

Results of this analysis show that RGGI resulted in net reductions of both pollutants in each year of RGGI's first two compliance periods. Figure 6 shows that the largest reductions in NO_x emissions due to

[31] Note that RGGI Inc.'s monitoring reports are based only on comparisons of empirical data for generation and CO_2 emissions since RGGI's start in 2009 to similar data before the program began, and do not include modeling of a counterfactual No RGGI scenario. As such, RGGI Inc. notes that it cannot say conclusively what the likely magnitude of changes in generation and CO_2 emissions from neighboring non-RGGI states would have been in the absence of the RGGI program.

RGGI also coincide with years with the most significant declines in generation—2009, 2013, and 2014. In 2009, NO_x reductions from Maryland plants accounted for about one-third of total reductions, with plants in New York and New Jersey also accounting for significant NO_x reductions. In 2013 and 2014, reductions from plants located in Maryland and Delaware accounted for most of the reductions in total NO_x emissions. Decreases in NO_x emissions due to RGGI were at their lowest levels in 2010, 2011, and 2012.

Figure 6. Changes in NO_x Emissions due to RGGI

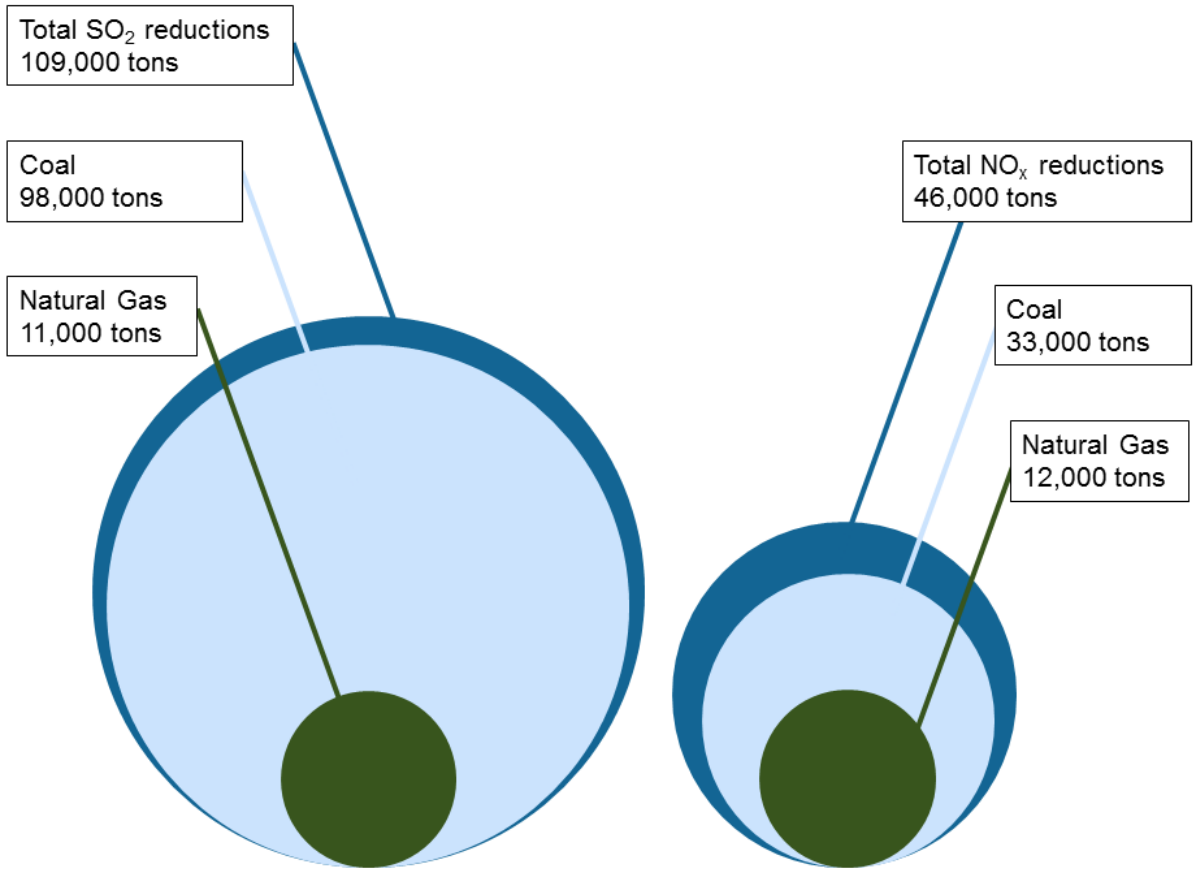


Source: Abt Associates analysis (2017).

Due to the high sulfur content of coal, emission rates of SO_2 are significantly higher for coal-fired power plants than for natural gas plants. Therefore, reductions in generation by coal-fired plants as a result of RGGI dominate total SO_2 reductions. As shown in Figure 7, coal plants account for 90 percent of reductions in SO_2 emissions resulting from RGGI. However, NO_x emission rates for coal- and natural-gas fired generation are much more comparable, especially when coal units are controlled for NO_x.[32] As such, RGGI-induced reductions in NO_x emissions can occur from a decline in generation by either coal-fired or natural gas-fired units. As shown in Figure 7, coal plants account for 73 percent of total RGGI-induced NO_x reductions from 2009 to 2014, while natural gas plants account for 26 percent of total NO_x reductions due to RGGI in the same timeframe.

[32] See Figure 18 in Appendix D for a comparison of NO_x and SO_2 emission rates across generation technologies and fuel types.

Figure 7. Changes in SO_2 and NO_x Emissions due to RGGI from 2009-2014, by Fuel Type

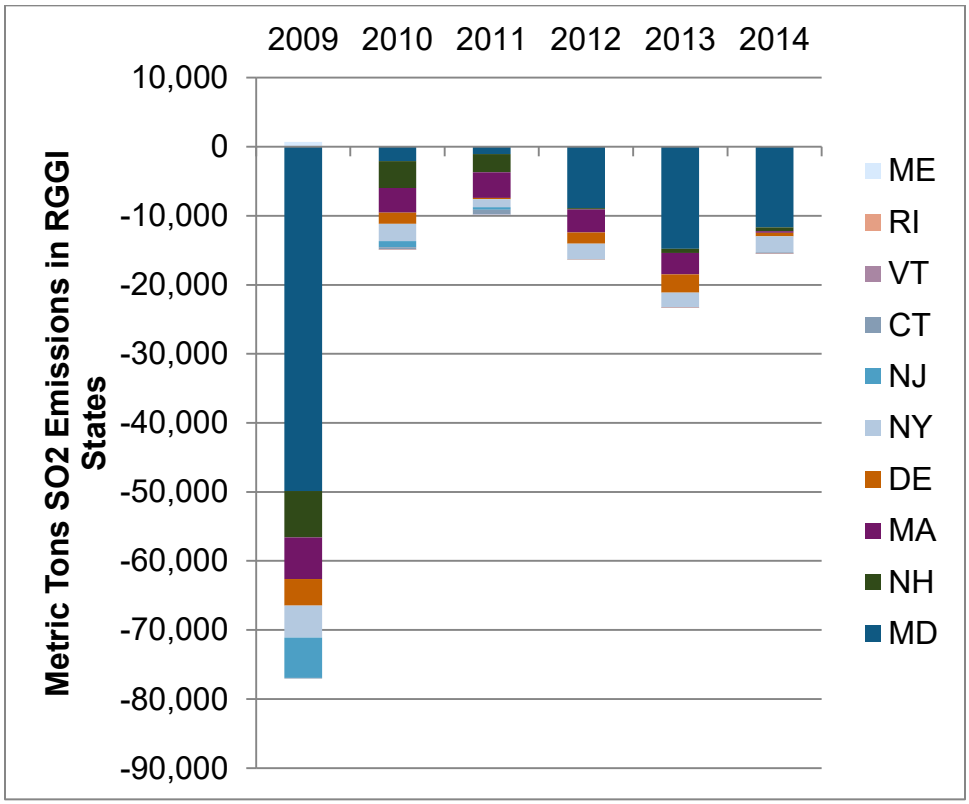


Source: Abt Associates analysis (2017).

Figure 8 shows that RGGI results in a decline in SO_2 emissions relative to the No RGGI baseline in every year of RGGI's first two compliance periods. RGGI had by far the greatest impact on SO_2 emissions in 2009, when SO_2 emissions fell by more than 76,000 metric tons. This single-year decline also accounts for nearly half of total reductions in SO_2 emission reductions over the full 2009 to 2014 timeframe. Moreover, the majority of SO_2 emission reductions in 2009 occurred in Maryland, which has the largest capacity of coal-fired power plants in all RGGI states. In response to Maryland's Healthy Air Act of 2006, SO_2 controls were installed at five of Maryland's coal plants in late 2009.[33] As a result of these controls, the SO_2 emissions rate (tons of SO_2 per MWh) declined by nearly an order of magnitude at some of these plants. This explains why absolute SO_2 reductions in Maryland are much smaller for all years after 2009, even in years such as 2013 and 2014 when RGGI resulted in meaningful decreases in generation from these plants.

[33] Controls for SO_2 were installed in the last two months of 2009 on the following Maryland coal plants (units): Brandon Shores (1 unit); AES Warrior Run (1 unit); Morgantown (2 units); Dickerson (3 units); and Chalk Point (2 units).

Figure 8. Changes in SO_2 Emissions due to RGGI



Source: Abt Associates analysis (2017).

Accounting for State Power Plant Regulations: Maryland's Healthy Air Act

With seven large power plants and more than 4,600 MW of capacity fired by coal, at the time of RGGI's start in 2009, Maryland had the largest inventory of criteria pollutant emissions from power plants of all states in the RGGI region. In 2006, Maryland passed the Healthy Air Act (HAA) in 2006 to achieve Clean Air Act goals for NO_x, SO_2, and Hg emissions from large power plants. Owners of Maryland coal-fired power plants installed a significant number of controls for these pollutants shortly after HAA took effect. Most of these controls, which included flue gas desulfurizers, baghouses, injection systems, and scrubbers, were installed on MD coal units within four years after HAA took effect. These controls were highly effective—between 2009 and 2010, SO_2 emissions fell by more than 80 percent, and NO_x emissions declined by more than 60 percent from 2007 to 2009 (Maryland Department of the Environment, 2015).

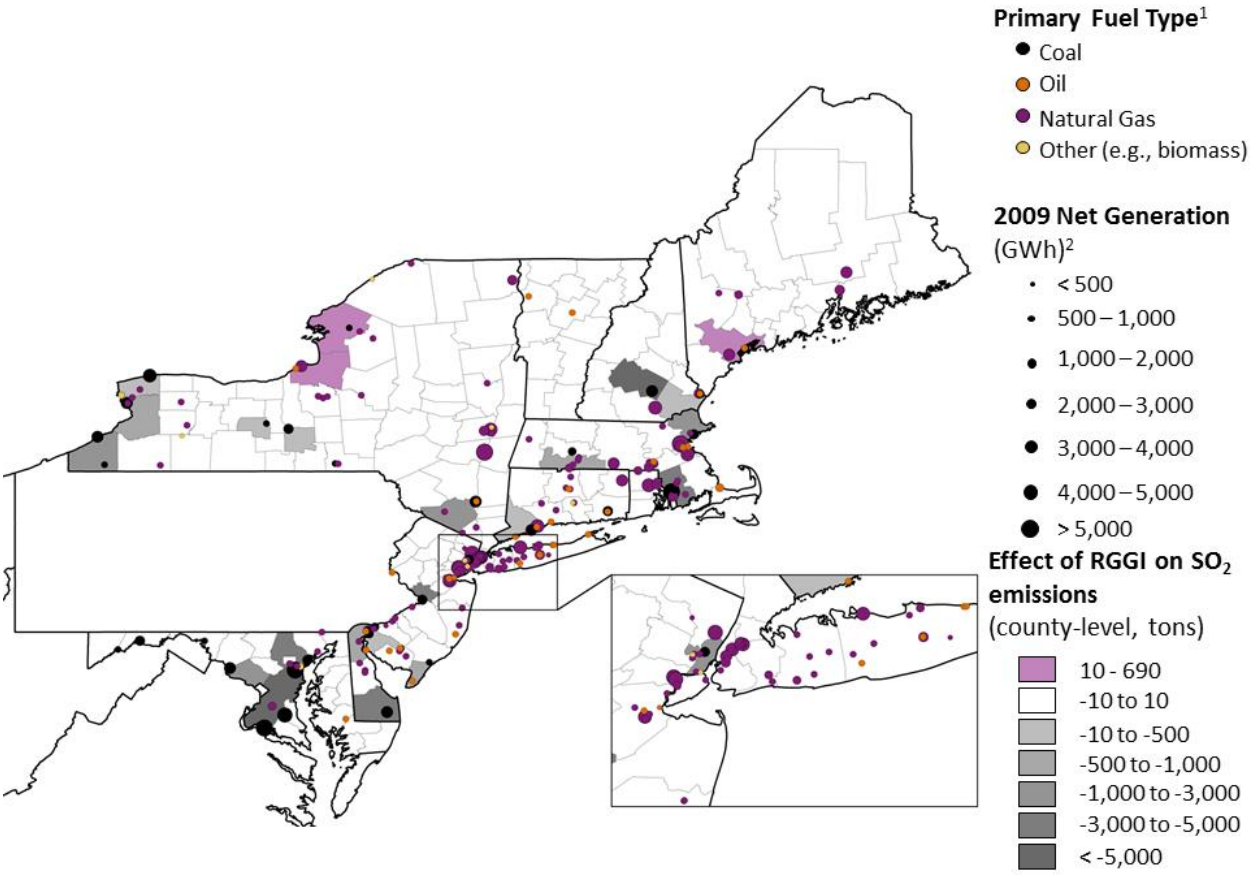
Given the importance of SO_2 emissions from Maryland's coal-fired power plants to this analysis, we sought additional input from Maryland Department of Environment staff to make sure that our emissions inventories for 2009 and 2010 accurately reflected total emissions for Maryland's power plants. We also pulled plant-specific data on control installations from EPA to ensure that our plant-specific emission factors for SO_2 and NO_x reflected changes made in response to the HAA. As a result, we are confident that results from this analysis reflect incremental emissions reductions in Maryland that are attributed to RGGI rather than to Maryland's HAA. We also confirmed that annual emission factors for other coal plants outside Maryland accounted for installations of pollution controls.

In addition to reductions from Maryland, RGGI has also resulted in SO_2 reductions from individual legacy coal plants[34] located in Delaware, New England, and New York, as shown in Figure 9. However, because these coal plants are generally more geographically isolated than Maryland's coal plants,[35] the impacts of SO_2 emissions reductions from these individual plants on air quality in surrounding downwind counties is more easily observable in air quality results. For the most part, the single largest county-level reductions in SO_2 emissions in 2009 occurred in or immediately adjacent to a county with a large coal-fired plant; however, a few oil-fired plants also played a role in changes in SO_2 emissions. In a few counties, SO_2 emissions actually increased to a small degree due to an increase in generation by a local oil- or coal-fired plant. However, each of these counties still experienced net improvements in air quality.

[34] Legacy in this context refers to older coal plants, built in the 1950s to 1970s to serve baseload power needs and whose original capital costs are fully amortized.

[35] Five of Maryland's coal plants are clustered relatively close together in Anne Arundel, Charles, and Prince Georges counties.

Figure 9. RGGI-Regulated Plants and 2009 SO_2 Reductions



Source: Abt Associates analysis (2017).

1. Primary fuel type identified from the Emissions and Generation Resource Integrated Database (eGRID) (U.S. EPA 2009).

2. Net generation data from the EIA Form 923 (U.S. EIA, 2009b). Net generation includes generation from all fuel types, not just the primary fuel type. Excludes generation from nuclear units.

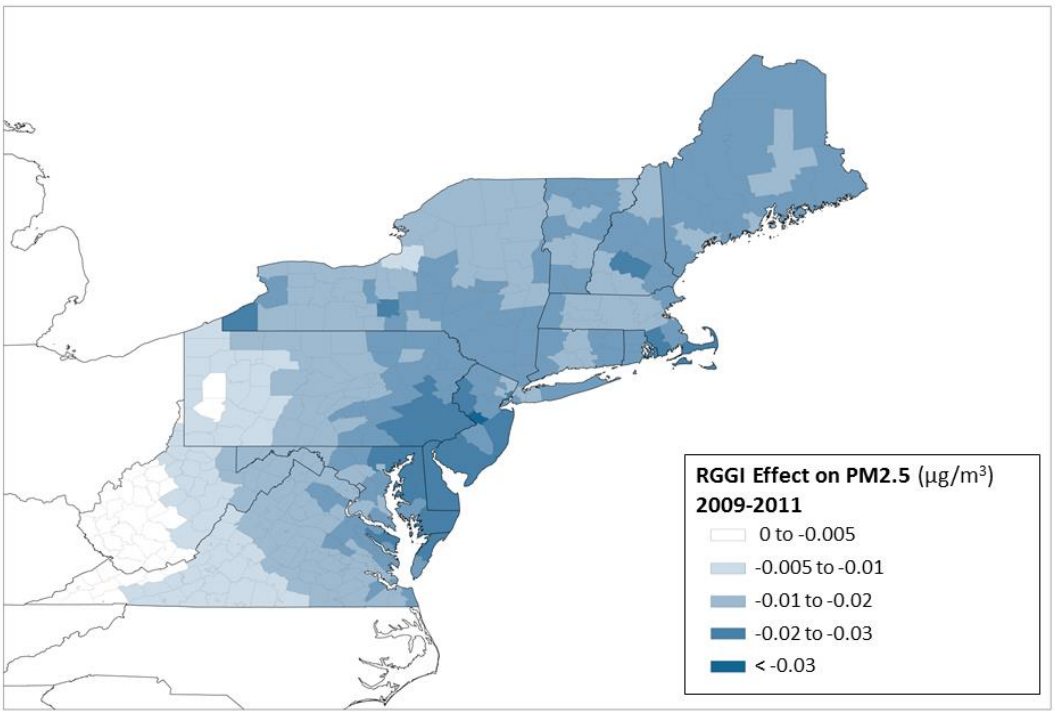
4.3 Impacts on Air Quality due to RGGI

RGGI resulted in incremental improvements to air quality in every year of the program's first six years. However, because air pollutants can be transported long distances from where they are first emitted, the spatial distribution of air quality improvements resulting from RGGI differs from the locations of plants where emission reductions originated.

Figure 10 and Figure 11 illustrate the spatial distribution of county-level changes in air quality due to RGGI for the first and second compliance periods, respectively. Generally, the most significant air quality improvements occurred in states and counties adjacent to or downwind of Maryland's power plants regulated under RGGI, although certain counties in New York (i.e., Chautauqua County and Tompkins County), and New England (Merrimack County, NH and Bristol County, MA) with or downwind of large coal plants also experienced notable air quality improvements due to RGGI. Counties in Delaware

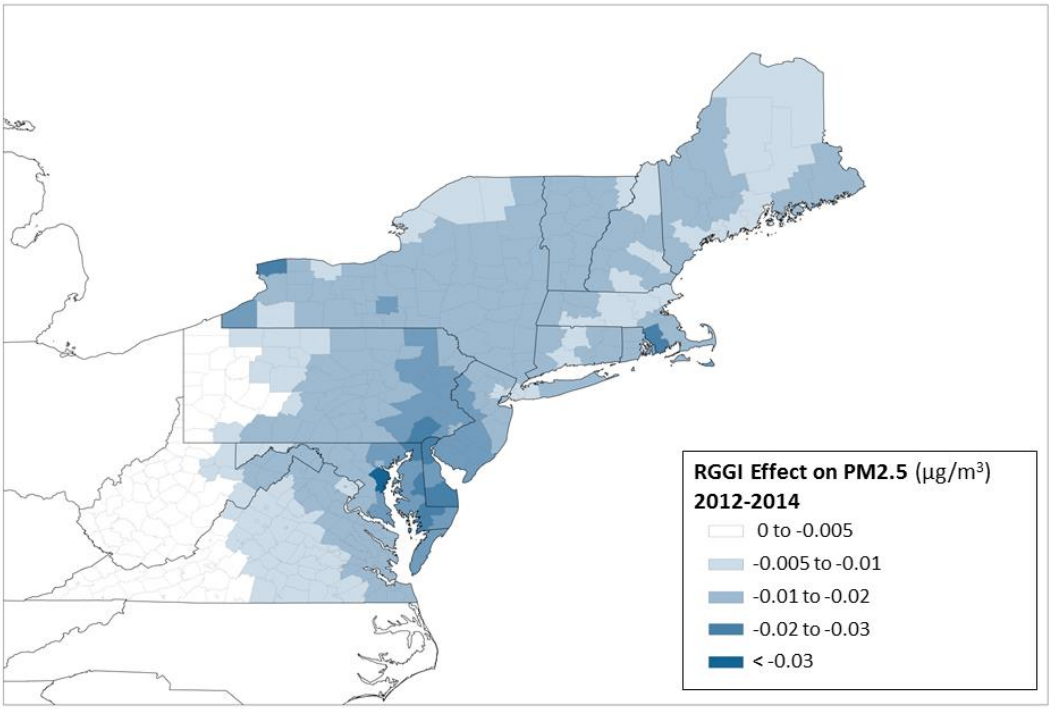
experienced the largest absolute declines in ambient $PM_{2.5}$ under RGGI because of their location immediately downwind of Maryland's coal plants, which account for the largest absolute reductions in SO_2 emissions as a result of RGGI.

Figure 10. RGGI Effect on Annual Average $PM_{2.5}$, 2009 to 2011



Source: Abt Associates analysis (2017).

Figure 11. RGGI Effect on Annual Average $PM_{2.5}$, 2012 to 2014



Source: Abt Associates analysis (2017).

Regional transport of pollution means that changes in emissions from plants located in RGGI states also impact air quality in non-RGGI states. Our modeling results show substantial air quality benefits in the non-RGGI states of Pennsylvania and New Jersey[36] due to emission reductions from plants located in RGGI states. However, as noted earlier, this analysis did not estimate possible shifts in generation and emissions that may have occurred in non-RGGI states in response to RGGI, so these changes cannot be considered net of those changes in emissions and air quality.

All counties in RGGI states met EPA's annual average $PM_{2.5}$ standard during the 2009 to 2014 timeframe and still met this standard when we modeled air quality without RGGI. EPA, however, does not set NAAQS at "zero-risk" levels,[37] which means that incremental benefits to health occur even when air quality improvements exceed EPA standards.

It is important to note that our analysis only addressed changes in annual average $PM_{2.5}$ concentrations, and that $PM_{2.5}$ concentrations are highly variable over the course of a year. A single short-term exposure to high $PM_{2.5}$ concentrations can lead to more severe human health outcomes than multiple exposures to low $PM_{2.5}$ concentrations, which is why EPA sets a 24-hour $PM_{2.5}$ standard as well as an annual average $PM_{2.5}$ standard. To the degree that RGGI states' investments in energy efficiency programs aimed

[36] Note that New Jersey was a participant in the RGGI program in the first compliance program (2009 to 2011) but not in the second (2012 to 2014).

[37] The Clean Air Act does not require EPA to establish air quality standards at a zero-risk level or at background concentrations, but rather at a level that reduces risk sufficiently to be protective of public health "…with an adequate margin of safety." (U.S. EPA, 2010).

specifically at reducing peak load, it is possible that RGGI had an amplified impact on low air quality days. However, the scope of this analysis did not include RGGI's effects on daily air quality changes.

Table 5 and Table 6 show RGGI's effect on air quality, as measured by changes in annual average levels of ambient $PM_{2.5}$, in RGGI states and non-RGGI states, respectively. RGGI's effect on air quality over time was largely consistent with its effect on emissions over time. Changes in air quality due to reductions in average $PM_{2.5}$ levels were the most significant in every state in 2009, and by a fairly significant margin over air quality improvements in other years. The next largest impact on average annual $PM_{2.5}$ occurred in 2012 to 2014, and RGGI's effect on average annual $PM_{2.5}$ was lowest in 2010 and 2011. Overall, air quality improvements in RGGI's first compliance period were larger than those in the second compliance period.

Delaware, Maryland, Pennsylvania, and New Jersey experienced the largest changes in $PM_{2.5}$ in 2009, and Delaware experienced the highest average reduction in annual $PM_{2.5}$ among all RGGI and non-RGGI states over the full time period. Pennsylvania experienced the largest average improvement among non-RGGI states. Improvements in air quality were the lowest in all states in 2011.

Table 5. RGGI Effect on Annual Average $PM_{2.5}$ in RGGI States

State	RGGI Effect on Annual Average $PM_{2.5}$ in RGGI States (Counties weighted by population)						
	2009	2010	2011	2012	2013	2014	Average
DE	-0.12	-0.02	-0.01	-0.03	-0.05	-0.03	-0.04
MD	-0.06	-0.01	0.00	-0.02	-0.03	-0.02	-0.02
RI	-0.05	-0.02	-0.01	-0.02	-0.02	-0.01	-0.02
MA	-0.04	-0.02	-0.01	-0.02	-0.02	-0.01	-0.02
NH	-0.05	-0.02	-0.01	-0.01	-0.01	-0.01	-0.02
VT	-0.04	-0.01	-0.01	-0.01	-0.02	-0.01	-0.02
ME	-0.04	-0.01	-0.01	-0.01	-0.01	-0.01	-0.02
CT	-0.04	-0.01	-0.01	-0.01	-0.01	-0.01	-0.02
NY	-0.04	-0.01	0.00	-0.01	-0.01	-0.01	-0.01
NJ	-0.08	-0.01	0.00				

Source: Abt Associates analysis (2017).

Table 6. RGGI Effect on Annual Average $PM_{2.5}$ in Non-RGGI States (PA, DC, VA, WV)

State	RGGI Effect on Annual Average $PM_{2.5}$ in non-RGGI States (Counties weighted by population)						
	2009	2010	2011	2012	2013	2014	Average
NJ				-0.01	-0.02	-0.01	
PA	-0.06	-0.01	0.00	-0.01	-0.02	-0.01	-0.02
VA	-0.04	0.00	0.00	-0.01	-0.01	-0.01	-0.01
DC	-0.03	0.00	0.00	-0.01	-0.01	-0.01	-0.01
WV	-0.02	0.00	0.00	0.00	-0.01	0.00	-0.01

Source: Abt Associates analysis (2017).

4.4 Impacts on Public Health due to RGGI

Our estimates show that RGGI's impact on air quality in the region resulted in substantial improvements to public health throughout the Northeast, in both RGGI and non-RGGI states. Results for avoided adverse health effects and their total estimated value across all RGGI states are presented in Table 7. The number of health effects avoided in RGGI states include 240 to 540 adult mortalities, 27 to 260 non-fatal heart attacks, 145 hospitalizations (respiratory or cardiovascular), and cases of asthma ER visits, asthma exacerbations, and minor respiratory illnesses. Overall, the main driver of the value of health benefits is avoided premature mortality among adults, which constitutes over 98 percent of the total health benefits across the 2009 to 2014 study timeframe. Health benefits due to RGGI also include improvements to productivity and quality-of-life, totaling 31,000 avoided lost work days and nearly 200,000 fewer days with lower levels of activity (e.g., walking, exercising).

To express the value of benefits which occur over multiple years in present value terms, we apply 3 and 7 percent rates of discount to the flow of estimated annual benefits from 2009 to 2014.[38] Results presented in this section are based on 3 percent rate of discount; similar results based on a 7 percent rate can be found in the Appendices.

Table 7. Health Benefits due to RGGI in RGGI States[39]

Health Effect	Incidences avoided due to RGGI. 2009-2014	Monetized health benefit due to RGGI, 2009-2014 (Million 2015 dollars), 3% discount rate
Acute Bronchitis	340	$0.20
Adult Mortality	240–540	$2,400–$5,300
Asthma ER Visits	160	$0.09
Asthma Exacerbations	6,500	$0.45

[38] These rates are based on EPA's guidelines on the use of a social rate of discount in economic analyses of public environmental and health policies and programs.

[39] Public health benefits in New Jersey from 2009-2011 are included in the total public health benefits due to RGGI in RGGI States

Cardiovascular Disease Hospital Admissions	80	$4.1
Infant Mortality	0.4	$4.5
Lower Respiratory Symptoms	4,300	$0.11
Minor Restricted Activity Days	190,000	$15
Non-fatal Heart Attacks	27–260	$4.4–$44
Respiratory Hospital Admissions	65	$2.3
Upper Respiratory Symptoms	6,100	$0.25
Work Loss Days	31,000	$7.5
Total		**$2,400–$5,400**

Source: Abt Associates analysis (2017).

For health impacts outside the RGGI states, our analysis included results for Pennsylvania, the District of Columbia, Virginia, and West Virginia (Table 8). Although these jurisdictions are not part of the RGGI program, they also accrue health benefits as a result of their location downwind of a RGGI state(s) where emissions reductions occurred as a result of the program. Pennsylvania's low-end benefits estimate of $823 million is greater than the total benefits for any single RGGI state, while Virginia's benefits ($244 million) exceed the estimates for several RGGI states. In addition, the District of Columbia's total benefits are over $18 million.

Table 8. Health Benefits due to RGGI in Non-RGGI States (PA, DC, VA, WV)[40]

Health Effect	Incidences avoided due to RGGI, 2009-2014	Monetized health benefit due to RGGI, 2009-2014 (Million 2015 dollars) 3% discount rate
Acute Bronchitis	180	$0.10
Adult Mortality	130–290	$1,300 - $2,900
Asthma ER Visits	73	$0.04
Asthma Exacerbations	3,400	$0.23
Cardiovascular Disease Hospital Admissions	44	$2.2
Infant Mortality	0.25	$2.8
Lower Respiratory Symptoms	2,200	$0.06
Minor Restricted Activity Days	95,000	$7.7
Non-Fatal Heart Attacks	14–130	$2.3–$21
Respiratory Hospital Admissions	32	$1.1
Upper Respiratory Symptoms	3,200	$0.13
Work Loss Days	16,000	$3.6
Total		**$1,300–$2,900**

[40] Public health benefits in New Jersey from 2012 to 2014 are included in the total public health benefits due to RGGI in non-RGGI states.

Source: Abt Associates analysis (2017).

Because of uncertainties regarding RGGI's effect on generation and emissions in non-RGGI states, we discount the low-end range of benefits estimated by BenMAP for non-RGGI states by 50 percent to create a new low-end, before adding these to benefits for RGGI states for a cumulative estimate. The high-end benefits for non-RGGI states are not adjusted, and are equal to 100 percent of BenMAP's high-end estimate. The range of cumulative health benefits due to RGGI are shown in Table 9. The total estimated value of health benefits associated with the RGGI program range from $3.0 to $8.3 billion (2015 dollars) in the region, with a central estimate of $5.7 billion (3 percent discount rate). The benefits estimates represent the value of reductions to affected populations in the health risks associated with $PM_{2.5}$.

Table 9. Cumulative Health Benefits due to RGGI[41]

Health Effect	Avoided Health Effects due to RGGI, 2009-2014		Value of Health Benefits due to RGGI, 2009-2014 (Million 2015 dollars)		
	Low	High	Low	Central	High
Acute Bronchitis	420	510	$0.25	$0.27	$0.3
Adult Mortality	300	830	$3,000	$5,600	$8,200
Asthma ER Visits	200	230	$0.11	$0.12	$0.13
Asthma Exacerbations	8,200	9,900	$0.57	$0.63	$0.69
Cardiovascular Disease Hospital Admissions	100	120	$5.2	$5.8	$6.3
Infant Mortality	<1	<1	$5.9	$6.6	$7.3
Lower Respiratory Symptoms	5,400	6,500	$0.14	$0.15	$0.17
Minor Restricted Activity Days	240,000	280,000	$19	$21	$23
Non-Fatal Heart Attacks	35	390	$5.5	$33.5	$61.6
Respiratory Hospital Admissions	82	98	$2.8	$3.1	$3.4
Upper Respiratory Symptoms	7,700	9,300	$0.31	$0.34	$0.37
Work Loss Days	39,000	47,000	$9.2	$10.1	$11
Total			**$3,000**	**$5,700**	**$8,300**

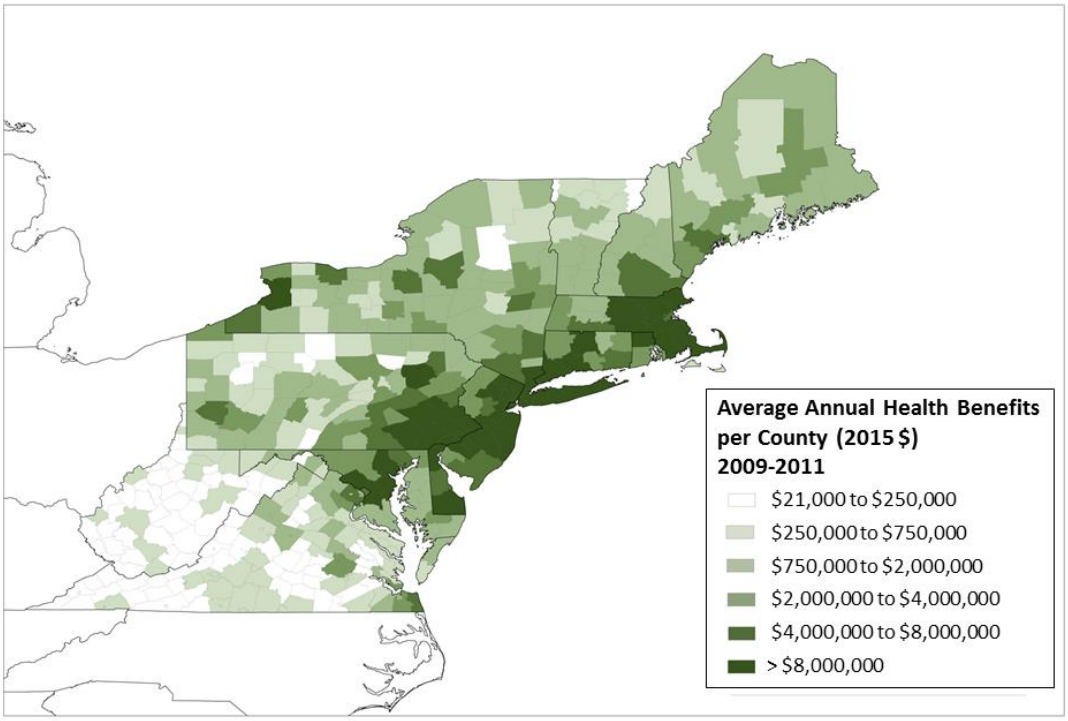
Source: Abt Associates analysis (2017).

Note: Value of avoided health effects is the sum of health benefits to states participating in RGGI and other northeastern states, based on a 3 percent rate of discount.

Figure 12 and Figure 13 show the geographic distribution of health benefits at the county level (central estimates, 3 percent discount rate). In each RGGI state, the most significant benefits were realized in 2009

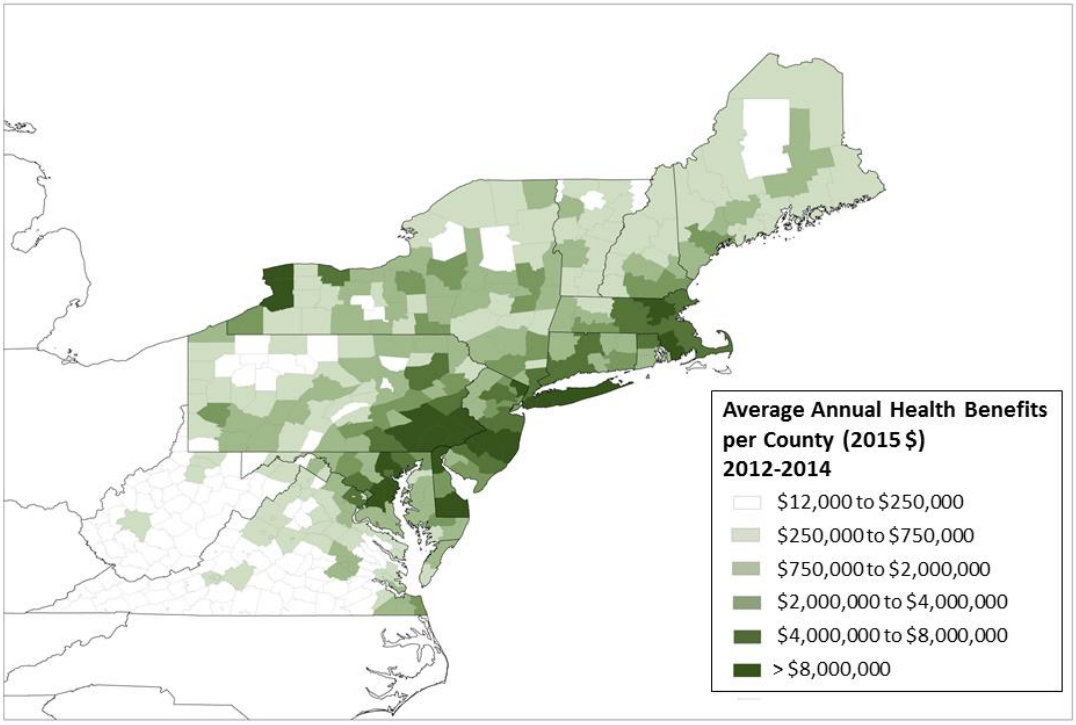
[41] Public health benefits in New Jersey from 2009-2011 are included in the total public health benefits due to RGGI in RGGI States. Public health benefits in New Jersey from 2012-2014 are included in the total public health benefits due to RGGI in non-RGGI States.

Figure 12. Annual Health Benefits of RGGI, 2009 to 2011 (Central Estimate, 3% Discount Rate)



Source: Abt Associates analysis (2017).

Figure 13. Annual Health Benefits of RGGI, 2012 to 2014 (Central Estimate, 3% Discount Rate)



Source: Abt Associates analysis (2017).

Figure 14 and Figure 15), the year with the largest estimated reductions in SO_2 emissions. State-level benefits were lower in 2010 and 2011, increased in 2012 and 2013, and decreased in 2014. Among the RGGI states, the largest health benefits by value are in New York, followed by New Jersey and Massachusetts. This is in contrast to the air quality results, which indicated the largest changes in air quality in Delaware, due to differences in population size across counties in the RGGI states. The same air quality change will result in different numbers of avoided cases (and therefore different monetized benefits) based on the affected population. For example, in 2010, $PM_{2.5}$ emissions in New York County decreased by 0.008 $\mu g/m^3$, resulting in a range of total health benefits of $4.8 to $10.8 million (2015 dollars). In the same year, the air quality change in New Castle County, DE was larger (0.014 $\mu g/m^3$), but resulted in lower benefits of $3.5 to $7.9 million (2015 dollars) (see sidebar for more information of the role of population on health benefits).

The Role of Population in Public Health Benefits in Two Maryland Counties

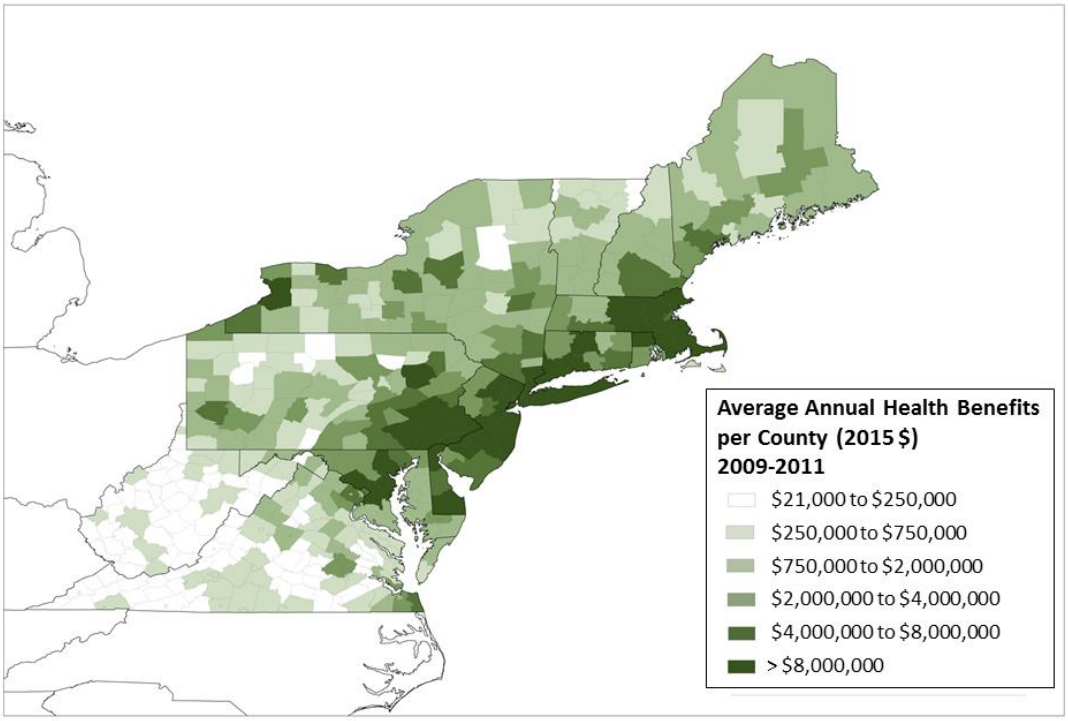
The benefits of RGGI to public health for a given county are a function of the county's population, baseline level of health, and changes to the level of ambient $PM_{2.5}$ attributable to RGGI. Because of differences in population and baseline health, counties with similar RGGI-driven $PM_{2.5}$ reductions can experience very different public health outcomes. The table shows avoided health outcomes for two counties in Maryland with different population sizes. Although RGGI results in a comparable $PM_{2.5}$ reduction in both counties (i.e., 0.022 to 0.023 $\mu g/m^3$), Baltimore County's population is about 810,000, while St. Mary's population is only 110,000. Because of these population differences, health benefits of RGGI are much more significant for Baltimore County than for St. Mary's County.

Public Health Benefits of RGGI in Baltimore County, MD and St. Mary's County, MD, 2014

Health Effect	Incidences Avoided due to RGGI, 2014	
	Baltimore County, MD	St. Mary's County, MD
Acute Bronchitis	1.2	0.20
Adult Mortality	1.0–2.3	0.10–0.23
Asthma ER Visits	0.65	0.06
Asthma Exacerbations	23	3.7
Cardiovascular Disease Hospital Admissions	0.37	0.04
Infant Mortality	<0.01	<0.01
Lower Respiratory Symptoms	15	2.5
Minor Restricted Activity Days	690	94
Non-Fatal Heart Attacks	0.12–1.1	0.01–0.08
Respiratory Hospital Admissions	0.28	0.03
Upper Respiratory Symptoms	22	3.6
Work Loss Days	115	16

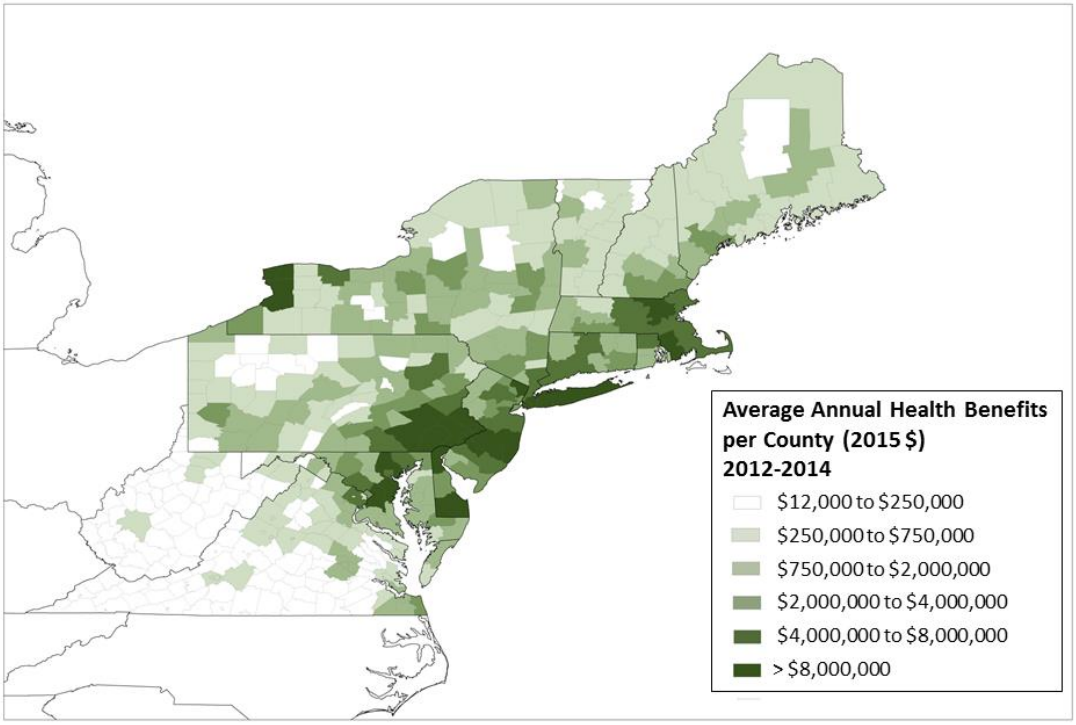
Source: Abt Associates analysis (2017).

Figure 12. Annual Health Benefits of RGGI, 2009 to 2011 (Central Estimate, 3% Discount Rate)



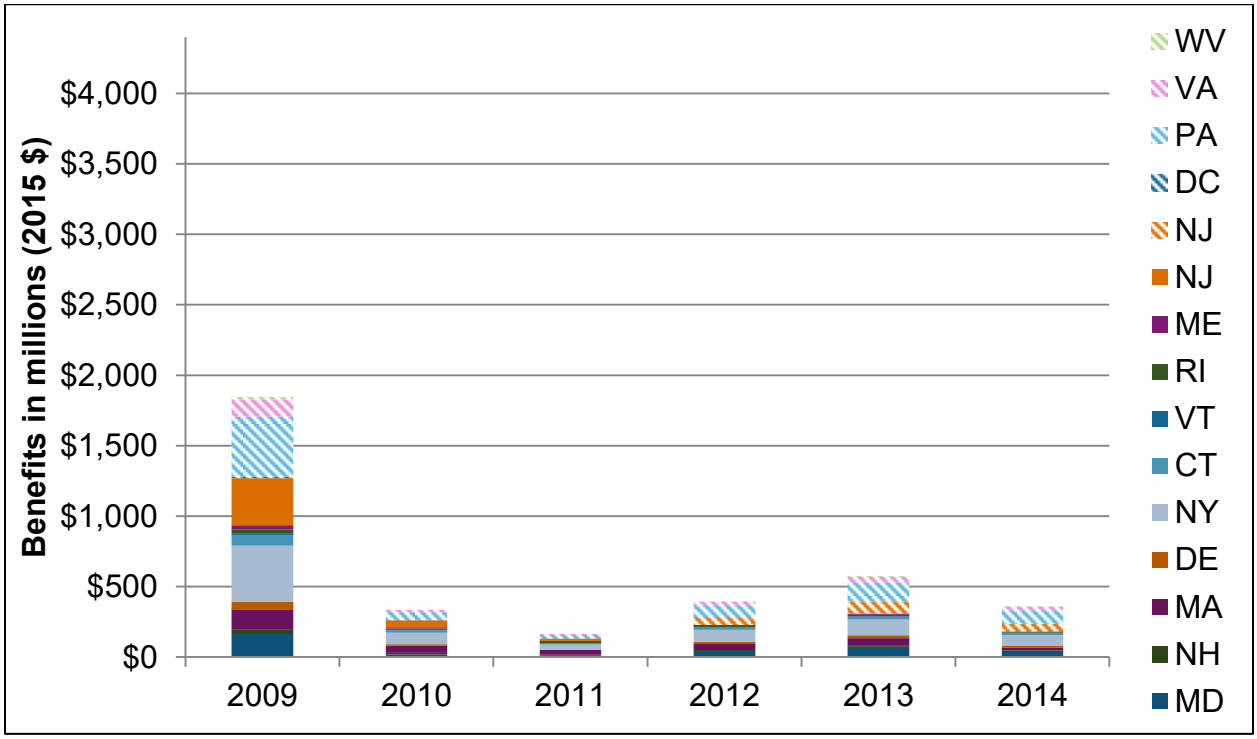
Source: Abt Associates analysis (2017).

Figure 13. Annual Health Benefits of RGGI, 2012 to 2014 (Central Estimate, 3% Discount Rate)



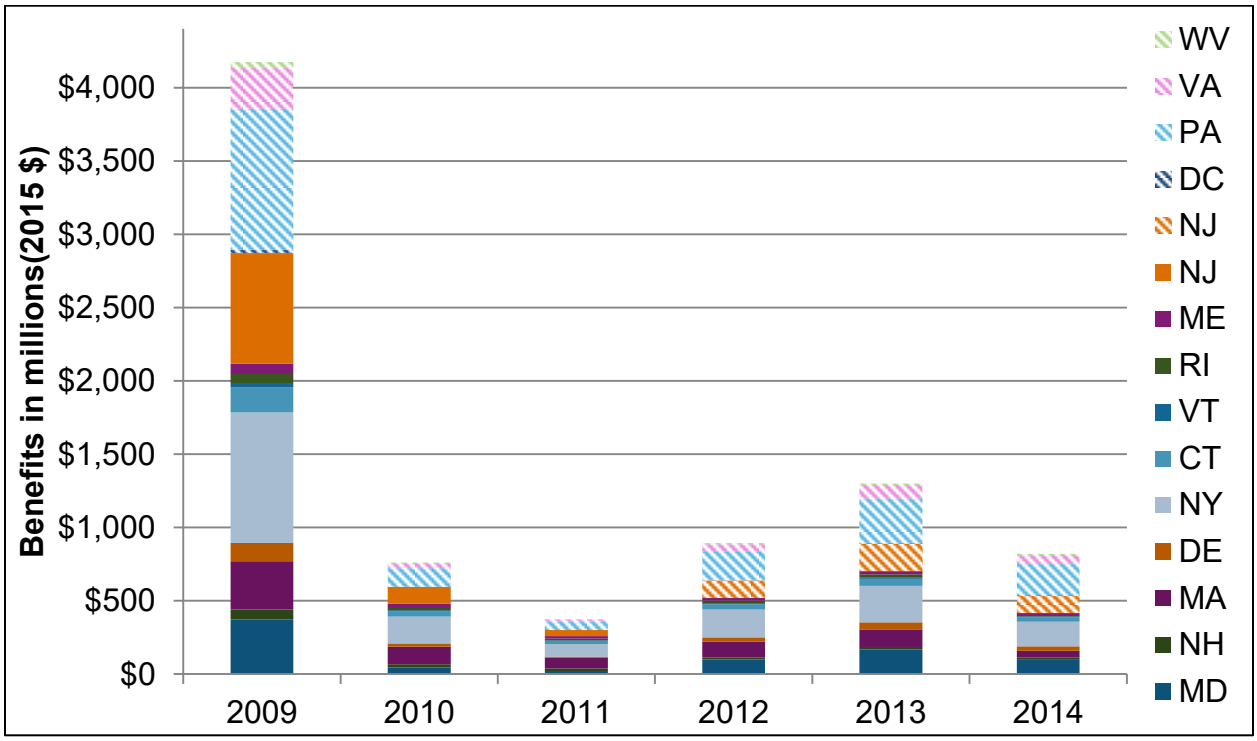
Source: Abt Associates analysis (2017).

Figure 14. RGGI Public Health Benefits by State (Low Estimate, 3% Discount Rate)



Source: Abt Associates analysis (2017).

Figure 15. RGGI Public Health Benefits by State (High Estimate, 3% Discount Rate)



Source: Abt Associates analysis (2017).

4.5 Key Findings and Implications

During the first six years of RGGI implementation, the program resulted in sizable reductions in key criteria air pollutants, especially SO_2 emissions, which contribute to the formation of $PM_{2.5}$. RGGI-induced reductions in ambient $PM_{2.5}$ occurred throughout densely populated areas of the northeastern corridor all the way to western New York and into New England, and resulted in significant benefits to human health. These benefits include hundreds of avoided cases of premature deaths, heart attacks, asthma attacks, and hospital admissions, and tens of thousands of avoided cases of other health symptoms, lost work days, and restricted activities. The estimated value of the health, productivity, and quality-of- life benefits associated with RGGI ranges from $3.0 billion to $8.3 billion, with a central estimate of $5.7 billion (2015 dollars, 3 percent discount rate).

RGGI's effect on annual air quality and public health are most significant in 2009 and 2013. This pattern is consistent with RGGI's two effects on wholesale power markets: 1) changes in power prices to absorb CO_2 allowance costs, which results in a shift of dispatch to lower-carbon sources, and 2) investments in energy efficiency, which reduce electricity demand and emissions. In addition, there is evidence that plant owners took early action to reduce CO_2 emissions in anticipation of RGGI.

As noted above, RGGI-induced changes at a relatively small number of legacy coal plants drive a high proportion of RGGI's total reductions in key air pollutants and health benefits. The fleet of power plants in RGGI states will be, on average, cleaner in the near future than the current fleet,[42] so future RGGI-induced reductions in generation are likely to result in lower total health benefits going forward.

However, the cleaner electricity grid does create opportunities for additional health benefits if energy demand from other sectors—transportation and buildings—shifts onto to a cleaner grid in RGGI (and neighboring) states, a process known as "electrification." Reductions of air pollutants and health benefits from decarbonizing other energy demand could be significant. For example, a 2016 study assessed future health and climate benefits that would occur if the eight northeastern states participating in the Zero Emission Vehicle (ZEV) program[43] transitioned to a vehicle fleet of about 65 percent ZEVs by 2050 (American Lung Association in California, 2016). According to the study, this would result in about $12 billion in annual health benefits. [44] Many RGGI states (e.g., Massachusetts, Rhode Island) are currently implementing or developing GHG mitigation plans to achieve 80 percent reductions in GHG emissions

[42] A number of states in the region are implementing GHG mitigation plans that require 80 percent reductions in GHG emissions by 2050, relative to 1990 levels.

[43] The ZEV program requires that automakers meet a threshold of electric vehicle sales in participating states. The exact number of electric vehicles required is linked to each automaker's total sales within the state. The eight northeastern states participating in the ZEV program, along with California and Oregon, include: Connecticut, Maine, Maryland, Massachusetts, New Jersey, New York, Rhode Island, and Vermont.

[44] The study reports state-level combined health and climate benefits, and we assume that health benefits constitute 62 percent of combined benefits. This assumption is based on the fact that health benefits across all states constitute 62 percent of combined health and climate benefits across all states.

by 2050,[45] and these plans include strategies for electrification of energy used in light-duty vehicles and building heating and cooling.

As in any analysis, there were certain uncertainties in data, assumptions, and models used in this study which influenced estimates. Table 10 below describes these sources of uncertainty and their potential impact on estimated changes in emissions, air quality, and health benefits due to RGGI, as well as our approach to addressing individual uncertainties within models or through quantified sensitivity cases. The fact that quantitative estimates of energy savings from RGGI investments in efficiency which persist after 2014 and reductions in ozone due to RGGI are excluded from this analysis implies a likely underestimation of benefits. We also applied a sensitivity factor of 50 percent to health benefits estimated for non-RGGI states to account for the lack of conclusive information describing RGGI's incremental effect on generation and emissions in these states. As such, our estimates of total health benefits due to RGGI are probably conservative.

Table 10. Key Uncertainties in the Analysis

Source of Uncertainty in the Analysis	Impact on Estimates	Likely Significance on Estimates of Health Benefits
Analysis excludes avoided emissions, air quality, and health benefits that occur after 2014 resulting from states' investments in energy efficiency from 2009 to 2014.	**Underestimation.** The magnitude of these excluded benefits is not known, but could be significant given the magnitude of EE investments particularly in 2013 and 2014.	Possibly significant.
Analysis excludes health benefits associated with reductions in ozone.	**Underestimation.** The effect of ozone reductions on health benefits is known to be smaller in magnitude than that of reductions in ambient $PM_{2.5}$.	Probably minor.
Analysis excludes changes in emissions in non-RGGI states as a result of RGGI.	**Overestimation**. Unable to determine magnitude based on current information, but the potential for lower benefits is addressed through a sensitivity factor that discounts benefits in non-RGGI states by 50 percent.	Possibly significant.
Gaps in baseline emissions datasets.	**Indeterminate.** Gaps for missing years in EPA emissions databases were addressed by adjustments to data describing adjacent years.	Probably minor.

[45] The base year against which each of these states calculates their 2050 emissions reduction goal in their GHG mitigation plans varies—some states use a base year of 1990, while others use 2001.

Source of Uncertainty in the Analysis	Impact on Estimates	Likely Significance on Estimates of Health Benefits
Uncertainties in assumptions and inputs used in dispatch, air quality, and health benefits modeling.	**Indeterminate.** Low- and high-end estimates from the BenMAP model account for uncertainties in the relationship between population exposures and health effects. Historical actual data were used in dispatch and air quality models, thereby reducing some sources of error.	Possibly significant.

Source: Abt Associates analysis (2017).

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Appendix A – Emissions Data Sources and Analysis

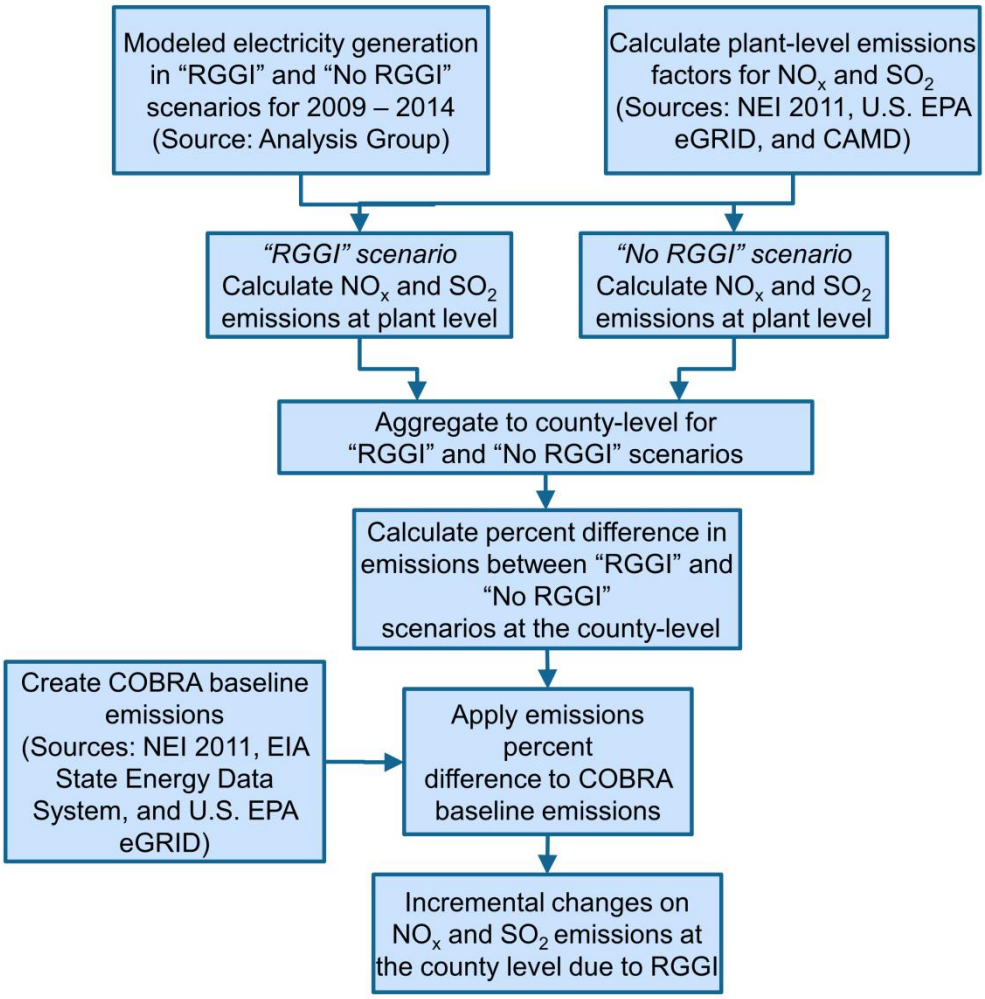
Detailed Analytic Approach

We developed a baseline of emissions for the RGGI scenario from actual emissions in the EPA's 2011 National Emissions Inventory (NEI) data. We chose the NEI dataset because it enabled us to represent emissions inventories from all sectors in the economy. This is necessary for Step 2 of our analysis because COBRA models changes in air quality based on a complete inventory of criteria pollutant emissions from all sectors (e.g., power plants, transportation, industrial processes.

We calculated emissions for the modeled electricity generation levels under the RGGI and No RGGI scenarios by (1) calculating plant-level emission factors and (2) applying plant-level emissions factors to modeled generation levels. We calculated plant-level SO_2 and NO_x emissions factors (tons pollutant/MWh generated) by dividing NEI-derived baseline emissions by actual generation. We created unique emissions factors for each year, which enabled us to reflect the effects of pollution control installations, operational characteristics, and changes in fuel mix for each plant. We applied these emissions factors to the modeled generation levels under RGGI and No RGGI to determine emissions under RGGI and No RGGI, respectively. Our workflow to calculate incremental changes in NO_x and SO_2 emissions at the county level is illustrated in Figure 16.

We then aggregated the modeled RGGI and No RGGI emissions to the county level and calculated the ratio of emissions between the RGGI and No RGGI scenarios. We applied this ratio to the actual RGGI emissions baseline to construct the counterfactual emissions inventory for No RGGI. The difference between the RGGI emissions inventory and the RGGI emissions baseline is the incremental change in emissions due to RGGI, which we input into COBRA under Step 2.

Figure 16. Approach to Estimating County-Level Changes in Emissions due to RGGI



Source: Abt Associates analysis (2017).

Description of Datasets Used

Analysis Group Datasets

We used results of modeling runs conducted by Analysis Group as part of their 2011 and 2015 retrospective studies of RGGI's economic impacts. These datasets provided estimates of annual plant-level electricity generation for all power plants located in RGGI states, for the RGGI and No RGGI scenarios (Analysis Group, 2011, 2015).

Analysis Group modeled electricity generation per unit with power system dispatch models, which simulate the optimal distribution of the electric power system load among generation facilities. Analysis Group used GE Energy's Multi-Area Production Simulation (MAPS) model for the first compliance period (see Analysis Group, 2011) and the PROMOD model for the second compliance period (see Analysis Group, 2015).

These dispatch models are useful for this retrospective analysis of RGGI because they compute optimal dispatch based on observed fuel prices, transmission system constraints, and operational constraints at a high geographic and temporal resolution. However, dispatch models cannot perfectly simulate power producers' actual, real-world decisions. For example, dispatch models tend to show that very small changes in marginal costs lead to significant changes in dispatch patterns, which is not always the case.

The modeled "RGGI" scenario reflects actual "RGGI" data accurately when aggregated to the regional scale. However, differences between the modeled "RGGI" scenario and actual "RGGI" data emerge at the county or plant level. Accuracy at the plant level is necessary to model public health benefits, because the estimated effect of changes in generation on emissions is highly dependent on the age, fuel use, and emissions controls of a given plant, and the effect of changes in emissions on public health are highly dependent on the emissions' location. We adopt a percent difference approach to deal with differences between the modeled RGGI scenario and actual RGGI data, as described in the main text.

National Emissions Inventory

The NEI is a comprehensive estimate of air emissions that EPA develops from data reported primarily from state, local, and tribal air agencies. The NEI includes emissions from multiple sources, including point sources (e.g., power plants), non-point sources (e.g., residential heating), on-road sources (e.g., light-duty vehicles), and non-road sources (e.g., boats, lawn and garden equipment). NEI datasets are available from 2008, 2011, and 2014. For our analysis, we used the 2011 NEI dataset. We estimated annual power plant emissions for each year in the 2009 to 2014 period by modifying the NEI 2011 baseline. We estimated plant-level emissions changes relative to 2011 based on fuel use ratios from the State Energy Data System and annual emissions factor ratios from the EPA Emissions and Generation Resources Integrated Database (eGRID). We also cross-checked our annual plant-level emissions estimates with other data sources, such as EPA's Clean Air Markets Division (CAMD), and spot-corrected our baseline as necessary.

EPA Emissions and Generation Resource Integrated Database

EPA's eGRID contains environmental data from all U.S. plants that supply power to the electric grid and provide data to the federal government. The database was developed by Abt Associates and CAMD. We use eGRID's plant-level SO_2 and NO_x emissions rates to adjust our annual emissions inventories to account for installation of emissions controls. Plant-level SO_2 and NO_x emissions rates are available for 2009, 2010, 2012, and 2014. For years of interest without a corresponding eGRID dataset, we calculate average emissions rates from adjacent years for which data are available.

U.S. Energy Information Administration (EIA) Annual Electric Generator Capacity Data (Form EIA-860)

The Annual Electric Generator Data is compiled from submissions of survey Form EIA-860. Form EIA-860 gathers generator-level data from all U.S. power plants with total nameplate capacity of one megawatt or greater. We used plant-level data for generators surveyed in 2009-2014. We used Form EIA-860 to identify the county in which plants are located.

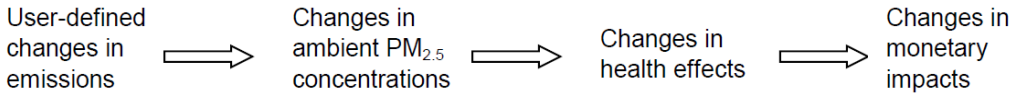
Appendix B – Estimating Air Quality Changes: Co-Benefits Risk Assessment (COBRA) Model

To estimate the air quality impacts of RGGI in 2009-2014, we used EPA's COBRA model. COBRA is a free screening tool that helps state and local governments evaluate the costs and benefits of clean energy and climate mitigation policies. COBRA provides preliminary estimates of the effects of air pollutant emission changes (e.g., NO_x, SO_2, and $PM_{2.5}$) on ambient air concentrations of $PM_{2.5}$, translates the estimated changes in ambient $PM_{2.5}$ concentrations into the number of avoided adverse health effects, and then provides a monetary value of the avoided health effects. COBRA enables policymakers and planners to identify and highlight air quality and public health co-benefits achieved through energy efficiency or renewable energy policies.

COBRA Model Components

Abt Associates originally developed COBRA in 2002 for EPA and continues to support updates of the screening tool. The model consists of four components, shown in Figure 17.

Figure 17. Components of the COBRA Model



Source: *COBRA User Manual* (U.S. EPA, 2015c).

A brief explanation of the two of the four components of the model that were used in this analysis is included below.[46] In lieu of COBRA's health valuation functions, we used the BenMAP model described in the next section.

User Inputs of Emissions Changes

COBRA contains baseline emissions estimates based on the National Emissions Inventory. Note that we prepared customized versions of the COBRA model that contain baseline emissions estimates for each modeling year 2009-2014 (see Section 3.2). We then created COBRA scenarios by entering increases or decreases to the baseline emissions estimates.

Changes in Air Quality (i.e., ambient $PM_{2.5}$ concentrations)

Based on changes in emissions levels, the COBRA model then calculates changes in particulate matter, which reflect changes in air quality. Specifically, COBRA estimates $PM_{2.5}$ concentrations using a simple air quality model known as the Phase II Source-Receptor (S-R) Matrix. The S-R Matrix consists of fixed transfer coefficients that reflect the relationship between annual average $PM_{2.5}$ concentration values at a single receptor in each county (a hypothetical monitor located at the county centroid) and the contribution by $PM_{2.5}$ species to this concentration from each emission source (E.H. Pechan & Associates Inc., 1994). COBRA models the formation of secondary $PM_{2.5}$ from NO_x and SO_2 by (1) assuming up to 25 percent of NO_x and 100 percent of SO_2 transform into ammonium nitrate and ammonium sulfate, respectively,

[46] For more detailed information, see the *COBRA User Manual* (U.S. EPA, 2015c).

depending on the limiting concentration of ammonia, (2) modeling secondary reactions among gaseous and particulate species, and (3) calibrating COBRA modeling results to measured $PM_{2.5}$ values.

Benefits of COBRA

The COBRA model allows us to quickly estimate air quality impacts based on a simplified air quality model. COBRA displays county-level results in both tabular and geographic formats. The mapping feature allows users to see changes in ambient $PM_{2.5}$ levels at the county level.

Limitations of COBRA

More sophisticated (and resource-intensive) air quality modeling approaches are available and would provide more refined estimates of the benefits of emissions reductions. Importantly, COBRA does not account for all air pollutants, such as ozone, carbon dioxide, and mercury. Therefore, the health benefits based on COBRA air quality results are likely a conservative estimate because many health impacts are exacerbated by other harmful air pollutants but are not included in the scope of the COBRA model.

Another key limitation of COBRA is that the health effects inputs cannot be easily customized. COBRA relies on population, incidence (i.e., the baseline probability of a health effect), and income data for a specific modeling year. Therefore, we did not use the health impact and valuation components of COBRA in our analysis of RGGI, and instead relied upon the BenMAP model.

Appendix C – Estimating Changes in Public Health: Benefits Mapping and Analysis (BenMAP) Model

Abt Associates designed and implemented the original BenMAP model for EPA, which was the first publicly available model for estimating the number and economic value of health impacts resulting from changes in air quality. EPA's current version of BenMAP (known as BenMAP-Community Edition) is being deployed around the world by governments, researchers, and policy analysts for generating monetized estimates of public health improvements resulting from reductions in air pollutants. For example, BenMAP has been used for local- and regional-scale analyses (e.g., Cohan et al., 2007; Nowak et al., 2013) and climate assessments (e.g., Hill et al., 2009; Tagaris et al., 2009).

We estimated the public health impacts of RGGI in 2009-2014 using the BenMAP model, Version 4.0.67. This is a legacy version of BenMAP that allows us to use configuration files EPA used for the 2012 PM National Ambient Air Quality Standards (NAAQS) Regulatory Impact Analysis (referred to below as the "2012 PM RIA configuration").[47]

We input COBRA-generated county ambient $PM_{2.5}$ estimates into BenMAP, which BenMAP used to calculate RGGI's effect on $PM_{2.5}$ relative to observed ambient $PM_{2.5}$ for 2009-2014. We selected BenMAP over COBRA for this step of the analysis because BenMAP allows us to capture changes in baseline population, incidence, and valuation over the study period. While COBRA is an appropriate tool for estimating ambient air quality, the fact that its datasets are tied to a specific calendar year limits its representation of how air quality affects public health over time.

BenMAP linked air quality changes to public health metrics by applying empirical relationships between $PM_{2.5}$ and multiple health effects.[48] BenMAP applied these statistical relationships to population datasets for 2009-2014. BenMAP uses county-level population projections based on the 2010 U.S. Census of Population and Housing and forecasting models developed by Woods and Poole (2011).

Based on the 2012 PM RIA configuration, BenMAP monetized the health impacts using "unit values" for each health endpoint (presented in Table 11). The unit values are based on published estimates of the costs of treating the illness (which can include both direct medical costs and costs of lost productivity), or the willingness to pay (WTP) to avoid the illness or to reduce the risk of premature death (i.e., value per statistical life, VSL). The unit values based on WTP estimates reflect expected growth in real income over time. This is consistent with economic theory, which argues that WTP for most goods (such as health risk reductions) will increase if real incomes increase.

In BenMAP, we estimated economic values in 2015 dollars and using income levels for each year of the analysis (e.g., 2009 income levels for valuing health impacts for 2009). In Table 11, we present the unit values at 2014 income level. Because some of the health benefits from emissions reductions in a particular year are expected to occur over several years, BenMAP discounts the estimated stream of

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[47] In BenMAP, configuration files specify the health impact and valuation functions, as well as settings for aggregation and pooling across the incidence and valuation results.

[48] The health impact functions are described in detail in Appendix E of the *BenMAP User's Manual* (U.S. EPA, 2012).

economic benefits to the analysis year using either a 3 percent or a 7 percent discount rate. We further adjusted all results to 2015 present values.

Table 11. Health Effects and Their Economic Values (2015 dollars/case)

Avoided Health Effect	Economic Value (2015 dollars, 2014 Income Level)[1]
Time-varying costs[2]	
Adult Mortality[1] (3% discount rate)	$8,937,339
Adult Mortality[1] (7% discount rate)	$7,960,346
Non-Fatal Heart Attacks (3% discount rate)	$38,253–$298,337
Non-Fatal Heart Attacks (7% discount rate)	$36,167–$286,735
Costs incurred in the year of exposure	
Infant Mortality[3]	$9,961,679
Hospital Admissions (Respiratory, Cardiovascular-related)[4]	$17,135–$46,318
Asthma Emergency Room Visits	$447–$534
Acute Bronchitis	$513
Respiratory Symptoms (Upper, Lower)	$22–$36
Asthma Exacerbations (attacks, shortness of breath, and wheezing)	$62
Minor Restricted Activity Days	$73
Work Loss Days[4]	$160

Source: U.S. EPA (2012d and 2012e).

1. The unit values based on WTP estimates reflect expected growth in real income over time. When estimating health benefits, we used the income level specific to each analysis year. In this table, we present the values at 2014 income level.

2. Most health effects and their economic values are expected to occur in the year of analysis. However, not all avoided cases of adult mortality are expected to occur in the year of analysis. In addition, while avoided cases of non-fatal heart attacks are expected to occur in the same year as the emissions change, the costs associated with this health effect would occur over multiple years. Thus, BenMAP uses discount rates of 3 percent and 7 percent to calculate the value of these health effects in present terms.

3. Following U.S. EPA (2012a), we assume that some of the incidences of premature adult mortality related to $PM_{2.5}$ exposures occur in a distributed fashion over the 20 years following exposure. This lag adjustment does not apply to infant mortality because Woodruff et al. (1997) estimated the number of infant deaths occurring in the same year as the emissions change. We applied the lag adjustments to the BenMAP output.

4. BenMAP uses county-specific median daily wages to value work loss days and opportunity costs for hospital admissions. In this table, we report unit values based on the national median daily wage.

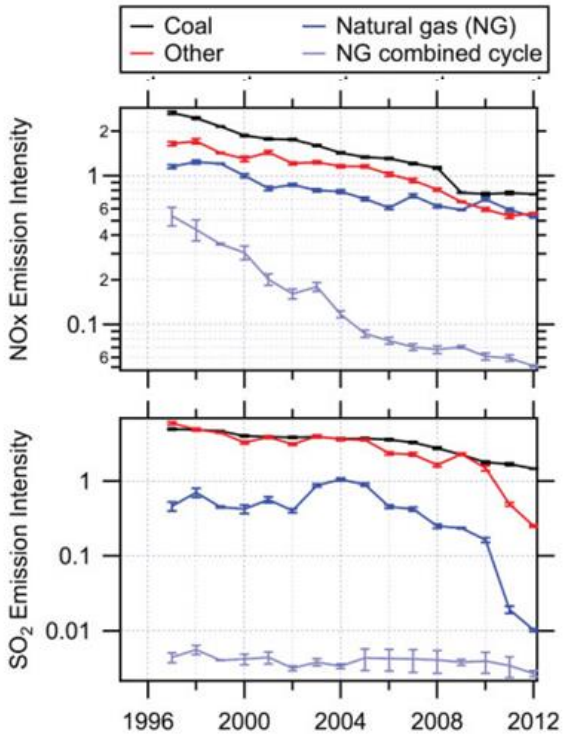
The resulting health impact results do not capture all uncertainty surrounding BenMAP's inputs. This analytic step introduces several uncertainties, including population forecasts and the VSL. Another source of uncertainty introduced in this analytic step relates to whether there is regional variability in some inputs. Because BenMAP's health impact and valuation functions represent national-level relationships,

the accuracy of regional-level analyses may be improved by identifying region-specific relationships from the literature.[49]

[49] Further details on uncertainty in BenMAP inputs are provided in the appendices of the *BenMAP User's Manual* (U.S. EPA, 2015a).

Appendix D – Supplementary Figures

Figure 18. NO_x and SO_2 Emission Rates across Generation Technologies and Fuel Types



Source: Adapted from de Gouw et al. (2014).

Table 12. Health Benefits due to RGGI in RGGI States, 7% Discount Rate

Health Effect	Incidences avoided due to RGGI from 2009-2014	Monetized health benefit due to RGGI from 2009-2014 (Million 2015 dollars), 7% discount rate
Acute Bronchitis	340	$0.23
Adult Mortality	240–540	$2,500–$5,700
Asthma ER Visits	160	$0.11
Asthma Exacerbations	6,500	$0.54
Cardiovascular Disease Hospital Admissions	80	$4.9
Infant Mortality	0.4	$5.4
Lower Respiratory Symptoms	4,300	$0.13
Minor Restricted Activity Days	190,000	$18
Non-fatal Heart Attacks	27–260	$5.1–$47
Respiratory Hospital Admissions	65	$2.7
Upper Respiratory Symptoms	6,100	$0.3
Work Loss Days	31,000	$8.9
Total		**$2,500–$5,700**

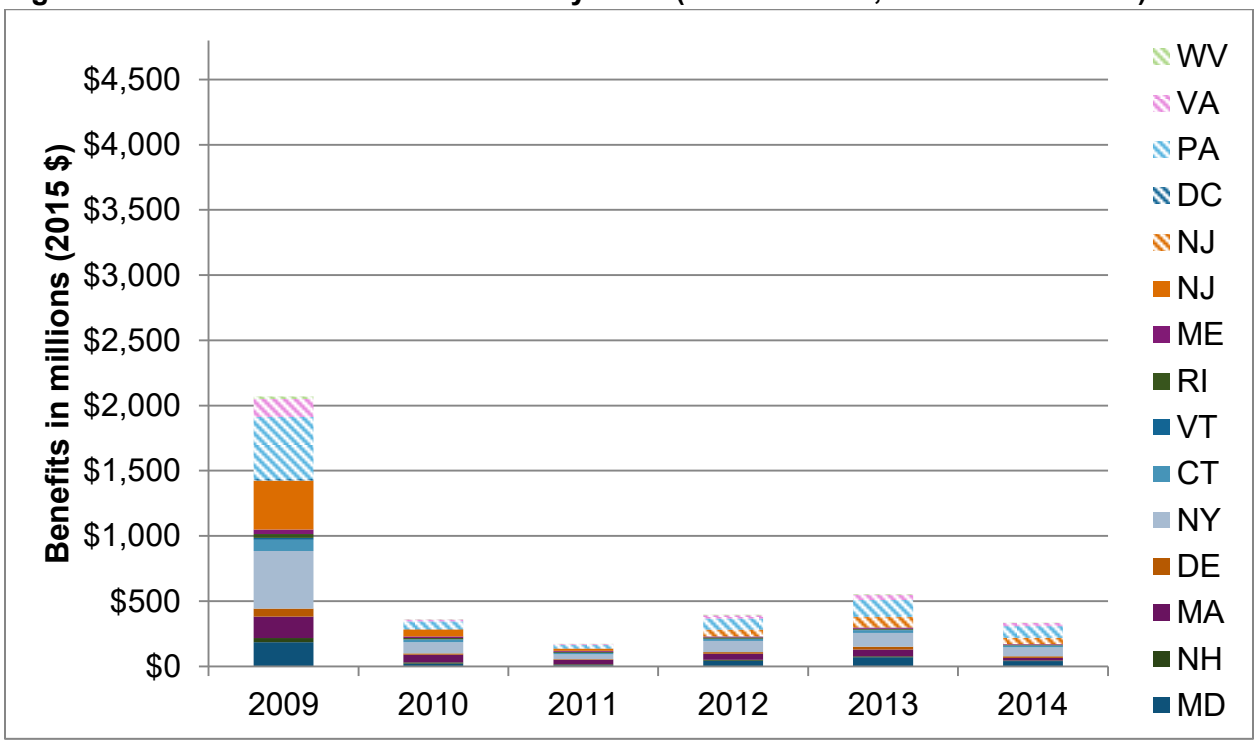
Source: Abt Associates analysis (2017).

Table 13. Health Benefits due to RGGI in Non-RGGI States, 7% Discount Rate

Health Effect	Incidences avoided due to RGGI from 2009-2014	Monetized health benefit due to RGGI from 2009-2014 (Million 2015 dollars) 7% discount rate
Acute Bronchitis	180	$0.12
Adult Mortality	130–290	$1,300–$3,000
Asthma ER Visits	73	$0.05
Asthma Exacerbations	3,400	$0.27
Cardiovascular Disease Hospital Admissions	44	$2.6
Infant Mortality	0.25	$3.3
Lower Respiratory Symptoms	2,200	$0.07
Minor Restricted Activity Days	95,000	$9
Non-Fatal Heart Attacks	14–130	$2.6–$24
Respiratory Hospital Admissions	32	$1.3
Upper Respiratory Symptoms	3,200	$0.15
Work Loss Days	16,000	$4.2
Total		**$1,300–$3,000**

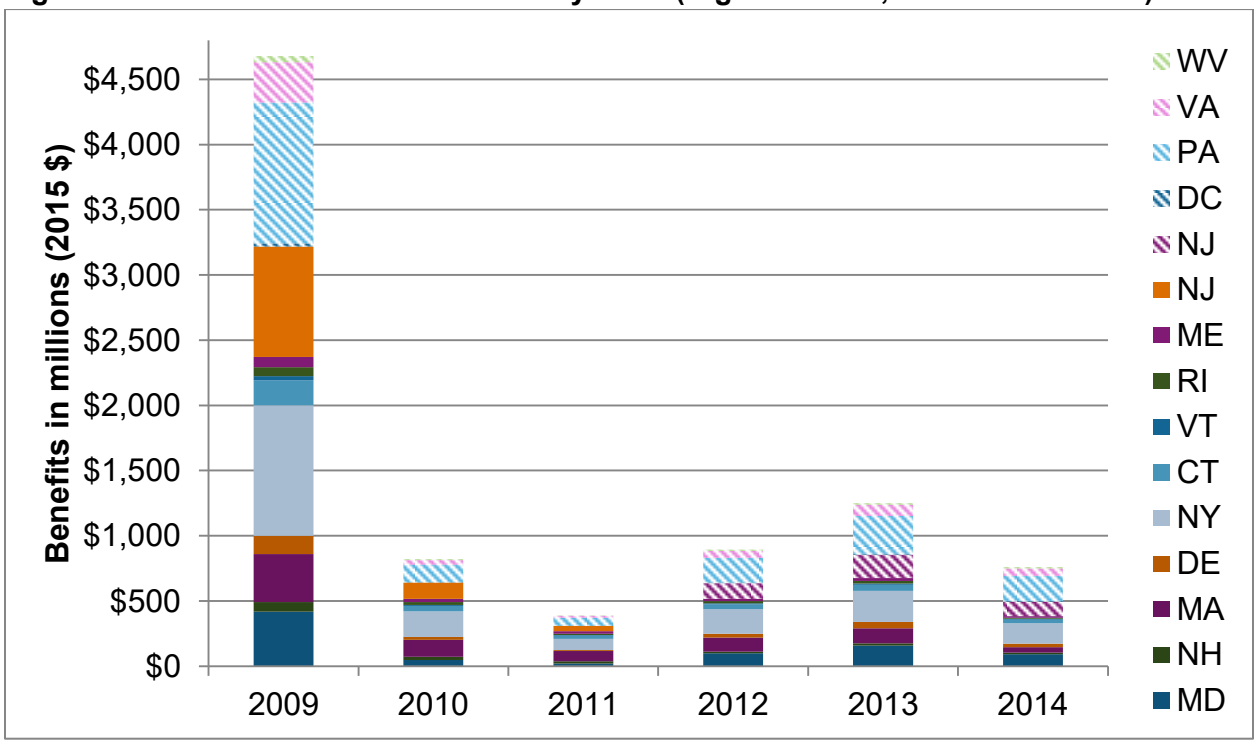
Source: Abt Associates analysis (2017).

Figure 19. RGGI Public Health Benefits by State (Low Estimate, 7% Discount Rate)



Source: Abt Associates analysis (2017).

Figure 20. RGGI Public Health Benefits by State (High Estimate, 7% Discount Rate)



Source: Abt Associates analysis (2017).

Attachment 26

A Section 508–conformant HTML version of this article is available at https://doi.org/10.1289/EHP6706.

Co-Benefits to Children's Health of the U.S. Regional Greenhouse Gas Initiative

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Background: While various policies have been implemented globally to mitigate climate change and reduce exposure to toxic air pollutants, policy assessments have considered few if any of the benefits to children.

Objective: To comprehensively assess the co-benefits of climate change mitigation to children, we expanded the suite of adverse health outcomes in the U.S. Environmental Protection Agency's Benefits Mapping and Analysis Program (BenMAP) to include additional outcomes associated with prenatal and childhood exposure to ambient fine particulate matter ($PM_{2.5}$). We applied this newly expanded program to an assessment of the U.S. Regional Greenhouse Gas Initiative (RGGI), the United States' first regional market-based regulatory program designed to reduce greenhouse gas emissions from the electric power sector within the Northeast.

Methods: We used calculated changes in ambient $PM_{2.5}$ concentrations for the period 2009–2014, with newly incorporated concentration–response (C-R) functions to quantify changes in the incidence of preterm birth (PTB), term low birth weight (TLBW), autism spectrum disorder (ASD), and asthma. These outcomes are causally or likely to be causally related to $PM_{2.5}$ exposure. Cost per case estimates were incorporated to monetize those changes in incidence.

Results: The estimated avoided cases of adverse child health outcomes included 537 asthma cases, 112 preterm births, 98 cases of ASD, and 56 cases of TLBW, with an associated avoided cost estimate ranging from $191 to $350 million. In a previous analysis of health benefits of RGGI, the only benefits accruing to children were limited to prevented cases of infant mortality and respiratory illnesses, with a monetized impact of $8.1 million—only 2–4% of the new results attributable to RGGI.

Conclusion: The results of this innovative analysis indicate that RGGI has provided substantial child health benefits beyond those initially considered. Moreover, those health benefits had significant estimated economic value. https://doi.org/10.1289/EHP6706

Introduction

Toxic air pollutants such as ambient fine particulate matter [PM ≤2.5 μm in aerodynamic diameter ($PM_{2.5}$)] and the major climate-altering gas, carbon dioxide (CO_2) emitted by fossil fuel combustion, are taking a significant toll on children's health and jeopardizing their future well-being. They are also major contributors to inequality worldwide (Perera 2017). Because of their biological vulnerability and rapid development, the developing fetus and young child are disproportionately affected by air pollution and climate change (Perera 2017). This is especially true in populations where poverty and environmental injustice compound the effects. A number of climate change mitigation policies and air pollution regulations have been implemented around the world to reduce fossil fuel combustion emissions, with sizeable health and economic benefits documented or projected. However, assessments of the public health benefits of such policies have considered few, if any, benefits to children; and their lifelong consequences have generally not been factored into the assessments of avoided costs. These include the U.S. Clean Air Act Amendments (U.S. EPA 2011), the Clean Power Plan (Driscoll et al. 2015), California's cap and trade program and low-cost fuel standards (O'Connor et al. 2014), the City of London Air Quality Strategy (City Of London Corporation 2019), and the Paris Climate Accord (Markandya et al. 2018). This omission has resulted in a serious undercounting of potential health benefits for this vulnerable population.

The Regional Greenhouse Gas Initiative (RGGI) is the United States' first regional market-based regulatory program designed to reduce greenhouse gas emissions from the electric power sector (RGGI Inc. 2019a). RGGI was established in the northeastern region in 2005 through a Memorandum of Understanding between the governors of Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont. In 2007, the program was expanded to include Maryland, Massachusetts, and Rhode Island, and in 2008 it held an initial auction for emissions allowances (Center for Climate and Energy Solutions 2019). Under RGGI program, participating states are expected to reduce their annual CO_2 emissions from the power sector by 45% below 2005 levels by 2020, and by an additional 30% by 2030 (Center for Climate and Energy Solutions 2019). RGGI included 10 states during its initial compliance period starting in 2009. The program is still currently operating with 9 of the original states, with New Jersey having withdrawn in 2012 but planning to rejoin in 2020 (Center for Climate and Energy Solutions 2019).

RGGI places limits on CO_2 emissions from new and existing fossil-fuel-fired electric generating units (EGUs) in the program area with a minimum capacity of 25 MW. Regulated EGUs must obtain allowances for each short ton of emitted CO_2. Allowances are auctioned quarterly and may be sold or traded between EGUs. Auction revenues have been reinvested to accelerate renewable energy use, improve energy efficiency, and support other public benefit programs (RGGI Inc. 2019a).

Although RGGI is focused on reducing greenhouse gas emissions, it also reduces emissions of other pollutants, such as $PM_{2.5}$, nitrogen oxides (NO_x), and sulfur dioxide (SO_2) (Manion et al. 2017). NO_x and SO_2 react in the atmosphere to form $PM_{2.5}$, which has a well-documented relationship with multiple adverse health outcomes, including respiratory and cardiovascular effects, premature mortality, and, more recently, adverse birth outcomes,

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respiratory illness, and neurodevelopmental problems in children (Perera et al. 2019).

Abt Associates previously analyzed health impacts of the first two compliance periods of RGGI (2009–2014) (Manion et al. 2017). The analysis estimated the reduction in NO_x and SO_2 emissions from RGGI-influenced EGUs based on modeling of the electricity sector and used the U.S. Environmental Protection Agency's (EPA's) Co-Benefits Risk Assessment (COBRA) to estimate changes in ambient levels of secondarily formed $PM_{2.5}$. The Environmental Benefits Mapping and Analysis Program (BenMAP) tool was used to estimate associated changes in health benefits due to changes in the ambient concentration of $PM_{2.5}$ in the nine then current RGGI states and in the adjacent states of New Jersey, Pennsylvania, Virginia, and West Virginia. BenMAP is a publicly available computer program supported by the U.S. EPA that can be used to estimate the number of air pollution-related illnesses and deaths and quantifies their economic value (U.S. EPA 2019). The program draws from a database that includes concentration–response (C-R) functions for a number of health outcomes attributable to different pollutants, population data, baseline health data, and cost of illness functions needed to quantify impacts (U.S. EPA 2019). The C-R functions included by default in the open-source program are focused largely on health outcomes for adults and do not currently include C-R functions or data for the children's health outcomes newly considered here.

Abt's 2017 assessment focused on avoided cases of premature adult deaths, heart attacks, acute bronchitis, asthma exacerbations, respiratory symptoms, hospitalizations, asthma emergency department visits, as well as productivity effects such as lost work days and days of minor restricted activity (Manion et al. 2017). These end points have traditionally been included in the U.S. EPA's regulatory analyses such as the *Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter* (U.S. EPA 2012). The 2017 assessment found that between 2009 and 2014, emissions reductions from RGGI resulted in avoided health outcomes having an estimated value of between $3 billion and $8.3 billion (2015$).

Since Abt's original analysis, the evidence base has strengthened the relationship between $PM_{2.5}$ and additional health end points, particularly end points that affect children. Specifically, Perera et al. (2019) conducted a systematic review of epidemiological studies quantifying the impacts of changes in ambient $PM_{2.5}$ concentrations on health end points identified as having a causal or likely causal relationship with $PM_{2.5}$: preterm birth (PTB), term low birth weight (TLBW), autism spectrum disorder (ASD), and incidence of asthma. Based on this review, the authors selected odds ratios that could be used to develop C-R functions for each outcome in estimating the benefits of reducing $PM_{2.5}$ exposure.

The present analysis provides a more comprehensive evaluation of children's health benefits under RGGI by including these additional health end points. This involved incorporating C-R functions for the new health end points and data on baseline incidence of these end points into BenMAP. These inputs were used with emissions reductions and air quality modeling results from the 2017 RGGI analysis to estimate the impacts of RGGI on PTB, TLBW, ASD, and asthma between 2009 and 2014 in RGGI states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont) and adjacent non-RGGI states (Pennsylvania, the District of Columbia, New Jersey, Virginia, and West Virginia). Per-case monetary estimates (unit values) were incorporated into the expanded BenMAP based on a systematic review of the published literature on the cost of illness (Shea et al. 2020).

In addition, in order to more fully present the impacts/benefits in children, this report highlights the change in incidence of infant mortality, acute bronchitis, and respiratory symptoms in children included in the results of the 2017 analysis. However, these were not explicitly reported as occurring in children.

Methods

This section describes in detail the methods and data sources used to quantify and monetize the change in incidences of PTB, TLBW, ASD, and childhood asthma. Both RGGI states and adjacent non-RGGI states were included in the analysis.

Figure 1 summarizes the general analytic approach used in Abt's 2017 RGGI analysis (Manion et al. 2017). Step 1 involved estimating the change in NO_x and SO_2 emissions at the county-level based on electricity dispatch modeling conducted by the Analysis Group, an economics consulting firm, which included the change in electricity generation by EGUs under two scenarios: with RGGI and without RGGI. Abt then estimated the change in emissions due to the change in generation based on facility-specific emissions rates from U.S. EPA data. In Step 2, Abt used COBRA, a screening-level tool, which includes a reduced-form air quality model to estimate how changes in NO_x and SO_2 emissions would impact ambient concentrations of $PM_{2.5}$ in RGGI and neighboring states. The estimated incremental changes in NO_x and SO_2 emissions calculated in Step 1 were used to model changes in concentrations during individual years (2009–2014). Outputs from this model included annual changes in levels of ambient $PM_{2.5}$ in each county in RGGI and neighboring states and were the inputs for modeling the associated health impacts. Finally, in Step 3, Abt used the expanded BenMAP to estimate how changes in ambient $PM_{2.5}$ concentrations resulted in changes in health impacts in children.

The present analysis made no changes to Steps 1 and 2 from the 2017 analysis—we obtained annual average $PM_{2.5}$ concentration data from Abt Associates for the years 2009–2014. Rather, the present analysis added additional health end points to BenMAP and estimated how the modeled changes in $PM_{2.5}$ concentrations under RGGI (2009–2014) affected those additional end points. The remainder of this section discusses the specific inputs and steps taken in this analysis.

C-R Functions

C-R functions are estimates of the relationship between changes in ambient pollutant concentrations and incidences of specific health end points. These functions are derived from epidemiological studies that compare the change in incidences of specific health outcomes to, in this case, changes in ambient $PM_{2.5}$ concentrations.

Perera et al. (2019) conducted a systematic review of epidemiological studies, meta-analyses, and review articles to determine the current state of the science on the associations of ambient air pollutants, including $PM_{2.5}$, and children's health outcomes. Through this comprehensive review the authors identified four key meta-analyses that estimated the relationship between changes in $PM_{2.5}$ concentrations and changes in the incidence of each health end point (Table 1).

We used the results of Perera et al. (2019) to incorporate C-R functions for each end point into BenMAP. The C-R functions include a beta coefficient, which quantifies the impact on each health outcome per 1-unit change in $PM_{2.5}$ concentrations. We developed the beta coefficients shown in Table 1, based on the natural log of the odds ratio reported by the meta-analysis, divided by the reported exposure change (in micrograms per cubic meter), as is consistent with U.S. EPA practice (U.S. EPA 2012). The beta coefficients were combined with county-level data on

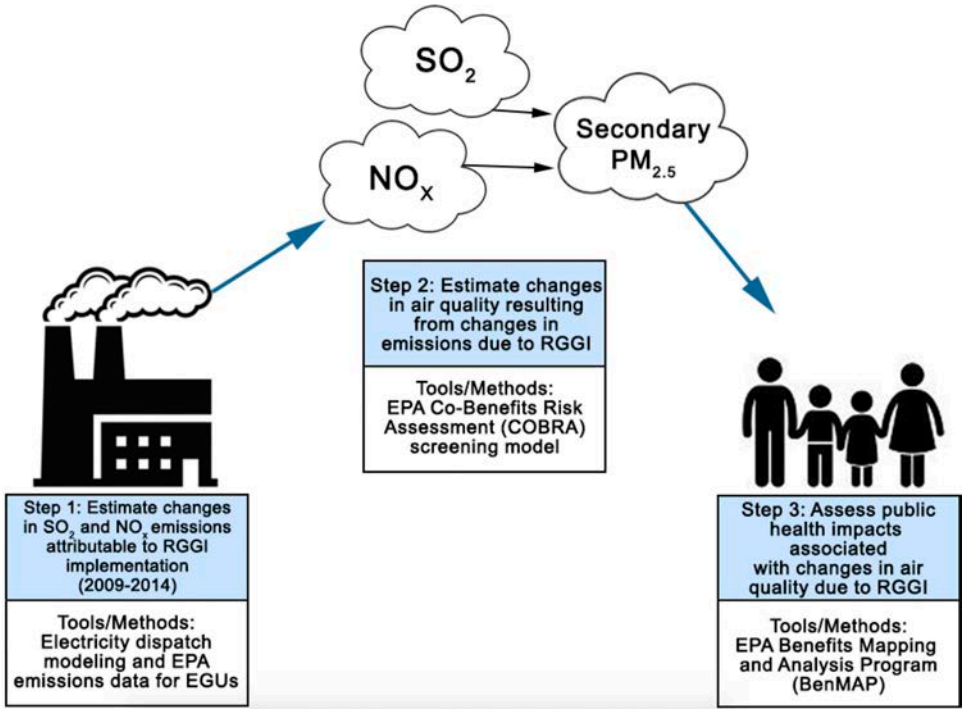

Figure 1. Overview of the analytic steps and tools. Source: Manion et al. 2017. Note: EGU, electric generating unit; EPA, Environmental Protection Agency; NO_x, nitrogen oxides; $PM_{2.5}$, particulate matter ≤2.5 μm in aerodynamic diameter; RGGI, U.S. Regional Greenhouse Gas Initiative; SO_2, sulfur dioxide.

population, baseline incidence, and the modeled change in county-level $PM_{2.5}$ concentrations to estimate the change in incidence of each health outcome in each county.

Population

The impact assessments require data on the affected age groups in the population. For this analysis, we used the county-level population by age group data loaded in BenMAP for each year of the analysis (2009–2014). These data were taken from the 2010 U.S. Census of Population and Housing models (developed by Woods and Poole 2011).

The C-R functions for PTB, low birth weight (LBW), and ASD reported in Perera et al. (2019) are based on maternal exposure during pregnancy. We applied the C-R functions to the population in Age Group 0 in BenMAP, which was used as a proxy for pregnant mothers. The C-R function for asthma incidence is based on the exposure of children under the age of 18 y. Accordingly, we applied this C-R function to populations in Age Groups 0–18.

Table 1. Meta-analyses for additional health end points associated with $PM_{2.5}$ identified by Perera et al. (2019).

Health end point	Study	Odds ratio	Exposure metric	Beta coefficient
PTB	Sun et al. 2015	1.13	Per 10-μg/m^3 increase	0.012
LBW	Sun et al. 2016	1.09	Per 10-μg/m^3 increase	0.009
ASD	Lam et al. 2016	2.32	Per 10-μg/m^3 increase	0.084
Asthma incidence	Khreis et al. 2017	1.03	Per 1-μg/m^3 increase	0.030

Note: Perera et al. (2019) conducted a systematic review to determine the current state of the science on the associations of ambient air pollutants, including $PM_{2.5}$, and children's health outcomes. The authors identified four key meta-analyses that estimated the relationship between $PM_{2.5}$ concentrations and the incidence of each health end point: PTB, LBW, ASD, and asthma. ASD, autism spectrum disorder; LBW, low birthweight; $PM_{2.5}$, particulate matter ≤2.5 μm in aerodynamic diameter; PTB, preterm birth.

Baseline Incidence

Baseline incidence rates for each end point were drawn from public data sources and the academic literature. County-level incidence rates of PTB and LBW were taken from the Centers for Disease Control and Prevention (CDC) WONDER database (CDC 2019), which contains extensive data on births, including gestational age and infant birth weight.

PTB is defined as a birth that occurs before the 37th week of pregnancy. The incidence of PTB was developed by dividing the number of births in each county occurring before the 37th week of pregnancy by the total number of births in each county. The county-level average incidence rate of PTB in RGGI and neighboring states was 13.4%. For comparison, the national average rate was 11.6%.

TLBW is defined in this analysis as a weight <2,500 g at birth when the infant was delivered on or after the 37th week of pregnancy (i.e., early to late term). This analysis does not include LBW in infants born before the 37th week of pregnancy to avoid double-counting the effects of PTB. The incidence of TLBW was calculated by dividing the number of full-term births in each county where the weight of the infant was <2,500 g by the total number of full-term births in each county. The county-level TLBW rate average was 3.2%. For comparison, the national TLBW rate average was 3.3%.

In the absence of county-level and complete state-level data, the asthma incidence rate for this analysis was taken from Winer et al. (2012), who estimated a national rate of 11.1 per 1,000 children ages 5–11 y from 2006–2008. This estimate was based on the Asthma Call-Back Survey, which was first implemented in 2006. Incident cases of asthma were defined as children diagnosed with asthma by a health care provider within 12 months prior to survey participation.

Because incidence rates were not directly available for ASD, we used prevalence as a proxy. In the absence of county-level and complete state-level data for prevalence, we selected the national prevalence rate of ASD for 2014 based on a CDC report (Zablotsky et al. 2015). We note that incidence is difficult to measure with rarer

chronic diseases such as autism. In addition, the disorder starts long before it is diagnosed, and the gap between initiation and diagnosis is influenced by many factors unrelated to risk (Hertz-Picciotto and Delwiche 2009). The rate used in this analysis was 14.7 per 1,000 children (Zablotsky et al. 2015).

Economic Valuation

The economic value of the change in incidences of each health end point was estimated using unit cost values from the literature (Shea et al. 2020). As described, those values were adjusted to 2015$ using a discount rate of 3% (Shea et al. 2020). Table 2 lists the values used in this analysis and the studies from which they were taken. The economic costs of each health end point were estimated by multiplying the change in incidences, as estimated by BenMAP, by the values in Table 2.

The values for asthma and ASD in Table 2 include high and low values. For asthma this is related to whether or not there is a persistence of the disorder into adulthood. For ASD this is related to whether there is an intellectual disability or not. For these end points, both the high and low values were used, and the results are reported as a range.

Results

This section describes the results of the analysis, including the estimated change in incidences of each health end point (the number of avoided cases) due to the emissions reductions associated with RGGI, as well as the economic valuation of those changes in incidences. Both the change in incidences and the economic valuation are summarized as the cumulative change between the year 2009 and the year 2014 (for both RGGI and neighboring states). The results are summarized separately for RGGI and neighboring states, and then totaled.

The results of this analysis are also compared with the results of the previous RGGI analysis (Manion et al. 2017), specifically the other health end points in children that were included in the previous analysis but not all explicitly labeled as occurring in children.

Change in Incidences

Table 3 shows the estimated change in incidence—the estimated number of avoided cases—of each health end point in RGGI and neighboring states between 2009 and 2014. Asthma had the largest change in incidence, at 537 cases avoided in the study area between the year 2009 and the year 2014. TLBW had the lowest change in incidence, at a total of 56 incidences avoided. This largely reflected that LBW had the smallest beta coefficient of the four end points (Table 1).

Table 3. Number of estimated avoided cases by health end point in RGGI and neighboring states (2009–2014).

Health end point	RGGI states	Neighboring states	Total
PTB	58	54	112
TLBW	29	27	56
ASD	50	48	98
Asthma	274	263	537

Note: RGGI states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Adjacent non-RGGI states include Pennsylvania, the District of Columbia, New Jersey, Virginia, and West Virginia. ASD, autism spectrum disorder; PTB, preterm birth; RGGI, U.S. Regional Greenhouse Gas Initiative; TLBW, term low birth weight.

Economic Valuation

Table 4 shows the results of the economic valuation of the change in incidences in RGGI and neighboring states between 2009 and 2014 for the newly incorporated health end points: ASD, asthma, TLBW, and PTB. As discussed above, both ASD and asthma have high and low estimates for the economic values of each end point. Results using both the high- and low-end estimates are shown here.

Although ASD was estimated to have the second-lowest number of avoided incidences compared with other health end points, it had by far the highest valuation per case, estimated at $1.8–3.1 million (Table 2). As a result, the economic valuation of the reduction in ASD incidences accounted for 84–89% of the total health benefits of the four health end points. Although asthma had a lower valuation per end point, it had the highest estimated change in incidence, leading it to have the second-highest value of the four health end points, at 6–13% of the total health benefits of those four end points. PTB and TLBW both had relatively lower per-unit economic values and lower estimated change in incidences. Therefore, the estimated economic valuation for those end points was comparatively smaller: 2–4% of the total benefits for PTB and <1% for TLBW.

Table 2. Per-case monetary estimates of each health end point (Shea et al. 2020).

Study basis	Health end point	Cost of illness definition	Unit value (2015$)
PTB			
Institute of Medicine Committee on Understanding Premature Birth and Assuring Healthy Outcomes 2007	Any PTB	Medical costs + special education costs + lost productivity costs, 3% discount rate (DR)	70,101
LBW			
Russell et al. 2007	LBW among those with slow growth/malnutrition	Initial hospital costs	15,560
ASD			
Buescher et al. 2014	ASDs with intellectual disability	Medical costs + non-medical expenditures + special education costs + lost productivity costs, 3% DR	3,109,096
	ASDs without intellectual disability	Medical costs + non-medical expenditures + special education costs + lost productivity costs, 3% DR	1,805,941
Asthma			
Nurmagambetov et al. 2018	Age 3 y onset, no persistence into adulthood	Medical costs + absentee costs, 3% DR	23,573
	Age 3 y onset, persistence into adulthood	Medical costs + absentee costs, 3% DR	91,954

Note: The values for asthma and ASD include high and low values. For asthma this is related to whether or not there is a persistence of the disorder into adulthood. For ASD this is related to whether there is an intellectual disability or not. For these end points, both the high and low per-case monetary estimate values were used, and the results are reported as a range. ASD, autism spectrum disorder; LBW, low birth weight; PTB, preterm birth.

Table 4. Estimated economic valuation (million 2015$) of change in incidence by health end point in RGGI and neighboring states (2009–2014).

	Low value			High value		
Health end point	RGGI states	Neighboring states	Total	RGGI states	Neighboring states	Total
ASD	87.3	83.7	171.0	150.2	144.1	294.4
Asthma	6.2	5.9	12.1	24.2	23.1	47.4
TLBW	0.4	0.4	0.8	0.4	0.4	0.8
PTB	3.9	3.6	7.5	3.9	3.6	7.5
Total	97.8	93.7	191.5	178.8	171.3	350.1

Note: The values for asthma and ASD include high and low values. For asthma this is related to whether or not there is a persistence of the disorder into adulthood. For ASD this is related to whether there is an intellectual disability or not. For these end points, both the high and low per-case monetary estimate values are used, and the results are reported as a range. ASD, autism spectrum disorder; PTB, preterm birth; RGGI, U.S. Regional Greenhouse Gas Initiative; TLBW, term low birth weight.

Comparison of Current Results to Estimates from the Previous (2017) Analysis

The 2017 Abt analysis of the health benefits of RGGI estimated total health benefits of between $3.0 billion and $8.3 billion between 2009 and 2014, using a 3% discount rate (Manion et al. 2017). This included an estimated 300–830 avoided premature adult mortalities, which accounted for the great majority of the monetized benefit.

The economic value of the health benefits of the four health end points in the present analysis were estimated at between $191 million and $350 million, or approximately 4–6% of the total benefits of the 2017 analysis, but considerably larger than the originally estimated impact from health outcomes excluding premature mortality.

Although the 2017 analysis did not specifically report benefits that accrue to adults and children separately, some of the health end points included in that analysis were focused on children. Specifically, the child-focused health end points included infant mortality, acute bronchitis, and respiratory symptoms. The numbers of estimated avoided incidences and economic valuation of those incidences are shown in Table 5. Note that the 2017 analysis included some health effects that applied to both children and adults, such as asthma emergency department visits and respiratory hospital admissions. Because it was not possible to separate out the impacts in children, those results are not discussed here.

As shown in Table 5, the economic value of the estimated health benefits to children from the 2017 analysis is dominated by avoided infant mortality. Although the estimated incidence was <1, the economic value per incidence is so high (approximately $11 million per incidence) that it vastly outweighs the economic value of the other health end points, which have per-incidence economic values of <$1,000 each.

The four health end points for children included in the 2017 analysis (Table 5) have a much lower total economic value than the four health end points in the present analysis (Table 4). The economic value of the benefits to children included in the 2017 analysis are approximately 2–4% the size of the value of the benefits to children newly included in the present analysis.

The total health benefits to children from RGGI between 2009 and 2014, including all eight health end points (both those in the 2017 analysis and the present analysis), were estimated at $199.6–358.2 million.

Table 5. Estimated health benefits for children due to RGGI (2009–2014) from the previous Abt Associates analysis [RGGI and neighboring states (Manion et al. 2017)].

Health end point	Avoided incidences	Economic value (million 2015$)
Acute bronchitis	510	0.30
Infant mortality[a]	<1	7.30
Lower respiratory symptoms	6,500	0.17
Upper respiratory symptoms	9,300	0.37
Total[b]	16,310	8.10

Note: BenMAP, Benefits Mapping and Analysis Program; RGGI, U.S. Regional Greenhouse Gas Initiative.
[a]The 2017 analysis estimated <1 avoided infant mortality due to RGGI. It is important to note that the C-R functions in BenMAP estimate actual health outcomes based on the change in risk of an outcome. Therefore, estimating <1 avoided infant mortality means that RGGI reduced the risk to infants by a relatively small, although not negligible, amount. Nevertheless, this reduced risk still has a very high economic value relative to the other health outcomes.
[b]Totals may not sum due to rounding.

Distributional Analysis of Benefits across Counties

The map in Figure 2 shows considerable variation across RGGI and neighboring counties in the distribution of economic benefits from the cumulative avoided child health outcomes: PTB, TLBW, ASD, asthma, infant mortality, acute bronchitis, lower respiratory symptoms, and upper respiratory symptoms.

Figure 3 maps the spatial distribution of reductions in average annual $PM_{2.5}$ concentrations between 2009 and 2014 at the county level attributable to RGGI during its first and second compliance periods. These results show substantial air quality benefits, particularly in counties downwind of Maryland's power plants regulated under RGGI. In addition, counties in New Jersey and Pennsylvania, both currently non-RGGI states, experienced significant air quality improvements attributable to emission reductions in neighboring RGGI states.

It is important to note that estimates of reductions in $PM_{2.5}$ concentration represented in Figure 3 account only for secondary $PM_{2.5}$ formed by chemical reactions of NO_x and SO_2. This analysis does not account for impacts of directly emitted $PM_{2.5}$. Nor does it account for the health effects from other pollutants such as ozone (O_3) or nitrogen dioxide (NO_2), thereby underestimating the health benefits under RGGI.

Discussion

Over the past decade, RGGI has driven significant emission reductions from the electric power sector. The program's initial goal was to reduce annual power sector CO_2 emissions by 45% below 2005 levels by 2020. Their 2030 goal was to reduce emissions by an additional 30% (Center for Climate and Energy Solutions 2019). According to a recent report by RGGI, by 2017, participating states had reduced CO_2 emissions from the power sector by more than 50% since 2005 while maintaining steady regional gross domestic product growth (RGGI Inc. 2019b), suggesting that RGGI states have exceeded their initial goal and are on track to meet their 2030 goal. Additional findings from a 2019 assessment (Acadia Center 2019) indicate that since 2008 (1 y prior to the program's launch), RGGI states' emissions from the electric power sector decreased from 133 million short tons of CO_2 to 70 million; these reductions exceeded those of the rest of the country by 90% (Acadia Center 2019). Although RGGI has not been the single driver behind the northeastern region's decarbonization in the electric power sector, a previous analysis (Murray and Maniloff 2015) has suggested that the program has

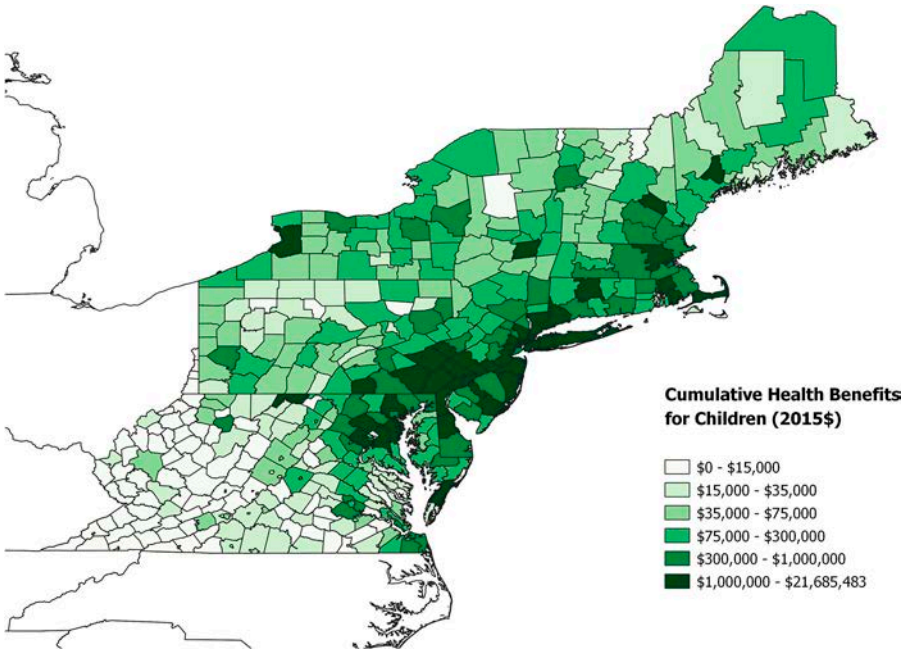

Figure 2. Economic benefits of avoided cases of child health outcomes attributable to RGGI by county, 2009 to 2014 (low value, 2015$). Note: RGGI, U.S. Regional Greenhouse Gas Initiative.

been a significant factor in the reduction of power plant emissions. Simulations from that analysis also suggested that emissions would have been approximately 24% higher in the region and 1.4% higher in the United States in 2012 without the program's implementation in 2009 (Murray and Maniloff 2015).

The results of our analysis of RGGI's co-benefits from the reduction in air pollution indicate that RGGI has provided substantial child health benefits beyond those considered in the 2017 analysis. Moreover, those health benefits have significant estimated economic value. The previous analysis found large total health benefits with a total economic value of $3.0–8.3 billion; nearly all of those benefits were due to avoided adult mortality (Manion et al. 2017). The benefits from health end points specific to children included in the 2017 analysis (infant mortality, acute bronchitis, and other respiratory symptoms) were estimated at $8.1 million, accounting for a very small fraction (0.09–0.27%) of the total estimated health benefits. The four additional health end points considered here—PTB, TLBW, ASD, and asthma—have a much larger combined economic value ($191–350 million) than those previously considered and amount to 4–6% of the total adult and child benefits from the 2017 analysis. This is likely to be an underestimate, as discussed below. Of the four additional health end points, asthma had the most significant change in incidence (number of avoided cases) between 2009 and 2014. This is expected, given that the C-R function used to estimate the incidence of asthma was applicable to all children ages 0–18 y, while the C-R functions for the other health end points were applied only to infants (age 0 y). As a result, there is a larger population of children for whom the analysis estimated impacts on the incidence of asthma.

Although a modest contribution to the total avoided costs, estimates from the present study are 20–40 times greater than the value of the avoided child outcomes in the 2017 analysis (Manion et al. 2017). The estimated total economic benefit from these avoided cases attributed to RGGI between 2009 and 2014, including the combined eight health end points considered in the 2017 analysis and the present analysis, was $199.6–358.2 million.

Not only is this a substantial economic benefit, but it is likely an underestimate of the true benefit because the adverse outcomes in children associated with $PM_{2.5}$ not only have immediate heath impacts but can also have serious consequences for their future health, well-being, and ability to contribute to society. These long-term health or lifelong consequences are not adequately considered in most of the outcome valuations used in this analysis.

In addition, it is important to note that the per-case estimates used in our calculations of avoided costs are likely underestimates for a few reasons, including the reliance on the cost of illness (COI) (Shea et al. 2020). For instance, as the U.S. EPA *Guidelines for Preparing Economic Analyses* notes, the COI method for developing per-case estimates typically does not attempt to quantify a loss in utility from pain and suffering (U.S. EPA 2010). Given that these costs are often omitted from COI estimates, the value of an individual's willingness to pay to avoid a lifetime of an illness like asthma may be significantly larger than the COI value. Furthermore, potential long-term costs to children or parents were not generally considered in the per-case monetary estimates used in this study (Shea et al. 2020). Examples are a child's cognitive disability associated with PTB and the impact on parents' employment behaviors, affecting their household income (Petrou et al. 2001).

A further factor in potentially significant underestimation of benefits is that both the 2017 and the present analyses include only emission reductions of NO_x and SO_2. Although secondary $PM_{2.5}$ accounts for the majority of $PM_{2.5}$ resulting from power plant emissions (NARSTO 2004), the analysis did not consider impacts from directly emitted $PM_{2.5}$. Nor were the health benefits of reductions in O_3 precursors, NO_2, and climate-altering greenhouse gases factored into this analysis. For these reasons, the results are conservative.

The health benefits from RGGI are not likely to be evenly distributed geographically, with some populations receiving higher health benefits than others. This analysis (like Manion et al. 2017) estimated the geographic distribution of health benefits by county but did not attempt to estimate disparities in health benefits by differences in socioeconomic status or ethnicity/race. This is because air quality results used in this analysis (and the previous 2017 analysis) are at the county level, and socioeconomic

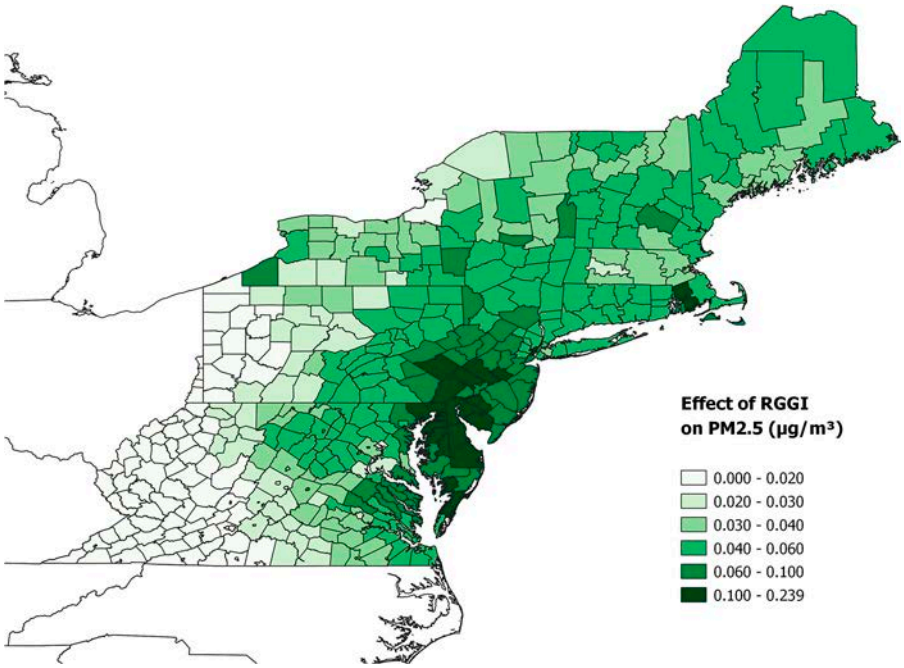

Figure 3. Reductions in average annual $PM_{2.5}$ concentrations by county attributable to RGGI (2009–2014) Source: Abt Associates 2017. Estimates of reductions in $PM_{2.5}$ concentration account only for secondary $PM_{2.5}$ formed by chemical reactions of NO_x and SO_2. This analysis does not account for impacts of directly emitted $PM_{2.5}$. Nor does it account for the health effects from other pollutants such as O_3 or NO_2, thereby underestimating health benefits under RGGI. Note: NO_x, nitrogen oxides; NO_2, nitrogen dioxide; O_3, ozone; $PM_{2.5}$, particulate matter ≤2.5 µm in aerodynamic diameter; RGGI, U.S. Regional Greenhouse Gas Initiative; SO_2, sulfur dioxide.

status and distribution of population by ethnicity/race can vary widely within counties (Sommeiller et al. 2016).

Exploratory assessment of the distributional impacts of the health benefits and associated economic benefits at the county level showed significant variation in benefits across counties, as demonstrated in Figure 2. The monetized benefits are a function of the change in air quality and the total population affected. As a result, more densely populated areas would be expected to have higher benefits because there is a larger at-risk population (more pregnant women and children) breathing cleaner air. This is likely occurring in densely populated counties across New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, and New Jersey. Reductions in average annual $PM_{2.5}$ concentrations between 2009 and 2014 under RGGI, as shown in Figure 3, suggest substantial air quality benefits.

A comparison of the two maps (Figures 2 and 3) gives a sense of the magnitude of the air quality changes experienced in each county relative to their corresponding health benefits. Similar to the economic benefits map (Figure 2), the map of reductions in $PM_{2.5}$ concentrations (Figure 3) shows considerable variation across counties. In most counties, the distribution of economic benefits corresponds with reductions in levels of $PM_{2.5}$; highlighting the direct benefit from emission reductions. On the other hand, as shown in Figure 3, some counties—for example, in Massachusetts, Connecticut, and Rhode Island—experienced disproportionately high estimated health and economic benefits in relation to their low level emission reductions; indicating that even slight reductions in $PM_{2.5}$ emissions resulted in considerable benefit.

Because of the scale of analysis, we were not able to meaningfully examine whether benefits were shared equitably across socioeconomic strata and different racial/ethnic populations. This is a major concern with respect to environmental justice given that it is the less affluent communities and communities of color that have borne the brunt of fossil fuel–related pollution and climate change impacts (Morello-Frosch et al. 2011). Although regional cap and trade policies like RGGI may be effective in reducing greenhouse gases and their co-pollutants on a regional scale, they may not maximize public health benefits or adequately address existing environmental justice issues. A more granular analysis (e.g., at the census tract or neighborhood level) is necessary to better understand finer-grained changes in air quality and the true distribution of health benefits by population density, socioeconomic status, and ethnicity/race. Such a comprehensive assessment could provide an opportunity to evaluate whether alternative programs could achieve the same greenhouse gas mitigation goals while also redressing environmental injustice.

As noted by Manion et al. (2017), the benefits associated with reducing emissions of the major greenhouse gas, CO_2, are outside of the scope of this study. Thus, the analysis does not cover the many health benefits of mitigating climate change, such as fewer heat-related illnesses or cases of vector-borne disease to which children are especially vulnerable. In addition, benefits to ecosystems and natural resources that support human livelihood are not captured in this analysis.

Because the epidemiologic evidence on the association between $PM_{2.5}$ and child intelligence quotient (IQ) is suggestive only (Chiu et al. 2016; Harris et al. 2015), we were not able to consider the potentially large benefit of RGGI in terms of improvement in child IQ. Decreased IQ in boys has been associated with gestational exposure to higher $PM_{2.5}$ levels (Chiu et al. 2016). Prenatal exposure to polycyclic aromatic hydrocarbons, a component of $PM_{2.5}$, has also been associated with lower child IQ (Perera et al. 2009). In addition, the association between PTB and IQ reduction, previously identified in the literature (for review, see Allotey et al. 2018; Bhutta et al. 2002; Kerr-Wilson et al. 2012), is not accounted for—thereby underestimating the impacts of PTB. A meta-analysis by Kerr-Wilson et al. (2012) estimated a decrement of 11.94 (95% confidence interval: 10.47, 13.42) IQ points among preterm children compared with children born at term. The loss of 1 IQ point has been estimated to result

in a $17,815 loss of lifetime earnings per child (Gould 2009). Therefore, preventing the contribution of $PM_{2.5}$ exposure to PTB could have substantial economic benefits.

We note that the evidence with respect to $PM_{2.5}$ and ASD support a likely causal association. A highly cited systematic review and meta-analysis by Lam et al. (2016) has identified a number of studies on air pollution exposure during developmental periods that have found associations with ASD. The analysis by Lam et al. (2016) included 23 human studies published between 2006 and 2015, 9 of which assessed particulate matter (including PM_{10} and $PM_{2.5}$). The review found evidence for associations between prenatal exposure to $PM_{2.5}$ and ASD (Lam et al. 2016). Additional studies have been published since this review that have found positive associations between prenatal and/or early life $PM_{2.5}$ exposure and ASD (Kaufman et al. 2019; Jo et al. 2019; McGuinn et al. 2020).

Despite its limitations, the present analysis provides evidence of the importance of comprehensive assessments of child health benefits in analyses of the benefits of climate mitigation and air pollution emissions reduction policies. With respect to the distributional impacts, additional research is needed to refine and extend the overall benefits estimates provided here. Nevertheless, this analysis has estimated substantial benefits of RGGI for children's health.

Conclusion

Findings from the present assessment indicate that RGGI has provided considerable child health benefits to participating and neighboring states beyond those conventionally considered. Moreover, those health benefits are estimated to have significant economic value. Our assessment of the projected health co-benefits to children under RGGI can provide valuable support for the design and implementation of future programs to mitigate climate change targeting other sectors, including the transportation sector. Findings from this assessment also should encourage other states to join the program or initiate similar strategies of their own. In addition, our newly incorporated C-R functions and economic values for children's health end points into BenMAP are important additions to the existing program, which can be used widely. In this sense, the present study is generalizable and the methods can be used to quantify children's health and economic benefits under other climate change mitigation, air pollution control, and environmental programs.

Acknowledgments

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Attachment 27

RGGI Inc.

Auction 57
State Proceeds and Allowances

State	Auction 57 Allowances Sold	Cumulative Allowances Sold (Auctions 1-57)	Auction 57 Proceeds	Cumulative Proceeds (Auctions 1-57)
Connecticut	940,372	77,661,975	$12,648,003.40	$324,500,587.44
Delaware	685,377	44,946,643	$9,218,320.65	$206,125,780.11
Maine	485,316	38,606,364	$6,527,500.20	$163,333,875.24
Maryland	2,821,238	238,275,781	$37,945,651.10	$969,904,153.28
Massachusetts	2,342,218	194,723,623	$31,502,832.10	$807,691,967.91
New Hampshire	783,517	54,587,572	$10,538,303.65	$242,214,144.90
New Jersey	2,869,949	84,041,643	$38,600,814.05	$442,402,874.02
New York	5,494,081	445,998,184	$73,895,389.45	$1,844,916,098.88
Rhode Island	375,821	24,760,685	$5,054,792.45	$116,056,234.93
Vermont	108,423	8,950,733	$1,458,289.35	$37,101,642.09
Virginia	5,497,711	40,212,808	$73,944,212.95	$452,218,091.37
Sub-Total	**22,404,023**	**1,252,766,011**	**$301,334,109.35**	**$5,606,465,450.17**

Attachment 28

HOUSING INNOVATIONS IN ENERGY EFFICIENCY (HIEE)

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The Department of Housing and Community Development's (DHCD) Housing Innovations in Energy Efficiency (HIEE) funding makes energy efficiency upgrades to new and existing residential buildings to reduce energy bills for low-income Virginians. HIEE is funded through Regional Greenhouse Gas Initiative (RGGI) proceeds.

BACKGROUND

In 2020, the Commonwealth of Virginia became the first southern state to join RGGI, a regional cap and trade program designed to reduce climate pollution from fossil fuel power plants. Legislation passed by the Virginia General Assembly authorizes proceeds from these auctions to be used for community flood preparedness, coastal resilience and energy efficiency programs for affordable housing. DHCD will administer approximately 50% of the auction proceeds through HIEE, with technical assistance from the Virginia Department of Energy.

CURRENT STATUS

DHCD administers HIEE funds to enhance affordable housing programs benefiting low- to moderate-income (LMI) families in Virginia. For fiscal year 2021, HIEE funds are allocated to DHCD’s Affordable and Special Needs Housing (ASNH) program and the Weatherization Deferral Repair (WDR) Program . DHCD will continue to develop the HIEE program and other initiatives that will further benefit LMI families in fiscal year 2022 and beyond. ASNH and WDR information and program guidelines are posted under Resources.

STAKEHOLDER ADVISORY GROUP AND PUBLIC PARTICIPATION

If you would like to provide public comments at an upcoming meeting, please email **aaron.shoemaker@dhcd.vi** sign up. Each commenter will be given two minutes. To submit written public

HIEE-FUNDED PROGRAM RESOURCES

Weatherization Deferral Repair Page

Weatherization Deferral Repair Program Guidelines

Weatherization Deferral Repair Program Updates

HELPFUL LINKS

Regional Greenhouse Gas Initiative (RGGI) Auctions

Attachment 29

WEATHERIZATION DEFERRAL REPAIR (WDR)

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For project administration questions

The Weatherization Deferral Repair (WDR) program funds repairs that have caused homes (or units in multifamily buildings) to be deferred from the Weatherization Assistance Program (WAP). Once the needed repairs are made using the WDR funds and the home is "weatherization-ready," clients can then receive energy efficiency and health and safety measures available through WAP (such as insulation, air sealing, energy efficient light bulbs, and carbon monoxide detectors). Clients are required to sign an agreement with the weatherization agency, agreeing to both the WDR repairs and the weatherization services. Households may not receive the initial repairs without agreeing to also receive the weatherization services.

PERSONS SEEKING ASSISTANCE:

Contact the local weatherization agency serving your area.

For the Weatherization Deferral Repair (WDR) program, clients must work with the local weatherization agency serving their area through the Weatherization Assistance Program (WAP). In order to qualify for WDR, clients must meet WAP eligibility requirements.

FIND YOUR LOCAL WAP PROVIDER

FOR THOSE SEEKING RESOURCES

Weatherization Provider List by Organization

Weather Provider List by Locality

Weatherization Provider Map (find your locality and

WDR FORMS FOR SERVICE PROVIDERS

WDR Program Guidelines

WDR Program Updates

WDR Remittance Cover Sheet

WDR Application Form and Homeowner Agreement

OTHER HELPFUL RESOURCES

CAMS Overview Webinar Slides

CAMS Overview Webinar Recording

Attachment 30

WEATHERIZATION ASSISTANCE PROGRAM

Bipartisan Infrastructure Law Funds for WAP

Visual Guides for Home Energy Efficiency Upgrades

E&I and SERC Project Selections Announced

Bipartisan Infrastructure Law Funds for the Weatherization Assistance Program

View the Weatherization Program Notice to learn more.

Read the press release.

The U.S. Department of Energy (DOE) Weatherization Assistance Program (WAP) reduces energy costs for low-income households by increasing the energy efficiency of their homes, while ensuring their health and safety. The program supports **8,500 jobs** and provides weatherization services to approximately **35,000 homes every year** using DOE funds.

Through weatherization improvements and upgrades, these households save on average **$372 or more every year** according to a national evaluation of the program. Since the program began in 1976, WAP has helped improve the lives of more than 7 million families through weatherization services.

Contact Your Local Weatherization Organization for Weatherization Assistance

If you're interested in learning more about applying for weatherization services, contact your state WAP program and they can assist in identifying the local organization that serves your area.

VIEW MORE

Program Resources

Program Notices & Memorandums

Find active and archived Weatherization Program Notices and Memorandums.

Learn more

WAP Fact Sheet

Download and share the WAP fact sheet with your community leaders and decision makers.

Learn more

WAP Administrative Professional Training

Self-paced training geared toward WAP directors, fiscal, and administrative staff interested in implementing WAP at the local level.

Learn more

Energy Audit Tools

Learn more about the audit tools approved for use in the WAP.

Learn more

Guidelines for Home Energy Professionals

Explore the Guidelines for Home Energy Professionals, which support the development of a skilled residential energy upgrade

workforce.

Learn more

WAP Monitoring

Learn more on how WAP monitors the work to ensure high-quality work and energy savings for each client.

Learn more

Additional Links

- **WIP Project Map**
- **State Energy Program**
- **State and Local Solution Center**

Sign Up for Program Notices and Memorandums

Receive notification of the latest Weatherization Program Notices and Memorandums.

Enter Email Address

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ENERGY.GOV RESOURCES

FEDERAL GOVERNMENT

Attachment 31

Virginia Weatherization Deferral Repair Program Guidelines 2021 - 2022

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I. INTRODUCTION

The Department of Housing and Community Development (DHCD) administers the Weatherization Assistance Program (WAP) for low-income persons in Virginia, in partnership with a network of local weatherization agencies ("agencies"). DHCD is making additional funding available to the agencies through the Housing Innovations of Energy Efficiency (HIEE) program to assist households in Virginia who have been deferred from receiving WAP services to their homes due to needed repairs to ensure the effective installation of the WAP measures. HIEE funds are derived from the auction proceeds that DHCD receives from Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI).

DHCD refers to the HIEE funds used for this purpose as **Weatherization Deferral Repair (WDR) funds**. WDR funds are provided to weatherization agencies by DHCD via separate agreements from WAP, however these repairs are intended specifically to enable making the home "weatherization ready," and for the income-eligible household to receive weatherization services. *WDR funds are to be utilized only for repairs identified by the agency as causing the deferral of the home or unit from WAP*.

- For more information on HIEE, access the DHCD HIEE webpage.
- For more information on WAP and household eligibility requirements, access the WAP webpage.

II. WDR OVERVIEW

WDR funds are allocated to weatherization agencies specifically for repairs of the most common and frequently-cited issues causing WAP deferrals in Virginia: leaking roofs, minor structural, biological contaminants (e.g. mold), non-operational or unsafe HVAC unit, moisture issues, electrical, and plumbing. Other measures needed to bring the home out of deferral status and enable the home to be weatherized may be considered on a case-by-case basis. DHCD will cap WDR repair costs at reasonable and regionally-specific limits, as shown in Table 1. If estimated repair costs exceed the caps, the agency must contact DHCD so that the request may be evaluated. DHCD has appropriated $13.0 million in HIEE funds to be made available to weatherization agencies for WDRs starting July 1, 2021. Additional allocations of HIEE funds will be determined based on need and funding availability. Allocations are subject to final approvals by the Office of the Governor and Secretary of Commerce and Trade.

WDR funds are to be used solely to make repairs on income-eligible occupied homes and address the specific issue(s) that caused, or are causing, the home to be deferred so that the homeowner/tenant may regain eligibility for WAP and are NOT intended for full housing rehabilitation. Gut rehabilitations, projects requiring full plumbing, electrical and HVAC replacements, and major structural repairs (such as foundation repairs or collapsed roofs) are beyond the scope of WDR and WAP. Derelict, abandoned, and/or condemned homes are not eligible. If, in consultation with DHCD, agencies determine repairs needed to address the issue(s) causing the deferral and make the home weatherization-ready are beyond the scope of the WDR program, DHCD may work with agencies to refer these homes to local or other state

housing rehabilitation programs. For more detailed information see the section on eligible repairs.

III. FUNDING ALLOCATION

A. AGENCY AGREEMENTS AND REPAIR COSTS

The WDR Program requires agencies to adhere to a WDR Program Agreement, separate from the WAP agreement, beginning July 1. Allocation of WDR funds through these agreements is based on the agency's identification of eligible existing deferrals in its service area and estimated cost of the associated repair(s).

DHCD intends to ensure that agencies have a sufficient allocation of funds to initiate the necessary work to address their current deferral lists. WDR funds will also be allocated to ensure that the weatherization network overall is able to address the maximum number of deferrals that currently exist.

B. ADMINISTRATIVE COSTS

For agencies requesting less than $1.0 million in HIEE funds, DHCD will include an additional twenty (20) percent of the identified WDR allocation amount for agencies' administrative overhead and equipment costs with each agreement; those agencies requesting over $1.0 million will receive an additional ten (10) percent for administrative costs. Administrative costs may include accounting for the use of WDR funds, preparing reports for submission to DHCD, project management (e.g. obtaining evaluations/estimates on needed repairs, inspections of completed work), similar costs related to administering the funding, vehicle purchases or leases, and associated staff salaries. **As with all billed expenditures, billing for administrative costs must be based on actual costs incurred during a particular billing period.**

C. DEFERRAL TRACKING

Participation in the WDR program will require that all WDR recipient agencies participate in deferral tracking procedures established by DHCD. DHCD will work with the agencies to establish a consistent tracking procedure for deferrals that protects client confidential information. DHCD will distribute specific guidance on identifying and tracking deferral-related issues and repairs. As WDR projects are completed, the agency must accurately track the addresses of the projects to ensure that they are now eligible for WAP services. Agencies may establish their own systems and processes for re-engaging with clients and prioritizing WDR projects, but participation in the deferral tracking system will be mandatory. Agencies must adhere to DOE regulations for addressing completed WDR projects through WAP: the client should be integrated into the established weatherization queue based on the original intake date and should not go to the bottom of the priority list.

D. SERVICE PROVIDER/CONTRACTOR ELIGIBILITY

For WDR projects that agencies do not perform with their own staff, agencies must utilize subcontractors appropriately licensed and insured to perform the work needed to repair the issue(s) causing the deferral. Staff or subcontractors performing the WDR repairs are not

required to have WAP-specific training. However, subcontractors must be appropriately trained and credentialed in accordance with all relevant regulations, guidelines, and agreements.

E. SERVICE AREA

WDR funds may only be used to assist households in the municipalities of the Commonwealth of Virginia. WDR service areas are established for each funded agency based on the WAP service area. With explicit permission from DHCD, agencies may serve households in municipalities outside of the established service area. Allowances to serve outside the service area are based on the need, capacity, and available funding.

F. REALLOCATION OF UNSPENT FUNDS AND PERFORMANCE POOL

DHCD will actively review the expenditures of WDR funds by agencies regularly to ensure that the agency is progressing satisfactorily towards addressing needed repairs of deferred homes in its service area. Agencies are not required to spend 100% of funds allocated per the WDR Program Agreement in the contract year, but must demonstrate reasonable and substantial progress toward addressing the projected number of deferrals. Unspent funds may be rolled over into the subsequent program year agreement with approval from DHCD. However DHCD reserves the right to adjust WDR funding allocations or recapture/reallocate funding.

If at any point the agency has been identified by DHCD to have production issues that may compromise the success of the WDR Program, DHCD will confer with the agency to understand barriers and identify a production improvement plan and process. The agency must agree in writing to implement steps identified for production improvement. If issues relating to lack of production are unable to be resolved, DHCD reserves the right to de-obligate and reallocate part or all remaining funds subject to this agreement.

In addition, DHCD may set aside HIEE funds in a performance pool, which may be quickly allocated by addendum to existing agreements to agencies that are able spend all allocated HIEE funds for WDRs before the end of the agreement period and need additional funding to maintain their WDR repair pipeline.

G. MATCHING FUNDS AND COST CAPS

Matching funds are not required for WDR, and the agency cannot require a client contribution. If a repair estimate exceeds the regional cost caps (see Table 1), the agency may request an exception to exceed the limit. However, the agency must receive DHCD approval before proceeding.

H. VEHICLE PURCHASES AND LEASES

Prior written approval from DHCD is required for agency purchase of any vehicle with WDR funds. The cost of vehicles or equipment to support the program must be charged to the administrative budget category. Agencies must use approved bidding and purchasing procedures to acquire vehicles, or through a fleet contract. Vehicles will be titled in the name of the agency and a first lien in the name of DHCD must be placed on the title. Agencies must submit the title to DHCD upon receipt. Insurance coverage is required for vehicles purchased with DHCD funds.

Agencies must request permission from DHCD to sell or dispose of vehicles with a value greater than $5,000.00 purchased with WDR funds. DHCD must approve all vehicle leases prior to lease execution

IV. PROGRAM GUIDELINES

A. CLIENT ELIGIBILITY AND INCOME VERIFICATION

All clients (homeowners and tenants) must be determined as WAP-eligible (meet income guidelines) consistent with the procedures in the WAP Operations Manual. Agencies must receive property owner approval in writing for rental properties. Homeowners or renters must sign a service agreement with the local weatherization agency committing to the needed deferral repairs and the subsequent weatherization work. DHCD notes that all WAP clients participate on a voluntary basis. If it is determined up front that a client intends to forgo WAP services and/or will not sign the service agreement, they are ineligible for use of the WDR funds.

If it has been more than a year since the initial client intake, income eligibility must be re-verified. Agencies must prioritize serving income eligible clients first, along with immediate health and safety issues (such as unsafe combustion appliances or no heat/no A/C). Consistent with WAP guidelines, agencies have no obligation to serve potential clients who are unresponsive or hostile, or to offer services where dangerous or illegal activity is taking place.

If a client's income exceeds WAP eligibility requirements, weatherization agencies may refer the client to utility weatherization programs, which typically serve clients up to 80 percent of area median income (AMI). WDR funds may be used for deferral repairs for households with up to 80 percent of AMI, subject to availability of funds and the customer's agreement to participate in a utility-sponsored (investor-owned utilities and electric cooperatives/municipal utilities) weatherization program where those income limits are applicable.

B. ELIGIBLE REPAIRS

WDR funds are to be used solely for addressing needed repair(s) causing the home or unit to be deferred from WAP. The following repairs are most commonly-identified as causing weatherization providers to defer weatherizing the home and are eligible for WDR funding. The list is non-exhaustive and is subject to change. DHCD reserves the right to determine the eligibility of repairs or any costs not listed. All repairs must be code compliant and permitted if required by the Authority Having Jurisdiction (AHJ). Repairs not listed must be pre-approved by DHCD.

Roofs and minor structural

- Roof repair or replacement (e.g. roof leaks and attic cannot be insulated)
- Wall repair- interior or exterior (e.g., walls cannot support insulation without repair)
- Ceiling repair - interior (e.g., ceiling cannot support insulation without repair)
- Floor repair

Electrical, plumbing and HVAC

- Plumbing repair (e.g. water leaks that would damage insulation)
- Electrical repair (safety hazard or exposed wiring; cannot insulate due to presence of knob and tube wiring)
- Non-working or unsafe HVAC unit repair or replacement
- Non-working or unsafe gas/propane hot water heater repair or replacement
- Non-working or unsafe gas/propane range/oven repair or replacement

Hazardous materials

- Mold identification and remediation
- Suspected Asbestos Containing Materials ("SACM" e.g. attic, walls, pipes etc.)

The following are other issues that may cause WAP deferrals and may be remedied with repairs (requires DHCD pre-approval):

- Removal of vegetation (e.g. tree, bush, shrub trimming) needed to provide safe access to make eligible repairs
- Pest infestation
- Clutter restricting access to necessary areas

C. INELIGIBLE REPAIRS

The following repairs are not eligible uses of WDR funds. DHCD reserves the right to determine the eligibility of repairs or any costs not listed. The list is non-exhaustive and subject to change:

- Gut rehabilitation or major structural repairs (e.g. foundation, collapsed floor/roof)
- Replacement of entire plumbing, electrical, or HVAC systems
- Replacement of windows or doors where existing ones are not broken, missing, or damaged beyond repair
- Repairs covered by homeowner's or flood insurance
- Repairs needed due to willful damage or negligence on the part of the owner/occupant
- Cosmetic improvements (e.g. interior or exterior painting)
- Repairs to detached garages, barns, sheds, or storage buildings

TABLE 1 - REPAIR COST CAPS (BY REGION)

Eligible Measures/Repair Needed*	Northern VA	Central and Hampton Roads	Eastern Shore, Southside, and SWVA
Roof repair/replacement** (per project)	$10,300	$9,700	$9,500
Structural (per project)	$6,660	$6,200	$6,100
Hazardous material removal (e.g. mold, asbestos) (per project)	$14,000	$13,200	$12,800
Electrical (per project)	$5,600	$5,300	$5,200
HVAC unit replacement (per system)	$14,000	$13,200	$12,800
Plumbing (per project)	$2,700	$2,600	$2,500

*Cost limits are developed by triangulating three data sources including: The National Residential Efficiency Measures Database, RS Means 2020 Assembly estimates (normalized by city, state), and data collected from projects by the Virginia Center for Housing Research (VCHR) at Virginia Tech.
**Multifamily roof repair/replacement: NOVA: $3.40/FT^2; Central, and Hampton Roads: $3.20/FT^2; Eastern Shore, Southside, and SWVA: $3.10/FT^2. Roof repair/replacement is based on typical asphalt shingles; flat roofs requiring a membrane system will be more expensive so agencies should contact DHCD for exemption to cost cap.

V. FINANCIAL AND REPORTING REQUIREMENTS

A. CLIENT REPORTING/REQUIRED DOCUMENTATION

For each household served by WDR funds, the agency must retain the following:

- Documentation of incurred costs (timesheets, contractor invoices, materials and equipment cut sheets, etc.) to support all invoices, consistent with procedures for WAP jobs.
- A quarterly report including number of homes repaired, amount of WDR funds invoiced, and the nature of repairs accomplished.

B. PROJECT MANAGEMENT – CAMS

Agencies must manage documentation of WDR projects (applications, invoices, and reports) through the DHCD Centralized Application & Management System (CAMS). All grantees must be registered in CAMS and have approved audits in order to manage their project and receive payment. CAMS login and profile registration page may be accessed via the following link: CAMS login portal.

Agencies are responsible for managing their own staff access and user roles assignments.

The CAMS User Guide contains project management instructions including but not limited to:

- managing staff access and user role assignment
- submitting the agency audit
- requesting budget revisions
- submitting remittances (a.k.a. invoices, drawdowns)
- fulfilling reporting requirements

C. PAYMENT REQUESTS - SUBMITTING REMITTANCES IN CAMS

Payment is established based on the agreed-to repair estimate for each project. Agencies are encouraged to request payment in CAMS upon full project completion to the extent feasible, especially for smaller jobs (less than $5,000). However, agencies have the option to request payment on a draw-down basis, based on completing pre-established milestones as follows: homeowner and subcontractor agreement signed 10%, materials and equipment delivery, 60%, installation and project completion, 30%.

Prior to beginning each job, the weatherization agency or local service provider must submit the WDR Application Form and Homeowner Agreement signed by agency representative, homeowner, or landlord and tenant and WDR Authorization and Release in CAMS for reservation of funds to DHCD for approval and funding. The application will include site address, homeowner/tenant name, and a description of the repairs needed. The issues to be repaired/replaced must be photographed and submitted accompanying the WDR Application Form and Homeowner Agreement.

Once DHCD has approved the WDR Application Form and Homeowner Agreement, WDR Authorization and Release WDR Application Form and accompanying documentation in CAMS, agencies may either fund each repair upfront and request reimbursed by DHCD once the WDR Certification of Completion, financial supporting documents (i.e. contractor invoices, receipts) and photos of completed repair(s) have been submitted in CAMS as the remittance supporting documentation. Agencies may pay for the repairs and seek reimbursement or request funds to pay the contractor invoices upon completion on a drawdown basis as noted above. DHCD will not reimburse for work outside of the approved scope of work, or if work is determined to be substandard.

To initiate the payment process, the agency must submit remittances in CAMS. For each remittance, the agency must submit the required documentation which consists of:

- DHCD-provided signed cover sheet(template available on
- Invoice documentation (e.g. paid contractor invoices)
- Certification of Completion form
- General Contractor Affidavit, Warranty, and Lien Waiver
- Photos clearly showing completed work

All forms are available in CAMS or on the HIEE webpage.

The average time from submission to DHCD approval is 30 days for remittances that are accurate, complete, and include all required documentation at time of submission. If there are discrepancies or issues with the remittance documentation, and changes or resubmittals are required, the process may extend beyond 30 days. DHCD will reach out to the submitting agency regarding incomplete remittances.

D. METHOD OF PAYMENT

DHCD requires that agencies receive funds via electronic transfer. Instructions on establishing an account with the Virginia Department of Accounts (DOA) is located on their website through the selection of Electronic Data Interchange (EDI) from the link on the DOA main webpage. The EDI guide can then be accessed through a link under the Trading Partner Information section. Any grantee with unresolved findings or compliance issues, including for other programs, may have payments suspended.

E. ACCOUNTING AND FINANCIAL CONTROLS

Agencies must have established standard accounting practices including internal fiscal controls, standard accounting procedures, and track agency and program budgets by revenue sources and expenses.

VI. ADDITIONAL AGENCY REQUIREMENTS

A. COMPLIANCE WITH FAIR HOUSING AND CIVIL RIGHTS LAWS

(1) WAP agencies must comply with all applicable state and federal fair housing and civil rights requirements (see 24 CFR 5.105(a)). This includes the Virginia Values Act (effective July 1, 2020) which expands the list of protected classes under the Virginia Fair Housing Act. As the Virginia Fair Housing Act prohibits discrimination based on race, color, national origin, sex, pregnancy, childbirth or other related conditions (including lactation), age (over 40), marital status, disability, sexual orientation, gender identity, or veteran status (collectively the "Protected Classes"). (2) If the WAP agency: (a) Has been charged with an ongoing systemic violation of the Fair Housing Act; or (b) Is a defendant in a Fair Housing Act lawsuit filed by the Department of Justice alleging an ongoing pattern or practice of discrimination; or (c) Has received a letter of findings identifying ongoing systemic noncompliance under Title VI of the Civil Rights Act of 1964, section 504 of the Rehabilitation Act of 1973, or section 109 of the Housing and Community Development Act of 1974, and the charge, lawsuit, or letter of findings referenced in subparagraphs (a), (b), or (c) above has not been resolved before the application deadline, then the subgrantee is ineligible to apply for funds.

CONTACT INFORMATION

Weatherization Deferral Repair Program Contacts:
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Weatherization Assistance Program Contact:
Nancy Palmer
Housing Program Manager
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CAMS Issues and Troubleshooting
CAMShelp@dhcd.virginia.gov

Attachment 32

Weatherization Client Roof in Disrepair Resulting in Client Being Deferred for Weatherization Services

Utilizing Virginia RGGI Revenue to Support Existing Low-Income Energy Efficiency Programs

Chase Counts, CEM
Reducing energy burdens with weatherization at CHP Energy Solutions
Published Dec 11, 2020

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Energy efficiency and weatherization programs serving low-income, elderly, individuals with disabilities, and other energy burdened populations in Virginia have evolved dramatically since 2015. Federal resources through U.S. Department of Energy's Weatherization Assistance Program (WAP) and U.S. Department of Health & Human

have served as the foundational resource for weatherization services provider operations. In 2015, providers saw an increase in utility-sponsored energy efficiency programs which are designed to serve the same client base. In 2021, utility-sponsored programs will have increased by 19-times from their 2015 funding levels, exceeding the federal resources available for weatherization for the first time in Virginia's history.

Figure 1. Historic Funding Levels for Low-Income Energy Efficiency Programs in Virignia by Source, 2015-2021

While encouraging progress has been made to serve thousands more energy burdened households in Virginia, weatherization providers face challenges in service delivery to nearly 1 in 5 households that apply for their programs according to a 2020 survey by the Association of Energy Conservation Professionals (AECP) - the local trade association of weatherization providers in Virginia.

All 17 subgrantees in Virginia DHCD's weatherization program responded to the survey for the federal weatherization program year 2018 - the most recent program year uninterrupted by the COVID-19 pandemic. The survey revealed providers had to defer weatherization services to 525 households of the 2,901 applications received that year. Deferral issues vary in scope and scale, but the core is consistent: weatherization providers do not have the resources needed to address health and safety and other incidental repairs required prior to the installation of weatherization and energy saving measures.

Figure 2. AECP Weatherization Deferral Rate Survey Results for Program Year 2018-2019

moisture and other biological hazards, electrical issues, and more. These repairs are needed before weatherization providers can provide energy saving measures to these energy burdened households. Attic insulation, for example, cannot be installed if a leak in the roof may result in the insulation being compromised before the end of its expected useful life.

Access to home repair funds that could prevent these deferrals is sparse and inconsistent throughout the Commonwealth. Federal funds and utility-sponsored programs have limited health and safety and incidental repair funds available, averaging approximately 11-percent of the total funds available statewide, which have been further strained by additional personal protective equipment (PPE) needs resulting from the current pandemic. Those funds also come with many restrictions and are often insufficient to resurrect a weatherization applicant from deferral. Other funding sources include a handful of municipalities or private donations. Community Housing Partners (CHP), Virginia's largest non-profit weatherization provider, sets aside nearly $200,000 of internal funds each year to address health and safety issues and/or incidental repairs needed to unlock weatherization candidates' households to then deliver energy saving weatherization services. Even with the application of those extra funds, CHP still had to defer 197 jobs during the reporting period.

Figure 3. Weatherization Deferral Due to Roof Issues Resulting in Ceiling Damage

Based on the feedback in the survey responses, Virginia's weatherization providers estimate an average range of $5,000-$8,000 is often needed to bring a weatherization candidate back from deferral status. With the increase in funding available in 2021 and beyond, Virginia's weatherization provider network expects to complete an estimated 8,500 comprehensive weatherization retrofits per year for the foreseeable future. At current weatherization deferral rates, the weatherization providers can expect to defer

providers are not able to recover. At an average of $7,500 per household in health and safety and/or incidental repair funds serving 1,500 households per year, the weatherization network would like to leverage $11,500,000 of RGGI revenues each year in support of Virginia's most effective and shovel-ready energy efficiency program serving low-income, elderly, and individuals with disabilities to reduce their household energy burdens.

Considering new utility-sponsored programs beginning in 2021 will allow weatherization providers to braid federal resources to serve more multifamily properties, particularly in urban areas where gas heating and water heating are more prevalent and prone to health and safety issues, deferrals due to combustion safety hazards are expected to rise that were not captured on the AECP survey. Rough estimates anticipate an additional 20-percent of the projected $11,500,000 of RGGI revenues could be leveraged to address health and safety issues arising from gas appliances in disrepair at multifamily properties driving the leveraged funding request closer to $14,000,000 per year.

Figure 4. Commonly Reported Reasons for Deferral from AECP Survey

From historic records, the typical weatherized home in Virginia realizes approximately 28.54 MMBtu of energy savings annually, unlocking the energy efficiency potential of more than 1,500 households that would otherwise be weatherization deferrals could translate into an additional 43,000 MMBtu energy savings each year, offsetting greenhouse gas emissions while fulfilling the legislative intent of the 2020 House Bill 981 by supporting low-income energy efficiency programs. The weatherization network has demonstrated its ability to scale operations through the American Reinvestment and Recovery Act stimulus funding in 2009, and today amidst an increase in utility-sponsored programs that can be leveraged with federal resources.

weatherization clients' roofs will create additional opportunities to consider those households for distributed rooftop solar - complementing efforts like 2019 House Bill 2789's low-income solar and energy efficiency program and the work of the Virginia Clean Energy Advisory Board - to have a fair and equitable clean energy transition in Virginia.

The weatherization provider network requests the Virginia DHCD RGGI Stakeholder Advisory Group and all participating stakeholders consider the energy efficiency potential of this proposal while taking into account how RGGI revenues used for this purpose aligns with the intention of the legislation.

Sign up for updates and have your voice heard at the upcoming Virginia DHCD RGGI Stakeholder Advisory meeting on Tuesday, December 15, 2020 from 2-4 PM EST, by visiting Virginia DHCD's Housing Innovations in Energy Efficiency Program landing page here: https://dhcd.virginia.gov/hiee

For additional information, please contact:

Chase Counts, CEM

Senior Director of Operations

Community Housing Partners | Energy Solutions

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ccounts@chpc2.org

Kevin Brauer 2y
Great work! Wondering if opportunity to add ACA funds to address home-caused health issues?
Like Reply | 1 Like

Robert W. Lazaro, Jr. 2y
Chase you guys at Community Housing Partners and our friends at the LEAP (Local Energy Alliance Program) are doing great work in VA and the region. Keep it up!
Like Reply | 1 Like

Loren Ahonen 2y
This is fantastic. Great work here, Chase.
Like Reply | 1 Like

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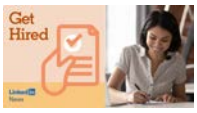

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Attachment 33

ENERGY NEWS NETWORK

SOUTHEAST

Virginia weatherization program is changing lives, but Gov. Youngkin wants to cut off its funding source

A Virginia program that uses money from the Regional Greenhouse Gas Initiative to help low-income residents with deferred maintenance and energy efficiency overhauls has been hailed by advocates as a national model.

by **Elizabeth McGowan**
September 21, 2022

Paul Acker, program manager with Community Housing Partners energy solutions division, speaks with Dorothy Carter on her front porch about upcoming installations. Credit: Everett Brubaker / Community Housing Partners

Dorothy Carter pined to remain in her Elkton, Virginia, home, but that possibility seemed less and less likely as health and safety issues mounted.

Sewage from broken pipes leaked into the basement. Rain poured in through holes in the roof. And blown fuses were a constant headache when she bypassed a balky oil furnace to warm rooms with space heaters.

But where would the 61-year-old go? And how would she gather the resources to move?

Fortunately, relief from that anguish began arriving in mid-August when a crew spent several days scrubbing away the sewage. That deep cleaning laid the groundwork for a phalanx of other contractors that are part of a now-at-risk Virginia program dedicated to tackling deferred home repairs that stand in the way of energy efficiency improvements.

Carter was again beaming on Sept. 13 as an electrician and several other contractors darted in and out of her rural Rockingham County house replacing her water heater and breaker panel. Within the next few weeks, she will gain a new roof, heat pump and water pipes.

Dorothy Carter of Elkton, Va., on her front porch in Rockingham County. Credit: Everett Brubaker / Community Housing Partners

“It will be so much nicer here when I come home from work,” said Carter, who has a job at nearby Friendship Industries, which employs people with disabilities. “They’re putting in stuff I can’t afford to buy.”

Carter is relieved the electric heat pump will end the $700 payments to fill her oil furnace.

“Now I’m going to call and tell them I don’t need it no more,” she said. “I’ve been here for about 43 years. There have been challenges, but I’m going to keep on living here.”

Carter is far from the only Virginian to benefit
from the new statewide initiative for low- and moderate-income residents designed to pair out-of-reach repairs with energy efficiency overhauls.

However, she could be one of the last if Republican Gov. Glenn Youngkin succeeds in his quest to extract his state from an East Coast carbon cap-and-invest enterprise Virginia joined in 2020. Virginia targeted a share of its Regional Greenhouse Gas Initiative dollars to lift up Carter and other homeowners struggling to modernize basic infrastructure that keeps houses ticking.

Briefly, what's known as RGGI curbs the emissions of heat-trapping gases from fossil fuel power plants by auctioning carbon dioxide allowances. Facilities are assigned a cap on how much carbon dioxide they can emit, and they must purchase allowances for any pollution above that threshold. The 11 member states decide independently how to spend the revenue.

Virginia's General Assembly opted to direct roughly half of the annual auction proceeds to a range of energy efficiency programs for lower-income households. Programs are administered by the Department of Housing and Community Development.

Through June, records show the state agency has distributed $189 million in RGGI funds toward energy efficiency from its start date in March 2021.

Sara Hayes, a health and environment specialist with the research nonprofit American Council for an Energy-Efficient Economy, praised Virginia for directing a RGGI allotment toward big-ticket home repairs that aren't covered by traditional weatherization programs funded by utilities and the federal government.

"I have huge kudos for the people in Virginia who made that happen," Hayes said about a front where other states are lagging. "That kind of coordination rarely happens.

"Virginia created a program that outshines everybody. Why would you wake up one day and say you're going to get rid of a wildly successful framework?"

Everett Brubaker asks the same question.

As a Harrisonburg-based business development specialist with the energy solutions division of Community Housing Partners, he's been an eyewitness to the impact of the RGGI cash infusion. His

employer is the largest of 15 nonprofits statewide qualified to **perform weatherization services**. It's also coordinating the repairs at Carter's house.

In years past, these nonprofits couldn't undertake more run-of-the-mill weatherization until health and safety threats such as mold and leaky roofs were tackled. Cases placed on what's known as the deferred list lingered because local charities were often too strapped to step up.

"I don't think people realize that many of their neighbors are living in these conditions," said Brubaker, who visited Carter's house with work crews. "It's not like she's an exception."

Ed Bradley and a crew member with Bradley Electric carry a new water heater to Carter's home. Credit: Everett Brubaker / Community Housing Partners

Advocates: Legislators control RGGI's destiny

Youngkin's administration has targeted RGGI withdrawal as a priority since Virginians elected the Republican governor last November. In January, he issued an executive order calling for an exit.

Then, in late August, at a regular meeting of the Virginia Air Pollution Control Board, acting Natural Resources Secretary Travis Voyles announced the administration's intention to file the paperwork to extract the state from RGGI by the end of 2023.

Environmental advocates **have vowed** to beat back that repeal.

Conservation attorneys claim withdrawal is an act of overreach by the governor and regulators.

"The lawmakers who do have that authority in the General Assembly know RGGI is already delivering real resources to Virginians on the frontlines of climate change," said Nate Benforado, a senior attorney with the Southern Environmental Law Center. "It would be a colossal mistake to pull out of a program that is … helping Virginians solve real problems they often can't afford to tackle alone."

Sixty-one Democratic state legislators echoed that perspective in a **September letter**, stating that, "only a change in the law that passes both chambers of the General Assembly and is signed by the Governor can remove Virginia's participation. No proposed regulation, emergency regulation, regulatory act, or any subsequent administrative process can do so."

Virginia's journey to becoming the first southern state to RGGI has been circuitous and twisted. Democratic Gov. Ralph Northam, whose four-year term ended in January, backed membership.

After years of obstruction, the General Assembly finally voted to join the 2008 initiative in 2020. With **House Bill 981**, legislators tasked the Department of Environmental Quality with establishing parameters for the Clean Energy and Community Flood Preparedness Act. The RGGI money is split between flood mitigation projects and energy efficiency.

The state is **funding two other non-weatherization housing initiatives**. Both target low- and moderate-income Virginians. One "bucket" covers energy efficiency efforts for new construction, rehabilitation, and adaptive reuse of affordable and special needs housing. The other, not yet rolled out, is a grant program for housing innovation partnerships.

During this year's legislative session, the Republican-majority House of Delegates voted to halt RGGI participation. But the Senate, where Democrats have a slim lead, thwarted that effort by deep-

sixing a similar bill in its conservation committee.

Chelsea Harnish, executive director of the Virginia Energy Efficiency Council, is urging Virginians to voice support for RGGI by submitting comments to the state Department of Environmental Quality during the Sept. 26-Oct. 26 window.

“This money has been instrumental in moving homeowners in the most dire need of help off the deferral list,” Harnish said. “Before, providers were having to walk away from those in need. With RGGI funding, they don’t have to do that anymore.”

She emphasized that the pot of money RGGI provides is far greater than all other energy efficiency and weatherization programs combined at the federal and utility level.

Harnish pointed to how Project: HOMES deployed a portion of its $16 million from RGGI to fix up 12 Eastern Shore homes initially tagged for the deferral list. The nonprofit hired 30 local subcontractors to address roof, mold, insulation, and heat and cooling issues before engaging in more routine weatherization. Homeowners’ utility bills have dropped by about 20%.

The state Department of Housing and Community Development did not respond to requests for comment about RGGI funding potentially being in jeopardy. While the agency is the clearinghouse tracking how the 15 nonprofits are spending RGGI money, those collective figures are not available. However, each nonprofit is recording its individual statistics.

For instance, since July 2021, Community Housing Partners has spent $1.2 million serving 226 households in need of RGGI pre-weatherization repairs.

Another 325 households remain in the repair queue. Currently the nonprofit has $1.3 million on hand to address those needs.

While Virginia will certainly benefit from clean energy provisions in the Inflation Reduction Act, Harnish said that federal law is no substitute for RGGI money that provides weatherization deferral repairs.

“It’s comparing apples and oranges,” she said. “While IRA money coming to the states is historic, it isn’t going to help fix roof or mold problems.”

In a nutshell, the IRA offers multiple rebates and tax credits for electric appliances and overall energy savings.

For instance, states will administer the IRA rebate program "and we don't know what that will look like yet," Harnish said.

She was pleased that Hayes, with the American Council for an Energy-Efficient Economy, had lauded Virginia for acting boldly with its RGGI funding.

"It's wonderful to hear a national nonprofit referring to us as a model," Harnish said. "And now our governor wants to take away that money."

RGGI money gives Virginia a boost

Virginia ranked a respectable 19th in an overarching state energy efficiency scorecard that Hayes and three other ACEEE researchers released in mid-August. Overall, the authors discovered that no state is knocking it out of the park with efforts to support healthy, affordable and decarbonized homes.

Maryland, Virginia's neighbor to the north, was the top finisher with 54.5 out of a possible 100 points. Virginia tallied 29 points.

In the 119-page "Pathways to Healthy, Affordable, Decarbonized Housing," ACEEE evaluated each state across 33 possible actions that could reduce pollution and housing costs for residents through energy efficiency, electrification and renewable energy investments.

Detailed categories covered energy utilities, weatherization and bill assistance, affordable housing, healthy homes and communities, and cross-agency coordination.

While Virginia's list of shortcomings is lengthy, it earned points for funneling RGGI dollars into its unique weatherization repair deferral program that benefitted Carter and hundreds of others.

"Usually, these programs happen because they have champions who develop relationships with people in other agencies," Hayes said. "That takes time and effort.

"Virginia is reaching the neediest by building a mechanism where money can help people being harmed in their homes."

Hayes and her colleagues opted to undertake this first-of-its-kind report because people's homes are linked to their health and their economic circumstances. That became even more apparent during the pandemic.

"We wanted to come at it holistically and we didn't want to advocate policies that don't take people into account," said Hayes, a 20-year energy policy veteran. "As the climate changes, how do we make sure those hit the hardest can survive?"

Lower-income people not only have higher energy burdens because their inefficient homes consume more energy per square foot, Hayes said, but they also pay higher utility bills because of gaping problems with mold, roofs and windows.

Rhode Island, California and Vermont, which ranked two, three and four, were the only states with marks of 50 or higher. She also noted that five of the 10 bottom-ranking states lead the nation in poverty rates.

The report provides a potential roadmap for ambitious states.

"But they have to get into the weeds," Hayes said. "We've done the work of saying, 'Here is the body of things you need to address.' To take action, states have to look at what they do have and don't have."

A brighter Christmas

Carter is grateful her home, built in 1962, will be buttoned down before cool weather envelopes the Shenandoah Valley.

She began falling behind on upkeep when her husband, Chester, died 26 years ago. They had moved into the family home after marrying in 1979.

Carter is so enamored with the upgrades Community Housing Partners is coordinating that she is serving as an informal ambassador for the program. She's puzzled why Youngkin seems so intent on dismantling it.

"I've talked to family members, neighbors and coworkers about how it can help," she said. "I don't know why [the governor] can't just leave it alone and let it keep going. There are a lot of people out there who can't afford what it provides."

With some of her savings on utility bills, Carter plans to purchase a washer and dryer — and also splurge a bit during the holiday season.

“A friend asked me why I didn’t decorate at Christmas. I told her I ain’t got time to blow no fuses.”

Later this year, the two women will string dazzling arrays of lights.

With my new electrical box,” Carter said, “I can put out a lot of Christmas stuff.”

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Attachment 34

Affordable and Special Needs Housing
Competitive Application
Program Guidelines

FY 2023

Applications Due:
October 31, 2022
March 31, 2023 (tentative)

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Program Overview

Background

The Affordable and Special Needs Housing (ASNH) Program is a consolidated, competitive application used by the Virginia Department of Housing and Community Development (DHCD) to award National Housing Trust Fund (NHTF), HOME Investment Partnerships (HOME), Virginia Housing Trust Fund (VHTF), Housing Innovations in Energy Efficiency (HIEE), and Permanent Supportive Housing (PSH) funds[1] to multifamily rental developments and single family homeownership developments across the Commonwealth.

The Program's goals are to expand the supply of decent, safe, sanitary, and affordable housing available to low-income, very low-income, and extremely-low income Virginians.

Eligible projects are scored on a 100 point scale (Need – 40 points; Feasibility – 30 points; Developer Capacity – 30 points) and projects with scores above a 60 point threshold are ranked and considered for funding awards of the sources above.

These Program Guidelines are intended to provide guidance on applicant and project eligibility, program and regulatory requirements, funding availability and limits, as well as the application and decision notification process for the FY23 ASNH application cycle. If you require information not contained below, please contact DHCD staff for assistance.

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[1] DHCD also uses HOME, VHTF, and HIEE funds for other eligible activities administered by other programs.

Funding Sources Available

HOME

The *HOME Investment Partnerships Program* (HOME) was created through the National Affordable Housing Act of 1990. Funds from the HOME program are made available annually through formula allocations to states and local governments (*Participating Jurisdictions* or PJs).

PJs are responsible for conducting needs assessments and establishing priorities and goals, and developing and managing the programs that will help meet these goals. The ASNH Program is a subset of DHCD's HOME funding, and uses HOME to support the development of rental units made available to individuals or families with incomes at or below 50% or 60% of their Area Median Income (AMI), and to the development of homeownership units made available to buyers with incomes between 60% and 80% AMI.

While projects may be located anywhere in Virginia, DHCD's HOME program gives priority to projects located in cities or counties which do not receive a direct federal HOME allocation through a local PJ or HOME Consortium through a scoring preference. The list of cities and counties which do not receive a scoring preference are listed in **Appendix A**.

The ASNH program also gives DHCD-certified Community Housing Development Organizations (CHDOs) a scoring preference for HOME funding. See DHCD's online resources for more information on CHDO requirements.

National Housing Trust Fund

The *National Housing Trust Fund* (NHTF) was created as a federal block grant to states, issuing its first allocation in 2016, and is the largest federal program designed to specifically support the production and preservation of affordable housing for extremely low income individuals and families.

DHCD awards all of its NHTF funds through the ASNH Program, and uses NHTF to support the development of rental units made available to individuals or families with incomes at or below 30% AMI.

Virginia Housing Trust Fund (Competitive Loan Pool)

The *Virginia Housing Trust Fund Competitive Loan Pool* is funded through Virginia's Housing Trust Fund, which is a special allocation of state funds intended to help address the commonwealth's housing needs and reduce homelessness. No less than 80% (eighty percent) of the VHTF must be allocated to a competitive loan pool.

The ASNH Program satisfies this requirement for a competitive loan pool, and provides low-interest loans to meet the financing needs of housing projects which address key state housing policies. Funds may be awarded to projects developing rental units or for sale homes which are made available to individuals or families with incomes at or below 80% AMI.

Virginia Housing Trust Fund expenditures associated with projects funded through the ASNH program will be used to meet the State's federal HOME program match requirement and may not be utilized for any subsequent regulatory match requirement without permission from DHCD.

State Permanent Supportive Housing Funds (PSH fund)

The State *Permanent Supportive Housing Funds* (PSH fund) are awarded to support the development of new permanent supportive housing (PSH) units. Supportive housing is an evidence-based housing intervention that combines non-time-limited affordable housing assistance with wrap-around supportive services for people experiencing homelessness, as well as other people with disabilities.

These funds are typically awarded to small development projects which specifically aim to provide independent living options for individuals with intellectual or developmental disabilities or serious mental illnesses, and which assist DHCD in meeting the requirements of the Department of Justice Settlement Agreement. These projects may be 100% 'special needs' populations and exempt from the five-unit minimum.

Housing Innovations in Energy Efficiency (HIEE) Funds

Housing Innovations in Energy Efficiency (HIEE) funds assist affordable housing project development teams in completing energy efficiency upgrades that would not have been feasible otherwise. These funds are made available by DHCD to projects which demonstrate that they are designed to meet the HIEE energy efficiency performance requirements detailed below, and supplement competitively awarded state and federal funds.

Projects must score well enough to obtain an award of ASNH's competitive sources (HOME, NHTF, VHTF, or PSH) to be eligible for an allocation of HIEE funds. During the application review process for each cycle, the panel will score and rank projects to determine competitive award recommendations. If a project which requests HIEE funds is recommended for a competitive award, the panel then evaluates the additional required documentation to ensure the project is designed to meet the relevant energy efficiency performance requirements. HIEE energy efficiency performance requirements are detailed in **Appendix B.**

Program Year Available Funds

For the 2022-2023 program year (Virginia FY23), the sources and approximate amounts allocated to the ASNH Program are below. DHCD reserves the right to update these funding amounts during the program year, and the right to roll over funding to future program years at its sole discretion.

Per project and per source maximums awards apply, with further details below and under Eligibility Criteria. DHCD reserves the right to restrict total funds awarded to a project.

SOURCE OF FUNDS	FY23 ALLOCATION[2]
HOME Investment Partnerships Program (HOME)	$8,766,531
National Housing Trust Fund (NHTF)	$12,975,688
Virginia Housing Trust Fund (VHTF)	$60,000,000
Housing Innovations in Energy Efficiency (HIEE)	$80,000,000
State Permanent Supportive Housing (PSH fund)	$500,000

Project Competitive Funding Limits

Each eligible project is subject to funding request limits, or caps. These caps are inclusive of all DHCD commitments to a project in previous application cycles. DHCD reserves the right to adjust funding offers by funding source to meet project needs, and reserves the right to limit funding offers made to a project even if 'cap' remains.

DHCD will consider excluding Vibrant Community Initiative VCI) commitments from these caps if such a request is made in writing prior to application. Exclusion of VCI commitments is not guaranteed and is granted at DHCD's sole discretion on a case-by-case basis.

Projects with HOME assistance from any source are ineligible for an award of HOME funds from the ASNH Program while the project is in its HOME affordability period.

Each project is limited to an award of $700,000 per competitive source (HOME, NHTF, or VHTF); with an increased limit of $900,000 for any two of those three sources if the project provides qualified Permanent Supportive Housing (PSH) units, as detailed in Criteria below, and provides the required documentation at the time of application.

- $700,000 – Maximum request per source (HOME, NHTF, or VHTF)
- $900,000 – Maximum request per source for projects providing qualified PSH units
- $2,100,000 – Maximum award for a project requesting HOME, NHTF and VHTF
- $2,400,000 – Maximum award for a project providing qualified PSH units and requesting HOME, NHTF, and VHTF

The State Permanent Supportive Housing fund (PSH fund) award is limited to $500,000 per project, and are typically awarded to small development projects which are either not are eligible for or do not request an award of HOME, NHTF, VHTF awards.

[2] Allocation amounts listed are approximate and subject to change.

Project HIEE Funding Limit

Each project earning a competitive source award (HOME, NHTF, VHTF, or PSH fund) which is designed to meet the HIEE minimum performance requirements is eligible for an award of up to $2,000,000 or ten percent (10%) of its total construction costs as calculated in the ASNH Application Workbook underwriting tab, whichever is the lesser amount.

- $2,000,000 – Maximum HIEE award for an eligible project
- $4,100,000 – Maximum total awarded funds for an eligible project requesting HOME, NHTF, VHTF, and HIEE
- $4,400,000 – Maximum total awarded funds for an eligible project providing qualified PSH units and requesting HOME, NHTF, VHTF, and HIEE

Eligibility

Applicant Eligibility

Eligible Applicants are non-profit organizations or for-profit housing developers, DHCD-certified Community Housing Development Organizations (CHDOs), and public housing authorities seeking to develop affordable housing projects in Virginia.

The Applicant must be the Owner, Developer, or Sponsor of the proposed project:

- Owner – holds valid legal title to, or long term leasehold interest in the property
- Developer – owns the property and is developing the project, or has a contractual obligation to develop the project
- Sponsor – is the owner or partial owner and agrees to convey ownership to a second non-profit at a predetermined time prior to or during development or upon completion (requires consultation with DHCD prior to application)

The Applicant must be registered in CAMS as an eligible organization defined above, and should be the primary partner in the project, responsible for long-term operations and compliance. Applicants with incomplete CAMS profiles (including applicants without UEIs) are ineligible.

Applications made by a project legal entity or limited liability corporation are ineligible.

Applicants with outstanding or unresolved findings from audit or monitoring findings, unresolved IRS findings, unresolved compliance findings – including those issues which may be identified to DHCD by another previous partner such as Virginia Housing (VH or VHDA) –, or which are not in compliance with previous DHCD agreements will not be eligible for a funding commitment for any Project until such findings and/or compliance issues are resolved. DHCD staff are committed to working with any interested party to develop a plan for resolution and restoration of eligible status.

Developer Requirements

Federal regulations require DHCD to certify developer capacity, including Community Housing Development Organizations (CHDOs) prior to the commitment of HOME or NHTF funds.

The evaluation of developer capacity includes reviewing:

- Developer's demonstrated experience developing similar projects
- Staff experience in housing development (excluding consultants, contractors, or partners)
- Current financial soundness, including compliance with DHCD's audit policy

DHCD also evaluates the capacity of applicants requesting only state sources of funding. It is critical that applicants and development teams have demonstrated success with similar projects including ongoing operations and long-term compliance. Applicants must be able to clearly articulate the relationship between all partners involved in the development, ownership, and property management of a project, and describe partner capacity and experience.

CHDO Certification Requirements

Applicants must have an approved CHDO Certification application in CAMS, and the related Certification or Re-Certification letter provided by DHCD to be eligible for the five (5) point scoring preference on applications for HOME funds. This scoring preference enables DHCD to meet the 'CHDO Reserve' or 'CHDO set-aside' requirements of the HOME program.

Generally, CHDOs must meet organizational, mission, financial management, and capacity requirements, which include, but are not limited to, the following:

- Certified nonprofit status
- Being a community-based organization
- Low-income representation in board composition
- Primary mission is the provision of affordable housing
- Demonstrated capacity to develop affordable housing
- Conformance to accounting standards and financial soundness

CHDO requirements must be met at the time of fund commitment, for the duration of the development phase, and through the long-term compliance period for CHDO's in the role of project/property owner.

Organizations interested in determining if they meet the requirements to become certified as CHDOs and therefore eligible for the HOME scoring preference should refer to the HUD publication CHDO Survivor Kit[3] or the CHDO Capacity Self-Assessment Tool

Project Eligibility

To be eligible for ASNH funding, all projects must be new construction or substantial renovation of affordable housing units, or the adaptive reuse of buildings to create new affordable housing units for lower income homeowners or renters. Acquisition-only projects, public housing, and public facilities including emergency shelter, hospitals, nursing homes, or intermediate care or assisted living facilities are not eligible for ASNH funding.

In limited cases group homes may be eligible for ASNH funding. There must be an identified local need, and these projects require a pre-application consultation with DHCD. Applications submitted without completing this pre-application consultation are ineligible.

[3] Link validated September 2022; document title is searchable on hudexchange.info

Eligible property types include multi-unit structures, single family, two- to four-unit structures, and manufactured homes. Scattered site projects are allowable, but all projects must be under common ownership, management, and financing. Regardless of type, the units must be considered modest relative to the neighborhood.

Projects may include units structured as Single Room Occupancy (SRO) units. Eligible SROs are efficiency-style units that are the primary resident of a single one- or two-person household, with a valid twelve-month lease to that household. The unit must contain food preparation and/or sanitary facilities. If the unit does not contain food preparation or sanitary facilities, then the building must contain and provide access to these.
Generally, an eligible project must:

- Include a minimum of five units,
- Be under common ownership, management, and financing,
- Represent a minimum investment/development cost of $15,000 per unit, and
- Meet the affordability requirements of every source for which it is requesting funds.

Eligible Project Types

Projects may be new construction, substantial rehabilitation, or adaptive reuse. Development activity beyond the original footprint will be considered new construction. Projects must meet Section 504 accessibility requirements based on project type, as described in these Guidelines.

For rehabilitation projects, minimum total development cost per unit is $15,000 and must include replacement of at least three out of five major systems (e.g., HVAC, plumbing, roofing, electrical). Development costs are limited to eligible costs and must exclude non-eligible costs such as community buildings, market rate units, and retail space.

Projects of any type must meet DHCD's Minimum Design, Construction, and Rehab Requirements to ensure that no further investment is required during the affordability period. Projects awarded National Housing Trust Funds must follow the Housing Trust Fund Rehabilitation Standards.

Rental & Homebuyer Project Eligibility

An eligible project must be either a **homebuyer** project or a **rental** project (not both).

Homebuyer projects must be a minimum of five units of housing, which will be made available for sale to households earning incomes below 80% AMI. These projects may apply for either HOME or VHTF funds.

Rental projects must be a minimum of five units (unless 100% special needs, with DHCD approval), and must be structured to meet each individual program's affordability requirements. For rental projects requesting federal sources, a minimum of five units are required to meet AMI targeting requirements per source.

For example, a project requesting HOME and NHTF funds would need a minimum of ten total units, five of which must meet the NHTF requirement of 30% AMI or below; and five of which must meet the HOME requirement of 60% and 50% AMI or below. Rental projects requesting

state funding sources (VHTF, PSH funds, or HIEE) must restrict at least some units to households with incomes at or below 80% AMI.

Mixed income and multiple-use projects are eligible; however these projects must contain assisted units that will meet income and rent or sales value requirements, and the number of assisted units must meet Program Guidelines.

For both homebuyer and rental projects, applications designed to provide a greater proportion of lower income targeting will be given scoring preference on the *need* criteria. The actual number of ASNH assisted units and income mix will be determined by DHCD during underwriting.

For both homebuyer and rental projects, the maximum investment of HOME or NHTF funds must be equal to or less than the actual costs *or the 221 (d)(3) limit*, whichever is lower, on a per-assisted-unit basis.

Maximum Subsidy Limit – *221(d)(3) limit* (effective March 17, 2022)	
Bedrooms	Cost Limit
0	$159,754
1	$183,132
2	$222,694
3	$288,094
4+	$316,236

Program requirements including the number of required assisted units are based on total amount of HOME or NHTF assistance (including HOME from other resources) as compared to the total development costs. For this purpose, total development costs are limited to HOME or NHTF eligible costs (Appendix C) and must exclude non-eligible costs such as community buildings, market rate or unrestricted units, and retail space.

The final number of assisted units in a project will be determined by DHCD during underwriting. Selected projects will always be assisted with the minimum amount of funds needed, as demonstrated by the underwriting and subsidy layering review.

Program Terms & Agreements

Affordability Period

All commitments of ASNH funds to a project result in a mandatory affordability period on the project property, which is the period of time that the rental units or single family home must be maintained as "affordable" according to the agreement between the developer and DHCD, and is enforced through a restrictive covenant deed recorded on the property.

Affordability periods for ASNH funded rental projects are thirty (30) years. As noted below, for HOME-assisted projects, this affordability period is comprised of a federal compliance period followed by a state-level affordability period. For all sources, the required type and number of

source-assisted units to be maintained as "affordable" for this time period determined by DHCD during underwriting.

For ASNH funded homeownership projects, the affordability periods for any available source are based on the total amount of funds (including HOME funds from local Entitlements or Consortiums) invested in the project and DHCD's determination of investment through developer subsidy or direct homeowner assistance.

Rental Affordability Periods	
Source/Activity	**Length**
NHTF (all activities)	30 years (federal compliance only)
HOME New Construction	20 years (federal compliance) + 10 years state affordability)
HOME Rehabilitation	15 years (federal compliance) + 15 years state affordability)
VHTF, HIEE, and PSH funds	30 years (state compliance only)

Homeownership Affordability Periods	
Investment By Unit	**Length**
HOME or VHTF/HIEE; less than $15,000*	5 years
HOME or VHTF/HIEE; $15,000 - $40,000*	10 years
HOME or VHTF/HIEE; more than $40,000*	15 years

**If only homebuyer developer subsidy, a resale provision applies. If DHCD DPA is included in a unit then a recapture provision applies and affordability is based on the amount of DPA only.*

Type of Assistance Provided

Funds made available through the ASNH Program have standard terms based on project type.

Rental project assistance is provided as permanent, must pay debt after all other financial commitments are received. These funds are leveraged to close a financing gap in the affordable housing project, and the amount of funds committed must be the minimum amount needed.

All rental project applications must assume permanent financing structured as a 3% interest-only, deferred principal loan, with must-pay interest over the full required affordability period of time of 30 years. Cash flow loan requests will not be considered. Construction draws or other payments of ASNH funds prior to conversion to permanent financing will not be considered.

Homebuyer project assistance is structured as reimbursement-based construction financing. Construction draws are allowed based on predetermined and specific project completion milestones. No reimbursement draws are permitted until DHCD has received a fully executed deferred loan agreement, and a copy of the restrictive covenant deed of trust recorded on all properties under the loan agreement. Reimbursement draws or remittances are sent to the Applicant's organization address as listed in CAMS via paper check until the organization completes registration with the Department of Accounts for ACH payments.

This structure may also be available to rental projects with only PSH funds assistance.

For all projects, DHCD reserves the right to charge agency-incurred project costs to the project. These costs include only actual, applicable project costs such as environmental review notices and legal services. Any incurred costs charged to the project are structured as a grant, included in the total amount of project assistance. The total ASHN project assistance is reflected in the restrictive deed, the program agreement, underwriting, and subsidy layering analysis.

Additional Criteria

Income Restriction Criteria

Each ASNH awarded source has income restriction criteria, and regulations about how and when income determinations or qualifications are made.

Projects must be able to meet the ASNH Program requirement of a minimum of five units, but the actual number of assisted units in a project will be determined during underwriting. These units must be made available to eligible households that meet the income-restriction requirements of the source based on Area Median Incomes (AMI). Income calculations must be based on HUD's Section 8 income eligibility standard.

For all projects, households must meet income-restriction eligibility requirements at the time that program eligibility is determined, and determinations expire after six months.

For rental projects, all NHTF-assisted units must be restricted to households with incomes at or below 30% AMI; HOME-assisted units must be restricted to households with incomes at or below 60% AMI, and twenty percent (20%) of HOME-assisted units in a project must be further restricted to households with incomes at or below 50% AMI. VHTF and HIEE assisted projects must have units restricted to households with incomes at or below 80%. All ASNH sources allow for rental projects to be mixed-income and/or include 'workforce units,' market-rate or unrestricted units, but these projects must have appropriate numbers of restricted units to meet program requirements and have eligible costs to support the ASNH award value or investment.

For homebuyer projects, all sales must be made to households at or below 80% AMI regardless of ASNH source. For homebuyer projects, closing must occur within six months of income determinations. If closing does not occur during that time, then income eligibility must be re-established.

HOME Program Criteria

Match Funds and non-Entitlement Preference

Eligible projects may be located in any locality in Virginia. For projects requesting HOME funds, there are criteria that change based on the locality in which the project will be developed.
Some localities in Virginia, called HOME Entitlements or HOME Consortiums, receive HOME funds directly from HUD.

Projects located in these localities (listed in **Appendix A**) must meet a *local match requirement*. These projects must have a commitment of 25% of their ASNH Program HOME funds request from locally-administered funds. Examples of local match include local HOME, CDBG, or other federal or state funds awarded and administered by a local government. Match requirements can also be met based on the waiver of locally collected fees directly associated with the specific development (e.g., water and sewer connection fees). Documentation of local match must be included in the application.

Projects located in non-Entitlement or non-Consortium localities do not have a match requirement on their application for ASNH Program HOME funds, and have a scoring preference of 5 points on their HOME funds score.

HOME Environmental Reviews

Projects awarded HOME funds will require an additional environmental record review completed and approved by DHCD. **No development activity including the acquisition of the property can occur prior to the completion of this review, which may include the publication of a notice of findings and the request for release of funds from HUD.** Projects proceeding with development or 'choice limiting' activities prior to the completion of the review may be ineligible.

Coordination of the environmental review will be required for any project combining DHCD's State HOME funds with local HOME or Community Development Block Grant (CDBG) funds.

NHTF Program Criteria

NHTF Environmental Reviews

Projects awarded NHTF funds will require an additional environmental record review. The NHTF Environmental Provisions for new construction and rehabilitation under the Property Standards at 24 CFR § 93.301(f)(1) and (2) are similar to HUD's Environmental Regulations at 24 CFR Parts 50 and 58 for HOME funds. The main difference is that the HTF Environmental Provisions are outcome based, and exclude consultation procedures (including notice requirements and public comment periods) that would be applicable if NHTF project selection was a federal action. Parts 50 and 58 are process based, and include consultation procedures for several laws and authorities where there may be environmental impacts. See CPD notice 16-14 for further details.

Permanent Supportive Housing Criteria

Rental projects may include permanent supportive housing (PSH) units, which is permanent housing made available to individuals in qualified target populations in which supportive services are provided to assist at least that individual (who may be a member of a multi-person household) in achieving housing stability. These units may also have housing assistance in the form of rental

subsidies, or the individuals may have their own tenant-based rental assistance. Projects may target special needs populations such as veterans, formerly homeless, or elderly individuals.

However, for the purposes of achieving a scoring preference (5 points) or accessing the increased funding cap, projects must target households which meet the HUD definition of chronic homelessness, households with at least one member with an intellectual or developmental disability (ID/DD), or households with at least one member with a serious mental illness (SMI).

The minimum number of PSH units required per project to gain the scoring preference is as follows:

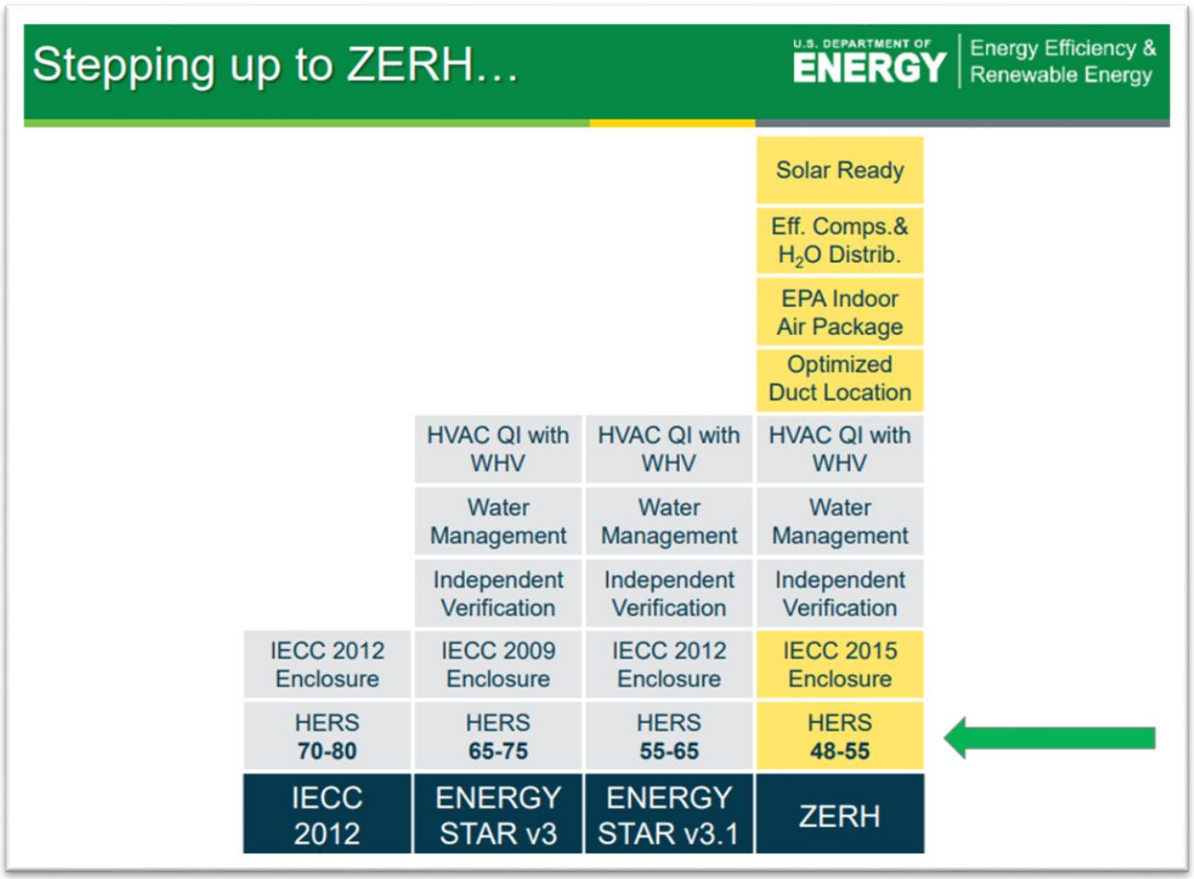
Total Unit Count	PSH requirement
32 units or greater	8% of total units
11-31 units	Minimum of 2 units
10 Units or less	Minimum of 1 unit

Compliance with fair housing always applies, tenants must have a lease in their name, and participation in services may not be a condition of tenancy.

HIEE Funds Criteria

Projects must meet or exceed the following performance requirements, and must submit their HERS rater plan review and preliminary rating, and their preliminary documentation of green build certification. Applications for which these documents are incomplete or missing will be considered ineligible for an award from this ASNH HIEE Supplemental Funding Round, and DHCD staff will advise applicants that they will need to resubmit documentation in conjunction with a completed application for the ASNH competitive loan pool at a later date.

Please note the minimum requirements differ substantially from Virginia Housing's Low-Income Housing Tax Credit (LIHTC) energy efficiency requirements. Meeting the LIHTC Qualified Allocation Plan energy-related standards or meeting EnergyStar standards do not qualify a project for HIEE funding.



Slide courtesy Newport Partners/Jamie Lyons from the ASNH Webinar: HIEE Requirements
Presentation recording available at dhcd.virginia.gov/hiee
Further information available at buildings.energy.gov

HIEE Minimum Energy Efficiency Performance Requirements	
New Construction	Green building certification required* Zero Energy Ready Homes (ZERH)**
Substantial Rehabilitation	Green building certification required* Average HERS index of 70 or below across all units OR 40% improvement in HERS index Additional requirements: ACCA Manual J calculations for heating/cooling loads Fresh air ventilation and dehumidification** Duct leakage testing and sealing*** Architect cost certification of upgrades needed to meet HIEE requirements
Adaptive Reuse	Green building certification required* Average HERS index of 80 or below across all units Additional requirements: ACCA Manual J calculations for heating/cooling loads Fresh air ventilation and dehumidification** Duct leakage testing and sealing*** Architect cost certification of upgrades needed to meet HIEE requirements

*Eligible green building certifications include: LEED, EarthCraft Gold or higher, National Green Building Standard Silver or higher, and Enterprise Green Communities.

**Dehumidification strategy/equipment shall provide for occupant comfort and health by maintaining interior RH in 40-60 percent range. For renovations and adaptive reuse projects, if building/unit envelopes are tightened to new construction standards (5 ACH_{50}), ventilation system(s) shall provide fresh air supply per the most current version of ASHRAE 62.1 or 62.2, or the most current version of USBC, whichever is more stringent.

***Existing ductwork shall be sealed and tested to be ≤10 percent total duct leakage; if HVAC system/ductwork will be newly-installed, duct leakage shall meet new construction energy code requirements (≤4 percent total duct leakage).

Additional Federal and State Requirements

Section 504

Section 504 applies to all ASNH assisted rental projects based on project type, which is determined by DHCD staff in coordination with the Applicant/Developer.

New Construction

New construction of multifamily rental housing with five or more units must be designed and constructed to be readily accessible to and usable by persons with disabilities. All common areas in the building must be made accessible, and a minimum of individual units must also be accessible.

- A minimum of five percent (5%) of the dwelling units in the project (but not less than one unit) must be accessible to individuals with mobility impairments.
- An additional two percent (2%) of the dwelling units (but not less than one unit) must be accessible to individuals with sensory impairments (i.e., hearing or vision impairments).

Rehabilitation: Substantial alterations

Multifamily rental projects of fifteen units or more that undergo "substantial alterations" must also comply with Section 504's accessibility requirements. Substantial alterations are defined as projects where costs of the planned rehabilitation will be seventy-five percent (75%) or more of the replacement cost of the completed facility. For these projects, all common areas in the building must be made accessible, and a minimum of individual units must also be accessible.

- A minimum of five percent of the dwelling units in the project (but not less than one unit) must be accessible to individuals with mobility impairments.
- An additional two percent, at a minimum (but not less than one unit), must be accessible to individuals with sensory impairments.

The requirements for multifamily projects undergoing substantial alterations are found at 24 CFR 8.23(a).

Rehabilitation: Other Alterations

If a multifamily rental project does not meet the definition of substantial alterations, the alterations that are made must, to the maximum extent feasible, make the dwelling units accessible to and usable by individuals with mobility impairments.

If alterations of single elements or spaces of a dwelling unit, when considered together, amount to an alteration of a dwelling unit, then the entire dwelling unit shall be made accessible to persons with mobility impairments. This would include alterations that involve certain kitchen and bathroom renovations, as well as entrance door jamb replacements. In addition, alterations to common spaces must make those areas accessible to the maximum extent feasible.

For this category of rehabilitation, only:

- When a minimum of five percent of the dwelling units (but not less than one unit) are accessible to people with mobility impairments, then no additional units are required to be made accessible
- There is no requirement to make any units accessible to individuals with sensory impairments.

A recipient is not required to make these accessibility alterations if doing so would impose undue financial *and* administrative burdens on the operation of the multifamily housing project (24 CFR 8.23(b)). However, projects in this category of rehabilitation may not be funded at DHCD's sole discretion when projects which do create additional accessible units are eligible within the same application round.

Program agreements will reflect Section 504 units, and will require that any vacant 504 units are listed on Virginia Housing Search and held for at least 60 days before being leased to household not requiring a unit-specific accommodation. Tenant selection plans must also include 504 units.

Fair Housing Act

The Fair Housing Act prohibits discrimination in the sale or rental of housing based race, color, religion, sex, national origin, handicap or familial status. This prohibition applies to all projects assisted with the ASNH program, and any project or applicant that discriminates or projects which are structured to discriminate are ineligible.

Lead Safe Housing

Lead Safe Housing policies apply to ASNH projects, unless they are found to be exempt. For non-exempt projects appropriate measures must be taken to assure that:

- Rehabilitation or demolition activities meet lead safe requirements;
- Development costs include associated costs;
- Homebuyers or tenants will receive notification (if applicable);
- Operating costs include ongoing associated maintenance costs for rental projects; and
- Records are maintained to document all measures taken.

Uniform Relocation Act (URA)

Accommodations for any relocations are required for all funding sources. However, the Uniform Relocation Act (URA) applies to all HOME/NHTF assisted projects where development activity will result in the permanent or temporary dislocation of households, businesses, farms and nonprofit organizations. When permanent or temporary dislocation is possible, a notice of the intent and a survey of the occupants must be conducted prior to the ASNH application. All application must include a completed URA Assessment Form and documentation of the notice and survey results. Development costs must reflect any associated costs that the project anticipates.

Section 3 Requirements

Section 3 requirements apply to all HOME/NHTF-assisted projects. These requirements mean that development-generated opportunities must be designed to benefit to the greatest degree possible low and very low income persons in the project services area and the business that employ them.

Developer hiring, contracting, and subcontracting must be structured to maximize this benefit. Project owner/developers are required to adopt specific goals, develop a Section 3 plan, and comply with required notifications, documentation, and reporting documented to DHCD through CAMS.

Labor Standards

Labor Standards apply to all projects. All projects must assure that workers receive "overtime" compensation at a rate of 1.5 times their basic rate of pay for all hours worked in excess of 40 hours a work week. This applies to all project associated construction contracts funding in whole or in part with HOME/NHTF resources.

Davis-Bacon Act and the Copeland "Anti-Kickback" Act requirements apply to projects with 12 or more HOME assisted units (determined in underwriting by DHCD, in part on the proportion of HOME funds to total development costs). In these cases, Davis-Bacon prevailing wages must be paid to workers at least weekly without any deductions or rebates except permissible deductions. Reporting requirements include the payroll submissions.

Violence Against Women Act

Violence Against Women Act applies to all projects and provides housing protection for survivors of domestic and date violence, sexual assault, and stalking. This requirement requires that all tenants are notified of their rights under the provision. The provision allows for emergency transfers to other units, bifurcation of leases, protection against denials, evictions, and terminations that directly result from being a victim, and allow for a low-barrier certification process.

Environmental Review

All applicants must complete and submit with their application a Phase 1 Environmental Site Assessment. In addition, as stated in the HOME and NHTF Criteria sections above, compliant environmental review must be completed before DHCD can execute any HOME or NHTF Program Agreement to secure a formal commitment of funds.

It is essential that developers not proceed with any project activity (e.g., acquisition, rehabilitation, demolition, construction, etc.) prior to the execution of the program agreement or the project will likely be rendered ineligible for funding. Applicants must allow sufficient time to complete and submit all required environmental site assessment documentation to DHCD.

Coordination on the environmental review procedure is required if combining ASNH resources with CDBG or other federal funding such as local HOME. Part 58 checklists must be submitted within six months of a HOME or NHTF award being made, and prior to any potentially choice limiting activities being undertaken.

Application Submission and Evaluation

All applications for Affordable and Special Needs Housing (ASNH) must be submitted through DHCD's Centralized Application and Management System (CAMS) prior to the application submission deadline.

The deadline for Fall 2022 submissions is October 31, 2022 at 11:59pm
CAMS automatically closes the application to submissions at this time.

The CAMS User Guide provides information and instructions on setting up and managing a CAMS account, and should be used first to troubleshoot any errors. Please allow up to two business days for responses to any CAMS Help Desk request. DHCD technical assistance is limited to normal business hours.

ASNH Application Instructions are available in CAMS to further assist Applicants in completing and submitting applications for ASNH funds. Applications submitted with incorrect or missing information will be reviewed *as is,* and may be ruled ineligible.

DHCD conducts panel reviews of all Applications submitted in CAMS prior to the submission deadline. During this panel review, the Application is first screened to ensure the Project and Applicant meet the eligibility requirements. Projects or Applicants which do not meet eligibility requirements are not provided with a numerical score.

Applicants with outstanding or unresolved findings from audit or monitoring findings, unresolved IRS findings, unresolved compliance findings – including those issues which may be identified to DHCD by another previous partner such as Virginia Housing (VH or VHDA) –, or which are not in compliance with previous DHCD agreements will not be eligible for a funding commitment for any Project until such findings and/or compliance issues are resolved. DHCD staff are committed to working with any interested party to develop a plan for resolution and restoration of eligible status.

Scoring Criteria

Applications are scored on a one hundred (100) point scale, and Projects must score sixty (60) points or higher to be qualified for funding.

Scoring criteria are as follows

- Need – 40 points
    - The Applicant demonstrates through narrative responses and information in attachments that the Project fills a critical need in the market area.
    - For rental projects only, PSH projects receive points (5) in this category
    - For HOME funds only, projects in non-Entitlement or non-Consortium localities receive points (5) in this category

- Feasibility – 30 points

    - The Applicant demonstrates through narrative responses and information in attachments that the Project is likely to come to a timely completion

- Developer Capacity – 30 points
    - The Applicant demonstrates through narrative responses and information in attachments that the development team has the ability to successfully complete projects and deliver affordable housing
    - For HOME funds only, CHDO-involved projects receive points (5) in this category

DHCD staff will rank all qualified Applications based on score. The highest scoring Applications from each round will received offers of funding from DHCD, up to the amount requested in the Application as available based on per-project and per-source caps, and remaining funds for allocation through the ASNH Program. These offers are preliminary awards and are contingent upon the Applicant meeting certain requirements as outlined in the Program Guidelines and in the source-specific letter of award offer.

DHCD reserves the right to retain any funds offered during an application cycle or program year as unallocated, and such unallocated funds will carry forward to future application cycles and program years as allowed.

Notification of Funding Decision

The Office of the Governor of Virginia makes the Affordable and Special Needs Housing program funding award announcements public, typically by the publication of a press release.

After the ASNH Program application cycle closes, ASNH staff are unable to answer inquiries as to the timing or contents of this announcement. Any such inquiries will not be returned.

After the public announcement of ASNH Program awards, DHCD staff will send an email to the Project Primary Contact as listed for each Project in CAMS containing either a notification of awarded funds or a denial of funding. Projects which are denied funding may request to schedule a technical assistance call, or *debrief*, with ASNH staff to discuss comments or feedback on the Application.

Execution of Award Terms

Applicants receiving a notification of awarded funds for Projects are considered preliminarily qualified. For each source awarded, the notification of awarded funds is comprised of two documents. The first document is a letter of award, which will be signed by the Senior Deputy Director of Community Development and Housing.

The second document will contain additional terms of the awarded funds, including interest rate, length of affordability period, and details program requirements (including environmental review processes). This *terms letter* must be countersigned by the Applicant and returned to DHCD staff prior to the issuance of a Program Agreement.

DHCD's expectation is that all Applicants requesting ASNH funds are prepared to return executed *terms letter(s)* in a timely manner. Applicants which delay the return of an executed terms letter without communicating with their assigned Program Administrator may not be eligible for an extension of time to complete the Program Agreement.

Execution of Program Agreement(s)

Applicants have a maximum twelve (12) months from the date on the notification of awarded funds and *terms letter(s)* to complete all program requirements and execute the Project's Program Agreement. This window of time is intended to allow both Applicants and DHCD to complete necessary processes which may have predetermined time requirements, such as Applicant underwriting review or DHCD public notice and comment periods.

The Program Agreement (a formal commitment of funds, and prerequisite for a legal loan commitment for rental projects or prerequisite to Deeds of Trust and remittance eligibility for homeownership projects.) Program requirements vary by source, but may include an environmental review process with public comment periods as required by HUD, and program agreements cannot be issued until all contingencies and program requirements are met.

ASNH Program Agreements generally expire two years from the date of execution, by which time the Project should be completed and ready to schedule permanent conversion or closing (rental projects) or should be completed and ready to submit closing disclosures on final home sales (homebuyer projects). Written requests for extensions of any deadline above must be received by DHCD prior to the expiration of the agreement or commitment, and are approved on a case-by-case basis at DHCD's discretion.

Marketing Materials

DHCD and the specific funding source(s) must be including on all marketing materials to include press releases, the project website, and signage. DHCD requires that a project sign be installed within thirty (30) days of the execution of the Agreement. Please see signage requirements for more details.

Appendix A – HOME Consortiums & Entitlements

Projects in these localities must provide evidence of matching funds as detailed in the Program Guidelines to be eligible for an award of HOME funds from the ASNH Program.

HOME Consortiums

Charlottesville Consortium
- Albemarle County
- Charlottesville
- Fluvanna County
- Greene County
- Louisa County
- Nelson County

New River Consortium
- Blacksburg
- Christiansburg
- Giles County
- Montgomery County
- Pulaski County
- Radford

Suffolk Consortium
- Franklin City
- Isle of Wight
- Southampton
- Suffolk

Winchester Consortium
- Clarke County
- Frederick County
- Page County
- Shenandoah County
- Warren County
- Winchester

HOME Entitlements

Alexandria
Arlington County
Bristol City (TN Consortium)
Chesapeake
Chesterfield County
Danville
Fairfax County, including
- Fairfax City
- Falls Church

Hampton
Henrico County
Lynchburg
Newport News
Norfolk
Portsmouth
Prince William County, including
- Manassas
- Manassas Park

Richmond
Roanoke City
Virginia Beach

Appendix B – HIEE Minimum Energy Efficiency Performance Requirements

HIEE Minimum Energy Efficiency Performance Requirements	
New Construction	Green building certification required* Zero Energy Ready Homes (ZERH)**
Substantial Rehabilitation	Green building certification required* Average HERS index of 70 or below across all units OR 40% improvement in HERS index Additional requirements: ACCA Manual J calculations for heating/cooling loads Fresh air ventilation and dehumidification** Duct leakage testing and sealing*** Architect cost certification of upgrades needed to meet HIEE requirements
Adaptive Reuse	Green building certification required* Average HERS index of 80 or below across all units Additional requirements: ACCA Manual J calculations for heating/cooling loads Fresh air ventilation and dehumidification** Duct leakage testing and sealing*** Architect cost certification of upgrades needed to meet HIEE requirements

*Eligible green building certifications include: LEED, EarthCraft Gold or higher, National Green Building Standard Silver or higher, and Enterprise Green Communities.

**Dehumidification strategy/equipment shall provide for occupant comfort and health by maintaining interior RH in 40-60 percent range. For renovations and adaptive reuse projects, if building/unit envelopes are tightened to new construction standards (5 ACH_{50}), ventilation system(s) shall provide fresh air supply per the most current version of ASHRAE 62.1 or 62.2, or the most current version of USBC, whichever is more stringent.

***Existing ductwork shall be sealed and tested to be ≤10 percent total duct leakage; if HVAC system/ductwork will be newly-installed, duct leakage shall meet new construction energy code requirements (≤4 percent total duct leakage).

Appendix C – Eligible Costs

For all project types, all funded development costs must be allowable:

Eligible or Allowable Costs:

- *Demolition cost*s are eligible costs, however construction must begin within 12 months
- Construction, labor, and materials costs
- Project development costs (e.g., financing fees, legal fees, affirmative action marketing)
- Up to 18 months rental project operating deficit reserve
- Relocation costs for any household in project as a part of the project development costs

Ineligible Costs:

- HOME/NHTF investments not resulting in HOME/NHTF eligible units
- Project reserves other than the rental operating (above) or beyond 18 months
- Costs for the development, operation, or modernization of any public housing
- Some specific costs related to RAD (Rental Assistance Demonstration) projects
- Items not allowed under 2 CFR 200 or not deemed cost-reasonable
- Project-based rental assistance
- Delinquent taxes, fees, charges

Appendix D – Additional Program Requirements and Compliance

Rental Projects

While final cost certification and completion reports are required at closing, progress reports may be required quarterly on each project during the development phase, and regular construction inspections may be conducted to verify progress.

Affordability periods begin after permanent conversion (DHCD loan conversion) when all closing checklist items (which may include but are not limited to completion reports, including lease up data or rent rolls, HUD-required demographic data as determined by source) are provided to DHCD for review and approval.

Assisted units have income restrictions as detailed in the Program Guidelines, with initial certification and annual recertification required. HOME- and NHTF-assisted units also have HUD-determined rent limits. Rents cannot exceed these HUD-determined rent limits, with the exception of project-based rental assistance. Rent increases over those proposed in the project application must be approved by DHCD.

The Compliance in HOME Rental Projects: Guide for Property Owners and HOME Rental Compliance Training provide more detail on income and rent requirements; Additional requirements will be detailed in an individual project's program agreement and loan commitment documents.

Long-Term Compliance

During the affordability period each project will be required to submit annual rent and occupancy reports and project financials. DHCD will verify through onsite monitoring compliance with rent, occupancy, property standards, and other programmatic requirements. **Non-compliance may suspend eligibility for subsequent commitments and could result in the repayment of all funds to DHCD.**

Projects will be inspected for property standards and program compliance within 12 months of project completion. Projects will be inspected thereafter no less than every three years. All rental projects must submit annual rent and occupancy reports and project financials. Onsite inspections and monitoring frequencies are based on performance and risk assessments.

Rental projects must meet program rent, occupancy, and property standards and other applicable federal or state requirements for the duration of the affordability period in accordance with the program agreement. Additional HOME/NHTF program investments cannot occur during this time period. Projects unable to meet these requirements or projects at-risk of non-compliance may be required to submit to more frequent monitoring, to change property management, and/or transfer ownership.

Homebuyer Projects

Project Completion

While final cost certification and completion reports are required at the end of the development phase and prior to the last reimbursement remittance or draw, progress reports may be required quarterly on each project during the development phase, and regular construction inspections may be conducted to verify progress.

For homebuyer developments assisted with any ASNH source, the final reimbursement remittance or draw (typically 10% of the total award) will not be approved until all completion documentation is submitted and approved by DHCD. Completion documentation required may include the COs for all properties named on the deed of trust by DHCD, and covered by the deferred loan agreement between the Applicant and DHCD, closing disclosures and lien documentation from each sale, and completion reports such as the HUD HOME Homebuyer Set Up/Completion report. **Non-compliance could suspend eligibility for additional funds and could result in the repayment of all funds to DHCD.**

HOME-assisted homebuyer developments automatically convert to HOME rental units for the duration of the affordability period if there if there is no ratified sales contract at nine months after the date a Certificate of Occupancy is issued to the project. HUD allows no exception to this requirement.

Value or Sales Limits

Homebuyer properties must be considered *modest*, based on property sales price or value. The sales price cannot exceed 95% of the median area purchase price, using HUD 203 (b) limits or a local market survey. No luxury homes or amenities as determined by neighborhood standards are allowed for assisted units.

Lease-Purchase Projects

Homebuyer projects may be structured as lease-purchase projects, but must be identified as lease-purchase in the application. Lease-purchase projects must convert to a tenant-purchased homebuyer unit within three years. Any units which failing to meet this requirement will convert to HOME rentals unit for the duration of the affordability period. Applicants considering this option **are required** to consult with DHCD prior to submitting an application for a project.

Resale Requirement: Homebuyer Developer Subsidy Projects

Homebuyer units assisted through developer subsidy are subject to a resale provision. A resale provision requires the assisted unit to be resold to an income eligible household if the original purchaser chooses to sell their home prior to the end of the applicable affordability period.

The developer must monitor sales, foreclosures, and title transfers to assure affordability requirements. The developer must ensure that resale requirements are imposed if the housing does not continue to be the principal residence of the occupant or family for the duration of the period of affordability, and must also ensure that the housing is only made available for subsequent purchase to a buyer whose family household qualifies as a low-income family and will use the property as its principal residence.

The resale requirement must also ensure that the price at resale provides the original assisted owner a fair return on investment, which is can be *additional* amount calculated to return, based on the homeowner's original cash/equity investment in the property and any capital improvement made to the property. This calculation limit also ensures that the housing property will remain affordable to a reasonable range of qualified low-income homebuyers for the full period of affordability as determined by DHCD according to the amount of funds invested in the housing.

A "fair return on investment*"* is determined by the resale price that takes into account a return of the initial homebuyer's initial investment plus any capital improvements made to the housing unit, which are typically set or limited based on changes in area median sales price. These factors typically establish the fair market value for the city or county that the property is located. The intent is to provide a fair return to the seller while limiting price based solely on the Median Sales Price to a potential buyer.

To determine a *"*a fair return on investment*"*, the ASNH Program will measure the percentage change in median sales prices over the period of ownership as a reasonable index that is directly related to real estate prices in the area which will simplify the resale approach by taking both market appreciation and depreciation into account. It is important to note that in certain circumstances, such as a declining housing market where home values are depreciating, the original homebuyer may not receive a return on his or her investment because the home sold for less or the same price as the original purchase price. DHCD's intent is to set a resale price that provides a fair return to the original homebuyer while ensuring that the property is affordable to the target population, thus reducing the need for additional subsidies to eligible buyers.

A capital improvement is any addition or alteration to real property that meets the following conditions:

- It substantially adds to the value of the real property, or appreciably prolongs the useful life of the real property; and
- It becomes part of the real property or is permanently affixed to the real property so that removal would cause material damage to the property or article itself.

The value of any capital improvement will be determined by the national average increase in value that a specific type of improvement brings at sale. For example, if homeowner's down payment was $5000, the value of capital improvements is $9000 and the percentage change of median sales price over ownership period was 3.5%, then a calculation of ($5000 + $9000) x 3.5= $490. The fair return on investment is $490, and the total return to the original homebuyer at resale would not exceed $14,490 ($5000 + $9000 + $490).

A *"reasonable range of low-income buyers"* is defined in the ASNH Program as a household or family at or below 80 percent of Area Median Income paying no more than 30 percent of income for principal, interest, property taxes, and insurance.

DHCD will use deed restrictions, covenants running with the land, or other similar mechanisms as the mechanism to impose the resale and continued affordability requirements as outlined in §92.254(a)(5)(i)(A) of the HOME Rule. The developer may use purchase options, rights of first

refusal or other preemptive rights to purchase the housing before any conveyance to preserve affordability. The affordability restrictions shall be revived according to the original terms if, during the original affordability period, the owner of record before the termination event, obtains an ownership interest in the housing.

Recapture Provision: Direct Homebuyer Assistance

ASNH Homebuyer HOME-assisted units including DHCD HOME Down Payment Assistance (DPA) direct buyer assistance are subject to a recapture provision in order to assure that the units either remain affordable (i.e., housing eligible clients) or that DHCD recovers its investment based on the terms of the agreement. Recapture applies and the amount to be recaptured is limited to the amount of direct buyer assistance (not the developer subsidy).

Virginia will use the recapture provision at §92.254(a)(5)(ii))1) to recapture the entire amount. The total original amount of the direct buyer assistance is recaptured from the net proceeds in the case of sale, refinance (see exception below), foreclosure or failure to maintain as primary residency prior to the end of the affordability period. In these cases the required amount returned (total assistance amount from net proceeds) is due and payable in full to DHCD to the Treasurer of Virginia.

The assistance may not be subordinated to refinancing of the first lien position primary mortgage or an equity loan or line of credit during the period of affordability except under special hardship conditions at DHCD's discretion. Affordability requirements are secured by a Restricted Deed of Covenant in the amount of direct assistance. The loan is forgiven in full at the end of the affordability period.

Attachment 35

GOVERNOR NORTHAM ANNOUNCES OVER $21 MILLION IN AFFORDABLE AND SPECIAL NEEDS HOUSING LOANS

July 8, 2021

FUNDING WILL SUPPORT NEW CONSTRUCTION AND REHABILITATION OF 1,266 AFFORDABLE AND PERMANENT SUPPORTIVE HOUSING UNITS

Governor Ralph Northam today announced more than $21 million in Affordable and Special Needs Housing loans for 24 projects across Virginia, creating or preserving 1,266 affordable housing units for low-income and extremely low-income households. The funding will improve access to affordable housing, reduce homelessness, provide permanent supportive housing options for individuals with intellectual and developmental disabilities, and complete energy efficiency updates in affordable housing units.

“Quality, affordable housing is the key to advancing equity, opportunity, and economic prosperity in every corner of our Commonwealth,” said Governor Northam. “The Affordable and Special Needs Housing program is an important resource for increasing access to safe and sustainable housing for low-income families, individuals with disabilities, and Virginians experiencing homelessness.”

The Virginia Department of Housing and Community Development (DHCD) administers Affordable and Special Needs Housing (ASNH) loans, which combine state and federal resources to provide a simplified and comprehensive application process. Funding comes from four main sources: the federal HOME Investment Partnerships Program, the federal National Housing Trust Fund (NHTF), the Virginia Housing Trust Fund (VHTF), and Housing Innovations in Energy Efficiency (HIEE) funds. In this round, DHCD awarded approximately $1.6 million in HOME funding, $1.1 million in NHTF funding, $12.6 million in VHTF funding, and $6.2 million in HIEE funding.

Governor Northam and the General Assembly invested an historic $70.7 million in the Virginia Housing Trust Fund this fiscal year, which provides financing for housing construction projects that create or preserve affordable housing units, reduce the cost of affordable housing, and increase homeownership. VHTF is a key source of

financing to support moderate- and-low-income families in addition to providing homeless reduction grants for rapid re-housing and longer-term housing solutions for individuals experiencing chronic homelessness.

“Providing housing stability and supporting programs to make homelessness rare, brief, and nonrecurring is more important now than ever as we turn the corner from this pandemic,” said Secretary of Commerce and Trade Brian Ball. “These loans will fill gaps in financing to make safe and affordable housing for our most vulnerable populations possible, which in turn strengthens our communities, our economy, and improves the lives of many Virginians across the Commonwealth.”

ASNH loans are awarded through a competitive process. Forty-one applications requesting over $45 million were received for this round of funding. Proposals were reviewed, evaluated, and scored with proposals ranked and award offers recommended to the highest-ranking proposals based on funding availability. The funded projects will leverage over $307 million in additional federal, state, local, and private lending resources.

2021 Spring Affordable and Special Needs Housing Awardees:

Friendship Court Phase I | Piedmont Housing Alliance
$1,500,000 (HIEE)
$200,000 (NHTF)
$200,000 (VHTF)
City of Charlottesville

Friendship Court Phase I is the new construction of 106 units in the phased redevelopment of the existing Friendship Court site in Charlottesville. This new construction will occur in greenspace so there will be no displacement during construction, and it will consist of both stacked townhomes and a multi-family building. Friendship Court was previously awarded funds through a competitive ASNH application, and this additional application supports the implementation of Zero Energy Ready Homes and Passive House certification standards, as well as permanent supportive housing units, which will provide select tenants with additional wraparound services on site.

Premier Circle Permanent Supportive Housing | Virginia Supportive Housing
$900,000 (VHTF)
$560,000 (HIEE)
Albemarle County

Premier Circle Permanent Supportive Housing is the construction of 80 units for formerly homeless and low-income adults from the Charlottesville region. Each studio unit will be approximately 350 square feet and contain a kitchen and full bathroom, and resident amenities include phone and computer rooms, laundry facilities, a fitness area, and free Wi-Fi. The building will have staff offices for on-site supportive services and property management, a front desk staffed 16 hours per day, and a night monitor unit. The entire building will meet Universal Design standards and EarthCraft Gold certification.

Southwood Affordable Homeownership | Greater Charlottesville Habitat for Humanity

$1,400,000 (VHTF)

Albemarle County

Southwood Affordable Homeownership is the construction of 16 single-family condo units, five single-family attached townhome units, four single-family duplex units, and one single-family detached unit. The 26 new homes will be constructed in the existing Southwood mobile home park and serve families relocating from substandard mobile homes in the park. The homes will serve residents at or below 60 percent of the Area Median Income (AMI).

Braddock Four Senior | Arlington Partnership for Affordable Housing

$700,000 (VHTF)

$655,000 (HIEE)

Fairfax County

Braddock Four Senior is the new construction of a four-story building housing 44 senior housing units. All residents will have in-unit washers and dryers, free Wi-Fi, and access to a business center, fitness room, and wellness suite. The building will have on-site property management and leasing, bilingual resident services, and active outreach to residents at risk of eviction to enable immediate and long-term stability. All units are accessible via Universal Design and are available to seniors with incomes less than 60 percent of the AMI. Braddock Four will be co-located with another senior housing community, Braddock Nine Senior.

Braddock Nine Senior | Arlington Partnership for Affordable Housing

$700,000 (VHTF)

$555,000 (HIEE)

Fairfax County

Braddock Nine Senior is the new construction of a four-story building housing 36 senior housing units. All residents will have in-unit washers and dryers, free Wi-Fi, and access to a business center, fitness room, and wellness center. The building will have on-site property management and leasing, bilingual resident services, and active outreach to residents at risk of eviction to enable immediate and long-term stability. All units are accessible via Universal Design. Four units will be available to very-low income seniors with incomes less than 30 percent of the AMI, 14 will be available to those with incomes less than 50 percent of the AMI, and the remaining will be reserved for seniors with incomes less than 60 percent of the AMI.

Bickerstaff Crossing | Surber Development and Consulting, LLC

$637,052 (VHTF)

$590,835 (HIEE)

Henrico County

Bickerstaff Crossing is the new construction of one building containing 60 two- and three-bedroom rental units serving individuals or families earning less than 30, 50, and 60 percent of the AMI. All units will be built to meet Universal Design standards and with Energy Star appliances, and five units will be fully accessible and marketed

to individuals with disabilities. The building will be EarthCraft certified, contain community space, an on-site leasing office, and shared laundry, and each unit will have washer and dryer connections. Through its established adult programs, nonprofit Soar365 will provide support services and training and education programs to residents. The building will be served by a Tenants Council.

Powhatan Terrace Townhomes | Housing Partnership, Inc.
$700,000 (VHTF)
$500,000 (NHTF)
James City County

Powhatan Terrace Townhomes is the new construction of 36 two- and three-bedroom rental townhomes spread across six two-story buildings, one of which includes a community room with free Wi-Fi for residents. The site also features a playground, greenspace, and a walking path. Five units will meet Universal Design requirements and all buildings will meet Energy Star standards. Colonial Behavioral Health will provide permanent supportive housing services to residents with intellectual or developmental disabilities or serious mental illness. Housing and financial counseling services will be available to all residents. The development will serve individuals and families with incomes less than 60 percent of the AMI.

Poplar Creek Homes 2 | Southside Outreach Group
$900,000 (HOME)
$270,000 (HIEE)
Town of South Boston

Poplar Creek Homes 2 is the new construction of 16 duplexes that will have 32 units of rental housing in a new subdivision. These two-story units will be comprised of one-, two-, and three-bedroom homes on a 1/5 acre lot with their own driveways and will meet EarthCraft Gold standards and the Department of Energy's Zero Energy Ready Homes program.

South First Phase One | Charlottesville Redevelopment and Housing Authority
$434,000 (HIEE)
$250,000 (NHTF)
$250,000 (VHTF)
City of Charlottesville

South First Street Phase One is the new construction of 62 one-, two-, and three-bedroom apartment units across three garden-style apartment buildings. The development includes substantial indoor community resource space programmed and designed by residents. Outdoor amenity spaces and access to trails and recreational space along Pollack's Branch will be available for residents and the surrounding community. The buildings will be EarthCraft Gold certified, meet passive-house standards, and support a photovoltaic array.

Newport Gardens | The Hanson Company
$850,000 (VHTF)
City of Norfolk

Newport Gardens is the new construction of 50 apartments in the Park Place neighborhood. The single building of one- and two-bedroom apartments will be EnergyStar-certified and include a gym, community space, and laundry facilities. Individual units will have granite countertops, hardwood floors, and ceramic tile as well as full size appliances and washer and dryer connections.

Crescent Halls | Charlottesville Redevelopment and Housing Authority

$735,000 (HIEE)

$100,000 (VHTF)

City of Charlottesville

Crescent Halls is the substantial rehabilitation of an eight-story building comprised of 105 apartment units for lower-income seniors in Charlottesville. This renovation includes new unit layouts, finishes, plumbing fixtures and appliances, building-wide mechanical systems and windows, elevator modernization, and roofing that will support a photovoltaic array. The renovated units will continue to serve seniors and disabled residents, providing better access through the retrofitting of 11 units that will include roll-in showers, grab bars, roll under sinks, and front controls on ranges. Renovations will also address necessary repairs to asphalt paving and create accessible parking and building routes.

Holly Court | Community Housing Partners

$700,000 (VHTF)

Lancaster County

Holly Court is the substantial rehabilitation of 40 one-bedroom senior apartments across three one-story buildings in Kilmarnock. All units will meet Universal Design standards and five units will have additional design for accessibility under Section 504. Two units will be designed to serve residents with hearing or visual impairments. Improvements include a new roof, gutters, and downspouts, replacement of cabinets, countertops, appliances, lighting and bath fixtures, installation of low-flow faucets, shower heads, and toilets as well as the replacement of the existing HVAC and water heater systems. The building will be EarthCraft Gold certified.

Goose Creek Crossing | Hill Tide Housing Investments, LLC

$700,000 (VHTF)

Augusta County

Goose Creek Crossing is the new construction of 116 units of two- and three-bedroom rental apartments across a 6.6 acre site in Staunton. The site will include a community building with an exercise area, computer room, laundry facilities, and management and maintenance offices. A playground and picnic shelter for residents will be on site and Commonwealth Catholic Charities will provide resident services such as homeownership and financial counseling and employment services. All buildings in the development will be EarthCraft Gold certified for efficiency.

Oak Terrace | Hill Tide Housing Investments, LLC

$700,000 (VHTF)

City of Suffolk

Oak Terrace is the new construction of 120 two- and three-bedroom apartments across five three-story buildings in Suffolk. The construction will be built to EarthCraft standards and include a playground and picnic shelter, a community building with laundry facilities, a computer room, and exercise area. Forty units will meet Universal Design requirements, and 12 units will be ADA-compliant with three units equipped to serve individuals with sensory impairments. Commonwealth Catholic Charities will provide financial coaching and education and employment services to tenants.

Aaron Mills Apartments | Landmark Asset Services, Inc.
$700,000 (VHTF)
City of Martinsville

Aaron Mills Apartments is the new construction of 52 one- and two-bedroom senior apartments in a single building. Every unit and all common areas will meet Universal Design standards, and the building will be EarthCraft certified. The site includes a community room with free Wi-Fi, a business center with computers and printer, an exercise room, on-site laundry facilities, a covered picnic shelter with tables and a grill, and planting gardens. Units will be equipped with LED light fixtures, energy efficient appliances and mechanical systems, front-control ranges, and in-unit washer and dryer hookups.

Brook Villas | Mark-Dana Corporation
$175,000 (HIEE)
$175,000 (HOME)
$175,000 (NHTF)
$175,000 (VHTF)
Henrico County

Brook Villas is the new construction of 84 units of one-, two-, and three-bedroom low-rise apartments in Henrico County. The apartments will be built to EarthCraft Gold standards and all 28 first floor units will meet Universal Design requirements. All apartments will be built to allow high speed internet connectivity and will have washer and dryer connections. Community laundry machines will be provided and there will be on-site leasing, a community room and fitness facilities, and financial counseling and job search services available to tenants.

Magnolia Place Apartments | TM Associates Management, Inc.
$700,000 (VHTF)
Nottoway County

Magnolia Place Apartments is the substantial rehabilitation of 56 one-bedroom senior garden-style apartments. All units will be renovated to meet Universal Design standards and will have a dishwasher. Renovations include structural work, installation of free Wi-Fi in the community building, and apartments will have WaterSense fixtures and EnergyStar appliances installed to complement the new mechanical systems, cabinets, vanities, countertops, fixtures, and appliances. The buildings will be EarthCraft Gold certified. This development will continue to serve seniors with incomes less than 50 percent of the AMI.

Dupuy Road Project | Maggie Walker Community Land Trust

$700,000 (VHTF)

Chesterfield County

Dupuy Road is the new construction of 10 three-bedroom, single family affordable homes on the site of the former Ettrick Elementary School Annex. These homes will be built in partnership with project:Homes to meet EarthCraft standards. The site will include the installation of a road, utilities, walking paths, and greenspace.

Quarry Station | Wesley Housing

$700,000 (VHTF)

City of Manassas

Quarry Station is the substantial rehabilitation of 79 units of existing one- and two-bedroom senior apartments. This renovation allows for individuals with incomes less than 40 percent of the AMI to qualify for further reduction in rent while also increasing livability of the building. The renovation scope will include improvements to HVAC systems, installation of new water-saving fixtures, improvements to the accessibility and durability of common area spaces, the addition of a single one-bedroom unit, and upgrades to the parking lot and outdoor areas.

Lambert Landing II | Woda Cooper Companies, Inc.

$700,000 (VHTF)

Chesterfield County

Lambert Landing II is the new construction of 48 family apartment units comprised of 40 two-bedroom apartments and eight three-bedroom units in a single four-story garden apartment building. The apartments will have an open layout, ample storage and closets, and unit amenities including central air conditioning, dishwashers, garbage disposals, and full-size kitchen appliances. The building will be EnergyStar certified.

Cool Lane Apartments | Virginia Supportive Housing

$602,000 (HIEE)

Henrico County

Cool Lane Apartments is the adaptive re-use of a vacant building in Henrico County. Virginia Supportive Housing will renovate the former assisted living facility into permanent supportive housing for homeless and low-income individuals. The existing structure will be redesigned and adapted to create 86 units for homeless and low-income individuals earning less than 50 percent of the AMI from Henrico County and the City of Richmond.

Canterbury Subdivision Phase II | Greater Fredericksburg Habitat for Humanity

$500,000 (HOME)

City of Fredericksburg

Canterbury Subdivision Phase II is the new construction of five single-family homes in the Mayfield neighborhood in Fredericksburg. To accommodate five new affordable homes in the existing market-rate community, the neighborhood streets, including power lines, the sewer system, and the road will be extended. Homes will be built

to EnergyStar standards, lowering the ongoing costs to homeowners, and will be sold to families making less than 60 percent of the AMI. Homebuyers will be provided with pre- and post-closing homeownership and financial counseling and will perform ‘sweat equity’ to contribute to the construction of their home.

Oak Street Aging in Place | Community Havens, Inc.

$400,000 (VHTF)

City of Manassas

Oak Street Aging in Place is the new construction of a single-level, fully ADA-accessible home with six bedrooms and adjoining baths. The site already serves five individuals in a two-story home that is not ADA-compliant. This new construction will serve individuals with intellectual or developmental disabilities who have escalating needs as they age. Residents will be able to participate in activities such as gardening and meal preparation. Once demolition of the older structure is complete, residents will have ample space for yard games and activities.

Fairview Town Homes Energy Efficiency | Helping Overcome Poverty’s Existence, Inc.

$84,000 (HIEE)

Town of Wytheville

The Fairview Town Homes Energy Efficiency project will create 12 two-bedroom units with four units reserved for permanent supportive housing. These townhomes will be part of a larger 51-unit redevelopment effort at the former Woodlawn School. The permanent supportive housing services will be provided through a memorandum of understanding with Mount Rogers Community Services.

EQUAL HOUSING OPPORTUNITY

Attachment 36

GOVERNOR NORTHAM ANNOUNCES OVER $60 MILLION IN AFFORDABLE AND SPECIAL NEEDS HOUSING LOANS

January 13, 2022

FUNDING WILL SUPPORT NEW CONSTRUCTION AND REHABILITATION OF OVER 2,500 AFFORDABLE AND SPECIAL NEEDS HOUSING UNITS

Governor Ralph Northam today announced more than $60 million in Affordable and Special Needs Housing loans for 42 projects across the Commonwealth, creating or preserving 2,552 affordable housing units for low-income and extremely low-income households. The funding will improve access to energy efficient affordable housing, reduce homelessness, provide permanent supportive housing options for individuals with intellectual and developmental disabilities, and complete energy efficiency updates in affordable housing units.

“Quality, affordable housing is essential to building vibrant communities and ensuring every Virginian has the opportunity to thrive,” said Governor Northam. “We must keep investing in the Commonwealth’s stock of affordable housing, and the Affordable and Special Needs Housing programs will continue to be a vitally important resource for vulnerable Virginians. In addition to its tremendous work supporting affordable housing, community development, and other priorities, DHCD has led our programs to keep people in their homes and support small businesses during the pandemic. I want to thank DHCD Director Erik Johnson for his superb leadership of the agency, especially during the past 22 months. He has led an outstanding and creative team in finding innovative ways to help people during a challenging time.”

The Virginia Department of Housing and Community Development administers Affordable and Special Needs Housing loans, which combine state and federal resources to provide a simplified and comprehensive application process. Funding comes from four main sources: the federal HOME Investment Partnerships Program, the National Housing Trust Fund, the Virginia Housing Trust Fund, and Housing Innovations in Energy Efficiency funds.

Governor Northam and the General Assembly invested a historic $55 million in the Virginia Housing Trust Fund this fiscal year. VHTF provides financing for housing construction projects that create or preserve affordable housing units, reduce the cost of affordable housing and increase homeownership. This funding is a key source of

financing for these affordable housing initiatives to support moderate-and-low-income families, as well as supporting homeless reduction grants to provide rapid re-housing and longer-term housing solutions for individuals experiencing chronic homelessness.

“Housing stability is more important now than it has ever been as we turn the corner on this pandemic,” **said Secretary of Commerce and Trade Brian Ball.** “These projects will help address the affordable housing needs of the Commonwealth, protect our most vulnerable, strengthen our communities, and support our economy.”

Affordable and Special Needs Housing loans are awarded through a competitive process. Fifty-five applications requesting more than $79 million were received for this round of funding. Proposals were reviewed, evaluated, and scored with proposals ranked and award offers recommended to the highest-ranking proposals based on funding availability. The funded projects will leverage over $651 million in additional federal, state, local and private lending resources.

2021 Fall Affordable and Special Needs Housing Awardees:

ASPIRE | TRG Community Development LLC

$900,000 (VHTF)

$900,000 (NHTF)

$1,764,819 (HIEE)

City of Norfolk

The ASPIRE project consists of demolition and new construction of 85 apartment units in downtown Norfolk to serve families with area median incomes (AMI) between 40% and 80%. The project will accept project-based vouchers for 21 units and will have six permanent supportive housing units.

Southwood Apartments A | Piedmont Housing Alliance

$1,600,000 (HIEE)

$900,000 (NHTF)

$900,000 (VHTF)

Albemarle County

Southwood Apartments A will be a new construction of 70 rental units in Albemarle County. These one-, two- and three- bedroom units will be available for households earning between 30% and 60% AMI. Eight units will have project-based vouchers and six units will be designated for permanent supportive housing. Piedmont Housing is working with a partner to include an onsite Head Start program for residents.

Choice Neighborhood III-R| Newport News Redevelopment and Housing Authority

$700,000 (VHTF)

$700,000 (NHTF)

$2,000,000 (HIEE)

City of Newport News

Choice Neighborhood III-R is a new construction rental project consisting of four buildings for a total of 71 units located in Newport News.

Choice Neighborhood IV-R | Newport News Redevelopment and Housing Authority

$700,000 (VHTF)

$700,000 (NHTF)

$2,000,000 (HIEE)

City of Newport News

Choice Neighborhood IV-R is a new construction rental development with 84 apartments located in Newport News.

Arna Marbella | Arlington Partnership for Affordable Housing

$700,000 (VHTF)

$2,000,000 (HIEE)

Arlington County

Arna Marbella is the renovation of 163 rental units between two properties, Marbella Apartments and Arna Valley View, in Arlington County. The project will include onsite bilingual resident services and free Wi-Fi in each unit.

Premier Circle | Virginia Supportive Housing

$900,000 (HOME)

$900,000 (NHTF)

$714,909 (HIEE)

Albemarle County

Premier Circle is the new construction of 80 units of permanent supportive housing for formerly homeless and low-income adults from the Charlottesville region. Each studio unit will be approximately 350 square feet and contain a kitchen and full bathroom. Resident amenities include phone, computer rooms, a fitness room, laundry facilities and free Wi-Fi. The building will contain staff offices for on-site supportive services and property management, a front desk staffed 16 hours per day and a night-monitor unit.

Middlebrook Trace | Taft-Mills Group

$900,000 (VHTF)

$899,530 (NHTF)

$697,470 (HIEE)

City of Staunton

Middlebrook Trace is the new construction of 82 rental units in Staunton. Eight units will be reserved for permanent supportive housing, and 15 units will accept project-based vouchers. The project will include two- and three-bedroom units. The project will include services to tenants with intellectual and/or developmental disabilities.

CRHA South First Phase Two | Charlottesville Redevelopment and Housing Authority

$400,000 (NHTF)

$2,000,000 (HIEE)

City of Charlottesville

South First Phase Two is a new construction project of 113 rental units in Charlottesville. The project includes one-, two-, three- four-, and five-bedroom apartments across 21 buildings. Fifty-eight of the units will have either a Section 8 or Section 9 subsidy. The project will include a program, in partnership with the Charlottesville Office of Economic Opportunity and Piedmont Virginia Community College, to provide job training. The development also includes substantial indoor community resource space, outdoor amenity spaces, access to trails and recreational space along Pollack's Branch.

Arbors at Birchwood | Marlyn Development Corporation

$100,000 (VHTF)

$2,000,000 (HIEE)

City of Virginia Beach

Arbors at Birchwood is a new construction rental unit development for elderly persons 62 and older on 4.92 acres in Virginia Beach. This project will consist of 150 units designed to meet accessibility needs of residents.

Fairfax Hall | South River Development Corporation

$350,000 (VHTF)

$350,000 (NHTF)

$1,300,000 (HIEE)

City of Waynesboro

Fairfax Hall is an existing project serving primarily senior households in an historic structure in the former Brandon Hotel. This project proposes to retrofit the existing 54 apartments to meet physical accessibility requirements and promote universal access. This project aims to improve energy and operating efficiency by replacing outmoded systems, adding insulation and minimizing water waste. The project has 12 project-based vouchers through Waynesboro Redevelopment and Housing Authority.

Southwood Apartments B | Piedmont Housing Alliance

$900,000 (VHTF)

$1,075,000 (HIEE)

Albemarle County

Southwood Apartments B is a new construction of 51 rental units in Albemarle County. All units will be available for households at or below 60% AMI, with four designated permanent supportive housing units. Piedmont Housing is working with a partner to include an onsite Head Start program for residents.

Watermark Gardens | Surber Development and Consulting LLC

$600,925 (VHTF)

$600,925 (NHTF)

$638,150 (HIEE)

Chesterfield County

Watermark Gardens is the new construction of 80 rental units in Chesterfield. The project will provide services to tenants with intellectual and/or developmental disabilities and the project will accept project-based vouchers.

Horner | Better Housing Coalition

$900,000 (VHTF)

$900,000 (HOME)

Chesterfield County

Horner is the new construction of a 49-unit apartment building in Chesterfield County, comprised of one-, two- and three-bedroom apartments serving families with incomes up to 60% AMI. This development is designed to be pedestrian friendly with well-lit sidewalks, a walking trail, and both active and passive recreation sites. Residents will have access to a fitness room and a community room, which will be programmed with financial literacy classes.

The Villas on Main | Cumberland Plateau Redevelopment and Housing Authority

$450,000 (HOME)

$450,000 (VHTF)

$450,000 (NHTF)

$347, 550 (HIEE)

Russell County

The Villas on Main is a new construction independent residential facility project consisting of 21 units across 10 buildings located in Lebanon. All 21 units will meet Universal Design Standard and include patios and front gardens for the residents. The Villas on Main will serve low-income seniors and disabled persons. The Villas on Main will partner with local service providers to bring supportive services and partner with local agencies to provide transportation for residents.

Townhomes at Liberty Place | Cantebury Enterprises

$700,000 (VHTF)

$900,000 (HOME)

City of Richmond

The Townhomes at Liberty Place are the new construction of 39 rental townhomes in Richmond. The townhomes will consist of a mix of one-, two- and three-bedroom units and for families with incomes between 40-60% AMI. All units will meet Universal Design standards.

Colbrook | Better Housing Coalition

$700,000 (VHTF)

$700,000 (HOME)

Chesterfield County

Colbrook is the adaptive reuse of the historic Colbrook Motel to provide 47 affordable apartments in Chesterfield County. There will be a mix of one-, two- and three-bedroom units. Five units will be set aside for Chesterfield Community Service Board (CSB) clients who will receive rental assistance through the CSB. This project will include a standalone building to provide community space and a museum to honor the motel's previous appearance in the “Green Book,” a travel guide for African Americans during segregation.

Brinshore Block 17 | Brinshore Development, LLC

$700,000 (VHTF)

$700,000 (NHTF)

City of Norfolk

Block 17 Apartments is part of a HUD Choice Neighborhood Initiative and will consist of 68 newly constructed rental units in Norfolk. These units will be a mix of market-rate units and units dedicated for families earning between 30-60% AMI. The units will come with free Wi-Fi and residents will have access to Crestar Health, a nearby Mental Health Clinic, at no cost.

Brinshore Block 18 | Brinshore Development, LLC

$700,000 (VHTF)

$700,000 (NHTF)

City of Norfolk

Block 18 Apartments is part of a HUD Choice Neighborhood Initiative and will consist of 72 newly constructed rental units in Norfolk. These units will be a mix of market rate units and units dedicated for families earning between 30%-60% AMI. Block 18 Apartment residents will have access to Crestar Health, a nearby Mental Health Clinic, at no cost.

Spring Creek, Coleman and Cleveland | Greater Charlottesville Habitat for Humanity

$700,000 (HOME)

$700,000 (VHTF)

Louisa County and City of Charlottesville

Spring Creek, Coleman and Cleveland is a new construction home-buyer project consisting of eight units among three sites. Spring Creek is located in Louisa County, and Coleman Court/Cleveland Avenue is located in the city of Charlottesville. Spring Creek consists of four single-family, four-bedroom homes sitting on .25 acre lots. Coleman Court and Cleveland will consist of two duplex units located within established neighborhoods in Charlottesville. All eight homebuyer units will incorporate Universal Design concepts.

Bellwood Crossing | Hill Tide Investments

$700,000 (VHTF)

$700,000 (NHTF)

Chesterfield County

Bellwood Crossing is a new construction rental property, and this development will consist of 102 units with one- and two-bedroom options. Of the total units, 15 will be allocated for veterans, and up to 10 units will be available for lease through the Chesterfield County Community Services Board. All units will prioritize persons on the public housing waiting list and/or Section 8 of the Richmond Redevelopment and Housing Authority.

Ashlake Trails | Mark-Dana Corporation

$700,000 (VHTF)

$700,000 (HIEE)

Chesterfield County

Ashlake Trails is a low-rise new construction rental development for seniors (55+) comprised of 67 units. The project will consist of 36 one-bedroom units and 31 two-bedroom units. Each unit will be provide free individual Wi-Fi access.

Saint Elizabeth Apartments | Commonwealth Catholic Charities

$800,000 (VHTF)

$500,000 (NHTF)

City of Richmond

Saint Elizabeth Apartments is the new construction of 56 apartments comprised of studios, one-, two-, and three-bedroom units across15 buildings. The apartments would serve families with incomes between 30% and 60% AMI, and would have a community building, playground, and on-site rental office. Six units will be reserved for individuals living with HIV/AIDS that receive HOPWA tenant-based vouchers as well as financial counseling and case management.

Winchester Forest 4 | Better Housing Coalition

$350,000 (VHTF)

$915,000 (HIEE)

Chesterfield County

Winchester Forest 4 is the new construction of 88 one-, two- and three-bedroom rental apartments in North Chesterfield County. Winchester Forest 4 is an expansion of Winchester Greens and Market Square. Site-based services will be provided to improve residents' academic, health and economic outcomes.

Grande Oak III | Surber Development

$375,062 (VHTF)

$375,062 (NHTF)

$499,875 (HIEE)

City of Williamsburg and York County

Grande Oak III is the new construction of 49 rental units in York County. The project has two-bedroom apartments, all of which will fit Universal Design standards and be actively marketed towards people with disabilities.

Wellesley | Community Housing Partners

$900,000 (VHTF)

$285,000 (HIEE)

City of Newport News

Wellesley is the substantial renovation of an existing three-story, 40-unit building in Newport News. All units will serve residents over the age of 55, with an income at or below 50% AMI. All units will be occupied by households receiving project-based Section 8 vouchers. The proposed acquisition and rehabilitation will include but is not limited to new flooring, roofing, windows, mechanical systems, appliances, cabinetry, kitchen and bathroom fixtures.

Cross Creek Rehab | Community Housing Partners

$600,000 (VHTF)

$546,000 (HIEE)

City of Portsmouth

Cross Creek Rehab is an existing affordable multifamily development in the city of Portsmouth comprised of 78 two- and three-bedroom garden-style apartments, which will serve families with incomes between 40-80% AMI. Seven units will be reserved for permanent supportive housing and eight for project-based vouchers. This project proposes new flooring, windows, mechanical systems, appliances and fixtures and increased accessibility for eight units.

HRHA Lineweaver Annex Renovation | Harrisonburg Housing and Redevelopment Authority

$900,000 (VHTF)

$230,000 (HIEE)

City of Harrisonburg

The Lineweaver Annex is an extensive rehabilitation rental project located in downtown Harrisonburg. This rehabilitation consists of 60 one-bedroom units designated for the elderly and persons with disabilities, and 20 of the 60 units will be reserved for permanent supportive housing.

Grayson Manor | Community Housing Partners

$900,000 (VHTF)

$161,180 (HIEE)

Grayson County

Grayson Manor is an existing 32-unit affordable senior development with one-bedroom, garden-style units. This project will acquire and renovate Grayson Manor, with rehabilitation to include new flooring, windows, mechanical systems, fixtures and appliances. In addition, five units will be made more accessible. The units will serve seniors with income at or below 60% AMI.

Leggett Building Apartments | Taylor Hollow Construction

$700,000 (HOME)

$239,700 (HIEE)

City of Radford

The Leggett Building Apartments will convert the former Leggett Building in Radford into 11 mixed-income rental units. Seven of the units will be for households earning up to and between 50% and 60% AMI, and four will be market rate. The project will include free broadband access for tenants and is located in downtown Radford.

Mt. Sterling Nine | Arlington Partnership for Affordable Housing

$900,000 (VHTF)

Loudoun County

Mt. Sterling Nine is the new construction of 48 rental units for seniors in Loudoun County. The project will be a mix of one- and two-bedroom apartments. Residents will have access to free Wi-Fi in unit and communal spaces, as well as access to community amenities, such as a business center and a fitness and wellness suite. Five units will be available for seniors at 30% AMI and the remaining 43 will be available for seniors at 50% AMI.

Oak Terrace | Hill Tide Housing Investments, LLC

$700,000 (VHTF)

City of Suffolk

Oak Terrace is the new construction of 120 two- and three-bedroom apartments across five three-story buildings in Suffolk. The buildings will be built to EarthCraft standards and include a playground, picnic shelter, a community building with laundry facilities, a computer room and exercise room. Twelve units will comply with ADA requirements, with three units equipped to serve individuals with sensory impairments. Commonwealth Catholic Charities will provide financial coaching, education and employment services to tenants.

Goose Creek Crossing | Hill Tide Housing Investments, LLC

$700,000 (VHTF)

City of Staunton

Goose Creek Crossing is the new construction of 116 units of two- and three-bedroom rental apartments across a 6.6 acre site in Staunton. The site will include a community building with an exercise room, computer room, laundry facilities, and management and maintenance offices. A playground and picnic shelter for resident use will also be onsite. The development will be served by Commonwealth Catholic Charities to provide resident services such as homeownership, financial counseling and employment services.

Expanding Affordable Housing 2020-2021 | Richmond Habitat for Humanity

$700,000 (VHTF)

City of Richmond

Expanding Affordable Housing is the new construction of eight affordable homes. The scattered-site homes will be available for purchase by families earning up to between 40% and 80% AMI. All homes will be built to EarthCraft and Energy Star standards and four will be built to meet Universal Design standards.

Mecklenburg Manor | NFP Affordable Housing Corporation

$700,000 (VHTF)

Mecklenburg County

Mecklenburg Manor is an extensive rehabilitation of an existing Section 8 and family complex. This rehabilitation will consist of eight buildings for a total of 51 units. This project will continue to prioritize Section-8 applicants, located in South Hill. Upon completion the project will be Enterprise Green Communities certified.

Sweetbriar II Apartments 2021 | People Inc. Housing Group

$517,000 (HIEE)

Washington County

Sweetbriar II Apartments is a new construction rental development located in Abingdon. This development will consist of 22 units in 11 duplex-style buildings and comprised of two- and three-bedroom garden-style townhome units. Five of the garden-style units will be fully accessible, and six will include Universal Design features. The accessible units will be subsidized with project-based Mainstream Vouchers with prioritization of low-income households with disabilities.

Covenant Heights VII | Hope Community Builders

$500,000 (HOME)

Rockingham County

Covenant Heights will consist of eight new construction homebuyer units in two buildings located in Rockingham County. These units will be used to help low-income and first-time homebuyers.

Cool Lane Apartments | Virginia Supportive Housing

$466,872 (HIEE)

Henrico County

Cool Lane Apartments is the adaptive re-use of a vacant building located in Henrico County. The project will renovate the former assisted living facility into permanent supportive housing for homeless and low-income individuals. The existing structure will be redesigned and adapted to create 86 units for homeless and low-income individuals earning 50% or less AMI from Henrico County and the city of Richmond.

Fifeville Rehab | Piedmont Housing Alliance

$300,000 (VHTF)

$32,500 (HIEE)

City of Charlottesville

Fifeville Rehab is the rehabilitation of five vacant units across three buildings in Charlottesville for the sale to households at or below 50% AMI. Improvements to the properties include the addition of solar panels, the modernization of kitchens and upgrades to promote energy-efficiency and home health.

712-714 High Street | Southside Community Housing and Development Corporation

$300,000 (HOME)

City of Petersburg

High Street is the new construction of 12 rental units in Petersburg. The one-, two- and three-bedroom apartments will be targeted for households earning up to and between 30% and 80% AMI. This project will contribute two permanent supportive units to the region. Two of the units will be accessible for physically impaired persons. This project will accompany the 714 High Street project already funded by ASNH, bringing 22 total units, 12 of which are permanent supportive housing.

Holly Court | Community Housing Partners

$231,220 (HIEE)

Lancaster County

Holly Court is the substantial rehabilitation of 40 one-bedroom senior apartments across three one-story buildings in Kilmarnock. All units will meet Universal Design standards, and five units will have additional design for accessibility under Section 504. Two units will be designed to serve residents who have hearing or visual impairments. Improvements include a new roof, gutters, downspouts, replacement of cabinets, countertops, appliances, lighting and bath fixtures, installation of low-flow faucets, shower heads, toilets and the replacement of the existing HVAC and water heater systems.

Mt. Sterling Four | Arlington Partnership for Affordable Housing

$200,000 (VHTF)

Loudoun County

Mt. Sterling Four is the new construction of 50 rental units for seniors in Loudon County. The project will be a mix of one- and two-bedroom apartments. Residents will have access to free Wi-Fi in unit and communal spaces, as well as access to community amenities, such as a business center and a fitness and wellness suite. Five units will be available for seniors at 30% AMI and five units will be available for seniors at 50% AMI, with the remaining 40 available for seniors at 60% AMI. Mt. Sterling Nine will be co-located with Mt. Sterling Nine.

Armstrong Renaissance | Better Housing Coalition

$200,000 (VHTF)

City of Richmond

Armstrong Renaissance is a new construction project of 36 homes for purchase in Richmond. Twenty-eight of the units will be at market rate, and eight will be for homebuyers at or below 80% AMI. The project provides $15,000 in down payment assistance to eligible homebuyers. The development is next to a new supermarket, a community college and a library.

EQUAL HOUSING OPPORTUNITY

Attachment 37

Community Flood Preparedness Fund Grants and Loans

Virginia Community Flood Preparedness Fund Grant

The Virginia Community Flood Preparedness Fund (CFPF) was established to provide support for regions and localities across Virginia to reduce the impacts of flooding.

Round 1 Grant Awards (Announced Oct. 5, 2021) see below

Round 2 Grant Awards (Announced Dec. 22, 2021) see below

Round 3 Grant Awards (Announced Sept. 28, 2022)

Staffing, planning and assessments | $375,000.00
Accomack-Northampton PDC
Application (PDF) | **Scoring Sheet** (PDF)

Resilience Plan | $54,000.00
Central Virginia Planning District Commission
Application (PDF) | **Scoring sheet** (PDF)

Staffing and planning assessments | $332,505.00
Tazewell County
Application (PDF) | **Scoring sheet** (PDF)

Floodplain staff and resilience plan | $54,000.00
Town of Buchanan
Application (PDF) | **Scoring sheet** (PDF)

Resilience Plan and floodplain staff capacity | $140,590.00
City of Covington
Application (PDF) | **Scoring sheet** (PDF)

Resilience Planning | $75,656.00
Grayson County
Application (PDF) | **Scoring sheet** (PDF)

Resilience Planning | $51,300.00
Town of Clintwood
Application (PDF) | **Scoring sheet** (PDF)

Staffing capacity | $2,969.37
Shenandoah County
Application (PDF) | **Scoring sheet** (PDF)

Drainage study | $357,380.00
City of Covington

Application (PDF) | **Scoring sheet** (PDF)

H&H Studies to Update FEMA Maps | $90,000.00
Town of Front Royal
Application (PDF) | **Scoring sheet** (PDF)

Finney Outfall to Nansemond River Drainage Area Study in Downtown Suffolk | $65,593.00
City of Suffolk
Application (PDF) | **Scoring sheet** (PDF)

Acquisition, flood proofing, restoration | $2,232,415.00
Dickenson County
Application (PDF) | **Scoring sheet** (PDF)

Riverside Memorial Cemetery Shoreline Stabilization | $1,120,000.00
City of Norfolk
Application (PDF) | **Scoring sheet** (PDF)

Storm water system | $2,800,878.00
City of Petersburg
Application (PDF) | **Scoring sheet** (PDF)

First Colonial Road and Oceana Boulevard Stormwater Improvements | $2,021,662.50
City of Virginia Beach
Application (PDF) | **Scoring sheet** (PDF)

Resilience Planning | $119,755.00
City of Fairfax
Application (PDF) | **Scoring sheet** (PDF)

Resilience Plan | $30,300.00
King George County
Application (PDF) | **Scoring sheet** (PDF)

Floodplain staff and resilience plan | $118,313.00
Albemarle County
Application (PDF) | **Scoring sheet** (PDF)

Resource Assessments, planning, strategies, development | $94,545.00
Henrico County
Application (PDF) | **Scoring sheet** (PDF)

2-Dimensional Stormwater Management Model for Meadow Creek and Rivanna River Watersheds | $275,000.00
City of Charlottesville
Application (PDF) | **Scoring sheet** (PDF)

Study to assess changes in watershed hydrology using existing streamflow and precipitation monitoring data from Four Mile Run | $68,974.00
Northern Virginia Regional Commission
Application (PDF) | **Scoring sheet** (PDF)

Kimberly Bridge Feasibility Study | $149,373.50
City of Suffolk
Application (PDF) | **Scoring sheet** (PDF)

Mosby Wood Floodplain Improvement Study | $24,286.00
City of Fairfax
Application (PDF) | **Scoring sheet** (PDF)

Hydraulic and hydrologic study of the Goose Creek watershed/floodplain | $92,500.00
City of Chesapeake
Application (PDF) | **Scoring sheet** (PDF)

Inlet Capacity and New Inlet Program ("Inlet Program") | $764,000.00
City of Alexandria
Application (PDF) | **Scoring sheet** (PDF)

Mount Vernon Dual Corrugated Metal Pipe Culvert Replacement and Optimization | $1,250,000.00
City of Alexandria
Application (PDF) | **Scoring sheet** (PDF)

Gambles Mill Pump Station | $870,244.00
Henrico County
Application (PDF) | **Scoring sheet** (PDF)

Supplemental Review List (PDF)

Round 2 Grant Awards (Announced Dec. 22, 2021)

Waterfront Improvement Project Design (PDF) | $3,241,200
City of Alexandria

Arlandria Flood Mitigation – Edison Street and Dale Street Capacity Project Phase I (PDF) | $516,500
City of Alexandria

Staff Training and Certification (CFM) (PDF) | $2,579
Town of Ashland

Resilience Plan (PDF) | $60,051
Town of Ashland

Resilience Planning and Staff Training (PDF) | $94,276
City of Charlottesville

Resilience Plan (PDF) | $44,520.30
Town of Christiansburg

Resilience Plan Development and Training (PDF) | $103,500
Town of Colonial Beach

Big Bethel Blueway; Albany Drive at Big Bethel Road (PDF) | $3,008,500
City of Hampton

Sunset Creek Urban Channel Naturalization Project (PDF) | $2,022,143
City of Hampton

Billy Woods Canal (PDF) | $291,850
City of Hampton

Lake Hampton and North Armistead Avenue (PDF) | $3,841,544
City of Hampton

Pilot Project Development; Dashboard; Education and Outreach (PDF) | $361,500
Henrico County

Resilience Plan Development and Training (PDF) | $68,026
Isle of Wight County

Capacity Building and Planning (PDF) | $150,000
Lenowisco PDC

MPPDC Capacity Building (PDF) | $35,250
Middle Peninsula PDC

Dredging Project (PDF) | $336,000
Middlesex County

Master Plan Development, Stormwater, Floodplain, Resilience and Climate Change Management (PDF) | $4,926,063
City of Newport News

Watershed Master Plan Study and Purchase of Flood Sensors (PDF) | $315,000
City of Norfolk

Hazard Mitigation Plan Update (PDF) | $45,000
Northern Neck PDC

Data collection of regional significance, creation of tools and applications, dashboard for real-time flooding risk data (PDF) | $11,250
Northern Virginia Regional Commission

Resilience Plan Development and Staff (PDF) | $385,016
City of Petersburg

Comprehensive Citywide Drainage Study and FP Ordinance Update (PDF) | $2,238,542
City of Petersburg

Planning and Capacity Building-Staff (PDF) | $23,153
City of Richmond

Resilience Plan Development - Windsor Farms (PDF) | $19,394
City of Richmond

Resilience Plan Development (PDF) | $135,000
City of Roanoke

Town of Scottsville Study (PDF) | $123,346
Town of Scottsville

Capacity Building for Flood Resilience in Southern Virginia (PDF) | $135,000
Southside Planning District Commission

Hoskins Creek and Rappahannock River (PDF) | $69,920
Town of Tappahannock

Stormwater Project -South Birdneck Road between Hughes Avenue and Sea Street (PDF) | $1,925,000
City of Virginia Beach

West Point Study (PDF) | $22,800
Town of West Point

Round 1 Grant Awards (Announced Oct. 5, 2021)

Eastern Branch of Elizabeth River Wetland and Floodplain Restoration (PDF) | $3,000,000
City of Virginia Beach

McGuire and Chapel Drive Drainage Improvements Project (PDF) | $1,100,000
City of Richmond

Norfolk Coastal Storm Risk Management Analysis (PDF) | $900,000
City of Norfolk

Portsmouth's Data-Driven and Equity-Driven Resilience Strategy (PDF) | $527,949
City of Portsmouth

Lake Whitehurst Watershed Study (PDF) | $500,000
City of Norfolk

Plans and Capacity Building with Consultant Services (PDF) | $387,500
Buchanan County

Oyster Plan - Capacity Building and Resilience Planning (PDF) | $202,232
Northampton County

Resilient Hampton: Downton Hampton, Phoebus and Buckroe Beach (PDF) | $158,681
City of Hampton

Moores Creek Watershed (PDF) | $153,500
City of Charlottesville

Honor Park Resilience Project (PDF) | $147,994
City of Hampton

Mill Point Living Shoreline (PDF) | $126,498
City of Hampton

Resilient Stormwater Capacity and Green Streets Project (PDF) | $115,200
City of Alexandria

Richmond Manchester and Shockoe Bottom Neighborhoods (PDF) | $103,500
City of Richmond

Southern Chesapeake - Watershed 5 (PDF) | $91,404
City of Chesapeake

Resilience Plan (PDF) | $74,997
City of Chesapeake

Capacity Building and Planning (PDF) | $68,024
City of Suffolk

Resilience Plan (PDF) | $65,040
City of Winchester

The Impacts of Climate Change on Crop Planning and Production: An Agricultural Study of the Eastern Shore (PDF) | $47,121
Accomack-Northampton Planning District Commission

Carlton Road Boat Ramp, Wake, Virginia - Design and Permitting (PDF) | $26,400
Middle Peninsula Planning District Commission (Middlesex County)

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Attachment 38

Media Center - Press Release

Media inquiries: Please contact Dave Neudeck, **dave.neudeck@dcr.virginia.gov**, 804-786-5053.

FOR IMMEDIATE RELEASE
Date: September 28, 2022
Contact: Rebecca Jones, Senior PR and Marketing Specialist, 804-786-2292, rebecca.jones@dcr.virginia.gov

Virginia announces $13.6 million in Community Flood Preparedness Fund grant awards
Additional funds for grant round 3 will be released after supplemental review period

RICHMOND — The Virginia Department of Conservation and Recreation today announced $13.6 million in awards from the Virginia Community Flood Preparedness Fund.

Twenty-seven applications for flood prevention and protection projects including mitigation, capacity building, planning and studies were funded in communities across the commonwealth.

Grant round 3 was initially advertised for $40 million. DCR received 64 applications with grant requests totaling nearly $93 million.

DCR therefore also announced that 32 proposals totaling $68 million in requests would be given a 60-day supplemental review period, allowing applicants to correct application deficiencies and submit additional information.

Finally, in order to support as many beneficial projects as possible, DCR announced that it has been authorized to release an additional $30 million in funding for grant round 3.

“The impacts of flooding are felt across the commonwealth, and Governor Youngkin has ensured that resiliency and flood mitigation efforts are a priority for this administration,” said Travis Voyles, Virginia’s acting secretary of natural and historic resources and chief resilience officer. “These projects will support important flood protection and resilience efforts in inland and coastal communities across Virginia.”

DCR, in cooperation with the Virginia Resources Authority, administers the fund and grant program. It oversees the commonwealth’s floodplain management program and is responsible for the development of the Coastal Resilience Master Plan and the Virginia Flood Protection Master Plan.

DCR Director Matthew Wells said, “We are pleased to award this initial group of grants and look forward to working with applicants who require additional review. Given the importance of addressing flooding and resilience challenges, and the level of interest in this grant round, we are extending this opportunity broadly to applicants with potentially viable projects. This supplemental review period and the release of additional funds will allow us to support critical projects now, rather than waiting for a future grant round.”

As a part of its commitment to transparency, DCR has made all grant round 3 applications available on its website. The list of approved projects, along with scoring sheets, will be posted later this week. The agency plans to release grant round 4 in early 2023, along with the initial round of the newly created Resilient Virginia Revolving Fund. Information is available at **https://www.dcr.virginia.gov/dam-safety-and-floodplains/dsfpm-cfpf**.

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Attachment 39

ENERGY + ENVIRONMENT GOVERNMENT + POLITICS

Flood Fund future uncertain as Youngkin pushes for carbon market withdrawal

State racks up $203 million for flood protection from RGGI revenues

BY: **CHARLIE PAULLIN** - SEPTEMBER 30, 2022 12:02 AM

Increased precipitation and sea level rise are leading to more frequent flooding in Virginia. (NBC12)

In January, strong winds led to high tides drowning parts of Hampton. Some roads were impassable, with water levels rising to near the top tread of the tires. Almost two years prior, stormwater had led to flooding severe enough to sweep parked cars down the roadways.

With climate change driving sea levels up and altering rainfall patterns, Hampton is certain to continue to be hit by flooding. What's less certain is where it will get funding to combat it.

Over the past two years, Virginia has accumulated over $200 million for flood protection from the state's participation in the Regional Greenhouse Gas Initiative. But the future of that funding pool is in doubt as Republican Gov. Glenn Youngkin has made it clear he wants to leave the initiative.

Gov. Glenn Youngkin. (Ned Oliver / Virginia Mercury)

"RGGI is a bad deal for Virginia," said Travis Voyles, acting secretary of natural and historic resources, when he outlined the administration's plans for withdrawing Virginia from RGGI at the end of last month.

RGGI is the 11-state cap-and-invest program in which energy producers must buy allowances at auction for the carbon they emit, and a cap is placed on overall carbon emissions.

The proceeds of those auctions are returned to the state. In Virginia, half is directed to low-income energy efficiency programs, while 45% goes toward the Community Flood Preparedness Fund, a pool of money that provides flood assistance to communities and local governments.

Including the latest sale of allowances on Sept. 7, Virginia has received some $452 million from RGGI, meaning $203 million will go toward flood resiliency efforts.

Local flood protection

Whether flooding occurs on Virginia's coast from sea level rise or in its inland areas from rainfall increases, the impacts are real, said Skip Stiles, executive director of Wetlands Watch, a Norfolk-based nonprofit working to address sea level rise adaptation, floodplain management and other waterway impacts.

Prior to Virginia joining RGGI in 2020 – a Democratic priority during the party's brief period in power – flood protection was left up to local and regional planning bodies, with no central pool of funds governments could draw from. Since the state joined, the Department of Conservation and Recreation, which administers the Flood Fund, has begun paying out grants from the revenues.

"Before Virginia joined RGGI there were ZERO state dollars going toward these resilience efforts," said Stiles in an email.

Any state spending on these efforts through the Virginia Coastal Zone Management Program, Virginia Sea Grant or the Virginia Department of Emergency Management used money derived from federal agencies, he said.

“We have to assume that if we leave RGGI we will return to that low-priority status for this work,” Stiles said.

The Flood Fund has proved to be “absolutely helpful” to combat problems linked to climate change, particularly stormwater issues and sea level rise, said City of Hampton Resiliency Officer Carolyn Heaps-Pecaro.

“We have a lot of projects lined up,” she said. “We have a lot of ideas for how to fix the town. We need that money to actually make them a reality.”

Hampton was the largest recipient of the second round of grants announced in December from the proceeds, receiving about a third of the $24.5 million the Flood Fund paid out. The projects that were funded included plans for elevating a roadway, improving drainage canals and reducing nutrient pollution.

Millions in local funding is needed to complete the projects, but the state funds help cover design and engineering costs to begin them, Heaps-Pecaro said.

“Several of these projects probably would not have moved forward nearly as quickly as they did had we not received the grant funding,” she said.

Flood Fund dollars also go toward projects outside of coastal areas. In the first round of grants, announced in October 2021, $400,000 was awarded to Buchanan County.

An underpass in Big Rock, Buchanan County, on Aug. 31, 2021. (Sarah Vogelsong / Virginia Mercury)

The Southwestern Virginia locality had been slammed with devastating floods the prior August. The region also suffered severe flooding this July and, according to a Thursday morning update from the National Hurricane Center and Central Pacific Hurricane Center, could lie in the pathway of Hurricane Ian.

The Buchanan funding is intended to go toward an engineering analysis that would lead to a local flood resilience plan and training for a staff member to become a certified floodplain manager.

A quarter of Flood Fund dollars need to go to low-income communities, a designation Buchanan qualifies for, with a median income that in 2019 was less than half of the state's average.

"Buchanan County and our neighbors in Southwest Virginia have experienced devastating recurrent flooding that has increased in recent years," the county's application stated. "Flooding is often thought of as a coastal problem, but we are pleased to see that DCR seeks to direct some of this fund to mountainous and disadvantaged communities such as ours."

An unclear future

While Youngkin has been adamant that he believes Virginia should withdraw from RGGI, the administration's plans for how the state will help local governments pay for the massive costs of flood protection are less clear.

Youngkin has been arguing for months that RGGI proceeds are being generated from an unfair "tax" on electric utility ratepayers. Virginia utilities, which are responsible for about three-quarters of the carbon emissions subject to RGGI, are allowed to pass on the cost of buying allowances to their customers, an approach Youngkin says is flawed.

"RGGI was sold to Commonwealth residents as a deal that returned the 'proceeds' to the ratepayers to offset the costs of the program, but that is not what is happening," a statement from the governor's office to the Mercury said. "We can provide funding for flood resiliency in a transparent way without using an RGGI tax on Virginians."

Youngkin's office said the administration intends to develop a plan to provide direct funding for flood resiliency with the General Assembly. That would require buy-in from Senate Democrats.

But when pressed for specifics of the plan, such as whether it will be crafted through legislation or the budget process, which can involve fluctuating revenues and regular competition among different interests competing for a piece of the pie, the governor's office didn't clarify beyond saying it will "provide direct funding and coordination for flood resiliency."

“We can do this in a way that is transparent and not a hidden tax that was misrepresented to Virginians,” the governor’s office stated. “This will ensure we have a long-term comprehensive strategy to sustain flood resilience efforts in Virginia.”

Millions of dollars remain uncommitted

Even while the future of the Flood Fund remains uncertain, millions of dollars remain on its books.

Before leaving office, Gov. Ralph Northam’s administration awarded two rounds of grants in the last three months of 2021 equal to $32.3 million.

A third round of $13.6 million was announced Wednesday, nine months into Youngkin’s term.

Flood Fund oversight to remain with executive branch

Virginia’s Community Flood Preparedness Fund, a pot of millions of dollars earmarked for community flood protection work across the state, will remain under the oversight of the executive branch despite recent legislative efforts to shift authority to an appointed citizen board. Gov. Glenn Youngkin has vetoed legislation that would have transferred administration of the Flood … Continue reading

Virginia Mercury

Round 3 was initially advertised to award $40 million, but with applications requesting nearly $93 million, DCR said it has been authorized to release an additional $30 million. The agency is allowing 32 applicants to revise and resubmit their proposals and plans to make a decision on them by the end of the year.

If DCR awards all $70 million it’s been authorized to grant during the third round, Virginia will have spent about 50% of its Flood Fund revenues to date, with just over $100 million left to be designated.

A DCR spokesperson said plans for that unused funding include “future grant rounds as well as loan opportunities going forward.” A fourth application round is expected to be opened in early 2023, along with the first round of the newly created Resilient Virginia Revolving Loan

Fund, which will provide loans or grants for resilience to not only local governments, but also residents.

Increasing climate impacts

Stiles pointed to data from Carnegie Mellon University, the Northeast Regional Climate Center at Cornell University and the RAND Corporation showing that rainfall intensity has increased an average of 18% since 2006.

Increased rainfall in the state has been documented for years, and the Virginia Coastal Resilience Master Plan projects that between 2020 and 2080, the number of residents living in homes exposed to major coastal flooding will grow from approximately 360,000 to 943,000, an increase of 160%. The report also found that more residential, public and commercial buildings will be exposed to extreme coastal flooding, while annualized flood damages will increase from $0.4 to $5.1 billion.

What's more, a recent Climate Central study found that rising water levels on land reduce the amount of property that local governments can tax.

"Climate change isn't going away," Heaps-Pecaro stated. "We have to accelerate" the fight against it.

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CHARLIE PAULLIN

Charles Paullin covers energy and environment for the Mercury. He previously worked for Northern Virginia Daily in the Northern Shenandoah Valley and for the New Britain Herald in central Connecticut

Virginia Daily in the Northern Shenandoah Valley and for the New Britain Herald in central Connecticut. An Alexandria native, Charles graduated from the University of Hartford initially wanting to cover sports. He's received several Virginia Press Association awards for his coverage of crime, local government and state politics. Catch him in nature experiencing all the outdoors has to offer, and contact him at cpaullin@virginiamercury.com.

MORE FROM AUTHOR

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Attachment 40

AFFORDABLE AND SPECIAL NEEDS HOUSING (ASNH)

HOME Funds

The HOME Program: HOME Investment Partnerships are grants to states and units of general local government to implement local housing strategies designed to increase homeownership and affordable housing opportunities for low- and very-low-income Americans

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National Housing Trust Fund

The National Housing Trust Fund is an affordable housing production program that complements existing Federal, state and local efforts to increase and preserve the supply of decent, safe and sanitary affordable housing for extremely-low- and very-low-income households, including homeless families.

CLICK HERE

Virginia Housing Trust Fund Competitive Loan Pool

The Virginia Housing Trust Fund is intended to create and preserve affordable housing and to reduce homelessness in the commonwealth.

CLICK HERE

Home Innovations In Energy Efficiency (HIEE)

RGGIis a market-based collaborative effort among Northeast and Mid-Atlantic states to combat climate change and reduce greenhouse gas emissions from the power sector, while driving economic growth. Proceeds from the RGGI cap and trade program to energy efficiency programs will benefitlow-income Virginians by making investments in affordable housing.

CLICK HERE

Attachment 41

JUDITH WILLIAMS JAGDMANN
COMMISSIONER

JEHMAL T. HUDSON
COMMISSIONER

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

BERNARD LOGAN
CLERK OF THE COMMISSION
P.O. BOX 1197
RICHMOND, VIRGINIA 23218-1197

September 1, 2022

The Honorable Glenn A. Youngkin
Governor, Commonwealth of Virginia

The Honorable Richard L. Saslaw
Chairman, Senate Committee on Commerce and Labor

The Honorable Kathy J. Byron
Chairman, House Committee on Commerce and Energy

Members of the Commission on Electric Utility Regulation

Ladies and Gentlemen:

Please find enclosed the Virginia State Corporation Commission's Status Report on the Implementation of the Virginia Electric Utility Regulation Act pursuant to § 56-596 B of the Code of Virginia.

Please let us know if we may be of further assistance.

Respectfully submitted,

Jehmal T. Hudson
Chairman

Judith Williams Jagdmann
Commissioner

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

Report to the Governor of the Commonwealth of Virginia, the Chairman of the Senate Committee on Commerce and Labor, the Chairman of the House Committee on Commerce and Energy, and the Commission on Electric Utility Regulation of the Virginia General Assembly

Status Report: Implementation of the Virginia Electric Utility Regulation Act Pursuant to § 56-596 B of the Code of Virginia

September 1, 2022

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Appendix 1: Glossary of Terms

EXECUTIVE SUMMARY

This document contains the report of the Virginia State Corporation Commission ("Commission") pursuant to § 56-596 B of the Code of Virginia ("Code"), which directs the Commission to provide an update by September 1 of each year on the status of the implementation of the Virginia Electric Utility Regulation Act, Code §§ 56-576 through 56-596.3 ("Regulation Act"). The Regulation Act has expanded in recent years with new programs and requirements that fall within the Commission's purview. This report summarizes the Commission's efforts to implement the Regulation Act for incumbent electric utilities[1] as well as the electric cooperatives.

Key highlights from the report include:

A. Current Status of the Regulation Act

- Over the past several years, the Regulation Act has been amended to require new or expanded programs and rulemakings that apply to the Commonwealth's incumbent electric utilities and electric cooperatives. These programs include ones that implement the requirements of the Virginia Clean Economy Act ("VCEA").[2] The VCEA includes provisions establishing mandatory Renewable Energy Portfolio Standard ("RPS") and Energy Efficiency Resource Standard. The relevant Commission dockets that implement or update these programs, as well as the dockets that continue to provide oversight of the utility's existing operations, are summarized in Section IV, below.

- On November 18, 2021, the Commission issued its Final Order concerning its triennial review of Dominion Energy Virginia's ("DEV") rates, terms, and conditions for the provision of generation, distribution, and transmission services.[3]

[1] Code § 56-580 G generally suspends application of the Regulation Act to Kentucky Utilities, d/b/a Old Dominion Power Company ("KU/ODP"), which is an investor-owned incumbent electric utility whose service territory is located entirely within Dickenson, Lee, Russell, Scott, and Wise Counties. However, certain provisions of the Regulation Act, including Code §§ 56-585.5 and 56-594, have been made applicable, at least in part, to KU/ODP.

[2] 2020 Va. Acts chs. 1193, 1194.

[3] *Application of Virginia Electric and Power Company, For a 2021 triennial review of the rates, terms, and conditions for the provision of generation, distribution,and transmission services pursuant to § 56-585.1 A*

- On January 7, 2022, the Commission issued a Final Order concerning its review of DEV's petition for approval of Phase II of its Grid Transformation ("GT") Plan.[4] The approved GT Plan investments focus on grid reliability and are designed to accommodate or facilitate the expected increase in distributed energy resources. Approved Phase II investments include (i) advanced metering infrastructure; (ii) the customer information platform; (iii) grid infrastructure, which comprises targeted corridor improvement and voltage island mitigation; (iv) grid technologies; (v) telecommunications; (vi) cyber security; (vii) physical security; and (viii) customer education. The projected capital and operations expenses for Phase II are projected to be approximately $776 million. The Commission's approval of these projects was made subject to certain contingencies, cost caps, and reporting requirements.

- On March 15, 2022, the Commission issued a Final Order concerning its review of DEV's 2021 RPS Filing which included (i) DEV's RPS Development Plan (encompassing proposed development of new solar, onshore wind, and energy storage resources); (ii) requests for approval to construct 13 new utility-scale projects and to enter into 24 new purchase power agreements ("PPAs"); and (iii) DEV's request for approval of revised Rider CE. The Commission (i) found that, for the limited purpose of filing its second annual RPS plan under Code § 56-585.5 D 4, DEV's plan was reasonable and prudent; (ii) approved the utility-scale projects and PPAs proposed by the Company; and (iii) approved revised Rider CE.[5]

- On July 1, 2022, the Commission issued a Final Order concerning its review of DEV's request for approval of a rate adjustment clause, designated Rider SNA, for costs associated with preparing Petitions for Subsequent License Renewal to the Nuclear Regulatory Commission to extend the operating licenses of, and the projects reasonably appropriate to upgrade or replace systems and equipment deemed to be necessary to operate safely and reliability, Dominion's Surry Units 1

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of the Code of Virginia, Case No. PUR-2021-00058, 2021 S.C.C. Ann. Rept. 444, Final Order (November 18, 2021).

[4] *Petition of Virginia Electric and Power Company, For approval of a plan for electric grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia,* Case No. PUR-2021-00127, Doc. Con. Cen. No. 22010126, Final Order (January 7, 2022).

[5] *Petition of Virginia Electric and Power Company, For approval of the RPS Development Plan, approval and certification of the proposed CE-2 Solar Projects pursuant to §§ 56-580 D and 56-46.1 of the Code of Virginia, revision of rate adjustment clause, designated Rider CE, under § 56-585.1 A 6 of the Code of Virginia, and a prudence determination to enter into power purchase agreements pursuant to § 56-585.1:4 of the Code of Virginia,* Case No. PUR-2021-00146, Doc. Con. Cen. No. 220320113, Final Order (March 15, 2022) (approving 857 megawatts ("MW") of new solar generation capacity and 103 MW of energy storage capacity). The Commission previously approved 498 MW of new solar facilities for Dominion. *See Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: Establishing 2020 RPS Proceeding for Virginia Electric and Power Company,* Case No. PUR-2020-00134, 2021 S.C.C. Ann. Rept. 242,243, Final Order (April 30, 2021).

and 2 and North Anna Units 1 and 2 in an extended period of operation.[6] The Commission adopted a proposed Stipulation in that case and approved the Petition as modified by the Stipulation.

- On July 15, 2022, the Commission issued its Final Order concerning Appalachian Power Company's ("APCo") 2021 RPS Plan. The Commission: (i) found APCo's RPS Development Plan is reasonable and prudent for the limited purpose of its second annual plan; (ii) approved APCo's requests for approval of cost recovery for 313.9 MW of solar and onshore wind capacity, including both company-owned resources and PPAs; (iii) granted APCo's request for a prudency determination for 238.9 MW of solar capacity, including company-owned resources and PPAs; (iv) approved the recovery of projected costs of renewable energy certificates ("RECs") purchased in the PJM[7] REC market; and (v) approved rate adjustment clauses ("RACs") for cost recovery.[8] The Commission also established additional directives regarding APCo's modeling in its subsequent RPS Plans.[9] The Commission further directed APCo to continue filing a consolidated bill analysis in its RPS Filings.

- On August 5, 2022, the Commission issued a Final Order approving requested cost recovery associated with DEV's proposed 2,587 MW Coastal Virginia Offshore Wind Commercial Project ("CVOW Project") to be located in a federal lease area off the coast of Virginia Beach, Virginia.[10] The project consists of 176 wind turbines, each designed to generate 14.7 MW. The project is expected to have a capital cost of $9.8 billion and will likely be the largest capital investment, and single largest project, in the history of Dominion Energy Virginia. The Commission also approved the electric interconnection and transmission facilities to connect the CVOW Project reliably with the existing transmission system. DEV and Consumer Counsel have requested the Commission reconsider aspects of the Final Order.

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[6] *Petition of Virginia Electric and Power Company, For approval of a rate adjustment clause, designated Rider SNA under § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2021-00229, Doc. Con. Cen. No. 220710001, Final Order (July 1, 2022).

[7] PJM Interconnection, L.L.C. ("PJM")

[8] *Petition of Appalachian Power Company, For approval of its 2021 RPS Plan under § 56-585.5 of the Code of Virginia and related requests*, Case No. PUR-2021-00206, Doc. Con. Cen. No. 220720045, Final Order on Petition and Associated Requests, and Order Bifurcating Proceeding (July 15, 2022).

[9] *See, e.g., id.* at 6-7.

[10] *Application of Virginia Electric and Power Company, For approval and certification of the Coastal Virginia Offshore Wind Commercial Project and Rider Offshore Wind, pursuant to § 56-585.1:11, § 56-46.1, § 56-265.1 et seq. and § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2021-00142, Doc. Con. Cen. No. 220820117, Final Order (August 5, 2022).

- On August 10, 2022, the Commission issued a Final Order in DEV's annual demand-side management ("DSM") filing that approved, among other things, (i) DEV's proposed Phase X DSM Programs including proposed enhancement and expansion of certain previously approved programs; (ii) reorganization and consolidation of the DEV's DSM Portfolio; and (iii) cost recovery through associated RACs.[11] The Commission had previously approved, on September 7, 2021, the DEV's application seeking (i) approval of the Company's Phase IX DSM programs, including 11 new energy efficiency and demand response programs; (ii) the expansion and modification of certain existing programs; and (iii) approval of cost recovery through associated RACs.[12]

- Both APCo (a Phase I Utility) and DEV (a Phase II Utility) estimate that they are on target to implement energy efficiency programs and measures to achieve the total annual energy savings targets for 2023 as specified by Code § 56-596.2.

B. Rate and Capital Outlook

DEV

- DEV's typical[13] monthly residential bill has increased by $46.34 to $136.93[14] (a 51.15% increase) from July 1, 2007,[15] to July 1, 2022. Over the 12 months ended July 1, 2022, DEV's typical monthly residential bill has increased by $15.65.

- DEV did not file an Integrated Resource Plan ("IRP") in 2021. In accordance with Code § 56-599, DEV's next IRP will be due by May 1, 2023.

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[11] *Petition of Virginia Electric and Power Company, For approval of its 2021 DSM Update pursuant to § 56-585.1 A 5 of the Code of Virginia*, Case No. PUR-2021-00247, Doc. Con. Cen. No. 220830003, Final Order (August 10, 2022).

[12] *Application of Virginia Electric and Power Company, For approval of its 2020 DSM Update pursuant to § 56-585.1 A 5 of the Code of Virginia*, Case No. PUR-2020-00274, 2021 S.C.C. Ann. Rept. 350, Final Order (September 7, 2021).

[13] For purposes of this report, a typical residential bill is based on usage of 1,000 kilowatt-hours ("kWh") per month.

[14] This amount includes an interim fuel factor rate of $0.35379 which is subject to change pending a final order in Case No. PUR-2022-00064. *Application of Virginia Electric and Power Company, To revise its fuel factor pursuant to § 56-249.6*, Case No. PUR-2022-00064, Doc. Con. Cen. No. 220540002, Order Establishing 2022-2023 Fuel Factor Proceeding (May 24, 2022).

[15] Enactment Clause 7 of 2007 Va. Acts chs. 888 and 933 requires the Commission, in consultation with the Office of the Attorney General, to "submit a report to the Governor and General Assembly by November 1, 2012, and every five years thereafter, assessing the rates and terms and conditions of incumbent electric utilities in the Commonwealth." The first five-year window for this rate assessment was 2007-2012. The Commission begins its rate analysis with the year 2007 in this report to coincide with this window.

- On November 18, 2021, the Commission issued a Final Order in DEV's first triennial review, covering the period 2017 – 2020.[16] The Commission approved a Stipulation among DEV, Commission Staff, and certain case participants.[17] The Stipulation provided for customer refunds, totaling $330 million, the statutory maximum annual rate reduction of $50 million, and customer credit reinvestment offsets of $309 million.[18] For a typical residential customer, this results in a decrease of approximately $0.90 per month effective January 1, 2022 and refunds totaling approximately $67.00 over the 2022-2023 period. The Commission also approved a 9.35% return on common equity ("ROE") as fair and reasonable for the 2021 – 2023 period that will be the subject of DEV's next triennial review.[19]

- As reported by DEV, its base rate financial results for 2021 reflect an actual earned ROE of 11.49%, which is above its authorized ROE of 9.35%.[20] DEV's 2021 financial results will be audited as part of its next triennial review, which will be filed in 2024 and will cover the period 2021 – 2023.

- In a February 2022 presentation to investors, DEI[21] identified DEV capital investments of approximately $27.9 billion for the five-year period 2022 – 2026, including investments in wind and solar generation, energy storage, nuclear facility relicensing, transmission, distribution undergrounding, and grid transformation. These investments would reflect a 74% increase in DEV's rate base by 2026, with 55% being recovered from customers through RACs.

APCo

- APCo's typical monthly residential bill has increased by $55.64 to $122.25 (an 83.53% increase) from July 1, 2007, to July 1, 2022. Over the 12 months ending July 1, 2022, APCo's typical monthly residential bill has increased by $5.16.

- On August 18, 2022, the Supreme Court of Virginia issued its opinion on the appeals of APCo and the Office of the Attorney General, Division of Consumer Counsel ("Consumer Counsel") concerning the Commission's decision in APCo's

[16] *Application of Virginia Electric and Power Company, For a 2021 triennial review of the rates, terms, and conditions for the provision of generation, distribution, and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, Case No. PUR-2021-00058, 2021 S.C.C. Ann. Rept. 444, Final Order (November 18, 2021).

[17] The remaining participants did not join, but did not oppose, the Stipulation. *Id.* at 2-3.

[18] *Id.* at 3.

[19] *Id.* at 5.

[20] *Id.*

[21] Dominion Energy, Inc. ("DEI").

2020 Triennial Review.[22] The Court affirmed in part, reversed in part, and remanded the case to the Commission for further proceedings consistent with the Court's opinion.[23]

- As reported by APCo, its base rate financial results for 2021 reflect an actual earned ROE of 5.38%, which is below its authorized ROE of 9.20%.[24] APCo's 2021 financial results will be audited as part of its next triennial review, which is due to be filed by March 31, 2023, and will cover the period 2020 – 2022.

- APCo filed its 2022 IRP on April 29, 2022. Based on APCo's billing analysis, showing projected annual impacts to a residential bill over the next five years incorporating the requirements of the VCEA, the monthly bill of a Virginia residential customer using 1,000 kWh per month is projected to be between $141.73 and $143.07 by 2026, an increase of between $19.50 and $20.84 per month over the April 29, 2022 typical residential bill (or an estimated annual increase of $234.00 to $250.08).[25] APCo's 2022 IRP is pending before the Commission and an evidentiary hearing is scheduled to begin on October 25, 2022.[26]

[22] *Application of Appalachian Power Company, For a 2020 triennial review of its base rates, terms and conditions pursuant to § 56-585.1 of the Code of Virginia*, Case No. PUR-2020-00015, 2020 S.C.C. Ann. Rept. 421, Final Order (November 24, 2020).

[23] *Appalachian Power Co. v. State Corp. Comm'n*, Record No. 210391 (Va. Aug. 18, 2022).

[24] The authorized ROE of 9.20% was set in the Commission's Final Order in Case No. PUR-2020-00015.

[25] The projected monthly bill increases of $19.50 and $20.84 are based on the 2022 IRP Least Cost Plan and Hybrid Plan, respectively.

[26] *Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2022-00051, Doc. Con. Cen. No. 220540021, Order for Notice and Hearing (May 24, 2022).

I.
INTRODUCTION

The Commission appreciates this opportunity to provide an update to the General Assembly on the Commission's implementation of the Regulation Act including the VCEA. The Commission has conducted numerous proceedings over the last year pursuant to the Regulation Act that are discussed in detail below. As a general matter, the Commission is seeing upward pressure on utility rates, not just for investor-owned electric utilities,[27] but across all regulated utilities. Factors contributing to increased utility costs include inflation, pandemic recovery, supply chain limitations, and high natural gas and other commodity prices, as well as geopolitical events. The Commission is keenly aware of the economic pressures that are impacting all utility customers and takes seriously its responsibility to review rate recovery requests. In each case, the Commission evaluates the request pursuant to the applicable laws, as well as the findings of fact supported by the evidence in the record.

The Commission continues to implement the VCEA in a manner that faithfully applies the requirements that include carbon reduction, while best protecting consumers who expect and deserve reliable and affordable service. Since the effective date of the VCEA, the Commission has approved DEV's requests for approval of 1,355 MW of new solar facilities (DEV-owned and PPA) and 103 MW of new energy storage capacity under the VCEA.[28] The Commission also recently issued an order approving cost

[27] DEV's most recent fuel factor filing, for example, showed a projected fuel deferral balance over the July 2021-June 2022 period of approximately $1 billion, due to increases in commodity prices over the past year. *Application of Virginia Electric and Power Company, To revise its fuel factor pursuant to Va. Code § 56-249.*6, Case No. PUR-2022-00064, Application at 2 (filed May 5, 2022).

[28] *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: Establishing 2020 RPS Proceeding for Virginia Electric and Power Company*, Case No. PUR-2020-00134, 2021 S.C.C. Ann.

recovery associated with DEV's 2,587 MW CVOW Project, which is discussed in more detail below. For APCo, the Commission has approved 498 MW of new renewable generation supply since the passage of the VCEA.[29]

The Commission also concluded the first triennial review of DEV, approving the statutory maximum annual rate reduction of $50 million effective January 1, 2022, and customer refunds totaling $330 million over the 2022-2023 period, which is discussed in further detail below.

As detailed in Section V below, in addition to reviewing individual utility applications, the Commission has also sponsored and contributed to several stakeholder processes related to various aspects of utility regulation. Among those, as directed by House Bill 2282,[30] the Commission conducted a stakeholder process in the fall of 2021 focused on the transportation electrification with over 60 different organization participating in these meetings. On April 29, 2022, the Commission submitted a report to the General Assembly regarding policy proposals governing public electric utility programs to accelerate widespread transportation electrification in the Commonwealth,

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Rept. 242, 243, Final Order (April 30, 2021) (approving 498 MW of new solar facilities); *Petition of Virginia Electric and Power Company, For approval of the RPS Development Plan, approval and certification of the proposed CE-2 Solar Projects pursuant to §§ 56-580 D and 56-46.1 of the Code of Virginia, revision of rate adjustment clause, designated Rider CE, under § 56-585.1 A 6 of the Code of Virginia, and a prudence determination to enter into power purchase agreements pursuant to § 56-585.1:4 of the Code of Virginia*, Case No. PUR-2021-00146, Doc. Con. Cen. No. 220320113, Final Order at 6 (March 15, 2022) (approving 857 MW of new solar generation capacity and 103 MW of energy storage capacity).

[29] *Petition of Appalachian Power Company, For approval of its 2021 RPS Plan under § 56-585.5 of the Code of Virginia and related requests*, Case No. PUR-2021-00206, Doc. Con. Cen. No. 220720045, Final Order on Petition and Associated Requests, and Order Bifurcating Proceeding (July 15, 2022); *Petition* of A*ppalachian Power Company, For a prudency review, pursuant to § 56-585.1:4 H of the Code o*f *Virginia, with respect to the purchase of the Amherst Solar Facility*, Case No. PUR-2021-00066, Doc. Con. Cen. No. 220230049, Final Order (February 18, 2022).

[30] 2021 Va. Acts ch. 268 (Special Session 1).

noting that the increased deployment of motor vehicles powered by electricity presents several issues that potentially could affect the affordability and reliability of electricity service delivered to consumers by regulated utilities.[31] Consistent with the recommendations of the stakeholder report, the Commission subsequently issued an Order that required DEV and APCo to file transportation electrification plans on or before May 1, 2023.[32]

Pandemic-related Activities

The Commission has previously reported on its response to the public health concern related to the spread of the coronavirus, or COVID-19. As noted in the 2021 Report, through several orders, the Commission directed regulated electric, natural gas, and water and sewer companies in Virginia to suspend service disconnections through October 5, 2020, affording the General Assembly and the Governor time to address the economic impact on utility customers legislatively.[33] Thereafter, the General Assembly in a November 2020 Special Session enacted budget legislation further prohibiting utility shut-offs during the then state of emergency declared by the Governor, subject to certain

[31] House Doc. No. 8, Report: Policy Proposals Governing Public Electric Utility Programs to Accelerate Widespread Transportation Electrification in the Commonwealth Pursuant to Chapter 268 of the 2021 Virginia Acts of Assembly (Special Session I) (HB 2282) (April 29, 2022). https://rga.lis.virginia.gov/Published/2022/HD8/PDF

[32] *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: Electrification of Motor Vehicles*, Case No. PUR-2020-00051, Doc. Con. Cen. No. 220630077, Order Directing the Filing of Transportation Electrification Plans (June 15, 2022).

[33] *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: Temporary Suspension of Tariff Requirements*, Case No. PUR-2020-00048, 2020 S.C.C. Ann. Rept. 467, Order Suspending Disconnection of Service and Suspending Tariff Provisions Regarding Utility Disconnections of Service (March 16, 2020); 2020 S.C.C. Ann. Rept. 467, Order Extending Suspension of Service Disconnections (April 9, 2020); 2020 S.C.C. Ann. Rept. 469, Order on Suspension of Service Disconnections (June 12, 2020); 2020 S.C.C. Ann. Rept. 473, Order on Moratorium (August 24, 2020); 2020 S.C.C. Ann. Rept. 475, Additional Order on Moratorium (September 15, 2020).

conditions and limitations.[34] This budget legislation also directed the Commission to distribute $100 million of Virginia's portion of coronavirus relief funds ("CRF") received under Public Law 116-136: Coronavirus Aid, Relief, and Economic Security Act, to electric, natural gas, and water and sewer utilities, including municipal utilities, throughout the Commonwealth to offset utility customer billing arrearages due to COVID-19.[35] Relatedly, budget legislation enacted by the General Assembly during a 2021 Special Session directed the Commission, in coordination with the Department of Housing and Community Development, to distribute $120 million of additional coronavirus relief funds received by Virginia under Public Law 117-2: American Rescue Plan Act of 2021 ("ARPA").[36] These funds were also distributed to Virginia's utilities (as identified above) to offset utility customer billing arrearages due to COVID-19. The Commission and its Staff continue to provide oversight of these CRF and ARPA distributions. Additionally, and at the General Assembly's direction, the Commission since 2020 has submitted annual reports to the General Assembly and the Executive Branch detailing current utility customer billing arrearages and utility service disconnections.[37] The annual submission of these reports will continue through 2023.

Composition of the Electric Industry in Virginia

The Commission's responsibilities include regulating a diverse electric industry pursuant to the Virginia Constitution and the laws enacted by the General Assembly.

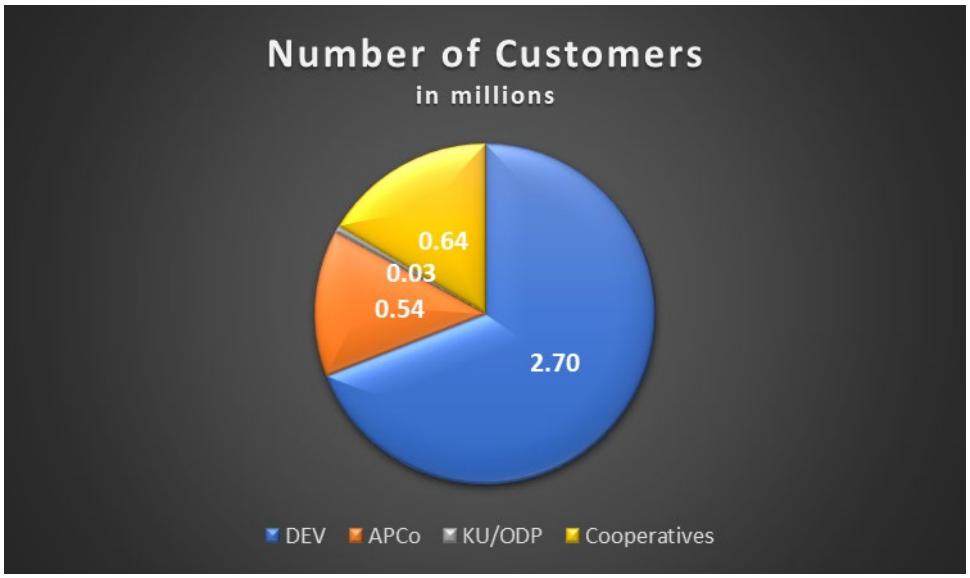
[34] *See*, House Bill 5005, 2020 Va. Acts, Special Session I, ch. 56 (Item 4-14)

[35] *See*, House Bill 5005, 2020 Va. Acts, Special Session I, ch. 56 (Item 479.10). *See also*, House Bill 1800, 2021 Va. Acts, Special Session I, ch. 552 (modifying pertinent provisions in Item 479.10).

[36] *See*, House Bill 7001, 2021 Va. Acts, Special Session II, ch. 1 (Item 479.20).

[37] *See*, House Bill 5005, 2020 Va. Acts, Special Session I, ch. 56 (Item 4-14)

Virginia's electric industry, for which the Commission regulates the rates and services to customers, consists of three investor-owned utilities and 13 member-owned electric cooperatives.[38] The number of Virginia jurisdictional customers by utility is shown below:[39]



II.
RATE AND CAPITAL OUTLOOK

DEV Typical Residential Bill

Below is a chart that reflects the magnitude of the three financial components of DEV customer bills as of the effective dates of the Regulation Act (July 1, 2007),[40] the Transitional Rate Period (July 1, 2015),[41] the Grid Transformation and Security Act

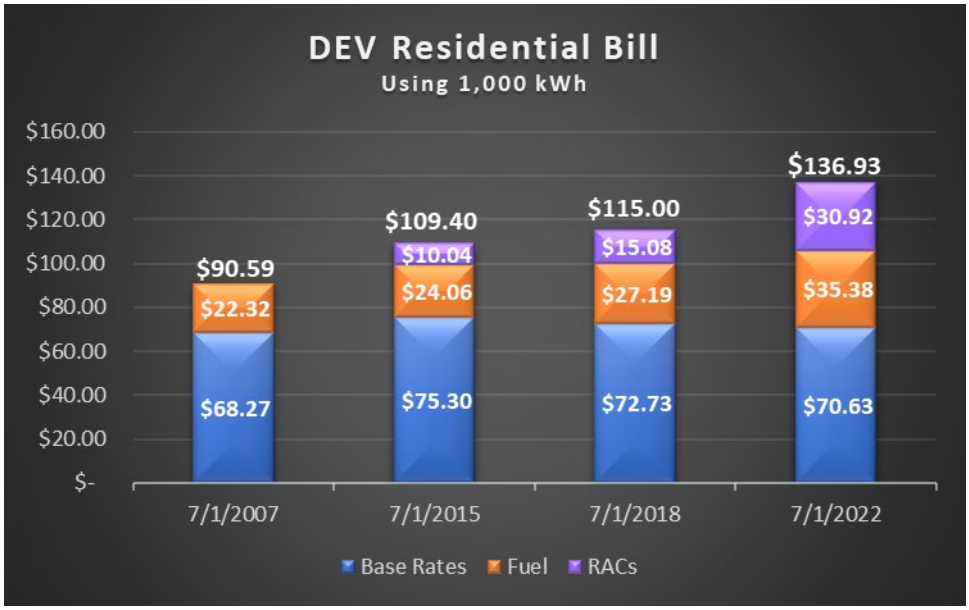
[38] Non-jurisdictional utilities, such as municipal electric utilities, also provide service in Virginia.

[39] Total Virginia customer numbers were reported in Federal Energy Regulatory Commission ("FERC") Form 1 and Annual Operating Reports.

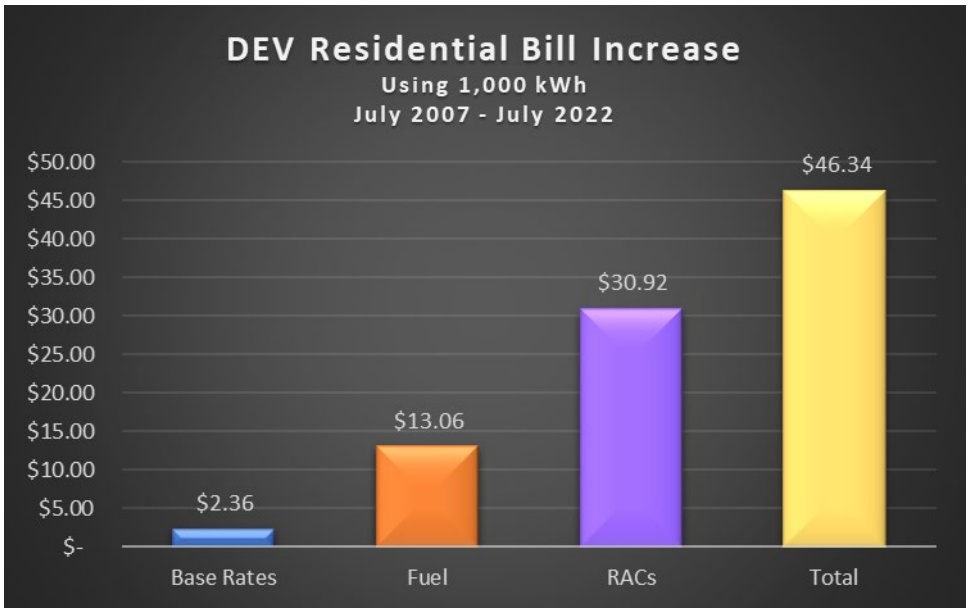
[40] 2007 Va. Acts. chs. 888 and 933.

[41] *See* Code § 56-585.1:1 for the specific transitional rate periods for Dominion and APCo. Both utilities were in their transitional rate periods on July 1, 2015.

("GTSA") (July 1, 2018), and the current year (July 1, 2022) for a typical residential customer using 1,000 kWh per month.



As the chart above indicates, DEV's monthly residential bill was $90.59 as of July 1, 2007. The bill has increased by $46.34 (51.15%) to $136.93 per month as of July 1, 2022. As reflected on the chart below, the RAC component of the bill experienced the largest increase over this period.


DEV Residential Bill Increase
Using 1,000 kWh
July 2007 - July 2022
$50.00
$45.00
$40.00
$35.00
$30.00
$25.00
$20.00
$15.00
$10.00
$5.00
$-
$2.36
$13.06
$30.92
$46.34
Base Rates
Fuel
RACs
Total

The following chart itemizes a typical residential customer's bill by rate recovery mechanism as of July 1, 2022.

DEV Electric Utility Bills
As of July 1, 2022

Recovery Mechanism	Description	Current Residential Bill	Proposed Increase if Pending	Proposed Bill	Requested Effective Date
Base Rates	Base	$ 70.63	$ -	$ 70.63	-
Fuel Factor	Fuel	$ 35.38	$ -	$ 35.38	7/1/22*
Rider T1	Transmission	$ 6.90	$ (3.69)	$ 3.21	9/1/22
Rider R	Bear Garden Gas CC	$ 1.14	$ -	$ 1.14	-
Rider W	Warren Gas CC	$ 2.34	$ (0.38)	$ 1.96	4/1/23
Rider BW	Brunswick Gas CC	$ 2.10	$ 0.70	$ 2.80	9/1/22
Rider GV	Greensville Gas CC	$ 2.75	$ -	$ 2.75	-
Rider S	VCHEC	$ 3.70	$ -	$ 3.70	-
Rider B	Biomass	$ 0.30	$ 0.33	$ 0.63	4/1/23
Rider US-2	Solar	$ 0.17	$ 0.05	$ 0.22	9/1/22
Rider US-3	Solar	$ 0.96	$ -	$ 0.96	-
Rider US-4	Solar	$ 0.30	$ -	$ 0.30	-
Rider CE	Solar	$ 1.32	$ 1.13	$ 2.45	-
Rider SNA	Nuclear Relicensing	$ -	$ 2.11	$ 2.11	9/1/22
Rider RPS	RECs	$ 0.18	$ 1.64	$ 1.82	9/1/22
Rider RGGI	RGGI	$ -	$ -	$ -	7/1/22**
Rider OSW	Offshore Wind	$ -	$ 1.45	$ 1.45	9/1/22
Rider PPA	Renewable PPAs	$ -	$ (0.07)	$ (0.07)	9/1/22
Riders C1A/C2A/etc.	Energy Efficiency	$ 1.31	$ 0.29	$ 1.60	9/1/22
Rider U	Strategic Undergrounding	$ 2.50	$ (0.51)	$ 1.99	4/1/23
Rider GT	Grid Transformation	$ 1.16	$ -	$ 1.16	-
Rider E	Coal Ash	$ 1.25	$ 0.70	$ 1.95	9/1/22
Rider CCR	Coal Ash	$ 2.95	$ 0.01	$ 2.96	12/1/22
Rider RBB	Rural Broadband	$ 0.03	$ 0.14	$ 0.17	12/1/22
PIPP USF***	PIPP	$ 0.03	$ -	$ 0.03	-
Rider VCR****	Voluntary Credit Rider	$ (0.47)	$ -	$ (0.47)	
Total		**$ 136.93**	**$ 3.90**	**$ 140.83**	

*The fuel factor rate was implemented on an interim basis on 7/1/22, subject to modification.

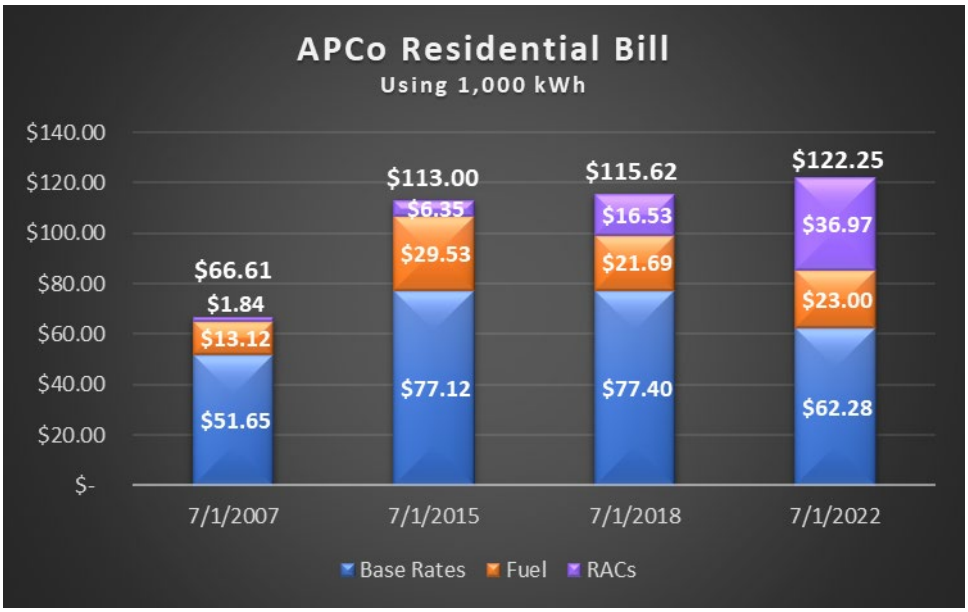
**The Commission granted DEV's petition to reset Rider RGGI to zero and recover the unrecovered RGGI compliance costs through base rates.

***Current PIPP collections are designed to fund the estimated start-up costs of DSS needed to establish the PIPP. The PIPP will commence no later than one year after DSS publishes guidelines for the adoption, implementation, and general administration of the PIPP and Percentage of Income Payment Fund.

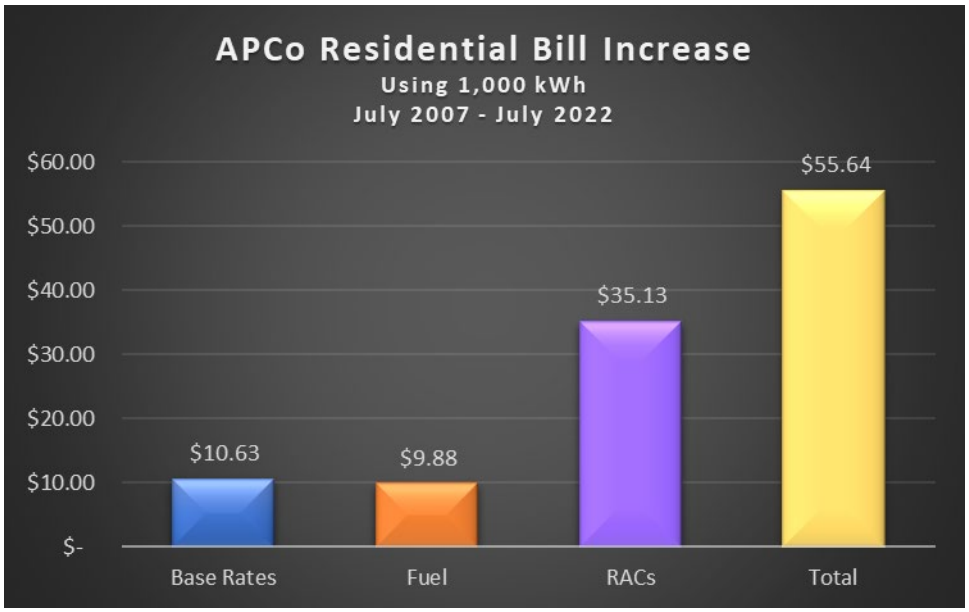
****Rider VCR provides bill credits to customers pursuant to the stipulation in DEV's 2021 triennial review.

APCo Typical Residential Bill

Below is a chart that reflects the magnitude of the three financial components of APCo customer bills as of the effective dates of the Regulation Act (July 1, 2007), the Transitional Rate Period (July 1, 2015), the GTSA (July 1, 2018), and the current year (July 1, 2022) for a typical residential customer using 1,000 kWh per month.



As the chart indicates, APCo's monthly residential bill was $66.61 as of July 1, 2007. The bill has increased by $55.64 (83.53%) to $122.25 per month as of July 1, 2022. As reflected on the chart below, the RAC component of the bill experienced the largest increase over this period.


APCo Residential Bill Increase
Using 1,000 kWh
July 2007 - July 2022
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
$10.63
$9.88
$35.13
$55.64
Base Rates
Fuel
RACs
Total

The following chart itemizes a typical residential customer's bill by rate recovery mechanism as of July 1, 2022.[42]

APCo Electric Utility Bills
As of July 1, 2022

Recovery Mechanism	Description	Current Residential Bill	Proposed Increase if Pending	Proposed Bill	Requested Effective Date
Base Rates	Base	$ 65.40	$ -	$ 65.40	-
Fuel Factor	Fuel	$ 23.00	$ -	$ 23.00	-
TRR Rider Credit	Tax Reform	$ (3.12)	$ -	$ (3.12)	-
PIPP USF	PIPP*	$ 0.04	$ -	$ 0.04	-
T-RAC	Transmission	$ 31.55	$ 2.88	$ 34.43	8/1/22
G-RAC	Dresden Gas CC	$ 2.55	$ -	$ 2.55	-
EE-RAC	Energy Efficiency	$ 1.12	$ 0.34	$ 1.46	9/1/22
DR-RAC	Demand Response	$ 0.22	$ -	$ 0.22	-
E-RAC	Coal Ash	$ 2.11	$ 0.80	$ 2.91	12/1/22
BC-RAC	Rural Broadband	$ 0.54	$ (0.69)	$ (0.15)	2/1/23
RPS-RAC (legacy)	Voluntary RPS	$ (1.16)	$ -	$ (1.16)	-
RPS-RAC (new)	Mandatory RPS	$ -	$ 2.37	$ 2.37	8/1/22
Total		$ 122.25	$ 5.70	$ 127.95	

*Current PIPP collections are designed to fund the estimated start-up costs of DSS needed to establish the PIPP. The PIPP will commence no later than one year after DSS publishes guidelines for the adoption, implementation, and general administration of the PIPP and Percentage of Income Payment Fund.

Rate and Capital Outlook

2021 RPS Plans

On September 15, 2021, DEV submitted its petition for approval of its 2021 RPS Plan to develop new solar and onshore wind generation capacity and energy storage as required by the VCEA pursuant to Code § 56-585.5 D 4. Among other things, DEV's 2021 RPS Plan calls for 3,105 MW of solar and onshore wind development through 2024 and the development of 331 MW of energy storage resources through 2025.[43] DEV

[42] The TRR Rider Credit is a temporary base rate rider credit to return to customers the impacts of the 2018 Tax Cuts and Jobs Act.

[43] *Petition of Virginia Electric and Power Company, For approval of its 2021 RPS Development Plan under § 56-585.5 D 4 of the Code of Virginia and related requests,* Case No. PUR-2021-00146, Doc. Con.

estimates that by 2045, it may have 18,356 MW (nameplate) of solar resources, 5,174 MW (nameplate) of offshore wind resources, and 316 MW (nameplate) of hydroelectric resources that it will use toward meeting its capacity obligations in PJM, in addition to 2,580 MW (nameplate) of energy storage.[44]

The Commission issued a Final Order on March 15, 2022, wherein it: (i) found DEV's RPS Plan was reasonable and prudent for the limited purpose of its second annual plan; (ii) approved approximately 857 MW of new solar generation capacity in the Commonwealth including both company-owned resources and PPAs; (iii) approved 103 MW of energy storage capacity; and (iv) approved a RAC for cost recovery associated with approved company-owned solar facilities.[45] The Commission also established additional directives regarding DEV's modeling in its subsequent RPS Plans.[46] The Commission further directed DEV to continue filing a consolidated bill analysis in its IRP and RPS Plan proceedings with information through 2035.[47] DEV has filed a notice of intent to file its 2022 RPS Plan on or after September 15, 2022.

On December 30, 2021, APCo submitted its 2021 RPS Plan to develop new solar and onshore wind generation capacity required by the VCEA. Among other things,

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Cen. No. 210930080, RPS Plan at 4, 7 (filed September 15, 2021). For additional information on renewable deployment, on or before December 1 of each year, the Commission files an annual report to the General Assembly on the construction of new solar and wind projects pursuant to Enactment Clause 14 of the GTSA, as amended by 2020 Va. Acts ch. 1190.

[44] *Id*. at 14.

[45] *Petition of Virginia Electric and Power Company, For approval of its 2021 RPS Development Plan under § 56-585.5 D 4 of the Code of Virginia and related requests,* Case No. PUR-2021-00146, Doc. Con. Cen. No. 220320113, Final Order (March 15, 2022).

[46] *See, e.g., id.* at 8-10.

[47] *Id.* at 11.

APCo's 2021 RPS Plan calls for approximately 553 MW of solar and onshore wind development through 2025, including resources that became operational in 2021 and resources expected to become operational by the end of 2022.[48] APCo anticipates adding storage resources beginning in 2025.[49] APCo estimates that by 2040, it may have 2,736 MW (nameplate) of solar, 750 MW (nameplate) of onshore wind, and 2,937 MW (nameplate) of energy storage, through a mix of company-owned resources and PPAs, to meet the requirements of the VCEA.[50]

On July 15, 2022, the Commission issued a Final Order on APCo's 2021 RPS Plan, wherein the Commission: (i) found APCo's RPS Development Plan is reasonable and prudent for the limited purpose of its second annual plan; (ii) approved APCo's requests for approval of cost recovery for 313.9 MW of solar and onshore wind capacity, including both company-owned resources and PPAs; (iii) granted APCo's request for a prudency determination for 238.9 MW of solar capacity, including company-owned resources and PPAs; (iv) approved the recovery of projected costs of RECs purchased in the PJM REC market; and (v) approved RACs for cost recovery.[51] The Commission also established additional directives regarding APCo's modeling in its subsequent RPS

[48] *Petition of Appalachian Power Company, For approval of its 2021 RPS Plan under § 56-585.5 of the Code of Virginia,* Case No. PUR-2021-00206, RPS Plan at 7 (filed December 30, 2021).

[49] *Id.* at 8, 37.

[50] *Id.* at 40.

[51] *Petition of Appalachian Power Company, For approval of its 2021 RPS Plan under § 56-585.5 of the Code of Virginia and related requests*, Case No. PUR-2021-00206, Doc. Con. Cen. No. 220720045, Final Order on Petition and Associated Requests, and Order Bifurcating Proceeding (July 15, 2022).

Plans.[52] The Commission further directed APCo to continue filing a consolidated bill analysis in its RPS Filings.[53]

The Commission also found that a separate proceeding should be established to further consider the appropriate cost recovery framework for APCo's VCEA-related resources, the allocation of costs net of benefits pursuant to Code § 56-585.5 F, and class and jurisdictional cost allocation.[54] The Commission directed APCo to make a filing addressing these issues on or before October 1, 2022.[55]

DEV Offshore Wind

On August 5, 2022, the Commission issued a Final Order on DEV's application for cost recovery associated with its proposed CVOW Project.[56] The project consists of 176 wind turbines, each designed to generate 14.7 MW, to be located approximately 27 miles off the coast of Virginia Beach. The project is expected to have a capital cost of $9.8 billion and will likely be the largest capital investment, and single largest project, in the history of Dominion Energy Virginia.[57]

The Commission approved a revenue requirement of $78.702 million for the rate year of September 1, 2022, to August 31, 2023, to be recovered through a new rate

[52] *See, e.g., id.* at 6-7.

[53] *Id.* at 8.

[54] *See id.* at 13-15.

[55] *Id.* at 17.

[56] *Application of Virginia Electric and Power Company, For approval and certification of the Coastal Virginia Offshore Wind Commercial Project and Rider Offshore Wind, pursuant to § 56-585.1:11, § 56-46.1, § 56-265.1 et seq. and § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2021-00142, Doc. Con. Cen. No. 220820117, Final Order (August 5, 2022).

[57] *Id.* at 5-6.

adjustment clause, designated Rider OSW.[58] Over the projected 35-year lifetime of the project, for a residential customer using 1,000 kWh of electricity per month, Rider OSW is projected to result in an average monthly bill increase of $4.72 and a peak monthly bill increase of $14.22 in 2027.[59]

The Commission recognized that significant concerns were raised throughout the proceeding regarding the affordability of the project and the financial risk to ratepayers. With a project of this magnitude, the Commission ordered the following consumer protections:[60]

- Dominion shall file a notice with the Commission within 30 calendar days if it determines that the total project costs are expected to exceed the current estimate, or if the final turbine installation is expected to be delayed beyond February 4, 2027.
- Each annual Rider OSW update application filed by Dominion prior to the project's commercial operation shall include any material changes to the project, the most recent biannual project update, and a written explanation as to the reason for any cost overruns above the most recent estimate provided by the company to include the reasonableness and prudence of the additional costs.
- Beginning with the commercial operation and extending for the life of the project, customers shall be held harmless for any shortfall in energy production below an annual net capacity factor of 42 percent, as measured on a three-year rolling average ("Performance Standard").

In a concurring opinion, Commissioner Jagdmann wrote that she agrees with the Final Order in all respects. She emphasized that these aforementioned protections do not completely address potential Project abandonment risks, stating:

> [i]mportantly, the General Assembly has effectively maintained its ability to implement additional protections – for example through funding mechanisms such as general

[58] *Id.* at 11-12.

[59] *Id.* at 5.

[60] *Id.* at 14-16.

> fund appropriation or other means, such as implementing new legislation designating the consumer-funded proceeds from Dominion's participation in the Regional Greenhouse Gas Initiative ("RGGI") be used to lessen the cost of the CVOW Project.... Such action may be appropriate given the public policy support for and economic development aspects of this Project.[61]

On August 22, 2022, DEV filed a Petition for Limited Reconsideration of the Commission's decision requesting the Commission reconsider the Performance Standard. Among other things, Dominion states that "[a]s ordered, [the performance standard] will prevent the Project from moving forward, and the Company will be forced to terminate all development and construction activities."[62] On August 24, 2022, the Commission issued an order granting reconsideration for purposes of continuing jurisdiction over the case and directed the filing of responses to DEV's request for reconsideration. On August 25, 2022, Consumer Counsel filed a Petition for Clarification or Reconsideration related to the Performance Standard.[63]

Nuclear License Extensions

The Commission approved DEV's petition for approval of a RAC, designed Rider SNA, for cost recovery associated with preparing Petitions for Subsequent License Renewal to the Nuclear Regulatory Commission to extend the operating license of, and

[61] *Id.* at 41-42.

[62] *Application of Virginia Electric and Power Company, For approval and certification of the Coastal Virginia Offshore Wind Commercial Project and Rider Offshore Wind, pursuant to § 56-585.1:11, § 56-46.1, § 56-265.1 et seq. and § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2021-00142, Petition of Virginia Electric and Power Company for Limited Reconsideration at 3 (filed August 22, 2022).

[63] *Application of Virginia Electric and Power Company, For approval and certification of the Coastal Virginia Offshore Wind Commercial Project and Rider Offshore Wind, pursuant to § 56-585.1:11, § 56-46.1, § 56-265.1 et seq. and § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2021-00142, Petition for Clarification or Reconsideration of Office of the Attorney General, Division of Consumer Counsel (filed August 25, 2022).

the projects reasonably appropriate to upgrade or replace systems and equipment deemed to be necessary to extend the life of, Dominion's Surry Units 1 and 2 and North Anna Units 1 and 2 nuclear generation facilities from 60 to 80 years.[64] The approved revenue requirement for the initial rate year of Rider SNA commencing September 1, 2022, is $106.664 million.[65]

Grid Transformation Plan

The Commission issued a Final Order concerning its review of DEV's petition for approval of Phase II of its GT Plan.[66] The approved GT Plan investments focus on grid reliability and are designed to accommodate or facilitate the expected increase in distributed energy resources resulting from recent policy developments, including the VCEA and FERC Order 2222. Approved Phase II investments include (i) advanced metering infrastructure; (ii) the customer information platform; (iii) grid infrastructure, which comprises targeted corridor improvement and voltage island mitigation; (iv) grid technologies; (v) telecommunications; (vi) cyber security; (vii) physical security; and (viii) customer education. The projected capital and operations expenses for Phase II are projected to be approximately $776 million. The Commission's approval of these projects was made subject to certain contingencies, cost caps, and reporting requirements.

APCo did not file a grid transformation plan in 2021.

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[64] *Petition of Virginia Electric and Power Company, For approval of a rate adjustment clause, designated Rider SNA under § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2021-00229, Doc. Con. Cen. No. 220710001, Final Order (July 1, 2022).

[65] *Id.* at 6.

[66] *Petition of Virginia Electric and Power Company, For approval of a plan for electric grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2021-00127, Doc. Con. Cen. No. 22010126, Final Order (January 7, 2022).

Integrated Resource Plans

DEV did not file an IRP in 2021.[67] In accordance with Code § 56-599, DEV's next IRP will be due by May 1, 2023. In DEV's most recent prior IRP, the Commission directed DEV's future IRPs to include actual bill impact information as each year passes.[68] Further, the Commission found that DEV should address environmental justice in future IRPs and updates, as appropriate.[69]

APCo did not file a 2021 IRP. It filed its 2022 IRP on April 29, 2022. Based on APCo's billing analysis, showing projected annual impacts to a residential bill over the next five years incorporating the requirements of the VCEA, the monthly bill of a Virginia residential customer using 1,000 kWh per month is projected to be between $141.73 and $143.07 by 2026, an increase of between $19.50 and $20.84 per month over the April 29, 2022 typical residential bill (or an estimated annual increase of $234.00 to $250.08).[70] APCo's 2022 IRP is pending before the Commission and an evidentiary hearing is scheduled to begin on October 25, 2022.[71]

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[67] DEV filed an update to its 2020 IRP, which was accepted for filing by the Commission. *Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's 2021 Update to its Integrated Resource Plan pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2021-00201, 2021 S.C.C. Ann. Rept. 544, Final Order (October 28, 2021).

[68] *Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2020-00035, 2021 S.C.C. Ann. Rept. 190, 195-196, Final Order (February 1, 2021). The Commission further directed that in addition to residential bills, the Company should include a billing analysis of small general service and large general service customer bills. *Id.* at 196.

[69] *Id*. at 195.

[70] The projected monthly bill increases of $19.50 and $20.84 are based on the 2022 IRP Least Cost Plan and Hybrid Plan, respectively.

[71] *Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2022-00051, Doc. Con. Cen. No. 220540021, Order for Notice and Hearing (May 24, 2022).

2022 Investor Presentations

DEI presented its fourth quarter earnings to investors on February 11, 2022.[72] [73] This February 2022 presentation to investors identified approximately $27.9 billion in anticipated growth capital expenditures for DEV over the period 2022 – 2026.[74] DEI identified the primary drivers as zero-carbon generation and storage, transmission, and customer growth, as outlined in the chart below.

February 11, 2022 Investor Presentation
DEV Identified Capital Investment
Five Year Outlook 2022 through 2026

	Growth Capex 2022 - 2026
Offshore Wind	$10 Billion
Solar	$6.8 Billion
Transmission	$4 Billion
Customer Growth	$2 Billion
Nuclear Relicensing	$2 Billion
Grid Transformation	$1.5 Billion
Strategic Undergrounding	$1 Billion
Energy Storage	$0.6 Billion
Total Growth Capex	$27.9 Billion

[72] Slides for the February 11, 2022 presentation ("Fourth Quarter Presentation Slides") are available at: https://s2.q4cdn.com/510812146/files/doc_financials/2021/q4/2022-02-11-DE-IR-4Q-2021-earnings-call-slides-vTCIII.pdf. DEI is the parent company of DEV.

[73] DEI also gave an investor presentation on May 5, 2022, for the first quarter of 2022, and August 5, 2022, for the second quarter of 2022. These presentations did not include the same level of DEV-specific capital investment information as the 2021 fourth quarter presentation. Slides for the May 5, 2022, presentation are available at: https://s2.q4cdn.com/510812146/files/doc_financials/2022/q1/2022-05-05-DE-IR-1Q-2022-earnings-call-slides-vTCI_Final.pdf. Slides for the August 5, 2022 presentation are available at https://s2.q4cdn.com/510812146/files/doc_presentations/2022/08/2022-08-08-DE-IR-2Q-2022-earnings-call-slides-vTC.pdf.

[74] *See* Fourth Quarter Presentation Slides 47-49.

In its February 2022 presentation to investors, DEI estimated that by 2026, 92% of the $27.9 billion of growth capex would be eligible to be recovered through RACs.[75] As a result, by 2026, DEI projected that a total of 55% of DEV's $50.7 billion net rate base would be eligible to be recovered through RACs.[76] DEV's projected $50.7 billion net rate base in 2026 would reflect an increase of 74% when compared to 2021. As with the Commission's 2021 report, the totality of these projected capital investments reflect DEI's presentation to investors and have not been independently reviewed by Commission Staff or as part of a Commission proceeding.

[75] *See* Fourth Quarter Presentation Slide 47.

[76] *See* Fourth Quarter Presentation Slide 51.

III.
BASE RATE FINANCIAL RESULTS

DEV 2017-2020 Triennial Review

On March 31, 2021, DEV filed its application for the 2021 triennial review provided for by Code § 56-585.1 A, docketed as Case No. PUR-2021-00058.[77] As filed, DEV presented a combined generation and distribution base rate earned ROE of 9.61%[78] for the combined test periods of 2017 through 2020, which is within the 70 basis point band above and below the 9.20% ROE approved by the Commission in Case No. PUR-2019-00050 to be used to measure earnings in DEV's first triennial review.[79] DEV's earned return was driven in large part by the impairment of the unrecovered balances of several generating units it had retired in 2019 and 2020, which it treated as a period expense subject to the provisions of Code § 56-585.1 A 8.

The evidentiary hearing for the case was held on October 25, 2021. On November 18, 2021, the Commission issued its Final Order in DEV's triennial review.[80]

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[77] *Application of Virginia Electric and Power Company, For a 2021 triennial review of the rates, terms and conditions for the provision of generation, distribution, and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, Case No. PUR-2021-00058, Doc. Con. Cen. No. 210340128, Application (filed March 31, 2021), *amended by* Doc. Con. Cen. No. 210530106, Amended Application (May 18, 2021) (including an amended application, supplemental testimony and filing schedules reflecting a revision to its earned return in the combined earnings test analysis).

[78] This ROE includes the earnings reduction resulting from $206 million of customer accounts receivable written off pursuant to House Bill 5005, 2020 Va. Acts, Special Session I, ch. 56, and House Bill 1800, 2021 Va. Acts, Special Session I, ch. 552. The earned ROE was 10.42% excluding this write-off.

[79] *Application of Virginia Electric and Power Company, For the determination of the fair rate of return on common equity pursuant to § 56-585.1:1 C of the Code of Virginia*, Case No. PUR-2019-00050, 2019 S.C.C. Ann. Rept. 400, Final Order (November 21, 2019).

[80] *Application of Virginia Electric and Power Company, For a 2021 triennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 of the Code of Virginia*, Case No. PUR-2021-00058, 2021 S.C.C. Ann. Rept. 444, Final Order (November 18, 2021).

The Commission approved a stipulation proposed by the majority of case participants, and which was unopposed by any party to the case. In so doing, the Commission approved customer refunds totaling $330 million, the statutory maximum annual rate reduction of $50 million,[81] and customer credit reinvestment offsets of $309 million. For a typical residential customer, this results in a decrease of approximately $0.90 per month effective January 1, 2022, and refunds totaling approximately $67.00 over the 2022-2023 period.

The Commission also approved a 9.35% ROE as fair and reasonable for the 2021 – 2023 period that will be the subject of DEV's next triennial review.[82]

APCo 2017-2019 Triennial Review

As the Commission previously reported, on November 24, 2020, the Commission issued its Final Order in APCo's 2017-2019 triennial review, finding APCo earned an ROE of 9.48% for the 2017 – 2019 triennial period.[83] APCo and Consumer Counsel both filed notices of appeal of the Commission's decision to the Supreme Court of Virginia. On August 18, 2022, the Court issued its opinion affirming in part, reversing in part, and remanding the case to the Commission for further proceedings consistent with the Court's opinion.[84] On remand, the Commission will recalculate APCo's earned ROE for the

[81] Code § 56-585.1 A 8 c.

[82] *Application of Virginia Electric and Power Company, For a 2021 triennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 of the Code of Virginia*, Case No. PUR-2021-00058, 2021 S.C.C. Ann. Rept. 444, Final Order (November 18, 2021).

[83] *Application of Appalachian Power Company, For a 2020 triennial review of its base rates, terms and conditions pursuant to § 56-585.1 of the Code of Virginia*, Case No. PUR-2020-00015, 2020 S.C.C. Ann. Rept. 421, Final Order (November 24, 2020).

[84] *Appalachian Power Co. v. State Corp. Comm'n*, Record No. 210391 (Va. Aug. 18, 2022).

2017-2019 triennial period and determine whether APCo is entitled to a rate increase effective January 1, 2021, and by what amount, based on the Court's findings in its opinion. On August 22, 2022, the Commission issued an Order Initiating Remand Proceedings directing APCo to file interim rates for (a) base rates going forward, and (b) a rider designed to collect revenues not collected from January 1, 2021, through September 30, 2022, to be implemented October 1, 2022.[85]

APCo will file its next triennial review application on or before March 31, 2023, which will cover the period 2020-2022.

DEV 2021 Base Rate Financial Results

During 2022, in response to requests from Staff pursuant to Code § 56-36, DEV provided certain analyses of its combined generation and distribution base rate financial results for calendar year 2021 on a regulatory accounting basis. Calendar year 2021 is the first year of DEV's second triennial review, which will be filed with the Commission in 2024 and will cover the period 2021 – 2023.

DEV analysis reflects a combined base rate generation and distribution ROE of 11.49% for 2021.[86] [87]

[85] *Application of Appalachian Power Company, For a 2020 triennial review of its base rates, terms and conditions pursuant to § 56-585.1 of the Code of Virginia*, Case No. PUR-2020-00015, Doc. Con. Cen. No. 220840166, Order Initiating Remand Proceedings (August 22, 2022).

[86] A 0.01 percentage point of ROE was worth approximately $709,000 in combined generation and distribution annual revenues for DEV in 2021 provided by its customers through payment of their electric bills.

[87] This 2021 earned ROE is based on information provided by DEV. The Commission did not conduct an audit or investigation of the financial information provided by DEV. The Commission will conduct an audit of DEV's 2021 earnings as part of its 2024 triennial review. Interested parties will have an opportunity to participate in that proceeding. The 2021 earned ROE determined by the Commission in the 2024 triennial review may differ from the information provided by DEV and included in this report.

DEV 2021 Earned Return on Equity

Generation	Distribution	Combined
19.39%	4.49%	11.49%

DEV's reported 2021 combined generation and distribution unaudited earned ROE is above the 9.35% base ROE approved by the Commission in Case No. PUR-2021-00058 to be used for the 2021 – 2023 period. The following table provides a breakdown of DEV's 2021 earnings in both percentage points and revenues:

DEV 2021 Earnings in Excess of or Below a 9.35% ROE
(Revenues in Millions of Dollars)

	Generation	Distribution	Combined
Percentage Points	10.04%	-4.86%	2.14%
Revenues	$334.8	-$182.7	$152.1

As discussed above, Code § 56-585.1 A 8, as amended by the GTSA, states that certain costs are deemed fully recovered in the test period in which they were recorded per books by the company for financial reporting purposes. DEV stated it recorded costs in base rates related to severe weather events of $45.5 million during 2021 that are subject to Code § 56-585.1 A 8. DEV also recorded costs in base rates related to coal combustion residual management of $3.0 million during 2021 subject to Code § 56-585.1 A 8. These costs reduced DEV's reported 2021 earned ROE by 0.64 and 0.04 percentage points, respectively.

DEV did not defer any COVID-19-related expenses in 2021.

APCo 2021 Base Rate Financial Results

During 2022, in response to requests from Staff pursuant to Code § 56-36, APCo provided certain analyses of its combined generation and distribution base rate financial results for calendar year 2021 on a regulatory accounting basis. Calendar year 2021 is the second year of APCo's second triennial review, which will be filed with the Commission in 2023 and will cover the period 2020 – 2022.

APCo's analysis reflects a combined base rate generation and distribution ROE of 5.38% for 2021.[88] [89]

APCo 2021 Earned Return on Equity

Generation	Distribution	Combined
11.16%	1.32%	5.38%

APCo's reported 2021 combined generation and distribution unaudited earned ROE is below the 9.20% base ROE approved by the Commission in Case No. PUR-2020-00015 to be used for the 2020 – 2022 period. The following table provides a breakdown of APCo's 2021 earnings above or below the 9.20% approved ROE in both percentage points and revenues:

[88] A 0.01 percentage point of ROE was worth approximately $177,000 in combined generation and distribution annual revenues for APCo in 2021 provided by its customers through payment of their electric bills.

[89] This 2021 earned ROE is based on information provided by APCo. The Commission did not conduct an audit or investigation of the financial information provided by APCo. The Commission will conduct an audit of APCo's 2021 earnings as part of its 2023 triennial review. Interested parties will have an opportunity to participate in that proceeding. The 2021 earned ROE determined by the Commission in the 2023 triennial review may differ from the information provided by APCo and included in this report.

APCo 2021 Earned Return on Equity

(Revenue in Millions of Dollars)

	Generation	Distribution	Combined
Percentage Points Above/(Below) 9.20% ROE	1.96%	-7.88%	-3.82%
Revenue Sufficiency/(Deficiency)	16.2	(73.9)	(67.4)

Section 56-585.1 A 8 of the Code, as amended by the GTSA, directs the Commission to order increases to base rates necessary to provide the opportunity to fully recover the costs of providing the utility's services and to earn a fair combined rate of return if APCo's combined 2020-2022 earnings are more than 0.70 percentage points below the approved ROE of 9.20%.[90]

APCo Combined Earnings

(Earnings in Millions)

	2020	2021	Combined
Net Deficiency (From Bottom of the Range)	57.4	51.4	108.8

As discussed above, Code § 56-585.1 A 8, as amended by the GTSA, states that certain costs are deemed fully recovered in the test period in which they were recorded per books by the company for financial reporting purposes. To the extent those costs cause APCo's combined return to fall below the bottom of the 0.7 percentage point range, they may be deferred and amortized over a future period. APCo stated it recorded costs in base rates related to severe weather events of $11.7 million during 2021 that are subject to Code § 56-585.1 A 8. These costs reduced APCo's reported 2021 earned return by 0.05 percentage points.

[90] If the Commission finds, based on the evidence in the 2023 triennial review, APCo has a combined ROE more than 0.7 percentage points above the approved ROE, the Commission shall order refunds or consumer credit reinvestment offsets equal to the amount above the approved ROE plus 0.7 percentage points.

APCo also reported that it incurred and deferred $2.1 million in COVID-19-related expenses in 2021, which consisted primarily of bad debt expense and protective materials and supplies.

IV.

CURRENT STATUS OF PROCEEDINGS UNDER THE REGULATION ACT

The Regulation Act has undergone a number of amendments over the last few years resulting in numerous new programs, requirements, and rulemakings that apply to the Commonwealth's incumbent electric utilities and electric cooperatives. Since the Commission's 2021 Report, the Commission has conducted additional proceedings brought pursuant to the Regulation Act. This section provides a high-level summary of certain proceedings decided by the Commission since September 1, 2021, the date of the 2021 Report, or pending at the time of this report.[91]

Renewable Energy Cases

Below is a table summarizing the renewable energy cases decided by or pending with the Commission at the time of this report. A description of the proceedings follows the table.

Company	Topic	Pending or Resolved?	Code Section	Case No.
DEV	Regulations for a multi-family shared	Pending	§ 56-585.1:12	PUR-2020-00124

[91] Copies of the Commission's full orders, as well as access to publicly-filed case documents, are available at the Commission's website: https://scc.virginia.gov/pages/Case-Information, by clicking "Docket Search," and clicking "Search By Case Information," and entering the case number in the appropriate box.

	solar program			
DEV	Regulations for a shared solar program	Pending	§ 56-594.3	PUR-2020-00125
APCo	RPS-RAC	Resolved	§ 56-585.2 E	PUR-2021-00048
SCC	GATS Business Rules	Resolved	§ 56-585.5	PUR-2021-00064
APCo	Amherst Solar Facility	Resolved	§ 56-585.1:4 H	PUR-2021-00066
Axton Solar, LLC	Solar Project	Pending	§ 56-580 D	PUR-2021-00085
DEV, APCo	Accelerated Renewable Energy Buyers	Resolved	§ 56-585.5 G	PUR-2021-00089
DEV	US-3 Solar Projects (Update)	Resolved	§ 56-585.1 A 6	PUR-2021-00118
DEV	US-4 Solar Project (Update)	Resolved	§ 56-585.1 A 6	PUR-2021-00119
DEV	Rider TRG (Update)	Resolved	§ 56-577 A 5	PUR-2021-00138
DEV	Offshore wind generation facilities	Pending	§ 56-585.1:11, et al	PUR-2021-00142
DEV	2021 RPS Filing	Resolved	§ 56-585.5	PUR-2021-00146
DEV	Allocation of RPS-related costs	Pending	§ 56-585.5	PUR-2021-00156
APCo	2021 RPS Filing	Resolved	§ 56-585.5	PUR-2021-00206
DEV	Rider PPA	Resolved	§ 56-585.1 A 5	PUR-2021-00248

DEV	Rider RPS	Resolved	§ 56-585.1 A 5	PUR-2021-00282
SCC	GATS business rules; revisions	Pending	§ 56-585.5	PUR-2022-00045
DEV	GATS Business Rules; calculating RECs for a hybrid facility	Resolved	§ 56-585.5	PUR-2022-00075
DEV	Rider TRG (Update)	Pending	§ 56-577	PUR-2022-00101

Decisions

- APCO RPS RAC (PUR-2021-00048). The Commission approved APCo's application to revise its RPS-RAC to recover residual, incremental costs related to APCo's participation in its voluntary RPS program that was in place prior to the passage of the VCEA. (Final Order, December 6, 2021). §§ 56-585.1 A 5 d and 56-585.2 E of the Code.

- GATS Business Rules: Registration and retirement of Virginia-eligible renewable energy certificates (PUR-2021-00064). The Commission revised its business rules concerning the registration and retirement of Virginia-eligible RECs in the PJM-EIS Generation Attribute Tracking System ("GATS"). This revision followed the Commission's then-recent update to these rules to reflect the categories of eligible generation sources for Virginia-qualified RECs in 2021-2024 under Virginia's mandatory RPS statute (§ 56-585.5). This docket was established to invite comment on that update and resulted in further revisions to these business rules. (Final Order, September 30, 2021). § 56-585.5 C of the Code.

- APCo Amherst Solar Facility (PUR-2021-00066). The Commission approved a prudency determination for APCo's proposed 4.875 MW Amherst Solar Facility. APCo did not seek cost recovery for the facility in this case. (Final Order, February 18, 2022). § 56-585.1: 4 H of the Code.

- Rules related to Accelerated Renewable Energy Buyers (PUR-2021-00089). The Commission adopted regulations implementing the provisions of Code § 56-585.5 G, enacted as part of the VCEA. Section 56-585.5 G permits certain customers of APCo and DEV to be certified as accelerated renewable energy buyers, and to be exempted from some or all of the RPS costs of these utilities. (Final Order, December 10, 2021). § 56-585.5 G of the Code.

- DEV US-3 Solar Projects RAC (PUR-2021-00118). The Commission approved DEV's annual update to its RAC for cost recovery associated with its US-3 Solar Projects (the Colonial Trail West Solar Facility, an approximately 142 MW solar generating facility located in Surry County, Virginia, and the Spring Grove 1 Solar Facility, an approximately 98 MW solar facility located in Surry County, Virginia). (Final Order, March 24, 2022). § 56-585.1 A 6 of the Code.

- DEV US-4 Solar Project RAC (PUR-2021-00119). The Commission approved DEV's annual update to its US-4 RAC for cost recovery associated with its Sadler Solar Facility (an approximately 100 MW utility-scale solar photovoltaic generating facility located in Greensville County, Virginia). (Final Order, March 18, 2022). § 56-585.1 A 6 of the Code.

- DEV Rider TRG Update (PUR-2021-00138). The Commission reviewed DEV's annual update of its previously approved 100% renewable tariff, Rider TRG. The update was filed on July 1, 2021. The update requested no change to the approved rate or to the portfolio of renewable resources providing service under Rider TRG. Rider TRG limits the ability of customers in DEV's service territory to purchase renewable energy from competitive suppliers under Code § 56-577 A 5. The Commission exercised its discretion not to address participant levels, and not to modify the filed rate, until Rider TRG has been in effect for a longer period of time in order to gain additional experience with its implementation. (Final Order, December 8, 2021). *See also below,* Case No. PUR-2022-00101, DEV's 2022 Rider TRG update filing. § 56-577 A 5 of the Code.

- DEV 2021 RPS Filing (PUR-2021-00146). The Commission reviewed DEV's 2021 RPS Filing which included (i) DEV's RPS Development Plan (encompassing proposed development of new solar, onshore wind, and energy storage resources); (ii) requests for approval to construct 13 new utility-scale projects and to enter into 24 new PPAs; and (iii) DEV's request for approval of revised Rider CE. The Commission (i) found that, for the limited purpose of filing its second annual RPS plan under Code § 56-585.5 D 4, DEV's plan was reasonable and prudent; (ii) approved the utility-scale projects and PPAs proposed by the Company; and (iii) approved revised Rider CE. In total, the Commission approved 857 MW of new solar generation capacity and 103 MW of energy storage capacity. The Commission directed DEV to continue filing a consolidated bill analysis in its RPS Filings. The Commission also established additional directives regarding DEV's modeling in its subsequent RPS Plans (Final Order, March 15, 2022). §§ 56-580 D, 56-46.1, 56-585.1 A 6, and 56-585.1:4 of the Code.

- APCO 2021 RPS Filing (PUR-2021-00206). The Commission reviewed APCo's 2021 RPS Filing where APCo estimates that by 2040, it may have 2,736 MW (nameplate) of solar, 750 MW (nameplate) of onshore wind, and 2,937 MW (nameplate) of energy storage, through a mix of company-owned resources and

PPAs, to meet the requirements of the VCEA. The Commission found that: (i) APCo's RPS Development Plan is reasonable and prudent for the limited purpose of its second annual plan; (ii) approved APCo's requests for approval of cost recovery for 313.9 MW of solar and onshore wind capacity, including both company-owned resources and PPAs; (iii) granted APCo's request for a prudency determination for 238.9 MW of solar capacity, including company-owned resources and PPAs; (iv) approved the recovery of projected costs of RECs purchased in the PJM REC market; and (v) approved RACs for cost recovery. The Commission directed APCo to continue filing a consolidated bill analysis in its RPS Filings. The Commission also established additional directives regarding APCo's modeling in its subsequent RPS Plans. (Final Order, July 15, 2022) § 56-585.5 of the Code.

- DEV Rider PPA (PUR-2021-00248). The Commission approved DEV's application for approval of a rate adjustment clause, designated Rider PPA, to recover projected and actual costs associated with certain PPAs for the energy, capacity, ancillary services, and RECs owned by third parties. (Final Order, August 3, 2022). § 56-585.1 A 5 d of the Code.

- DEV Rider RPS (PUR-2021-00282). The Commission approved revisions to DEV's Rider RPS. Rider RPS recovers the Company's projected and actual costs related to compliance with the mandatory RPS program established in the VCEA. (Final Order, June 30, 2022). § 56-585.1 A 5 d of the Code.

- DEV - GATS Business Rules; calculating RECs for a hybrid facility (PUR-2022-00075). DEV sought an exception to the GATS Business Rules for a combination solar generator/energy storage facility (Scott Solar/BESS-3). DEV requested that the Commission direct GATS to calculate the RECs for this hybrid facility based on the amount of energy that enters the BESS-3 system as charging energy, rather than the amount of energy discharged by BESS-3 to the grid. The Commission granted DEV's petition for exception in this matter, noting that (i) no comments or requests for hearing concerning it had been filed by interested parties or the Staff, and (ii) the exception granted may be subject to modification in the future as experience is gained with these types of facilities. (Order Granting Exception to GATS Business Rules, August 12, 2022). § 56-585.5 C of the Code, and the Commission's GATS Business Rules.

Pending Cases

- Regulations for a multi-family shared solar program (PUR-2020-00124) (DEV): DEV requests approval of an administrative charge associated with the Company's participation in a program affording eligible multi-family customers of investor-owned utilities the opportunity to participate in shared solar projects.[92] (Case filed September 1, 2021). § 56-585.1:12 of the Code.

[92] KU/ODP also has a multi-family shared solar program but did not request an administrative charge be set for its program.

- Regulations for a shared solar program (PUR-2020-00125) (DEV): The Commission issued a Final Order establishing the minimum bill, which may be modified over time, and set the bill credit rate for participants in DEV's shared solar program under Code § 56-594.3. The Commission is currently considering a petition for reconsideration filed by two respondents. (Order Granting Reconsideration, July 27, 2022) § 56-594.3 of the Code.

- Axton Solar Project (PUR-2021-00085). Axton seeks Commission approval to construct a 201.1 MW solar generating facility to be constructed in Henry and Pittsylvania Counties. The Application was initially filed on April 28, 2021. Axton subsequently filed with the Commission an amended application and supporting documents. (Amended application filed March 31, 2022). §§ 56-46.1 and 56-580 D of the Code.

- DEV offshore wind generation facilities (PUR-2021-00142). The Commission issued a Final Order approving requested cost recovery associated with DEV's proposed 2,587 MW CVOW Project to be located in a federal lease area off the coast of Virginia Beach, Virginia. The project consists of 176 wind turbines, each designed to generate 14.7 MW. The project is expected to have a capital cost of $9.8 billion and will likely be the largest capital investment, and single largest project, in the history of Dominion Energy Virginia. The Commission also approved the electric interconnection and transmission facilities to connect the CVOW Project reliably with the existing transmission system. The Commission issued an Order Granting Reconsideration for purposes of retaining jurisction over the case in response to a Petition for Limited Reconsideration filed by DEV. (Final Order, August 5, 2022; Order Granting Reconsideration, August 24, 2022). §§ 56-585.1, 56-585.1:11, 56-46.1, 56-265.1 of the Code.

- DEV allocation of RPS-related costs (PUR-2021-00156). This Commission docket was established to consider issues related to DEV's recovery of its RPS related costs, and the jurisdictional and class allocation of those costs among its customers. (Case filed December 22, 2021). § 56-585.5 of the Code.

- GATS business rules (PUR-2022-00045). This Commission proceeding will consider potential revisions to the Commission's GATS business rules ("GATS Business Rules"). In particular, the Commission will consider (i) incorporating language to establish a self-certification process for resources seeking to qualify as low-income projects pursuant to Code § 56-585.5 C; and (ii) additional issues related to the GATS Business Rules. (Case docketed April 14, 2022). § 56-585.5 C of the Code.

- DEV Rider TRG (PUR-2022-00101). DEV seeks approval of an annual update of its 100 percent renewable energy tariff, designated Rider TRG whereby participating customers can voluntarily elect to purchase 100 percent of their

energy grid capacity needs sourced from renewable energy resources. (Case filed July 1, 2022). §§ 56-577 A 5 and 56-234 of the Code.

Environmental Cases

Below is a table summarizing the environmental cases decided by or pending before the Commission at the time of this report. A description of the proceedings follows the table.

Company	Topic	Pending or Resolved?	Code Section	Case No.
DEV	Rider E (Update)	Resolved	§ 56-585.1 A 5	PUR-2021-00013
DEV	Rider CCR	Resolved	§ 10.1-1402.03	PUR-2021-00045
DEV	Rider RGGI Update	Resolved	§ 56-585.1 A 5	PUR-2021-00281
APCo	Environmental RAC	Pending	§ 56-585.1 A 5	PUR-2022-00001
DEV	Rider E (Update)	Pending	§ 56-585.1 A 5	PUR-2022-00006
DEV	Rider CCR	Pending	§ 10.1-1402.03	PUR-2022-00033
DEV	Rider RGGI (Suspension)	Resolved	§ 56-585.1 A 5	PUR-2022-00070

Decisions

- DEV Rider E (PUR-2021-00013). The Commission approved DEV's annual update to its Rider E to recover costs incurred to comply with state and federal environmental regulations at the Company's Chesterfield, Bremo, Clover, and Mt. Storm Power Station. (Final Order September 23, 2021). § 56-585.1 A 5 e of the Code.

- DEV Rider CCR (PUR-2021-00045). The Commission approved DEV's application seeking approval of Rider CCR to recover costs related to the removal of coal combustion residual from DEV's Bremo, Chesterfield, and Possum Point Power Stations and Chesapeake Energy Center. Such approval was made subject to certain cost allocations, reporting, and filing requirements applicable to future Rider CCR updates. (Final Order, October 6, 2021). §§ 56-585.1 A 5 e and 10.1-1402.03 of the Code.

- DEV Rider RGGI Update (PUR-2021-00281). On December 26, 2021, DEV filed an annual update of the Company's rate adjustment clause, Rider RGGI. This

Rider recovers projected and actual costs related to the purchase of allowances through the RGGI market-based trading program for carbon dioxide emissions. DEV subsequently sought, and the Commission granted, the Company's motion to withdraw the update filing, subject to future update and filing requirements. (Order Granting Motion, April 1, 2022). See, also, related docket, Case No. PUR-2022-00070. § 56-585.1 A 5 e of the Code.

- DEV Rider RGGI Suspension (PUR-2022-00070). The Commission approved DEV's May 5, 2022, petition to suspend Rider RGGI and to reset the Rider RGGI Projected Cost Recovery Factor to $0.00/kWh, effective July 1, 2022. The Commission further authorized DEV to recover RGGI compliance costs that are incurred up through July 31, 2022 (and ultimately approved by the Commission), and which have not been recovered prior to the suspension of the Rider through DEV's base rates for generation services in effect during the period incurred. This docket will remain open for future proceedings, including but not limited to an actual cost true-up proceeding to review incurred allowance costs that have been recovered through Rider RGGI. (Order Granting Petition, June 15, 2022). § 56-585.1 A 5 e of the Code.

Pending Cases

- APCo Environmental RAC (PUR-2022-00001). APCo seeks Commission approval to recover costs through its existing rate adjustment clause, the E-RAC, related to capital investments and operations and maintenance compliance expenses that are necessary to comply with state and federal environmental regulations. (Case filed March 18, 2022). § 56-585.1 A 5 e of the Code.

- DEV Rider E Update (PUR-2022-00006). DEV seeks an update to its Rider E to recover costs incurred to comply with state and federal environmental regulations at the Company's Chesterfield, Bremo, Clover, and Mt. Storm Power Stations. (Case filed January 25, 2022). § 56-585.1 A 5 e of the Code.

- DEV Rider CCR (PUR-2022-00033). DEV seeks to update its Rider CCR RAC. (Case filed February 28, 2022) §§ 56-585.1 A 5 e and 10.1-1402.03 of the Code.

Retail Access Cases

Below is a table summarizing the retail access cases decided by or pending before the Commission at the time of this report. A description of the proceedings follows the table.

Company	Topic	Pending or Resolved?	Code Section	Case No.
DEV	Aggregation Pilot	Continued	Chapter 796 of the 2020 Virginia Acts of Assembly	PUR-2020-00114
DEV	RPS Cost Allocation Proceeding	Resolved	§ 56-585.5 F	PUR-2020-00164

Decisions

- DEV RPS Cost Allocation to shopping customers (PUR-2020-00164). In this proceeding, DEV sought approval of its proposal to recover the non-bypassable RPS costs associated with Code § 56-585.5 F, net of benefits, from customers electing to take electric supply service from a competitive service provider. However, as part of the Commission's 2020 RPS Final Order, the Commission adopted the general RAC framework for the recovery of RPS-related costs as proposed by Staff, and as refined by Dominion, under which the Company will recover costs of resources approved under the VCEA, including the non-bypassable charge, in a single rate mechanism. As such, the Commission determined in this proceeding that Rider NBC (proposed by DEV) is no longer needed. Issues related to distinguishing between RPS Program compliance costs and other costs, as well as class cost allocation methodology and ARBs, will be addressed in appropriate subsequent proceedings, including Case No. PUR-2021-000156, discussed *supra*. (Final Order, September 23, 2021). §§ 56-585.5 and 56-585.1:11 of the Code.

Continued Cases

- DEV Aggregation Pilot (PUR-2020-00114). Pursuant to legislation passed by the 2020 General Assembly, the Commission established a pilot program through which non-residential customers that had previously sought to aggregate their load pursuant to Code § 56-577 A 4 in DEV's service territory would be permitted to purchase electric energy from a competitive service provider, subject to an overall cap of 200 MW of load participating in the Pilot. On June 17, 2022, the Commission issued an Order (i) finding that the Pilot should continue and remain open to any non-residential customer who is eligible for, and wishes to participate in, the Pilot; and (ii) continuing the case. Chapter 796 of the 2020 Virginia Acts of Assembly**.**

Energy Efficiency Cases

Below is a table summarizing the energy efficiency cases decided by or pending before the Commission at the time of this report. A description of the proceedings

follows the table. Both APCo (a Phase I Utility) and DEV (a Phase II Utility) estimate that they are on target to implement energy efficiency programs and measures to achieve the total annual energy savings targets for 2023 as specified by Code § 56-596.2.

Company	Topic	Pending or Resolved?	Code Section	Case No.
DEV	Evaluation, Measurement and Verification (EM&V) Methodologies	Resolved	§ 56-585.1 A 5	PUR-2020-00156
DEV	DSM RAC and Phase IX Programs	Resolved	§ 56-585.1 A 5	PUR-2020-00274
APCo	Energy Efficiency RAC and New Program	Resolved	§ 56-585.1 A 5	PUR-2021-00236
DEV	DSM RAC and Phase X Programs	Resolved	§ 56-585.1 A 5	PUR-2021-00247

Decisions

- DEV EM&V "Dashboard" proceeding (PUR-2020-00156). This Commission proceeding established guidelines for DEV's evaluation, measurement, and verification ("EM&V") reports related to the Company's DSM programs. DSM programs include energy efficiency and peak-shaving programs. EM&V reports address energy savings produced by such programs. (Final Order, October 27, 2021). § 56-585.1 A 5 of the Code.

- APCo Energy Efficiency RAC and New Program (PUR-2021-00236). The Commission approved APCo's application for approval of the continued implementation of its rate adjustment clause, the EE-RAC, to recover the costs of its existing portfolio of DSM programs, as well as for approval of one new pilot program, the Commercial and Industrial Custom Pilot Program. (Final Order, July 15, 2022). §§ 56-585.1 A 5 and 56-596.2 of the Code.

- DEV DSM RAC and Phase IX Programs (PUR-2020-00274). The Commission approved DEV's application seeking approval of its Phase IX DSM programs, including 11 new energy efficiency and demand response programs, the expansion and modification of certain existing programs, and approval of cost recovery through associated RACs. The Commission's approval was made subject to certain cost caps together with requirements for future DSM filings. (Final Order, September 7, 2021). § 56-585.1 A 5 of the Code.

- DEV DSM RAC and Phase X Programs (PUR-2021-00247). The Commission approved, among other things, (i) DEV's proposed Phase X DSM Programs including proposed enhancement and expansion of certain previously approved programs; (ii) reorganization and consolidation of the DEV's DSM Portfolio; and (iii) cost recovery through associated RACs. § 56-585.1 A 5 of the Code. (Final Order, August 10, 2022). § 56-585.1 A 5 of the Code.

Distribution Cases

Below is a table summarizing the distribution cases decided by or pending before the Commission at the time of this report. A description of the proceedings follows the table.

Company	Topic	Pending or Resolved?	Code Section	Case No.
APCo	Broadband Project	Resolved	§ 56-585.1:9	PUR-2020-00259
DEV	Rider GT	Resolved	§ 56-585.1 A 6	PUR-2021-00083
DEV	Rider U (Update)	Resolved	§ 56-585.1 A 6	PUR-2021-00110
DEV	Grid Transformation Plan	Resolved	§ 56-585.1 A 6	PUR-2021-00127
APCo	Broadband Project	Pending	§ 56-585.1:9	PUR-2022-00020
DEV	Broadband Project	Pending	§§ 56-585.1 A 6 and 56-585.1:9	PUR-2022-00062
SCC	Interconnection of Distributed Energy Resources	Pending	Pursuant to Final Order in Case No. PUR-2021-00127	PUR-2022-00073
DEV	Rider U (Update)	Pending	§ 56-585.1 A 6	PUR-2022-00089

Decisions

- APCo Broadband Project (PUR-2020-00259). The Commission approved APCo's petition seeking approval of a rate adjustment clause, the BC-RAC, for cost recovery of providing broadband capacity through its previously

approved Grayson County broadband pilot. (Final Order, October 1, 2021). §§ 56-585.1 A 6 and 56-585.1:9 of the Code.

- DEV Rider GT (PUR-2021-00083). The Commission approved DEV's application for a new rate adjustment clause, designated Rider GT, to recover certain costs of the Company's grid modernization plan that the Commission previously approved in Case Nos. PUR-2018-00100 and PUR-2019-00154. (Final Order, May 13, 2022). § 56-585.1 A 6 of the Code.

- DEV Rider U Strategic Undergrounding Program (PUR-2021-00110). The Commission approved DEV's annual update to Rider U. (Final Order, March 9, 2022). § 56-585.1 A 6 of the Code.

- DEV Grid Transformation Plan (PUR-2021-00127). The Commission approved DEV's third grid modernization proposal, which included requested approval of $669.4 million of capital investments and $109.5 million of operations and maintenance expense. The Commission's approval of these projects was made subject to certain contingencies, cost caps, and reporting requirements. (Final Order, January 7, 2022). § 56-585.1 A 6 of the Code.

Pending Cases

- APCo Broadband Project (PUR-2022-00020). APCo seeks approval of a new project to make available broadband capacity to an Internet Service Provider in parts of Bland County and Montgomery County and to revise its BC-RAC to reflect actual costs of providing broadband capacity under the Company's existing broadband project as well as the new project. (Case filed June 8, 2022) §§ 56-585.1 A 6 and 56-585.1:9 of the Code.

- DEV Broadband Project (PUR-2022-00062). DEV seeks approval to install middle-mile broadband capacity in certain unserved areas of Virginia, including the Northern Neck region and the Thomas Jefferson Planning District. The Company also seeks approval to revise rate adjustment clause Rider RBB, for the rate year commencing December 1, 2022, through November 20, 2023. (Case filed May 5, 2022). §§ 56-585.1 A 6 and 56-585.1:9 of the Code.

- Interconnection of Distributed Energy Resources (PUR-2022-00073). This Commission docket was established (pursuant to the Commission's Final Order in Case No. PUR-2021-00127) to address obstacles to the interconnection of distributed energy resources on electric utilities' distribution systems. (Docket established May 24, 2022).

- DEV Rider U Strategic Undergrounding Program (PUR-2022-00089). DEV seeks an annual update to Rider U. (Case filed June 13, 2022). § 56-585.1 A 6.

Integrated Resource Plan Cases

Below is a table summarizing the IRP cases decided by or pending before the Commission at the time of this report. A description of each proceeding follows the table.

Company	Topic	Pending or Resolved?	Code Section	Case No.
DEV	Integrated Resource Plan Update	Resolved	§ 56-597 *et seq.*	PUR-2021-00201
APCo	Integrated Resource Plan	Pending	§ 56-597 *et seq.*	PUR-2022-00051

Decisions

- DEV IRP Update (PUR-2021-00201). On September 1, 2021, DEV filed with the Commission the Company's 2021 update to its 2020 Integrated Resource Plan. The Commission found this update legally sufficient and accepted it for filing. The Commission stated, however, that such acceptance does not express approval of the magnitude or specifics of Dominion's future spending plans. (Final Order, October 28, 2021). § 56-599 of the Code.

Pending Cases

- APCo IRP (PUR-2022-00051). APCo has filed its 2022 IRP. Per the filing, the IRP, among other things, incorporates requirements of the VCEA related to resource acquisition, includes the most recent load forecast consistent with the VCEA, and incorporates updated renewable costs. The Commission will hear this case starting October 24, 2022. (Case filed April 29, 2022). § 56-599 of the Code.

Financial Review Cases

Below is a table summarizing the financial review cases decided by or pending before the Commission at the time of this report.

Company	Topic	Pending or Resolved?	Code Section	Case No.
APCo	Triennial Review	Pending	§ 56-585.1 A	PUR-2020-00015

DEV	Triennial Review	Resolved	§ 56-585.1 A	PUR-2021-00058

Decisions

- DEV Triennial Review (PUR-2021-00058). On March 31, 2021, DEV filed its application for the Commission's triennial review of the Company's rates, terms, and conditions for the provision of generation, distribution, and transmission services. The Commission Order in this case approved a stipulation that principally provided (i) customer refunds totaling $330 million; and (ii) the statutory maximum annual rate reduction of $50 million. (Final Order, November 18, 2021). § 56-585.1 A 3 of the Code.

Pending

- APCo Triennial Review (PUR-2020-00015). The Commission, among other things, determined that in the 2017-2019 triennial period under review, Appalachian earned 6 basis points above the fair ROE, which equates to approximately $1,992,987 in excess earnings for such period. Upon appeal to the Supreme Court of Virginia, on August 18, 2022, the Court affirmed in part, reversed in part, and remanded the case to the Commission for further proceedings consistent with the Court's opinion. (Final Order, November 24, 2020; Order on Reconsideration, March 26, 2021; Notice of Appeal, April 5, 2021; Petition of Appeal, July 6, 2021; Opinion of the Supreme Court of Virginia, Aug. 18, 2022; Order Initiating Remand Proceedings, August 22, 2022). § 56-585.1 A 3 of the Code.

See also, Section III, Base Rate Financial Results, of this report for details on these cases.

Miscellaneous Cases

Below is a table summarizing miscellaneous cases decided by or pending before the Commission at the time of this report. A description of the proceedings follows the table.

Company	Topic	Pending or Resolved?	Code Section	Case No.
DEV	Universal Service Fee/Rider PIPP	Pending	§ 56-585.6	PUR-2020-00109
APCo	Universal Service Fee/Rider PIPP	Pending	§ 56-585.6	PUR-2020-00117
DEV	Rider SNA	Resolved	§ 56-585.1 A 6	PUR-2021-00229

Decisions

- DEV Rider SNA (PUR-2021-00229). The Commission approved DEV's application for a RAC, Rider SNA, to recover the Company's costs associated with (i) preparing petitions to the Nuclear Regulatory Commission to extend the operating licenses of Dominion's Surry Units 1 and 2 and North Anna Units 1 and 2; and (ii) the projects reasonably appropriate to upgrade or replace systems and equipment deemed to be necessary to operate these units safely and reliably. (Final Order, July 1, 2022). § 56-585.1 A 6 of the Code.

Pending

- Percentage of Income Payment Program (DEV: PUR-2020-00109; APCo: PUR-2020-00117). The VCEA requires the Commission to determine the universal service fees to be collected from customers of APCo and DEV to fund the Percentage of Income Payment Program ("PIPP") established by statute. PIPP eligible utility customers are persons or households whose income does not exceed 150 percent of the federal poverty level.[93] § 56-585.6 of the Code.

  The Commission authorized DEV and APCo to begin collecting a universal service fee from the statutorily designated customers as soon as practicable, effective for service rendered on and after September 1, 2021, at a level designed to fund the estimated start-up costs of Department of Social Services ("DSS") needed to establish the PIPP. The Commission also continued the proceedings to determine the rates, terms, and conditions of a "non-bypassable universal service fee" to be charged to DEV and APCo's customers to fund the PIPP, instructing both utilities to file within 60 days after DSS rules or guidelines are published. (Orders, July 29, 2021). To date, DSS has not published these rules or guidelines. Consequently, neither APCO nor DEV has been required to make additional filings of their respective PIPP dockets, as otherwise required by the Commission's July 20, 2021 Orders.

V.
STAKEHOLDER MEETINGS

The Staff has been involved in multiple stakeholder meetings over the last year as required by recent legislation. Staff has attended these meetings as a resource to provide technical information or background on Commission procedures and proceedings. The following is a list of meetings the Staff has attended:

[93] Code § 56-576.

- Energy Efficiency Meetings: (required by SB 966,[94] SB 1605,[95] and HB 2293[96]) held on November 8, 2021, and April 25, 2022, for APCo; and, August 31, 2021, November 17, 2021, February 22, 2022, and, June 21, 2022, for DEV.

- Transportation Electrification Stakeholder Group Meetings: (required by HB 2282[97]) held on October 21, 2021, November 4, 2021, November 18, 2021, December 2, 2021, and December 16, 2021.

- Program to Encourage and Expedite Electric Utility Infrastructure Investments Stakeholder Meetings: (required by HB 894[98]) held on June 23, 2022, July 5, 2022, July 13, 2022, and July 25, 2022.

- Renewable Energy Facilities Lifecycle Task Force Meeting: (required by SB 499 and HB 774[99]) The Commission is in the process of selecting a third-party facilitator for this task force. Task force meetings are expected to occur in the fall of 2022.

- Shared Solar Stakeholder Workgroup for APCo and Kentucky Utilities: (required by SB 660[100]) The Commission is in the process of selecting a third-party facilitator for this work group. Stakeholder workgroup meetings are expected to occur in the fall of 2022.

VI.
PJM / FERC STATUS

DEV and APCo are members of PJM, a regional transmission organization that coordinates the movement of wholesale electricity across all or parts of the District of

[94] 2018 Va. Acts ch. 296.

[95] 2019 Va. Acts ch. 398.

[96] 2019 Va. Acts ch. 397.

[97] 2021 Va. Acts, Special Session I, ch. 268.

[98] 2022 Va. Acts ch. 488.

[99] 2022 Va. Acts chs. 69 and 70.

[100] 2022 Va. Acts ch. 591.

Columbia and 13 states.[101] Below is a list of recent matters involving PJM and FERC that may impact Virginia:

- In June 2018, FERC invalidated PJM's capacity market design. FERC ruled that state-subsidized resources were artificially and improperly suppressing market prices.[102] Following a FERC technical conference on wholesale market reform in March 2021, during which the FERC Chairman indicated FERC would take action to address deficiencies in the Minimum Offer Price Rule ("MOPR") (including concerns that the MOPR could cause undue burden to resources supported by state policies) by year-end if PJM did not do so, PJM initiated an accelerated stakeholder process, or Critical Issue Fast Path. On July 30, 2021, PJM filed its replacement MOPR proposal in Docket No. ER21-2582. On September 29, 2021, FERC allowed PJM's proposal to become effective by operation of law, stating that "[t]he Commission did not act on PJM's filing because the Commissioners are divided two against two as to the lawfulness of the change."[103] Several parties, including other state commissions, have appealed FERC's order.

- In April 2021, DEV announced that it would elect to procure its capacity through the Fixed Resource Requirement alternative to the PJM capacity market auction.[104] A competitive power supplier challenged PJM's approval of this election. FERC rejected this challenge on July 15, 2021.

- In September 2020, FERC issued Order 2222, which adopted reforms to allow distributed energy resource aggregations to participate in the regional transmission organization markets.[105] PJM made its compliance filing on February 1, 2022, outlining how it will comply with Order 2222.[106]

- On June 30, 2021, the transmission owners ("Transmission Owners") in the PJM region submitted a consolidated filing at FERC that proposed revisions to the PJM Tariff to provide Transmission Owners with the option to elect to fund the capital

[101] Specifically, the 13 states consist of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

[102] *Calpine Corp. v. PJM Interconnection, LLC*, 163 FERC ¶ 61,236 (2018).

[103] *PJM Interconnection L.L.C.*, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582 (Sep. 29, 2021).

[104] APCo has always chosen the PJM Fixed Resource Requirement alternative since joining PJM in 2004.

[105] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172 FERC ¶ 61,247 (September 19, 2020).

[106] *PJM Interconnection, L.L.C.*, Docket No. ER22-962.

cost of network upgrades necessary to accommodate generator interconnections.[107] The proposed revisions would allow the PJM Transmission Owners the opportunity to earn a return of and on the costs of network upgrades that are necessary to interconnect generation resources to the PJM transmission system. Under the current tariff, those costs must be paid by the interconnecting generator. FERC set this matter for paper hearing on November 19, 2021, and parties filed briefs in January 2022.

- On July 19, 2021, PJM filed a brief in a Pennsylvania federal court case challenging the Pennsylvania Public Utility Commission's ("PAPUC") rejection of a transmission line. Following the PAPUC's order, the developer (TransSource) sued the PAPUC in federal court, alleging that the PAPUC's decision violated the dormant Commerce Clause and was preempted by PJM's earlier determination of need. PJM claims that the PAPUC does not have authority to reject a line on the grounds that the line is not needed where PJM has concluded the line is necessary under mechanisms approved by FERC. On August 26, 2021, the District Court denied in part PAPUC's motion to dismiss, finding that TransSource had standing to file the action. The court abstained on the remainder of the motion, electing to wait until an appeal in state court was completed. On May 6, 2022, the Pennsylvania Commonwealth Court upheld the PAPUC's order rejecting the line. The District Court lifted its stay of the proceedings on May 17, 2022, and discovery in the case is ongoing. The current schedule calls for discovery to continue until January 2023, with dispositive motions and supporting briefs due on or before February 15, 2023.

- On April 21, 2022, FERC issued a Notice of Proposed Rulemaking ("NOPR") seeking comment on the potential need for change to existing regulations on electric regional transmission planning, cost allocation, and generator interconnection processes.[108] Comments were due by August 17, 2022.

- On June 14, 2022, PJM proposed changes to its generator interconnection process, seeking to change from a first-come, first-served process to a first-ready, first-served process, to give priority to projects that are more likely to be completed.[109] PJM claims this will help alleviate significant queue backlogs.

- On June 16, 2022, FERC issued a NOPR, proposing changes to its interconnection procedures to address interconnection queue backlogs, improve

[107] *PJM Tariff Revisions to Implement Transmission Owners' Funding of Network Upgrades*, Docket No. ER21-2282 (June 30, 2021).

[108] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (Apr. 21, 2022).

[109] *PJM Interconnection, L.L.C.*, Docket No. ER22-2110.

certainty, and prevent undue discrimination for new technologies.[110] Comments on the NOPR are due October 13, 2022.

VII.
CONSUMER EDUCATION

The Regulation Act, specifically § 56-592 of the Code, directs the Commission to establish, implement, and maintain a consumer education program to provide retail customers with information regarding energy conservation and efficiency, DSM, demand response, and renewable energy. The Virginia Energy Sense ("VES") consumer education program is in its twelfth year of building awareness of the value of energy efficiency.

Highlighted VES accomplishments from the last year (July 1, 2021 – June 30, 2022) are as follows:

- VES' new contract team comprehensively analyzed communications about consumer energy in Virginia and developed a messaging framework to guide the program's strategies and activities.
- To measure public attitudes on energy conservation, VES conducted an online quantitative survey, which garnered responses from 1,208 Virginia residents. Survey results suggested that awareness of the VES program remains high; approximately 1 in 4 respondents recalled recently seeing or hearing messages from or about VES.
- VES secured 10 news stories about the program and its energy saving tips in 10 media outlets, including TV stations in Richmond, Charlottesville, and Norfolk.
- Following a pandemic-driven pause in community outreach events, VES exhibited at three in-person events in spring 2022. The events' total attendance was approximately 75,400.
- VES ran two statewide radio advertising campaigns that collectively generated over 9.7 million impressions. The campaigns ran in October 2021 and April –

[110] *Improvements to Generator Interconnection Procedures and Agreements*, Docket No. RM22-14, 179 FERC ¶ 61,194 (June 16, 2022).

May 2022 and drove a 31.5% and a 16.3% increase in web visits, respectively. VES also created 36 public service announcements for radio, tailored to the six regions of Virginia, that collectively garnered around 120,000 impressions as of May 31, 2022.

- A VES advertising campaign on Facebook and Instagram that ran from May 4 to June 1, 2022, garnered over 2.8 million impressions and drove 12,627 visits to VES' new "10 ways to save" landing page, shown below:

- The VES website garnered 19,891 site visits and 22,833 page views.

- VES published 218 posts on its Facebook and Twitter accounts, reaching 31,625 users and generating 722 engagements. VES also relaunched its Instagram account in March 2022.

VIII.
CLOSING

Code § 56-596 directs the Commission to provide "recommendations for any actions by the General Assembly, the Commission, electric utilities, or any other entity that the Commission considers to be in the public interest."[111] While the Commission has no statutory recommendations at this time, we bring to the General Assembly's attention a matter for its consideration, specifically the Commission's lack of proactive authority, under current law, to protect reliability and security of electric service resulting from VCEA-directed retirements unless there is a request by the utility. Code § 56-585.5 B prescribes certain retirements of fossil fuel generation owned by Phase I (APCo) and Phase II (DEV) utilities.

Code § 56-585.5 B 4 further states:

> A Phase I or Phase II Utility [APCo or DEV] *may* petition the Commission for relief from the requirements of this subsection on the basis that the requirement would threaten the reliability or security of electric service to customers. The Commission shall consider in-state and regional transmission entity resources and shall evaluate the reliability of each proposed retirement on a case-by-case basis in ruling upon any such petition.[112]

The Commission appreciates the General Assembly's awareness of the importance of reliability and security of electric service to end-use customers. That said, the above

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[111] Specifically, Code § 56-596 B.

[112] Emphasis added. Similarly, Enactment Clause 9 of the VCEA reads:

> That nothing in this act shall require the utilities or the State Corporation Commission to take any action that, in the State Corporation Commission's discretion and after consideration of all in-state and regional transmission entity resources, threatens the reliability or security of electric service to the utility's customers.

While this Enactment Clause appears to protect the Commission *from having to* act, it does not appear to give the Commission authority *to* act.

provisions leave it to *the utility's* discretion whether to seek relief from VCEA requirements. The utility still has the ability to decide to retire and/or impair generating units even though customers may still be required to pay for such units. An after-the-fact review or finding of harm to reliability and/or security of electric service would leave the Commission with few options to protect customers.

If the General Assembly intends to leave this discretion solely in the hands of utilities, that is what the current law accomplishes. The General Assembly may wish to consider a required update or analysis from the Commission in close proximity and prior to unit closure.

The Commission continues to execute its responsibilities under the Regulation Act and stands ready to implement the laws passed by the General Assembly.

APPENDIX 1

GLOSSARY OF TERMS

ARPA	American Rescue Plan Act of 2021
APCo	Appalachian Power Company
Code	Code of Virginia
CTs	Combustion Turbines
Commission	Virginia State Corporation Commission
CRF	Coronavirus Relief Funds
Consumer Counsel	Office of the Attorney General, Division of Consumer Counsel
CVOW Project	Coastal Virginia Offshore Wind Commercial Project
DEI	Dominion Energy, Inc.
DEV	Virginia Electric and Power Company d/b/a Dominion Energy Virginia
Dominion	Virginia Electric and Power Company d/b/a Dominion Energy Virginia
DSM	Demand-side Management
DSS	Department of Social Services
EE	Energy Efficiency
EM&V	Evaluation, Measurement, and Verification
FERC	Federal Energy Regulatory Commission
GATS	PJM-EIS Generation Attribute Tracking System
GTSA	Grid Transformation and Security Act, Chapter 296 of the 2018 Acts of Assembly
IRP	Integrated Resource Plan
KU/ODP	Kentucky Utilities Company d/b/a Old Dominion Power Company
kWh	Kilowatt-hour
MOPR	Minimum Offer Price Rule
MW	Megawatt
NOPR	Notice of Proposed Rulemaking
PAPUC	Pennsylvania Public Utility Commission
PIPP	Percentage of Income Payment Program
PJM	PJM Interconnection, L.L.C.
PPA	Power Purchase Agreement
RAC	Rate Adjustment Clause
RGGI	Regional Greenhouse Gas Initiative
REC	Renewable Energy Certificate
Regulation Act	Virginia Electric Utility Regulation Act, codified at Code §§ 56-576 through 56-596.3
ROE	Return on Equity
RPS	Renewable Energy Portfolio Standard
Staff	State Corporation Commission Staff
VCEA	Virginia Clean Economy Act, Chapters 1193 and 1194 of the 2020 Acts of Assembly
VES	Virginia Energy Sense, a State Corporation Commission consumer education program

Attachment 42

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PUBLIC VERSION

May 5, 2022

BY HAND DELIVERY

Mr. Bernard Logan, Clerk
State Corporation Commission
c/o Document Control Center
Tyler Building – First Floor
1300 East Main Street
Richmond, Virginia 23219

Application of Virginia Electric and Power Company, To revise its fuel factor pursuant to Va. Code § 56-249.6
Case No. PUR-2022-00064

Dear Mr. Logan:

Please find enclosed for filing in the above-captioned proceeding an unbound original and one (1) copy of the **public version** of the *Application of Virginia Electric and Power Company to revise its fuel factor pursuant to Va. Code § 56-249.6.* A confidential version of this filing is also being filed under seal under separate cover.

Please do not hesitate to contact me if you have any questions in regard to the enclosed.

Highest regards,

/s/ Elaine S. Ryan

Elaine S. Ryan

Enclosures
cc: William H. Chambliss, Esq.
C. Meade Browder, Jr., Esq.
Paul E. Pfeffer, Esq.
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220512009

May 5, 2022

Mr. Bernard Logan, Clerk
Virginia State Corporation Commission
c/o Document Control Center
1300 East Main Street
Richmond, VA 23219

Re: Case No. PUR-2022-00064

Dear Mr. Logan:

Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company") hereby files with the Virginia State Corporation Commission ("Commission") its application to revise the fuel factor component of customer electric rates effective July 1, 2022 (the "Application"), pursuant to § 56-249.6 of the Code of Virginia. While in most years, this is a relatively routine filing, the dramatic increases in fuel prices as a result of the pandemic, inflation generally, and the war in Ukraine have created a significant fuel cost under-recovery and projections that fuel costs will remain elevated over the next year. The Company estimates that without steps to mitigate the effect of these costs, the fuel factor rate adjustment would result in an approximately 20% increase in the typical Dominion Energy Virginia residential customer's monthly bill for 1,000 kilowatt-hours of usage.

To avoid this outcome, the Company presents a voluntary mitigation proposal in the Application, including Two Year Mitigation and Three Year Mitigation alternatives. The Company recommends the latter option, which would reduce the impact to the typical residential customer to an approximately 12% bill increase due to the fuel factor rate adjustment. Taken together, the Three Year Mitigation proposal and separate rate revisions submitted to the Commission today would increase the typical residential customer's monthly bill by a net of approximately $9 or 7%, if approved as filed. This does not count a $1.98 savings from a filing previously approved by the Commission withdrawing a proposed increase for costs related to the Regional Greenhouse Gas Initiative. As always, the Company stands ready to work with customers to identify programs, services, and payment options that suit their particular needs.

The fuel factor rate is designed to recover purchased power costs and costs incurred to procure commodities, most notably natural gas and coal, needed to power the Company's traditional electric generating fleet and reliably serve its customers. The Company's current fuel factor rate, based on March 2021 commodity price projections, was set prior to significant increases in the price of purchased power, coal, and natural gas which have only been exacerbated by the war in Ukraine.

Differences between past projections and actual fuel costs are not unusual, and fuel factor rate revisions provide the opportunity to correct for any under- or over-recovery. However, the Company is mindful of the significant under-recovery which has accrued—the fuel deferral balance is expected to exceed $1 billion as of June 30, 2022. Additionally, current projections suggest that fuel commodity prices will remain at elevated levels for the medium term. This set of circumstances would ordinarily result in a significant customer impact from the fuel factor rate revision if the Commission were to approve a recovery rate over 12 months.

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The Application therefore presents alternatives to instead spread recovery over either two or three years. Both the Two Year Mitigation and Three Year Mitigation options would reduce the effect of the fuel factor rate revision on customer electric bills. Between these two alternatives, the Company recommends the Three Year Mitigation proposal because it provides for the smallest near-term rate increase, rate stability over the next several years, and greater flexibility in the event commodity markets have improved when the Commission revisits the fuel factor rate next year.

Dominion Energy Virginia is sensitive to any proposed electric rate increase, as evidenced by its recent motion to withdraw the proposed update to the rate adjustment clause associated with Regional Greenhouse Gas Initiative compliance (Rider RGGI). The Commission's approval of this motion last month avoided what the Company expected would have been a $1.98 increase to the typical residential customer's monthly bill. Today, the Company has proposed to cease customer billing for Rider RGGI effective July 1, 2022 and recover unrecovered RGGI-related costs through July 31, 2022 in its base rates. This will reduce the typical residential customer's monthly bill by approximately $2.39, subject to Commission approval.

The proposed revision to Rider T1, the Company's recovery mechanism for certain transmission-related costs, would save the typical residential customer another $3.69 per month in electricity costs if approved. Dominion Energy Virginia has also petitioned for a revision to Rider RBB, which enables cost recovery for projects undertaken in partnership with internet service providers to expand broadband access in Virginia. If approved, the Rider RBB update would increase the typical residential customer's monthly bill by $0.14. Thus, the Company anticipates that the net impact of other applications filed today with the Commission will help to offset the customer rate increase attributable to the fuel factor.

The Company is taking significant action to reduce customers' exposure to future fuel cost fluctuations. The ongoing diversification of its electric generating fleet—specifically, the addition of solar and offshore wind resources including the Coastal Virginia Offshore Wind project which have no associated fuel costs—will mitigate the risk of commodity price upheavals. Additionally, the Company will continue its practice of entering into market transactions that act as a hedge against future price uncertainty.

Dominion Energy Virginia believes this Application exemplifies its focus on ensuring that its safe and reliable electric service also remains affordable. With the Commission's approval, the Three Year Mitigation proposal described herein will help shield customers from what would otherwise be a significant fuel factor rate adjustment. The Company looks forward to a constructive and customer-beneficial outcome in this proceeding.

Sincerely,

Edward H. Baine

Edward H. Baine
President, Dominion Energy Virginia

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Dominion Energy®

Application, Direct Testimony, and Schedules of Virginia Electric and Power Company

Before the State Corporation Commission of Virginia

Application of Virginia Electric and Power Company, To revise its fuel factor pursuant to Va. Code § 56-249.6

Volume 1 of 1
PUBLIC VERSION

Case No. PUR-2022-00064

Filed: May 5, 2022

220510086

Application of Virginia Electric and Power Company, To revise its fuel factor pursuant to Va. Code § 56-249.6
Case No. PUR-2022-00064

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Application of Virginia Electric and Power Company, To revise its fuel factor pursuant to Va. Code § 56-249.6
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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

APPLICATION OF	)	
	)	
VIRGINIA ELECTRIC AND POWER COMPANY	)	Case No. PUR-2022-00064
	)	
To revise its fuel factor pursuant to Va. Code § 56-249.6	)	
	)	

APPLICATION

Pursuant to § 56-249.6 of the Code of Virginia ("Va. Code"), Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company"), by counsel, files this application to revise its fuel factor effective July 1, 2022 (the "Application"). In support of its Application, the Company respectfully states the following:

1. Dominion Energy Virginia is a public service corporation organized under the laws of the Commonwealth of Virginia furnishing electric service to the public within its certificated service territory. The Company also supplies electric service to non-jurisdictional customers in Virginia and to the public in portions of North Carolina. The Company's electric system, consisting of facilities and associated facilities for the generation, transmission, and distribution of electric energy, is interconnected with the electric systems of neighboring utilities and is part of the interconnected network of electric systems serving the continental United States. Because of its operations in Virginia and North Carolina and its interconnections with other electric utilities, the Company engages in interstate commerce. The post office address of the Company is P.O. Box 26666, Richmond, Virginia 23261.

2. The facts supporting this Application are set forth in the accompanying testimony and exhibits of Gregory A. Workman, J. Scott Gaskill, Whitney W. Johnson, Katherine E.

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Farmer, Dale E. Hinson, Tom A. Brookmire, Wesley A. Hudson, Ronnie T. Campbell, and Timothy P. Stuller.

3. The testimony and exhibits demonstrate that a revision to the Company's existing fuel factor rate is necessary to provide the Company with the appropriate level of fuel cost recovery pursuant to Va. Code § 56-249.6 over the period beginning July 1, 2022 through June 30, 2023.

4. The Company's total fuel factor, reflected in Fuel Charge Rider A, consists of both a current period and a prior period factor. As Company Witness Timothy P. Stuller discusses, for the July 1, 2022 through June 30, 2023 fuel year, the Company projects Virginia jurisdictional fuel expenses, including purchased power expenses, of approximately $2.278 billion, translating into a current period fuel factor rate of 3.0784 cents per kilowatt-hour ("¢/kWh"). The Company's projected June 30, 2022 fuel deferral balance is approximately $1.020 billion, translating into a prior period factor rate of 1.3784 ¢/kWh. Together, these components translate into a total proposed fuel factor rate of 4.4568 ¢/kWh for the period July 1, 2022 through June 30, 2023.

5. As explained by Company Witness Gregory A. Workman and others, the total projected fuel deferral balance attributable to the July 2021 – June 2022 is substantial, largely due to the increase in commodity prices over the past year. While significant, the under-recovery over the prior period was mitigated in part by the Company's comprehensive approach to fuel procurement and hedging, including the availability of a diverse generation portfolio, access to reliable fuel supply, and an effective commodity price hedging program. Comparing the July 2021 – March 2022 period with the similar period of July 2020 – March 2021, natural gas and coal fuel commodities experienced price increases of approximately 100% and 92%,

respectively, while the fuel component of the in-system generation output experienced only a 37% increase in $/MWh, as supported by Company Witness Dale E. Hinson.

6. While the Company is entitled to recovery of these prudently incurred fuel expenses on a prompt basis under Va. Code § 56-249.6, the Company recognizes the impact of such an increase in fuel rates on our customers. In order to mitigate the impact of an increase in the fuel factor rate on customers, the Company is voluntarily offering two alternative proposals to the full recovery rate, should the Commission find it to be in the public interest and so approve. Under the alternative proposals presented by Company Witness J. Scott Gaskill, the Company would waive its right to prompt recovery of the full deferral balance over the current period in favor of recovery of this balance equally over either two fuel periods ("Two Year Mitigation") or three fuel periods ("Three Year Mitigation"), at the Commission's discretion.

7. The Two Year Mitigation proposal would, if adopted, amortize the $1.020 billion projected June 30, 2022 fuel deferral balance for recovery equally over the fuel periods July 1, 2022 – June 30, 2023 *and* July 1, 2023 – June 30, 2024 (a total of 24 months). This would result in a prior period factor for the current fuel year of 0.6892 ¢/kWh and a total fuel factor rate of 3.7676 ¢/kWh for the current period—reducing the impact on the overall residential customer's monthly bill from 19.8% to 14.1%, compared to the full recovery rate during the current period.

8. The Three Year Mitigation proposal would, if adopted, amortize the $1.020 billion projected June 30, 2022 fuel deferral balance for recovery equally over the fuel periods July 1, 2022 – June 30, 2023, July 1, 2023 – June 30, 2024, and July 1, 2024 – June 30, 2025 (a total of 36 months). This would result in a prior period factor for the current fuel year of 0.4595 ¢/kWh and a total fuel factor rate of 3.5379 ¢/kWh for the current period—reducing the impact on the overall bill for the typical residential customer from 19.8% to 12.2%, compared to the full recovery rate during the current period. This represents a further 0.2297 ¢/kWh rate reduction,

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or approximately $2.30 per month bill savings for a residential customer, over the Two Year Mitigation.

9. The Company believes that its voluntary fuel factor mitigation proposals recognize the interests of customers in avoiding abrupt rate increases, as referenced in Va. Code § 56-249.6, and are consistent with the public interest. While either mitigation proposal is preferable to the full recovery rate, the Three Year Mitigation offers the smallest near-term fuel rate increase, promotes rate stability across the next several years, and offers the Commission flexibility next year if circumstances around commodity markets have improved. For these reasons, the Company requests that the Commission approve the Three Year Mitigation proposal and set a fuel rate of 3.5379 ¢/kWh.

10. Further, to the extent that the Commission directs implementation of an interim fuel rate for usage on and after July 1, 2022, the Company requests that the proposed fuel factor rate of 3.5379 ¢/kWh based on the Three Year Mitigation proposal be implemented as the interim rate.

11. Concurrent with this filing, the Company has also filed a petition to suspend its rate adjustment clause designated Rider RGGI effective July 1, 2022, which, if approved by the Commission, would lower the typical residential bill by $2.39 per month at the same time the fuel factor increase would take place. Additionally, the Company has filed its annual update to Rider T1, which, if approved would result in a reduction in the typical residential customer bill of approximately $3.69 per month. Taken as a whole—the Three Year Mitigation, suspension of Rider RGGI, and the Rider T1 reduction—the increase to a typical residential customer bill is approximately $9.00 per month. While the Company does not take any such rate increase lightly, it is mindful of the impact to its customers and is taking meaningful steps to limit the impact felt from the current commodity market pressures.

12. In connection with this Application, the Company is also seeking approval of an accounting change as it relates to the funding of the fuel factor for customers taking service under the approved market-based rate ("MBR") schedules, Rate Schedule MBR, Rate Schedule MBR-GS-3, Rate Schedule MBR-GS-4, and the SCR Rate Schedule (collectively, the "MBR Customers"), to more timely align the timing of the fuel expense incurred by the Company and the revenues received through the market-based charges from these customers as presented by Company Witness Gaskill. This change holds both MBR and non-MBR customers harmless and is intended to resolve the timing mismatch between revenue and fuel expense that exists for customers taking service on these voluntary rate schedules.

13. Specifically, the Company is proposing a going-forward accounting change with respect to MBR revenues such that it will fund the Company's *actual* average system fuel costs on a month-by-month basis instead of the approved fuel rate. By making this accounting change, there will be better alignment between MBR revenue, and the fuel costs incurred to serve these customers. In other words, MBR-customer revenues would fund their share of actual fuel costs on a real-time basis instead of contributing to an over- or under-recovery of fuel costs. MBR revenue would be removed from the fuel deferral process. The Company proposes that this change take effect on July 1, 2022.

14. Fuel Charge Rider A specifies how MBR revenues are treated with respect to the fuel deferral. Therefore, Company Witness Timothy P. Stuller presents the revised Fuel Charge Rider A tariff sheet to incorporate this change.

WHEREFORE, Virginia Electric and Power Company respectfully files the proposed fuel factor of 3.5379 ¢/kWh, as set out herein, effective for usage on and after July 1, 2022, and requests that the Commission approve the revised Fuel Charge Rider A tariff incorporating the proposed accounting change for MBR customers effective July 1, 2022.

220510089

Respectfully submitted,

VIRGINIA ELECTRIC AND POWER COMPANY

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Counsel for Virginia Electric and Power Company

May 5, 2022

Attachment 43

ENERGY + ENVIRONMENT

THE BULLETIN

Regulators approve Dominion bill increase for rising fuel costs; Appalachian Power also seeking hike

BY: **CHARLIE PAULLIN** - SEPTEMBER 19, 2022 12:01 AM

Transmission lines in Louisa County. (Ned Oliver/ Virginia Mercury)

Dominion customers will see their monthly electricity bills increase as a result of rising fuel costs, with Appalachian Power Company seeking similar hikes on the same grounds.

On Friday, the State Corporation Commission approved the increase for Dominion, which went into effect provisionally on July 1. According to

estimates, the average residential customer, defined as a household using 1,000 kilowatt-hours of electricity per month, will see their monthly bill increase by $14.93.

In its final order, the commission said it was aware "of the ongoing rise in gas prices, inflation, and other economic pressures that are impacting all utility customers."

"We are sensitive to the effects of rate increases, especially in times such as these," regulators wrote. "The commission, however, must follow the laws applicable to this case, as well as the findings of fact supported by the evidence in the record. This is what we have done herein."

Dominion applied for the increase in its fuel factor, the rate levied on customers to cover the costs of purchasing fuel for power plants, in May, citing increases in fuel costs linked to the COVID-19 pandemic, inflation and the ongoing war in Ukraine.

The company sought to minimize the impact on customers by proposing to spread its recovery of the additional $1 billion in fuel costs over three years, a recommendation the commission accepted.

Coinciding with the approval, Appalachian Power said Friday it intends to seek a similar rate increase that could raise monthly bills for the average residential customer by about $20.

The company is seeking to spread the recovery over a two year period.

"We recognize these are challenging financial times for many people and families," said Chris Beam, Appalachian Power's president and chief operating officer in a statement. "We strive each day to keep fuel costs as low as possible, continuously monitoring energy markets for opportunities to purchase fuel and energy at prices that are advantageous to customers."

The utility also said that its growing use of renewable energies such as solar and wind "is another step in reducing fuel costs."

"As Appalachian Power adds more renewables, there is less need for coal and natural gas to generate power," the company noted in its Friday statement.

Appalachian said that about 6% of the power used by the company's customers is generated by renewables.

Under the 2020 Virginia Clean Economy Act, both Appalachian and Dominion are required to decarbonize by 2050.

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CHARLIE PAULLIN

Charles Paullin covers energy and environment for the Mercury. He previously worked for Northern Virginia Daily in the Northern Shenandoah Valley and for the New Britain Herald in central Connecticut. An Alexandria native, Charles graduated from the University of Hartford initially wanting to cover sports. He's received several Virginia Press Association awards for his coverage of crime, local government and state politics. Catch him in nature experiencing all the outdoors has to offer, and contact him at cpaullin@virginiamercury.com.

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May 10, 2022

Attachment 44

ENERGY + ENVIRONMENT

Dominion asks to halt ratepayer charge for carbon market

Critics say request to recoup remaining costs through base rates shows extra charge was never needed

BY: **SARAH VOGELSONG** - MAY 6, 2022 12:04 AM

Dominion Energy offices in Richmond, Va. (Parker Michels-Boyce/ For The Virginia Mercury)

Dominion Energy is asking state regulators to stop charging customers on their monthly bill for the utility's participation in a carbon market in anticipation of Gov. Glenn Youngkin's plans to withdraw Virginia from the Regional Greenhouse Gas Initiative.

Suspending the charge, known as Rider RGGI, "will provide an immediate, material reduction to customer bills," the utility wrote in a filing with the State Corporation Commission Thursday.

The move comes as Dominion is is looking for ways to offset soaring fuel costs that could increase customer bills by between 7 and 20 percent.

But critics said the utility's plan to get rid of the rider appeared to be more of a political move and that its decision to recover the remaining RGGI costs through base rates, which make up the largest portion of a customer's bill, demonstrates that Dominion never needed to impose the extra charge for market participation at all.

"They are conceding that they could have been complying with RGGI all along without raising rates but instead simply chose to rate rates just because they could," said Will Cleveland, an attorney with the Southern Environmental Law Center.

In Virginia, Dominion customers' bills are made up of three components: base rates, fuel costs and rate adjustment clauses, generally referred to as riders. The riders are intended to cover the costs of specific projects like coal ash cleanup or various generation resources.

Dominion has calculated that the RGGI rider adds $2.39 to the average residential customer's monthly bill. If approved, suspension of the rider would eliminate that charge beginning July 1.

Under state law, Dominion was allowed but not required to recover RGGI costs through a rider.

The utility said in its Thursday filing that it has recouped approximately $82 million in RGGI compliance costs through the rider and that approximately $178 million will remain to be recovered through base rates.

Dominion said recovering the remaining amount through base rates "will prevent future incremental rate increases."

"The company believes that these actions are particularly in the public interest given current geopolitical and market conditions beyond its control which are driving increases in the costs to be recovered from customers of fuel commodities," the utility wrote.

Base rates are reviewed by the State Corporation Commission every three years. If regulators find that the company has not earned enough to cover its expenses and an allowable profit, they can order that base rates be raised. If they find Dominion has overearned, they can order the utility to refund part of the excess earnings.

Cleveland said that the remaining RGGI costs could potentially contribute to Dominion requesting a higher base rate at the next triennial review, which is slated to occur in 2024.

“That will be one of the many line items balanced to determine whether Dominion’s revenues exceeded its costs,” he said.

The Mercury asked Dominion how it is able to absorb the remaining RGGI costs into its existing base rates and whether it could have recouped them that way all along. Dominion General Manager of Regulatory Affairs Scott Gaskill said in an email that because of rising commodity prices, the utility has “been looking at ways to mitigate the near-term customer impact” and pointed out that Dominion this January asked regulators to cancel an expected increase to the RGGI rider.

“Since we expect RGGI costs to end soon, it made sense to eliminate this rider at this time and move to base rates as a one-time expense,” he wrote.

Del. Tony Wilt, R-Rockingham, who unsuccessfully carried a bill during the last legislative session that among other provisions would have given regulators more leeway to decide if costs should be recovered through riders or base rates, said Dominion’s request “demonstrates the importance of ensuring our state regulators have the authority to review, assess and analyze rate-making policies in the best interests of customers.”

Dominion also stated in its filing that if Virginia does not withdraw from RGGI by the end of July, it reserves the right to ask regulators to resume charging customers for participation costs.

Coal fired units at Dominion Energy's Chesterfield Power Station are scheduled to close. (Ryan M. Kelly/ For the Virginia Mercury)

A simmering conflict

While conflict over RGGI has been simmering since Youngkin announced last December that he intended to pull Virginia out of the market, the administration is expected to begin attempting to roll back regulations governing state participation this summer.

In an executive order issued on his inauguration day, Youngkin ordered the Virginia Department of Environmental Quality to develop an emergency regulation to repeal existing rules for RGGI participation. That regulation will need to be approved by the Virginia State Air Pollution Control Board.

In its Thursday filing, Dominion said it expects the emergency regulation to go into effect as early as July. That time frame is in line with a statement made by DEQ Director Mike Rolband to the air board in April that the regulatory process was expected to start in the third quarter of the year.

An air board action isn't likely to be the end of the fight. Several environmental groups, including the Southern Environmental Law Center, have contended that legislation is necessary to pull Virginia out of the carbon market.

Republicans proposed such legislation during the 2022 session, but it failed in the Democrat-controlled Senate.

"We've said before and we maintain that the 2020 law requires Virginia to participate, and whether acting through an executive order or acting through the air board, you can't simply repeal a regulation and still be in compliance with that law," said SELC attorney Nate Benforado.

Dominion has been critical of Virginia's participation in RGGI, largely on the grounds of customer expense, particularly given the utility's investment in renewables required under the Virginia Clean Economy Act.

"We're concerned that Virginia's linkage to the RGGI program … would result in a financial burden on customers with no real mitigation of greenhouse gas emissions regionally," said Dominion Chief Financial Officer Jim Chapman on an investor call Thursday.

SCC Judge Judith Jagdmann has also questioned whether Dominion customers are paying duplicative costs to both participate in RGGI and comply with the Virginia Clean Economy Act.

Other energy analysts, however, have disputed the characterization of RGGI as ineffective at reducing carbon emissions, pointing to steep emissions declines in participating states compared to non-participating ones and changes in utilities' decision-making about which power plants it decides to run to power the grid. They also point out that roughly a quarter of

Virginia's carbon emissions governed by RGGI come from non-regulated power producers that otherwise have no legal requirement to reduce emissions.

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SARAH VOGELSONG

Sarah is Editor-in-Chief of the Mercury and previously its environment and energy reporter. She has worked for multiple Virginia and regional publications, including Chesapeake Bay Journal, The Progress-Index and The Caroline Progress. Her reporting has won awards from groups such as the Society of Environmental Journalists and Virginia Press Association, and she is an alumna of the Columbia Energy Journalism Initiative and Metcalf Institute Science Immersion Workshop for Journalists. She is a graduate of the College of William and Mary. Contact her at svogelsong@virginiamercury.com

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January 27, 2022

Attachment 45

Virginia State Corporation Commission
eFiling CASE Document Cover Sheet

220322030361

Case Number (if already assigned)	PUR-2022-00001
Case Name (if known)	Petition of Appalachian Power Company for approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia
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March 18, 2022

By Electronic Filing **PUBLIC VERSION**

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State Corporation Commission
Document Control Center
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Re: Petition of Appalachian Power Company for approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia Case No. PUR-2022-00001

Dear Mr. Logan:

Please find attached for filing the Petition of Appalachian Power Company for approval of a rate adjustment clause under § 56-585.1 A 5 e to recover costs to comply with state and federal environmental regulations. Please note that the Company is requesting in the Petition a waiver of the Commission's Rate Case Rules that would permit it to file one hard copy of certain confidential and/or voluminous materials, as well as electronic copies of these documents on three compact disks, which are being filed simultaneously by hand with the Commission under separate cover. The Company has also made this information available to Staff.

The Company is also simultaneously filing a Motion for Protective Ruling.

Sincerely,

Noelle J. Coates

Enclosures
cc: William H. Chambliss, Esq.
C. Meade Browder, Jr., Esq.

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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PETITION OF

APPALACHIAN POWER COMPANY

Case No. PUR-2022-00001

for approval of a rate adjustment clause,
the E-RAC, for costs to comply with state
and federal environmental regulations
pursuant to § 56-585.1 A 5 e of the Code of Virginia

PETITION

March 18, 2022

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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PETITION OF

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for approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia

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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PETITION OF

APPALACHIAN POWER COMPANY

for approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to §§ 56-585.1 A 5 e of the Code of Virginia

Case No. PUR-2022-00001

PETITION AND REQUESTS FOR WAIVER

Appalachian Power Company ("Appalachian" or the "Company"), by counsel, pursuant to Section 56-585.1 A 5 (e) of the Code of Virginia (the "E-RAC Statute") respectfully petitions the State Corporation Commission (the "Commission") for approval to recover costs through its existing rate adjustment clause (the "E-RAC"), related to capital investments and operations and maintenance ("O&M") compliance expenses that are necessary to comply with state and federal environmental regulations. In support of this Petition, the Company respectfully states as follows.

1. Overview and Background

Appalachian is a Virginia public service corporation serving approximately 524,000 customers in Virginia and maintaining an office at 1051 East Cary Street, Suite 1100, Richmond, Virginia 23219. The Company is an incumbent electric utility as defined in Section 56-576 of the Virginia Electric Utility Regulation Act. The contact information for Appalachian's attorneys is stated at the end of the Petition.

With this Petition, the Company is requesting the Commission's approval to recover on a timely basis through its existing E-RAC, which the Commission initially approved in 2021[1]

[1] Order Granting Rate Adjustment Clause, *Petition of Appalachian Power Company For approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal*

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pursuant to the E-RAC Statute, actual and projected costs to comply with state and federal environmental laws and regulations applicable to generation facilities used to serve the Company's load obligations. Specifically, the Company seeks to recover a revenue requirement $33.6 million during the Rate Year of December 1, 2022 through November 30, 2023 through the E-RAC. This amount, detailed by Company witness Castle, is comprised of the following:

- Actual and projected capital investment incurred to comply with the EPA's Coal Combustion Residuals Rule ("CCR Rule") at the Company's Amos and Mountaineer Plants (the "Plants"), the recovery of which the Commission approved in the 2021 E-RAC Order;
- Actual and projected capital investment incurred to comply with the EPA's Steam Electric Effluent Limitation Guidelines ("ELG Rule") at the Plants (the "ELG Projects"), the recovery of which the Commission denied without prejudice in the 2021 Order (the "ELG Project Costs"), including those incurred up to August 2021 (the "Prerequisite ELG Project Costs");
- New capital investments related to dissolved oxygen levels at the hydroelectric generating units at the Company's Claytor Hydro Project ("Claytor") and the dry sorbent injection system at Amos;
- Actual and projected costs to comply with the regulation that established Virginia as a member of the Regional Greenhouse Gas Initiative ("RGGI") associated with the dispatch of the Company's gas-fired Clinch River Plant, which is located in Carbo, Virginia; and
- Actual and projected Operations and Maintenance ("O&M") compliance costs incurred in complying with State Solid Waste regulation, the National Pollution Discharge Elimination System, and provisions of the Clean Water Act at Appalachian's generation units (the "O&M Compliance Expenses"), the recovery of which the Commission approved in the 2021 E-RAC Order.

2. Procedural History

The Company filed for approval in December 2020 to recover the O&M Compliance Expenses, and costs associated with compliance with the CCR Rule and the ELG Rule at the Plants. In the 2021 E-RAC Order, the Commission approved recovery of the O&M Compliance Expenses and the costs to comply with the CCR Rule, which enabled the Plants to continue to

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environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia, Case No. PUR-2020-00258, Doc. Con. Cen. No. 210830184 (August 23, 2021) ("2021 E-RAC Order").

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operate for the benefit of Virginia customers. But the Commission denied the costs to comply with the ELG Rule, which is necessary for the Plants to operate past 2028, concluding that Appalachian had "not met its burden of proving the reasonableness and prudence of the proposed ELG investment costs," including the Prerequisite ELG Project Costs.[2] The Commission held that it was "critically important to analyze the overall impact of this investment on both customer rates and reliability," and concluded that Appalachian should be permitted to provide additional analyses and evidence to support the ELG investment, "should APCo conclude circumstances so warrant."

On December 23, 2020, Appalachian also filed a petition with the Public Service Commission of West Virginia ("WVPSC") seeking certificates of convenience and necessity authorizing both the CCR and ELG projects at the Plants, as well as a cost recovery mechanism.[3] The WVPSC approved the requests on August 4, 2021, concluding that the CCR and ELG Projects at the Plants were "prudent, cost effective, and in the best interest of the current and future utility customers."[4] On October 12, 2021, the WVPSC issued another order that confirmed its earlier decision, stating that, due to the 2021 E-RAC Order, "after 2028 West Virginia customers will receive the full capacity and energy capabilities of" the Plants."[5] That

[2] 2021 E-RAC Order at 12.

[3] The petition before the WV PSC also concerned the Mitchell Plant, which does not serve customers in Virginia and thus is not at issue in proceedings before this Commission.

[4] Commission Order at 16, *Application of Appalachian Power Company and Wheeling Power Company, public utilities, for a certificate of public convenience and necessity for the internal modifications at coal fired generating plants necessary to comply with federal environmental regulations and surcharge*, Case No. 20-1040-E-CN (WVPSC, Aug. 4, 2021).

[5] Commission Order at 7, *Application of Appalachian Power Company and Wheeling Power Company, public utilities, for a certificate of public convenience and necessity for the internal modifications at coal fired generating plants necessary to comply with federal environmental regulations and surcharge*, Case No. 20-1040-E-CN (WVPSC, Oct. 12, 2021).

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is: "Given [the 2021 E-RAC Order], Virginia...jurisdictional customers should receive no capacity or energy from the Plants after 2028."[6]

As the Plants will continue to operate past 2028, no matter how the Commission rules on this Petition, the Company concluded that circumstances warrant re-filing its request to recover the costs of the ELG Projects in accordance with the 2021 E-RAC Order. With this Petition, the Company provides a more robust record of the benefits realized, including the impacts of the investments on customer rates and reliability, by keeping the Plants available to serve its Virginia customers.

3. WITNESSES IN SUPPORT OF THE PETITION

The following witnesses testify in support of the Petition:

- **Christian T. Beam**, President and Chief Operating Officer at Appalachian. Mr. Beam describes the outcome of the CCR/ELG proceeding before the WVPSC and how it led Appalachian to make another request for ELG investment cost recovery from APCo's Virginia customers; explains the practical impact of the WVPSC's Order on Virginia customers; and sets out the options available to the Commission and the potential costs that Virginia customers would face if the Commission again denies ELG investment cost recovery from Appalachian's Virginia customers.

- **James F. Martin**, Director of Resource Planning Strategy for American Electric Power Service Corporation ("AEPSC"). Mr. Martin sponsors an economic analysis that he performed for and provided to the Company's management that compares the forecasted Virginia jurisdictional cost of service effects of a scenario in which the costs, energy, and capacity of the Plants continue to benefit Virginia customers after 2028 to scenarios in which they do not. Mr. Martin also explains the importance of the Company's PJM capacity requirement, and how PJM computes capacity credit for the primary alternative resource options that could replace the Plants. He discusses the impact of the Virginia Clean Economy Act ("VCEA") on the evaluation of the merits of the ELG investment, and on the value of continued operation of the Plants in general. Mr. Martin also discusses RGGI compliance at Clinch River.

- **Brian D. Sherrick**, Managing Director of Projects for AEPSC. Mr. Sherrick describes the Plants, and the planning for and status of the CCR/ELG projects. He discusses the costs the CCR/ELG projects, including the reasonableness and prudence of the previously incurred ELG costs. Mr. Sherrick also describes the DSI project at Amos and its cost.

[6] *Id.* at 8.

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- **Robert A. Gallimore,** Hydroelectric Asset Manager, AEPSC. Mr. Gallimore describes Claytor and the DO project; the costs and current status of the project; and the alternatives that were considered.
- **Gary O. Spitznogle**, Vice President of Environmental Services at AEPSC. Mr. Spitznogle describes the applicable environmental regulations that drive the need and timing for the environmental improvement projects at Appalachian's generation units, and describes the requirements for compliance that result from the WVPSC's orders related to the CCR/ELG projects at the Plants. He outlines the permitting required to install the environmental controls that are the subject of this Petition, and supports the identification of activities undertaken that are required to comply with state and federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations, including the O&M Compliance Expenses as well as new capital investments related to DO levels at Claytor and the DSI system at Amos. Mr. Spitznogle describes RGGI, and how Virginia's participation in RGGI caused the Company to incur costs.
- **Tyler H. Ross,** Director of Regulatory Accounting Services for AEPSC. Mr. Ross reviews the E-RAC over-/under-recovery accounting recorded on the Company's books through December 31, 2021, and provides details of accounting performed to date and proposed recovery and accounting regarding the RGGI costs incurred at Clinch. Mr. Ross provides an overview of costs incurred and forecasted costs related to the ELG Projects at the Plants, to the DSI project at Amos, and to the DO project at Claytor. Finally, Mr. Ross describes the required accounting for costs incurred related to the CCR, ELG, DSI and DO projects.
- **William K. Castle**, Director, Regulatory Services – VA/TN for Appalachian. Mr. Castle provides an overview of the Company's last E-RAC filing. He supports the Virginia jurisdictional revenue requirement of $33.7 million for the E-RAC, and explains the four components of that revenue requirement to be recovered through the Rate Year of December 1, 2022 through November 30, 2023. Mr. Castle explains the allocation factors used to allocate the E-RAC revenue requirement to the Virginia retail jurisdiction and the calculation of the proposed E-RAC rates designed to recover the revenue requirement. Finally, he sponsors the proposed E-RAC tariff sheets.

4. The Requests for Approval in this Petition

The E-RAC Statute allows utilities to request the Commission's approval to recover, through a rate adjustment clause, projected and actual costs to "comply with state or federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations." Such a petition should be approved if the Commission "finds that such costs are necessary to comply with such environmental laws or regulations." Va. Code § 56-585.1 A 5 (e).

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A. The Environmental Regulations

The costs that Appalachian requests for recovery in this Petition were or will be incurred to comply with the following state or federal environmental laws or regulations, as detailed in Mr. Spitznogle's testimony.

i. The CCR Rule

In 2015, the United States Environmental Protection Agency ("EPA") published a final rule to regulate the disposal of coal combustion residuals, the CCR Rule, which includes fly ash, bottom ash, and gypsum that may be generated at coal-fired electric generating units. The CCR Rule applies to new and existing CCR landfills and CCR surface impoundments (ponds) at operating coal-based electric generating facilities. Recent revisions to the CCR Rule require that unlined CCR storage ponds must cease operations and initiate closure by April 11, 2021. The EPA can extend the compliance date for the Plants to as late as October 15, 2023.[7]

ii. The ELG Rule

The Steam Electric Effluent Limitations Guidelines, the ELG Rule, establishes discharge limits on flue gas desulfurization wastewater, fly ash and bottom ash transport water, and flue gas mercury control wastewater. Recent revisions to the ELG Rule establish discharge limits that must be achieved as soon as possible between October 13, 2021 and December 31, 2025 based on the renewal of the existing wastewater discharge permit for the facility.

iii. Dissolved Oxygen Requirements

The dissolved oxygen requirements at Claytor were issued by the Federal Energy Regulatory Commission ("FERC") and are designed to improve low dissolved oxygen conditions in accordance with Virginia Department of Water Quality ("DEQ") requirements.

[7] The Company's request for an extension is still pending, as Mr. Spitznogle explains.

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iv. Cross-State Air Pollution Rule

Appalachian installed the DSI system at Amos to mitigate emissions of SO_3 that result from the operation of the Selective Catalytic Reduction ("SCR") and Flue Gas Desulfurization ("FGD") systems in tandem. Appalachian installed the SCR and FGD systems to comply with what is now the Cross-State Air Pollution Rule, as well as a consent decree with the EPA and others.

v. RGGI

In 2020, the Virginia General Assembly amended the Clean Energy and Community Flood and Preparedness Act to direct the Virginia DEQ to adopt regulations to establish a cap-and-trade program for carbon dioxide emissions to comply with the RGGI Model Rule. Those regulations became effective in July 2020, and are applicable to Clinch River, which is the Company's only fossil-fuel fired generation facility in the Commonwealth.

vi. Other Applicable Environmental Regulations

The other applicable environmental regulations for which the O&M Compliance Expenses were incurred are provided in APCo Exhibit No. ____ (GOS), Schedule 1, sponsored by Company witness Spitznogle.

5. The Requested Revenue Requirement and Rate Impact

The Company requests the Commission's approval to recover a total revenue requirement of $33.6 million during the Rate Year. Specifically, the Company seeks to recover:

- A Forecast Rate Year Component of $29.6 million
- A Forecast AFUDC Revenue Component of $4.3 million
- A True-up Revenue Component of ($0.5 million)
- An Actual Revenue Component of $0.2 million

Mr. Castle describes these components in greater detail in his testimony.

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If approved, the revenue requirement would be an increase of $6.2 million over that approved in the 2021 E-RAC Order. Appalachian estimates that implementing this revenue requirement would increase a residential customer's monthly bill, based on 1,000 kWh usage per month, by $0.80, or 0.6% when compared to rates effective December 1, 2021.

As described by Mr. Castle, the Company seeks to recover the revenue requirement by allocating costs to the Virginia jurisdiction consistent with the methodology proposed by the Company and adopted by the Commission in the 2021 E-RAC proceeding.

6. Compliance with the 2021 E-RAC Order

The Commission and Senior Hearing Examiner Berkebile concluded that the record in the 2021 E-RAC proceeding was deficient. In this Petition, the Company has attempted to address these deficiencies as follows, with some adjustments given that the Plants will still operate past 2028 regardless of the outcome of this Petition:

- The overall impact of the ELG investment on customer rates is discussed by Mr. Castle, and Mr. Martin's analysis focuses on the impact on Virginia customer rates, should ELG cost recovery be denied.
- The reasonableness and prudence of the Prerequisite ELG Project Costs is discussed by Company witnesses Spitznogle and Sherrick.
- The reasonableness and prudence of the ELG costs from an economic or resource adequacy perspective is discussed by Mr. Martin.
- The impacts of the VCEA on the ELG investment are discussed by Mr. Beam and Mr. Martin.
- The potential stranded costs are discussed by Mr. Ross.
- Mr. Ross sponsors the depreciation costs that would be the responsibility of Appalachian's Virginia customers if they no longer benefitted from the Plants after 2028.
- A detailed analysis of potential transmission cost impacts associated with retiring the Plants in 2028 is not provided because, as Mr. Martin recounts, the Plants will not retire in 2028 and thus there will be no resultant transmission cost impacts. Similarly, the Company did not assess the overall impact of the ELG investment on reliability, because the Plants will continue to operate after 2028.

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7. The Reasonableness and Prudence of the Requests

A. The CCR/ELG Projects

The testimony supporting this Petition demonstrates that the CCR and ELG Projects are the most reasonable and prudent means of meeting Appalachian's obligations to its Virginia customers.

As detailed in the 2021 E-RAC proceeding, the Company explored multiple alternative compliance strategies and ultimately determined that the Projects, which are described in detail in the testimony and schedules of Mr. Sherrick, were the most reasonable and prudent means of compliance with the CCR and ELG Rules.

As noted above, in the 2021 E-RAC Order, the Commission found that the Company had not met its burden to demonstrate the reasonableness and prudence of the investment in the ELG Projects.[8] Accordingly, in order to demonstrate that recovery of the costs related to the ELG Projects from Virginia customers is reasonable and prudent, Company witness Martin performed an analysis that compared the investment in the ELG Projects at the Plants to scenarios that assumed that the Plants were no longer available to Virginia customers. That analysis demonstrates clearly that continued operation of the Plants, even if they do not run at all, is less expensive and much less risky for Virginia customers than retiring the Plants early and replacing them. If the roughly 2,100 MW (nameplate) Virginia jurisdictional share of capacity of the Plants is available to Virginia customers, the Company will avoid incurring substantial cost, which will be passed along to the Virginia ratepayers, to obtain some other source of capacity to cover the Virginia portion of the PJM capacity obligation.

[8] 2021 E-RAC Order at 12.

As Mr. Martin and Mr. Beam testify:

- The relatively small $98 million jurisdictional share of the ELG investments and continued use of the Plants will be much less expensive than replacing them with billions of dollars of new resources;
- Replacement capacity costing between $3-4 billion would increase customers' rates by an incremental 17-21% in 2029 over what customers paid in 2021;
- In total, between 2029 and 2040, the net cost of service for the replacement resources would be between $2.8 billion and $3.4 billion, compared to the incremental cost of keeping the Plants operating of $1.0 billion; and
- The above is true even if the Plants do not generate a single MWh of electricity after 2029, due to their capacity value.

Mr. Martin also prepared an estimate of how much wind and solar would be needed to replace the Virginia jurisdictional share of the Plants' PJM-accredited capacity. By his estimation, it would take 8,800 MW (nameplate) to be placed in service by 2028 in order to match the capacity that the Plants provide for the benefit of Virginia customers. This is 17.7 times the amount of wind and solar that is required to be added by the VCEA. This massive investment would be costly (as much as $15 billion) and difficult, given the challenges of siting and constructing renewable facilities. Mr. Martin estimates that the cost of such a portfolio would be four times the incremental cost of keeping the Plants available to Virginia customers through 2040.

In addition to imposing great expense and uncertainty on Virginia customers, the Commission's denial of cost recovery for the ELG investment from Virginia customers would create a practical and regulatory conundrum, as Mr. Beam explains. Appalachian would have to find a way to replace the energy and capacity that the Plants currently provide to its Virginia customers, and, as the Plants will continue to operate past 2028, an equitable – but complicated - arrangement could be made in which Virginia customers compensate West Virginia customers for the capacity provided by the Plants. As Mr. Martin's analysis demonstrates, the other options for replacement capacity are significantly more expensive and uncertain. For replacement

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energy to serve its Virginia customers, Appalachian could purchase replacement energy from PJM, which would expose them to more energy market volatility.

Importantly, as energy on the PJM market is overwhelmingly generated from fossil fuels, eschewing the energy generated from the Plants in favor of market energy would not materially advance any clean energy goals. Similarly, as the Plants will continue to provide capacity and energy to Appalachian's West Virginia customers no matter how the Commission rules, denying ELG investment cost recovery from Virginia customers will not result in closing the Plants in 2028.

This Petition is thus supported by compelling evidence that the ELG investments are reasonable and prudent, and that the Commission should approve cost recovery from Appalachian's Virginia customers for the ELG investments, so that customers can continue to benefit from the Plants after 2028.

B. Prerequisite ELG Project Costs

Through August 2021, Appalachian incurred approximately $19.5 million and $12.6 million for the ELG Projects at Amos and Mountaineer, respectively. The costs related to project initiation, technology feasibility studies, evaluation of risk balanced technical options, conceptual engineering, permitting, and site investigations (surveying, verifying as-built conditions, and geotechnical investigations), as Company witness Sherrick describes. Appalachian could not avoid incurring these costs before seeking regulatory approval as they were necessary to establish the projects' scope, schedule, and cost estimate, all of which inform the regulatory proceedings, as well as necessary to meet environmental compliance deadlines. No physical construction related to ELG project activities began at the Plants before August 2021. The costs were therefore reasonable, prudent, and necessary.

C. The DO Project at Claytor

The DO Project at Claytor, which is discussed by Company witnesses Spitznogle and Gallimore, is designed to increase dissolved oxygen in the plant's tailwaters, which will improve the water quality, thus reducing impacts to aquatic organisms and angling opportunities. The DO Project involves the installation of auto-venting turbines ("AVT") in two generating units. AVT is the preferred technology for downstream DO improvement by providing the greatest percentage of increased DO concentration. Appalachian expects that the installation of AVT at Claytor will produce an increase in megawatt output of at least 10% per unit. Accordingly, this project is the best, and most reasonable, solution at the plant.

D. The DSI Modification at Amos

As Mr. Spitznogle describes, Amos is equipped with SCR and FGD systems to reduce NO_x and SO_2. When both are operated together, a small portion of the SO_2 is converted to SO_3, which is an acid gas that can cause visible emissions from the stack. The DSI system mitigates those emissions. When it was first installed, the system used trona, but the Company is modifying the system to use hydrated lime, which will reduce O&M costs. Mr. Sherrick explains that the project will reduce corrosion and improve heat rate and the Equivalent Unplanned Outage Rate. It will also help with the long-term protection of the SCR catalyst, air heaters, and precipitators, all of which demonstrate the reasonableness and prudence of the investment.

E. RGGI Costs Related to Clinch River

Clinch River, a gas-fired plant, is located in Virginia, and thus subject to RGGI compliance costs, which have been deferred to date. Clinch River only dispatches when it is economic to do so compared to the other resources that have been offered into PJM. The total price offered into PJM's energy market for Clinch River includes the cost of RGGI allowances. Thus, any RGGI-related costs are offset by energy revenues, which flow back to customers as

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reductions in fuel expense. Appalachian thus incurs the RGGI costs in order to comply with the law, but manages them in a reasonable and prudent way.

8. Compliance with Rate Case Rules and Requests for Waiver

First, Rate Case Rule 60 requires that applications requiring an overall cost of capital include Schedules 3, 4, 5, and 8. Filing Schedules 3 through 5 and 8, sponsored by Mr. Castle, provide this information. The required components of Schedule 46, established by the Rate Case Rules, are sponsored by Company witnesses and are attached to and/or incorporated into their testimonies, as set out in the Index of Schedule 46 Requirements, which is attached to this Petition as Attachment 1.

Second, the Company provided the Commission notice of its intent to file this Petition, pursuant to Rule 10 A, on October 21, 2021.

Third, the Company requests, pursuant to Rule 20VAC5-204-10.E, that the Commission grant a limited waiver, for good cause shown, of the requirement to file the documents that comprise Schedule 46 in hard copy. Due to the size of some of these documents, as well as the current remote conditions under which many of the parties are working, it would be unduly burdensome and impractical to produce them in hard copy. Further, the supporting documentation is confidential, and as such would not be posted to the Commission's online docket for public review. In lieu of a physical production, consistent with the Commission's *Order for Notice and Comment* in Case No. PUR-2021-00066[9] and *Order Granting Limited Reconsideration* in Case No. PUR-2021-00146,[10] the Company requests a limited waiver of this

[9] Order for Notice and Comment at 12, *Petition of Appalachian Power Company For a prudency review, pursuant to § 56-585.1:4 H of the Code of Virginia, with respect to the purchase of the Amherst Solar Facility*, Case No. PUR-2021-00066, Doc. Con. Cen. No. 211210222 (Dec. 7, 2021).

[10] Order Granting Limited Reconsideration, *Petition of Virginia Electric and Power Company for Approval of the RPS Development Plan, approval and certification of the proposed CE-2 Solar Projects pursuant to §§ 56-580 D and 56-46.1 of the Code of Virginia, revision of rate adjustment clause, designated Rider CE, under § 56-585.1 A 6 of the Code of Virginia, and a prudence determination to*

Rule to permit it to file one hard copy of these confidential documents, accompanied by three compact disks containing electronic versions of the documents. In addition, the Company has made available electronic copies of these documents to the Division of Utility Accounting & Finance and the Division of Public Utility Regulation, and will make them available for review by any respondents in an iManage folder established for this proceeding.

Finally, the Company requests, pursuant to Rule 20VAC5-204-10.E, that the Commission grant a limited and ongoing waiver, for good cause shown, of the requirement to file the documents in future petitions on "any changes in projected costs," and permit the Company instead to file all new or changed contracts supporting E-RAC costs that are worth more than $75,000. The Company selected $75,000 as a reasonable cutoff point that would provide Staff the most significant new and changed contracts. The Company will provide Staff with a list of all contracts under $75,000 and will provide copies of any that Staff wishes to review in its entirety. The Commission granted a similar request in Case No. PUR-2021-00047.[11]

WHEREFORE, Appalachian respectfully requests that the Commission 1) approve the Company's request to implement a rate adjustment clause to recover costs that were and will be incurred to comply with state and federal environmental laws or regulations; 2) approve the proposed revenue requirement, cost allocation, rate design, accounting treatment and rate year; and 3) grant the requests for waiver.

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enter into power purchase agreements pursuant to § 56-585.1:4 of the Code of Virginia, Case No. PUR-2021-00146, Doc. Con. Cen. No. 210830286 (Aug. 26, 2021).

[11] Order for Notice and Hearing at 2, 3 and 13, *Petition of Appalachian Power Company For revision of a rate adjustment clause pursuant to § 56.585.1 A 6 of the Code of Virginia with respect to the Dresden Generating Plant*, Case No. PUR-2021-00047, Doc. Con. Cen. No. 210050009 (June 28, 2021).

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Respectfully submitted,

APPALACHIAN POWER COMPANY

By: _____

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Counsel for Appalachian Power Company

Dated: March 18, 2022

2022032801

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing Petition of Appalachian Power Company was served by electronic mail on this 18th day of March 2022 to:

William H. Chambliss, Esq.
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State Corporation Commission
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Richmond, VA 23219

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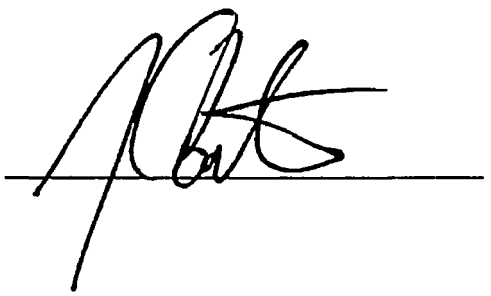

Appalachian Power Company- Virginia PUR-2022-00001					
Schedule 46 - Projected Rate Adjustment Clause Pursuant to § 56-585.1 A 5 e of the Code of Virginia					
Rate Case Rule	**Schedule 46 Index**	**Witness Sponsor**	**Section**	**Statement**	**Description**
20VAC5-204-90 Schedule 46 c 1	i.An updated schedule of all projected and actual costs by type of cost and year and by month to the extent available. The applicant shall provide such information by project if applicable for the specific rate adjustment clause.	BDS	1	1	Amos/Mountaineer
		RAG		1	Claytor Lake
20VAC5-204-90 Schedule 46 c 1	iii. Key documents supporting the projected and actual costs recovered through the rate adjustment clause, such as: economic analyses, support used by senior management for major cost decisions as determined by the applicant, contracts, studies, investigations, results from requests for proposals, cost-benefit analyses, and other items supporting the costs that have not been provided in previous applications.	JFM	2	1	Economic Analysis
		BDS/RAG		2	Documents, contracts, studies, and investigations to support projected costs
20VAC5-204-90 Schedule 46 c 1	ii. Within five business days of the application filing date, the applicant shall provide transaction-level details to facilitate the sampling and audit of such actual costs electronically to the Division to Utility Accounting and Finance in an electronic spreadsheet with all underlying formulas and assumptions. If the rate adjustment clause update includes a true-up, provide such information for costs incurred during the true-up period. If the rate adjustment clause does not include a true-up, provide the information based on most current actual costs available to-date.	THR	3	1	Over/Under Recovery workbooks (October 2021-December 2021)
20VAC5-204-90 Schedule 46 c 1	iv. The annual revenue requirement over the duration of the proposed rate adjustment clause by year and by class on a total company and Virginia jurisdictional basis, including all supporting calculations and assumptions. The applicant shall provide such information by project if applicable for the specific rate adjustment clause.	THR/WKC	4		Revenue Requirement Calculation
20VAC5-204-90 Schedule 46 c 1	v. Detailed information relative to the applicant's methodology for allocating the revenue requirement among rate classes and the design of class rates.	WKC	5		Allocation of Revenue Requirement/Revenue by Class
20VAC5-204-60	Rate adjustment clause filings. An application for a rate adjustment clause filed pursuant to Chapter 23 (§ 56-576 et seq.) of Title 56 of the Code of Virginia shall include Schedule 46 as identified and described in 20VAC5-204-90, which shall be submitted with the utility's direct testimony. Additionally, applications requiring an overall cost of capital shall include Schedules 3, 4, 5, and 8.	WKC	6		Cost of Capital Schedules

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Glossary of Terms

2020 Triennial Review	Commission Case No. PUR-2020-00015
2021 E-RAC Order	Order Granting Rate Adjustment Clause, Commission Case No. PUR-2020-00258 (August 23, 2021)
2021 E-RAC Proceeding	Commission Case No. PUR-2020-00258
2021 VCEA Proceeding	Commission Case No. PUR-2021-00206
ADIT	Accumulated Deferred Income Tax
ADITC	Accumulated Deferred Investment Tax Credit
AEP	American Electric Power Company, Inc.
AEPSC	American Electric Power Service Corporation
AFUDC	Allowance for Funds Used During Construction
APCo or Company	Appalachian Power Company
ARO	Asset Retirement Obligation
ARAM	Average Rate Assumption Method
Aurora model	Used by utilities for integrated resource and transmission planning, power cost analysis and detailed generator evaluation.
AVT	Auto-venting Turbines
BATW	Bottom Ash Transport Water
CCOS	Class Cost of Service Study
CC	Combined Cycle
CCR Rule	Coal Combustion Residuals Rule
Claytor	Claytor Lake Hydroelectric Project
Clinch River	Clinch River Plant
CLR	Capability Load and Reserve Analysis
CO_2	Carbon Dioxide
Code	Code of Virginia
Commission or SCC	The Virginia State Corporation Commission
CT	Combustion Turbine
CWIP	Construction Work in Progress
DBA	Dry Bottom Ash
DEQ	Virginia Department of Environmental Quality
DO	Dissolved Oxygen
Dominion	Virginia Electric & Power Co. d/b/a Dominion Energy Virginia
DSIT	Deferred State Income Tax
DSI	Dry Sorbent Injection
EIA	Energy Information Administration
EIA AEO 2020	EIA's Annual Energy Outlook 2020
ELG Rule	Effluent Limitation Guidelines
EPA	U.S. Environmental Protection Agency
E-RAC	Environmental Rate Adjustment Clause
E-RAC Statute	Va. Code § 56-585.1 A 5 e
ERCOT	Electric Reliability Council of Texas

FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FRR	Fixed Resource Requirement Plan
FRR OAD	Fixed-Resource Requirement Open Access Distribution
Fundamentals Forecast	North American Long-Term Energy Market Forecast
GAAP	Generally Accepted Accounting Principles
G-RAC	Generation Rate Adjustment Clause
I&M	Indiana Michigan Power Company
IRP	Integrated Resource Plan
KPCo	Kentucky Power Company
kW	Kilowatt
kWh	Kilowatt-hour
MATS	Mercury and Air Toxics Standards Rule
MOPR	Minimum Offer Price Rule
MW	Megawatt
MWh	Megawatt-hour
NO_x	Nitrogen Oxide
NPDES	National Pollution Discharge Elimination System
NPV	Net Present Value
O&M	Operations and Maintenance
OAD	Open Access Distribution
OPCo	Ohio Power Company
OVEC	Ohio Valley Electric Corporation
PJM	PJM Interconnection LLC
PLEXOS®	Modeling software tool
PowerTax	Power Plant Software
PPA	Purchase Power Agreement
Projects	Environmental improvement projects at the Amos and Mountaineer Plants
PSO	Public Service Company of Oklahoma
RAC	Rate Adjustment Clause
Rate Case Rules	The State Corporation Commission's Rules Governing Utility Rate Applications and Annual Informational Filings, 20 VAC 5-204-0, *et seq.*
Regulation Act	Virginia Electric Utility Regulation Act, Va. Code §§ 56-576 – 596.3
RFI	Request for Information
RGGI	Regional Greenhouse Gas Initiative
ROE	Return on Equity
RPS	Renewable Portfolio Standard
RPM	PJM Reliability Pricing Model
SCR	Selective Catalytic Reduction
SEC	Securities and Exchange Commission
SO_2	Sulfur Dioxide

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Staff	State Corporation Commission Staff
SWEPCO	Southwestern Electric Power Company
TDI	Tailrace Dissolved Oxygen
UCAP	Unforced Capacity
VCEA	Virginia Clean Economy Act
WPCo	Wheeling Power Company
WVPSC	Public Service Commission of West Virginia
WVPSC August Order	Case No. 20-1040-E-CN (August 4, 2021)
WVPSC CCR/ELG Proceeding	WVPSC Case No. 20-1040-E-CN
WVPSC October Order	Case No. 20-1040-E-CN (October 12, 2021)
WWT	Wastewater Treatment

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CHRISTIAN T. BEAM
Direct Testimony

APCo Exhibit No. __
Witness: CTB

220322001

DIRECT TESTIMONY OF
CHRISTIAN T. BEAM
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2022-00001

APCo Exhibit No. __
Witness: CTB

SUMMARY OF DIRECT TESTIMONY OF CHRISTIAN T. BEAM

In my testimony, I

- Describe the outcome of the CCR/ELG proceeding before the WVPSC and how it led APCo to make another request for ELG investment cost recovery from APCo's Virginia customers;
- Explain the practical impact of the WVPSC's Order on Virginia customers; and
- Set out the options available to the Commission and the potential costs that Virginia customers would face if the Commission again denies ELG investment cost recovery from APCo's Virginia customers.

APCo Exhibit No. __
Witness: CTB

DIRECT TESTIMONY OF CHRISTIAN T. BEAM FOR APPALACHIAN POWER COMPANY IN VIRGINIA S.C.C. CASE NO. PUR-2022-00001

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Christian T. Beam. My business address is 500 Lee Street, East, Charleston, West Virginia 25301. I am the President and Chief Operating Officer of APCo and WPCo, both operating companies of the AEP System.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor's Degree in Applied Science, with a focus on project management, from DeVry University. I am a certified Project Management Professional and completed the AEP Leadership Program at The Ohio State University in 2007 and The Executive Program: Strategic Leadership at the University of Virginia's Darden School of Business in 2019. I have held positions of escalating responsibility at AEP companies since I started with Ohio Power Company in 1990. I worked first in the Utility Operations department at the Kammer Plant. In 1997, I moved to the AEP Service Corporation and was named Outage Project Supervisor for the Regional Service Organization serving the Kammer, Mitchell, and Cardinal Plants. In 2000, I assumed a new role as Superintendent for the Regional Service Organization, supporting SWEPCO, and subsequently became Manager - Region Outage Management in 2002. In 2004, I was named Manager for the Flue Gas Desulphurization retrofit project at the Mountaineer Plant. I became Manager - Construction Technology in 2007 and then Director - Construction in 2008. In 2009, I was named the Project Director - Environmental Retrofit Projects. I was named Managing Director Projects and

Construction in November 2010. I assumed the position of Vice-President - Projects, Controls, and Construction in 2013. In January of 2017, I was named President and Chief Operating Officer of APCo and WPCo.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS PRESIDENT OF APCO.

A. I oversee all aspects of APCo, Kingsport, and WPCo, including their day-to-day operations. My primary goals are to see that they are operated in a responsible and efficient manner and to ensure that customers receive safe and reliable electric service at a reasonable price.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY AS A WITNESS BEFORE ANY REGULATORY COMMISSION?

A. Yes. I have testified before this Commission on several occasions, most recently in Case No. PUR-2020-00258, APCo's most recent E-RAC proceeding. In addition, I have filed testimony before the Public Service Commission of West Virginia in Case No. 11-0274-E-PC, before the Arkansas Public Service Commission in Docket No. 12-008-U, and before the Public Utility Commission of Texas in Docket Nos. 39708 and 40443.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to:

- Describe the outcome of the CCR/ELG proceeding before the WVPSC and how it led APCo to make another request for ELG investment cost recovery from APCo's Virginia customers;
- Explain the practical impact of the WVPSC's Order on Virginia customers; and
- Set out the options available to the Commission and the potential costs that Virginia customers would face if the Commission again denies ELG investment cost recovery from APCo's Virginia customers.

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I. BACKGROUND

Q. WHY IS THE COMPANY FILING THIS PETITION?

A. The Company files this Petition pursuant to the E-RAC Statute for two central purposes: to seek recovery of costs related to compliance with state and federal environmental laws and regulations that are applicable to the generation facilities APCo uses to serve its native load obligation, as described in the testimony of Company witnesses Spitznogle, Sherrick, and Gallimore; and to ask again the Commission's permission to recover costs from our Virginia customers that are necessary to comply with the ELG Rule at the Amos and Mountaineer Plants. The Company makes this second request pursuant to the 2021 E-RAC Order in which the Commission denied recovery of the ELG costs from Virginia customers without prejudice and stated that the Company could re-file for approval "should circumstances so warrant." I will explain below the current circumstances that necessitate this filing.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE PREVIOUS E-RAC PETITION, AS WELL AS THE REGULATORY FILINGS IN OTHER JURISDICTIONS RELATED TO THE PLANTS.

A. On December 23, 2020, APCo filed a petition for authority to recover through the E-RAC:

- costs of compliance with the CCR Rule at the Plants, which the Commission approved;
- costs of compliance with the ELG Rule at the Plants; which the Commission denied without prejudice; and
- O&M costs related to compliance with rules governing the handling and disposal of fly ash, bottom ash, and FGD by-product, which the Commission approved.

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The Commission's decision regarding the ELG Rule in the 2021 E-RAC Order effectively closed the Plants to Virginia customers the end of 2028, which is the last day the plant may combust coal if it chose to not make necessary modifications for ELG compliance.

On December 23, 2020, APCo also filed a petition with the WVPSC seeking certificates of convenience and necessity that would authorize both the CCR and ELG projects at the Plants, as well as a cost recovery mechanism. The WVPSC approved the requests on August 4, 2021. In the WVPSC August Order, the WVPSC found that the CCR and ELG Projects at the Plants were "prudent, cost effective, and in the best interest of the current and future utility customers." On October 12, 2021, the WVPSC issued another order that affirmed its earlier holdings and concluded that, given the 2021 E-RAC Order, the West Virginia jurisdictional customers would pay for the ELG projects at the Plants, and should also receive the benefit of capacity and energy made possible by the ELG projects starting January 1, 2029.

Q. WHAT IS THE PRACTICAL IMPACT OF THE WVPSC'S ORDERS ON VIRGINIA?

A. Simply put, the Plants will continue to operate and dispatch into PJM past 2028, regardless of the Commission's decision in this proceeding. If the Commission rules that APCo's Virginia customers should not pay for the ELG projects, APCo's West Virginia customers will pay all the costs, and, the WVPSC asserts, APCo's Virginia customers should receive none of the energy or capacity produced by the Plants after 2028. The WVPSC's orders make clear that West Virginia is committed to keeping the Plants operating.

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II. IF THE COMMISSION APPROVES ELG COST RECOVERY

Q. PLEASE DESCRIBE THE IMPACT OF THE COMMISSION'S APPROVAL OF ELG PROJECT COST RECOVERY FROM VIRGINIA CUSTOMERS IN THIS PROCEEDING.

A. If the Commission approves APCo's request in this Petition, nothing will change for its Virginia customers. They will continue to pay for the Virginia jurisdictional share of all investment, including ELG project investment, at the Plants, as well as O&M costs, and will continue to receive the benefit of their energy and capacity after 2028, as long as the Plants continue to run.

Q. PLEASE DESCRIBE THE COSTS THAT VIRGINIA CUSTOMERS WILL BEAR AND AVOID IF THE COMMISSION APPROVES ELG COST RECOVERY IN THIS PROCEEDING.

A. Company witness Martin's analysis shows that, if approved, our Virginia customers will pay approximately $15 million the first year and $150 million in total over the period through 2040 for depreciation and return on their $98 million share of those investments. In exchange, they will continue to benefit from the 2,100 MW (nameplate) jurisdictional share of capacity provided by the Plants, which will continue to operate regardless of the Commission's action in this proceeding. And, absent a complicated interstate, intracompany arrangement that I will discuss more, Virginia customers will avoid:

- Paying $3 or $4 billion for 2,700 MW or more of nameplate replacement capacity to be in place by 2028, which could increase APCo's cost of service by an incremental 17-21% in 2029 over what they paid in 2021.
- Being responsible for a revenue requirement for that replacement capacity in the amount of $1.8 billion to $2.35 billion from 2029-2040, compared to the incremental cost of keeping the Plants operating through 2040 of $1.0 billion.

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This assumes, of course, that APCo could construct and/or procure that much capacity in the pre-2028 timeframe.

- Possibly being subject to the uncertainty and volatility of capacity provided solely by the market (paper capacity).

From my perspective, as the President of APCo, as the person responsible for providing our customers with reliable energy as cost effectively as reasonably possible, approving the ELG project costs and allowing our customers to avoid these astronomical costs and uncertainty seems like the most prudent course of action, especially given the comparatively limited cost and revenue requirement.

Q. WHAT IMPACT WOULD APPROVAL OF ELG PROJECT COST RECOVERY FROM VIRGINIA CUSTOMERS HAVE ON APCO'S COMPLIANCE WITH THE VCEA?

A. None. The Company will continue to comply with the mandates in the Code to seek Commission approval to own renewable facilities, enter into renewable PPAs, and otherwise procure and retire RECs. It is important to note, as Company witness Martin explains, the total UCAP provided by the renewable resources planned for VCEA compliance is less than the amount of capacity needed to offset even the smallest unit at Amos until 2035. In addition, the VCEA does not place energy production restrictions on the Plants. Continued operation of the Plants will not cause APCo to fail to comply with the VCEA's renewable energy mandates, which are based on a percentage of energy load, not energy generation. APCo plans to meet those targets with renewable resources, which will be added with or without the Plants.

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III. IF THE COMMISSION DENIES ELG COST RECOVERY

Q. WHAT HAPPENS IF THE COMMISSION DENIES ELG PROJECT COST RECOVERY FROM VIRGINIA CUSTOMERS?

A. If the Commission denies recovery of the ELG investment, Virginia customers would avoid the O&M expenses and capital investment costs necessary to keep the Plants operating past 2028. But, by not paying its jurisdictional share of an investment necessary to keep the Plants operating past 2028, Virginia will have shifted a disproportional share of costs onto a different jurisdiction.

As APCo would have to find a way to replace the energy and capacity that the Plants have provided to its Virginia customers for decades, an equitable arrangement could be made whereby Virginia customers compensate West Virginia customers for the capacity provided by one or both Plants. This arrangement could take many forms, and would be very complicated, requiring approval in both jurisdictions. For energy, APCo could purchase replacement energy from PJM for its Virginia customers, but they would be more exposed to energy market volatility. Note that energy on the PJM market is overwhelmingly generated from fossil fuels: for example, per PJM, on March 14, 2022 at noon, a relatively clear and sunny day across the PJM, renewables accounted for only 12,324 MW of the 98,829 MW in load. Eschewing the energy generated from the Plants in favor of market energy would not materially advance any clean energy goals. In short, Virginia customers would likely still rely on the Plants for capacity, but in a more convoluted way, and would be more exposed to volatility in the PJM energy market, which is overwhelmingly fossil-based.

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Q. IF THE COMMISSION DENIES ELG COST RECOVERY IN THIS PROCEEDING, WILL VIRGINIA CUSTOMERS AVOID PAYING ANY COSTS RELATED TO THE PLANTS?

A. No. In addition to possibly making some type of intracompany, inter-jurisdictional capacity payment to West Virginia customers, Virginia customers will continue to be responsible for the undepreciated balance of the Plants for which those customers are responsible. This is both fair and in line with traditional utility practice. Company witness Ross provides APCo's forecasted December 31, 2028 remaining book values of Amos and Mountaineer.

Q. WHAT WOULD BE THE IMPACT IF THE COMMISSION DENIES THE ELG PROJECT COST RECOVERY FROM VIRGINIA CUSTOMERS, AND ALSO DENIES ANY INTERSTATE, INTERCOMPANY ARRANGEMENT THROUGH WHICH VIRGINIA CUSTOMERS COMPENSATE WEST VIRGINIA CUSTOMERS FOR THE PLANTS' CAPACITY?

A. As Company witness Martin's analysis illuminates starkly, these Plants are hugely important to Virginia and our ability to keep rates reasonable: the Plants provide a considerable amount of inexpensive capacity that is not easily replaced. APCo could, theoretically, enter into the PJM market to acquire an equivalent amount of capacity from another source, which would likely be fossil fueled. APCo could also acquire or construct an equivalent amount of renewable resources to replace the Virginia share of jurisdictional capacity, but it is highly unlikely that APCo could accomplish this by 2028, given the time necessary to site, permit, and procure that much capacity. Note that PJM just recently proposed a two-year pause on reviewing projects in order to process a

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backlog of 1200 proposed projects, mostly solar, which could further complicate the timeline getting replacement capacity built. Moreover, it is unlikely that customers in West Virginia would pay for such an expensive investment, when it is simply not needed to serve them. This significant cost would most likely fall squarely on the shoulders of our Virginia customers, an outcome the Company is trying to avoid with this Petition.

Q. IF THE COMMISSION DENIES RECOVERY OF THE ELG INVESTMENT FROM VIRGINIA CUSTOMERS, WHAT IS THE IMPACT ON THE COMPANY'S CAPACITY POSITION WITH REGARD TO PJM?

A. None, as PJM views APCo as whole. Because the WVPSC affirmed the Plants' ability to operate past 2028, the Plants will continue to be an integral component of the Company's FRR capacity plan. The Plants will continue to dispatch economically, providing energy for the benefit of customers.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

JAMES F. MARTIN
Direct Testimony

220320361

APCo Exhibit No. ____
Witness: JFM

220322038

DIRECT TESTIMONY OF
JAMES F. MARTIN
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2022-00001

220026801

APCo Exhibit No. ____
Witness: JFM

SUMMARY OF DIRECT TESTIMONY OF JAMES F. MARTIN

In my testimony, I

- Describe an economic analysis that I provided to APCo management that compares the forecasted Virginia jurisdictional cost of service effects of a scenario in which the costs, energy, and capacity of the Amos and Mountaineer plants (the Plants) continue to benefit Virginia customers after 2028 to scenarios in which they do not. Elements of this analysis include:
    - Calculations of the $84 million average annual incremental cost to Virginia customers of continued operation of the Plants between 2029 and 2040, and an estimate of between $235 and $280 million average annual net cost over that same period of resources that could replace the Plants. Over that 12 year period, customers would pay between $1.8 billion and $2.35 billion more without the Plants than with them.
    - A computation of the 17-21% 2029 cost of service increase versus 2021, and 12-15% sustained average increase over the 2029-2040 period that Virginia customers will experience if they have to pay for new resources that would replace Virginia's jurisdictional share of the Plants in 2028.
- Explain the importance of APCo's PJM capacity requirement, and why that requirement is critical to understanding the economics of possible replacements of the Plants.
- Explain how PJM computes capacity credit for all of the primary alternative resource options that could replace the Plants (wind, solar, gas, and energy storage), in order to identify how many megawatts of capacity would be required to replace them, and I provide estimates of how much that capacity will cost.
- Discuss the impact of the VCEA on the evaluation of the merits of the ELG investment, and on the value of continued operation of the Plants in general.

APCo Exhibit No. ____
Witness: JFM

220360961

DIRECT TESTIMONY OF
JAMES F. MARTIN
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2022-00001

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is James F. Martin. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by AEPSC as a Director of Resource Planning Strategy. AEPSC, a wholly-owned subsidiary of AEP, provides centralized professional and other services to subsidiaries of AEP. AEP is the parent company of APCo.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from The Ohio State University in 1990, receiving a Bachelor of Science in Business Administration (Accounting Major), and again in 2001 receiving a Master's in Business Administration. Between 1990 and 2000, I held various accounting-related positions in private companies and public accounting firms. In 2000, I joined AEPSC as a Senior Accountant in the Corporate Development department. In 2001, I was promoted to Manager of Financial Analysis. In 2003, I became Manager of Strategic Analysis in Corporate Planning and Budgeting. In 2007, I was promoted to Director-Corporate Budgeting and Capital Investments. In August 2010, I became Manager-Regulated Pricing and Analysis in AEP's Regulatory Services department, with responsibility for preparing retail and FERC jurisdictional and class cost of service studies. In 2016, I was promoted to Regulatory Case Manager, with responsibilities including FERC generation and transmission cost

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of service studies, along with support for special projects including wind resource additions. In February 2021 I was promoted to my current position in AEP's Resource Planning group.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AS A DIRECTOR OF RESOURCE PLANNING STRATEGY FOR AEPSC?

A. My responsibilities primarily include preparing and reviewing various resource planning analyses, including integrated resource plans (IRPs) for companies in the AEP system, using the Plexos® modeling software and spreadsheet models to evaluate future resource plan costs and benefits at both operating company and individual jurisdictional levels. Other responsibilities include levelized cost of energy analyses, evaluation and rankings of bids submitted into competitive solicitations for capacity and energy resources, and evaluations of costs and benefits of individual generating resources. In addition, I prepare custom financial modeling for special projects such as the economic analysis used in the recent Wind Catcher and North Central wind resource proposals by APCo affiliates Southwestern Electric Power Company and Public Service Company of Oklahoma.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY OR APPEARED BEFORE ANY ELECTRIC UTILITY COMMISSION OR OTHER REGULATORY BODIES?

A. Yes. I most recently submitted testimony with the Commission on behalf of APCo in support of an economic analysis I prepared supporting investments needed for compliance with both the federal CCR and ELG Rules at the Plants as part of the

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2021 E-RAC Proceeding. I provided similar testimony on behalf of APCo and Wheeling Power Company in the WVPSC CCR/ELG proceeding. I have submitted testimony in FERC Docket Nos. ER15-2114-000, ER17-419-000 and ER17-418-003 in support of the formula rate protocols and cost of service templates for AEP affiliates. I have also testified before the WVPSC in proceedings regarding Wheeling's purchase of a portion of the Mitchell Plant and potential merger with APCo.

In addition, I testified before the Commission on behalf of APCo in Case Nos. PUE-2011-00037 (regarding jurisdictional cost-of-service, revenue allocation, and rate design); PUE-2011-00036 (regarding the Dresden generation rate adjustment clause); and PUE-2011-00001 (regarding demand response programs).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide an analysis that compares the investment in the ELG Projects at the Plants to the option of assuming that the Plants are no longer available to Virginia customers. My analysis demonstrates clearly that continued operation of the Plants, even if they do not run at all, is less expensive and much less risky for customers than retiring them early and replacing them. Having the Plants and their 4,200 MW of capacity allows the Company to avoid incurring substantial cost to obtain another source of capacity to cover its PJM capacity obligation. The Virginia share of the ongoing non-fuel costs of operating the Plants is about $84 million annually, or around $100 per MW per day. Annual revenue requirements of replacement resources would cost 2.5-3.5 times that amount.

2020-0369

In sum, my analysis demonstrates that:

1. The relatively small $98 million jurisdictional share of the ELG investments and continued use of the Plants will be much less expensive than replacing them with billions of dollars of new resources;
2. Replacement capacity would increase customers' rates by an incremental 17-21% in 2029;
3. In total, between 2029 and 2040, the net cost of service for the replacement resources would be between $2.8 billion and $3.4 billion, compared to the incremental cost of keeping the Plants operating of $1.0 billion; and
4. The above is true even if the Plants don't generate a single MWh of electricity after 2029, due to their capacity value.

Thus, my analysis provides compelling evidence that the Commission should approve cost recovery from APCo's Virginia customers for the ELG investments, so that customers can continue to benefit from the Plants.

Q. ARE YOU SPONSORING ANY SCHEDULES OR EXHIBITS IN THIS PROCEEDING?

A. I am sponsoring the Company's economic analysis included in APCo Schedule 46, Section 2, Statement 1. In addition, I am sponsoring the following schedule, which is attached to my testimony:

- APCo Exhibit No. __ (JFM) Schedule 1 – VCEA Report

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR ANALYSIS.

A. My analysis is comprised of three scenarios. First, I prepared two cases, both of which are VCEA compliant, in which Virginia's half of the Plants were assumed to be replaced with physical resources in 2028, in order to assess if the Plants were more or less expensive than other resource options. Case 1 assumes replacement of the Plants with a mix of renewables and gas-fired resources (the thicker dotted line on

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Figures 1 and 2 below). Case 2 assumes replacement with 100% renewable and energy storage resources, with energy storage being the bulk of the replacement capacity (the thinner dotted line on Figures 1 and 2). I also compared the ongoing cost of operating the Plants to a PJM market capacity price projection (the paper capacity case, which is the combination dashed/dotted line on Figures 1 and 2). I compared the ongoing costs of keeping the Plants operating (the future fixed O&M and capital expenses from 2028 onward) to the other options. Amos is the dashed line, and Mountaineer is the solid line. The Plants are the two lowest lines on both graphs.

Figures 1 and 2 illustrate the results of my analysis in terms of both gross and net capacity costs per MW-Day. In my analysis, "gross capacity costs" are the fixed costs of the capacity other than sunk costs, and "net capacity costs" are the fixed costs minus the energy margin expected from the resource option. For this analysis I didn't count the fact that the Plants would generate energy margin to offset that capacity cost, so the gross and net lines are the same between the two graphs. As the Plants do not need energy margin to provide tremendous value to customers versus other options, I omitted that factor. In reality, the Plants will generate energy margin, so the net line would be lower than the gross line, increasing the cost advantage.

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The assumed PJM market capacity option would not come with any energy margin offset, so those lines are also the same on the two graphs. In Figure 2, Cases 1 and 2 have the energy margin deducted.

Figure 1 - Gross Capacity Costs - $/MW-Day

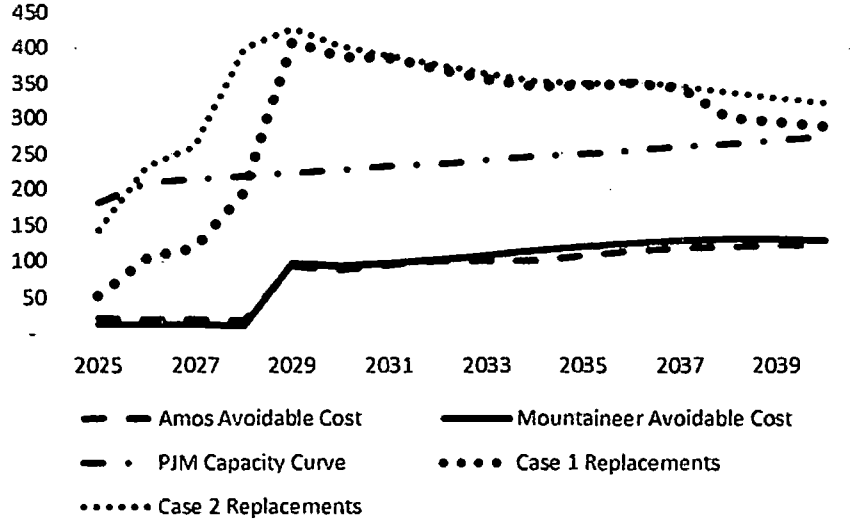
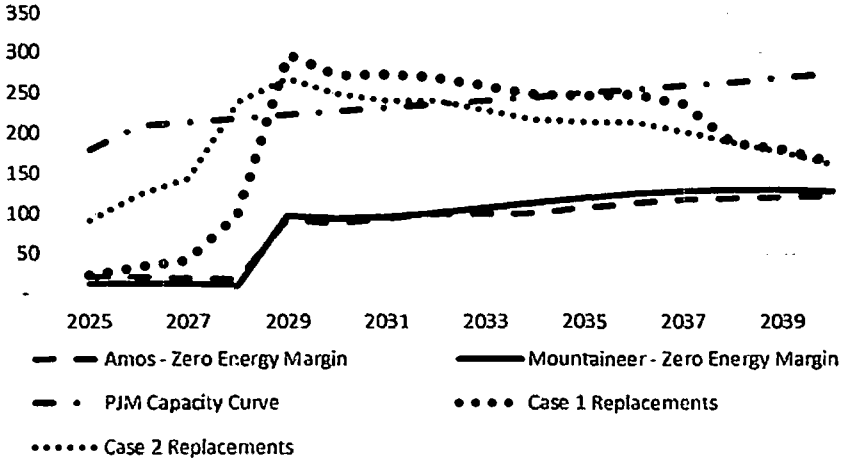


Figure 2 - Net Capacity Costs - $/MW-Day



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Q. PLEASE EXPLAIN WHAT IS PRESENTED IN FIGURES 1 AND 2.

A. Figures 1 and 2 are presented in terms of Dollars per Megawatt-Day ($/MW-Day), which is the unit of measure that PJM uses for its capacity auction price, and is a common measure of the cost of capacity. This metric puts differently sized capacity resources on an apples-to-apples basis as a cost per unit of capacity. The first year presented is 2025, which is the year that most of the new resources to be used for near-term VCEA compliance are projected to come online. The final year presented for purposes of my analysis is 2040, as the WVPSC approved the ELG projects at the Plants and indicated it would provide the Company an opportunity to run the Plants through 2040. Later in my testimony, I provide the underlying costs behind Figures 1 and 2 in millions of dollars of cost of service, which is another way to evaluate capacity cost.

The graphs show that the Plants are far less expensive than the other three options over the entire period through 2040. Figure 2 shows that the net costs of all the capacity options are 2-3 times the cost of the Plants in 2029, the year in which replacement capacity would need to be online to comply with APCo's PJM capacity obligations. Even though the relative cost advantage of the Plants then declines versus the physical resource options in Cases 1 and 2 through the 2030s, the Plants remain the least expensive capacity option through 2040.

The gross capacity cost in Figure 1 is similar to base rate cost of service, containing the incremental fixed costs of each option net of tax credits for the wind and solar resources. Those fixed costs of the replacement resources become sunk

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costs the minute the investments are made. Customers would need to pay for the replacements regardless of what happens in years after that. It is important to isolate the costs of just those replacement resources for the purpose of evaluating the value of making the ELG investment and operating the Plants beyond 2028.

Q. WHY DOES YOUR ANALYSIS ASSUME THAT THE PLANTS WILL NOT BENEFIT VIRGINIA CUSTOMERS AFTER 2028?

A. As described in the testimony of Company witness Beam, the WVPSC ordered the Company to make the ELG investments at the Plants. Therefore, the Plants will operate beyond the 2028 ELG compliance deadline regardless of the outcome of this proceeding. The WVPSC stated that if the Commission did not approve recovery of the ELG investment from Virginia customers, Virginia customers would not be entitled to the capacity and energy from the Plants, and the West Virginia customers would accept responsibility for the ELG investment and all ongoing operating costs after 2028. If this occurs, Virginia customers would no longer benefit from the capacity and energy of the Plants, despite their continued operation, but the Virginia jurisdiction would continue to be responsible for its share of APCo's overall capacity obligation. As that obligation will be met, in large part, with the Plants, Virginia customers could satisfy their responsibility with an inter-jurisdictional financial agreement or, conceivably, self-supply of the Virginia capacity obligation. Company witness Beam discusses the former, and the latter is the subject of my analysis.

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I. CAPACITY REPLACEMENT ANALYSIS.

Q. PLEASE DISCUSS THE BASIC STRUCTURE OF YOUR ANALYSIS.

A. My analysis compares the incremental cost of service of continued operation of the Plants beyond 2028, the "avoidable costs," to the costs of new resources, net of energy margin, from two portfolios of specific resources that would be needed to replace the Plants. I also compare the Plants to a paper capacity option priced at the forecasted PJM capacity market price. The avoidable costs of the Plants include fixed O&M and all capital expenses after 2028, and the $98 million Virginia share of the ELG capital investments. For the replacement resources, costs and revenues associated with resources added after 2028, such as resources the Company expects to add to comply with the VCEA, or to replace other Company resources when they retire, are irrelevant to the ELG approval decision, as they will come too late to allow customers to avoid paying for the required pre-2028 investments. My analysis eliminates all impacts of separate and unrelated resource additions or retirements occurring after 2028.

Q. HOW MUCH CAPACITY IS REPRESENTED BY VIRGINIA'S SHARE OF THE PLANTS?

A. The nameplate capacity of the Plants is approximately 4,200 MW. For the purpose of using the Plants to comply with the Company's PJM capacity obligation, the UCAP value of the Plants, after a forced outage rate adjustment made under PJM's rules, is expected to be 3,814 MW, as I discuss below. For this analysis, I combined the roughly 3% of APCo's load comprised of the Commonwealth and Public Authorities

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customers with the ~47% Virginia retail jurisdiction, because rates for those customers are based on the same cost of service as the retail jurisdiction. Virginia's half of the Plants' PJM accredited capacity would thus be 1,907 MW UCAP. I solved for this amount of replacement capacity for Virginia in my analysis.

Q. WHAT ARE THE AVOIDABLE COSTS?

A. As I discussed in more detail below, I estimate that the Virginia jurisdictional share of the ongoing avoidable costs of the Plants, including avoidance of the ELG investment, would be around $73 million in 2029, and would average $84 million annually from 2029-2040. By 2040 I project that amount to have increased to $95 million due to the cumulative effect of not paying a return on future capital expense. For this analysis, I excluded recovery of the sunk costs of the existing investment in the Plants from Virginia customers, as the Company would recover them in any scenario, either as depreciation should the Plants continue to run, or amortized over a given period, if the Plants are replaced.

Q. HOW DID YOU DETERMINE WHICH REPLACEMENT RESOURCES TO EVALUATE?

A. In Case 1 and 2, I used resources selected by the Plexos model in two of the resource plan scenarios included in the 2021 VCEA RPS Plan, which is attached to my testimony as APCo Exhibit No. ___ (JFM) Schedule 1 (the VCEA Report). In the VCEA Report, six VCEA compliant portfolios were prepared to illustrate various plans to comply with the VCEA's renewable energy requirements under futures with and without the Plants. The fundamental forecasts used in the VCEA analysis

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accounted for the expected build-out of renewables in Virginia and PJM, as well as Virginia's participation in RGGI.

Two of those VCEA Portfolios assumed a 2028 retirement of the Plants, and showed that retiring them in 2028 would be more costly than the VCEA Portfolios that kept the Plants running through 2040. I used the resources added up through 2028 in these VCEA Portfolios as the basis for the inputs to my two cases in this proceeding: Case 1 is based on VCEA Portfolio 3, which replaced the Plants with a mixture of renewables and gas-fired resources; and Case 2 is based on VCEA Portfolio 4, which relies on 100% renewable resources and energy storage. The full resource plans for those VCEA Portfolios, with both nameplate and firm (UCAP) capacity, is presented in Tables 26 and 27 in the VCEA Report.

In addition, I also evaluated what it would cost to replace the Plants with market purchase (paper capacity). This option would leave the Company heavily exposed to both market energy and capacity price risks that would be mitigated with ownership of actual resources.

Q. HOW DID YOU ALLOCATE THESE RESOURCES TO VIRGINIA IN YOUR TWO CASES?

A. Both of these VCEA Portfolios were prepared as if all of the Plants' 4,200 MW of capacity was retired and replaced. For this analysis, to better isolate the effects on Virginia, I only extracted enough resources from those VCEA Portfolios to replace Virginia's half of the Plants by making the following assumptions:

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1. If approved, the mixture of owned and PPA wind and solar projects that were selected from the 2021 RFP's totaling 498 MW[1] pending before the Commission in the 2021 VCEA Proceeding will come online at various dates between 2023 and 2025. I assumed that both Virginia and West Virginia would approve the projects, and Virginia would thus be allocated half.
2. The next group of resources added between 2025 and 2028 were assumed to be fully allocated to the Company's Virginia jurisdiction to meet the VCEA requirements. Between steps 1 and 2, all of the resources required by the VCEA prior to 2028 have been brought in to the analysis, reducing the replacement capacity that would otherwise be required to replace the Plants.
3. The "plug" to fully replace the remaining portion of Virginia's half of the Plants' UCAP capacity was then taken from the large resource added to replace the retiring coal plants in the two VCEA portfolios in 2028. This is a gas combined cycle in Case 1, and energy storage in Case 2.

Q. WHAT DO THESE PORTFOLIOS LOOK LIKE IN TERMS OF CAPACITY BY RESOURCE TYPE AND COST?

A. The capacity by resource type and costs for the Company's Virginia jurisdictional customers are presented in Tables 1 and 2. The capacity is presented in both nameplate (ICAP) and UCAP megawatts, which is what governs PJM capacity obligation compliance. For example, 200 MW of wind would give APCo 22 MW of PJM accredited capacity due to its intermittent nature under PJM's capacity market construct. Both Cases add up to 1,907 UCAP MW (half of the UCAP of the Plants). Cost amounts are presented in millions of dollars.

[1] See VCEA Report Table 2.

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Table 1 - Case 1 Replacement Resource Plan Cost

	Case 1 - Virginia Jurisdictional				
Resource Type	MW Nameplate	MW UCAP	Capital Cost ($MM)	2029 Gross Cost of Service ($MM)	2029 Net Cost of Service ($MM)
Under Development Wind/Solar	249	54	$420	$40	$18
Generic Owned Wind	200	22	$311	$25	$6
Generic PPA Wind *	150	17	$216	$20	$5
Generic Owned Solar	-	-	$0	$0	$0
Generic PPA Solar *	300	117	$355	$33	$12
Storage	300	210	$321	$61	$59
Hybrid Solar/Storage	0	0	$0	$0	$0
EE / VVO	67	67	$0	$19	$2
Gas CC	1,420	1,420	$1,546	$203	$188
Totals	2,686	1,907	$3,169	$400	$291

* PPA Capital Investment by PPA Counterparty. PPA cost is PPA price times energy

Table 2 - Case 2 Replacement Resource Plan Cost

	Case 2 - Virginia Jurisdictional				
Resource Type	MW Nameplate	MW UCAP	Capital Cost ($MM)	2029 Gross Cost of Service ($MM)	2029 Net Cost of Service ($MM)
Under Development Wind/Solar	249	54	$420	$40	$13
Generic Owned Wind	200	22	$309	$25	$2
Generic PPA Wind *	100	11	$142	$12	($0)
Generic Owned Solar	600	234	$843	$88	$37
Generic PPA Solar *	300	117	$388	$33	$7
Hybrid Solar/Storage	197	93	$280	$27	$14
EE / VVO	178	178	$0	$27	($10)
Storage	1,711	1,198	$1,862	$299	$284
Totals	3,535	1,907	$4,244	$551	$346

* PPA Capital Investment by PPA Counterparty. PPA cost is PPA price times energy

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The 2,686 MW (nameplate) of resources required in Case 1 (Table 1) to replace Virginia's half of the Plants' capacity would cost $3.2 billion. This assumes approximately 1,420 MW of the capacity is replaced by gas. In Case 2 (Table 2), 3,535 MW (nameplate) of resources costing $4.2 billion would be needed to replace half of the Plants with 100% renewables, with 1,711 MW of energy storage as the primary replacement resource.

I presented the Virginia jurisdictional cost of service in 2029 in the two Tables, which is the first year all of the revenue requirements of all of the new resources are fully included in cost of service. This year illustrates the immediate cost of service impact of replacing the Plants, costing Virginia ratepayers $291 million dollars that year if a combined cycle plant replaces the bulk of the capacity. This amount would be $346 million in 2029 if energy storage is the primary replacement resource. Both of these amounts are net of fuel savings customers would expect to receive from all new resources.

Q. HOW MUCH WOULD THE 2029 SINGLE YEAR COST OF SERVICE INCREASE BE UNDER THESE SCENARIOS?

A. These new resource costs would be offset by the avoided ongoing costs at the Plants, which I estimate will be $73 million in 2029. I did not include any energy margin the Plants might generate, in order to make my analysis as conservative as possible. The resultant net increase in 2029 cost of service would be $218 million in Case 1 and $273 million in Case 2, even if the Plants do not generate a single megawatt hour of energy. In comparison, Virginia customers paid a total of $1.3 Billion for regulated

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electric service (generation, transmission and distribution) from APCo in calendar year 2021. This incremental cost would amount to a customer rate increase of between 17 and 21% in 2029 above what they paid in 2021.

Q. WHAT WOULD THE TOTAL AND AVERAGE COST OF SERVICE INCREASE BE OVER THE 2029-2040 PERIOD?

A. See Table 3 below. In total, over the period between 2029 and 2040, the net cost of service for these replacement resource options would be $2.8 billion in Case 1 and $3.4 billion in Case 2. The paper capacity option would cost $2.3 billion during that period. In contrast, the incremental cost of keeping the Plants operating would be $1.0 billion. The annual average revenue requirement of the replacement resources included in these 12-year totals, net of fuel savings, is expected to be $235 million in Case 1 and $280 million in Case 2. These amounts are 2.8 to 3.3 times higher, respectively, than the $84 million average annual cost to keep the Plants operating during that period.

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Table 3 - 2029-2040 Cost of Service Impacts			
Line	Dollars In Millions	NPV of 2029-2040	Nominal Total 2029-2040
1	**Amos and Mountainer incremental capacity cost**	$647	$1,003
	Replacement Capacity Costs, net of Energy Margin		
2	Case 1 - Gas CC and Renewable Replacements	$1,935	$2,825
3	Case 2 - Storage and Renewable Replacements	$2,290	$3,356
4	Paper Capacity - PJM Market	$1,486	$2,280
	Replacement Cost Percentage of Amos/Mountaineer	2029-2040 Average % Increase	2029-2040 Average $(Millions) Increase
5	Case 1 - Gas CC and Renewable Replacements	290%	$152
6	Case 2 - Storage and Renewable Replacements	344%	$196
7	Paper Capacity - PJM Market	229%	$106

Additional details supporting Table 3 in the form of the annual gross and net cost of service over the 2029-2040 period are shown in Schedule 46, Section 2, Statement 1, which I sponsor in this proceeding.

II. PJM CAPACITY REQUIREMENTS

Q. PLEASE DESCRIBE THE REQUIREMENTS APPLICABLE TO PJM MEMBER COMPANIES LIKE APCO.

A. PJM utilities such as APCo and the AEP system companies are required to provide enough capacity to cover their summer peak loads plus a reserve margin. This requirement is forecasted to be 14.9% on an ICAP or nameplate basis, or around 8.6% on an UCAP basis. The difference between the two is due primarily to two downward adjustments that PJM makes. First, each resource's nameplate capacity is reduced by an assumed forced outage rate. Second, for renewable resources, PJM

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uses a methodology called Effective Load Carrying Capability (ELCC) to determine how much credit each resource gets. These ELCC adjustments in my analysis are reflected in Tables 1 and 2 in the differences between the nameplate and UCAP columns.

A utility must maintain reserve capacity (Capacity – Peak Load) of at least 8.6% of UCAP above its peak load. For example, if a utility has a capacity of 1,086 UCAP MW and a peak load of 1,000 MW, then its reserve margin reserve would be 8.6% ((1,086 -1,000)/1,000).

Q. HOW MUCH CAPACITY DOES EACH POSSIBLE REPLACEMENT RESOURCE PROVIDE?

A. The PJM capacity market rules determine how much capacity credit each type of resource is given towards a capacity obligation, which varies widely based on each resource's ability to contribute dependable output during high load hours. RTOs plan for how much capacity is needed for peak load conditions, plus a reserve margin, in order to make sure enough resources are available to reliably serve load at those times. Looking at how much energy a given resource can be counted on to produce in those high load hours is how RTOs determine how much capacity credit each resource should be given. The ELCC method does this calculation for the intermittent resource types. In general, fossil fueled resources like gas and coal provide more capacity value due to their dispatchability than intermittent resources like wind and solar. If APCo found itself needing this much capacity, this assumption would be critically important.

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This is illustrated for PJM in Table 4. That table shows how much capacity credit each major resource type is expected to get in PJM, compared to Virginia's half of the Plants. Wind, for example, would get 231 MW of credit for its 2,100 MW nameplate capacity. It would take 17,336 MW of wind to equal the Plants 1,907 MW of UCAP.

Table 4 - PJM Capacity Credit By Resource Type

	Nameplate Capacity	2028 PJM Capacity credit %	PJM Accredited UCAP Capacity	Capacity to Match Amos / Mountaineer UCAP
50% of Amos and Mountaineer	2,100	91%	1,907	
Wind	2,100	11%	231	17,336
Solar (Tracking)	2,100	39%	819	4,890
Storage - 4 hour	2,100	70%	1,470	2,724
Solar Plus 4 hour Storage	2,100	72%	1,512	2,649
Gas CT or CC	2,100	96%	2,016	1,986

III. RESOURCE COST ASSUMPTIONS

Q. WHAT IS THE COST OF SERVICE OF THE ELG COMPLIANCE INVESTMENTS?

A. Virginia's share of the ELG investments at the Plants is approximately $98 million. The annual revenue requirement (depreciation and return on investment) that Virginia customers would pay is $15 million in the year the ELG investments go in service. This assumes the depreciation rates approved by the Commission in the 2021 R-RAC proceeding for the CCR investments are also adopted for the ELG investments. This will drop to $2 million per year for Mountaineer in 2034, as the Amos ELG is assumed to be fully depreciated in 2033. Over the full period between 2022 and 2040 I would estimate the Virginia share of the nominal revenue requirement will be

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approximately $150 million. The present value of this cost of service will be approximately $93 million. I included these values in the incremental ongoing cost of operating the Plants.

Q. WHAT ASSUMPTIONS DID YOU MAKE ABOUT FUTURE INCREMENTAL CAPITAL COSTS OF THE PLANTS?

A. In both cases, all of the ongoing capital expense forecasts, excluding the ELG costs, were included through 2035. From 2036 to 2040, I used a "glide path" capital expense forecast, which reduced that maintenance capital in those years. I applied a levelized carrying charge to that capital expense starting in 2029 in order to determine what the cost of service savings would be by avoiding that capital.

Q. WHAT ASSUMPTIONS DID YOU MAKE REGARDING THE FUTURE OPERATIONS AND MAINTENANCE COSTS OF THE PLANTS?

A. The analysis assumed that the currently forecasted level of O&M through 2030. In years after that, O&M was projected to decline, commensurate with expected lower capacity factors if a national carbon tax is enacted. Reduced capacity factors would mean less maintenance and waste disposal costs, and thus O&M was assumed to be 75% of the 2030 forecast between 2031 and 2040. All of the fixed O&M was assumed to be avoidable starting in 2029.

I also prepared a forecast of taxes that could be avoided if Virginia customers were no longer benefitting from the Plants, including property taxes and a tax levied on generating plants in West Virginia called the Business & Occupation (B&O) tax. APCo is expected to pay about $10 million per year in property taxes and about $36

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million annual in B&O tax towards the end of this decade. Virginia's half of these two taxes is expected to be about $23 million annually in 2028 and beyond.

Q. HOW WERE THE COSTS OF THE REPLACEMENT RESOURCES COMPUTED?

A. I used a spreadsheet model to compute a forecast of the annual revenue requirement on the new resource additions using customary ratemaking principles. For the owned resources, this included forecasting rate base declining over time, return on rate base at a weighted average cost of capital, depreciation, O&M, production tax credits over the first 10 years on the wind assets, and normalization of the investment tax credits on the solar assets over the 35 year lifetimes. I used the PPA costs for those resources.

Q. WHAT WERE THE SOURCES OF THE COST OF REPLACEMENT RESOURCES?

A. I used the actual resource costs for the portion of replacement capacity provided by the Virginia half of the 498 MW of the currently proposed VCEA compliant projects which are currently pending before the Commission in Case No. PUR-2021-00206. The gross cost of service of the 498 MW is projected to average about $42 million per year for Virginia customers through 2040. Those resources are summarized here in Table 5.

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TABLE 5 – Near Term Planned Resources					
Facility	**Nameplate Capacity MW**	**Owned / PPA**	**State**	**Resource Type**	**Operation**
Firefly	150.0	Owned	Virginia	Solar	July 2024-June 2059
Amherst*	4.9	Owned	Virginia	Solar	Jan 2023 - Dec 2057
Horsepen	20.0	PPA	Virginia	Solar	Jan 2025 - Dec 2054
Dogwood*	18.9	PPA	Virginia	Solar	Jan 2025 - Dec 2054
Sun Ridge	50.0	PPA	Virginia	Solar	Jan 2025 - Dec 2054
Virginia Domiciled	**243.8**				
Top Hat	204.0	Owned	Illinois	Wind	Jan 2025 - Dec 2054
Bedington	50.0	Owned	West Virginia	Solar	Oct 2023 - Sep 2058
TOTAL	**498**				

*Distribution Resource

The remaining generic resource costs, including construction cost and fixed O&M for owned resources and PPA costs, were sourced as described in section 4 of the VCEA Report. The generic wind and solar resource costs were aligned with the average of the bids received by APCo in the RFPs it issued for both owned and PPA resources in 2021. All new wind and solar resource costs are based on actual market information available at the time the analysis was performed.

Q. HOW MUCH WIND AND SOLAR WOULD BE REQUIRED TO REPLACE THE PLANTS, AND WHAT WOULD IT COST, IF ALL OTHER RESOURCE TYPES WERE EXCLUDED?

A. The proposed portfolio in the 2021 VCEA Filing of 204 MW of wind and 294 MW of solar is projected to provide a total of 108 MW of UCAP capacity in 2028. Based on current ELCC capacity credit expectations (as illustrated in Table 4), it would take 17.7 times that amount of wind and solar to replace Virginia's half of the Plants'

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1,907 MW of UCAP: that equals 8,800 MW of resources needed by 2028. Based on the actual costs of these resources, replacing the Plants with this mix of 40% wind and 60% solar would cost close to $15 billion. An investment of this size in such a short period of time would be unprecedented in scope and scale for APCo, especially given the uncertainty around whether siting, constructing, and financing such a portfolio is achievable.

This group of seven proposed new resources selected from the 2021 RFP's amounting to 498 MW is projected to cost roughly $19 million per year on average through 2040 after deducting the expected energy revenue that will reduce customer fuel costs. As it would take 17.7 times this amount of resources to replace the UCAP of these plants, such a mix of wind and solar would equate to about $338 million per year in annual average net cost of service through 2040, which would be four times the incremental cost of the Plants over that period.

Q. HOW MUCH DO APCO'S NEW RESOURCES COST PER MEGAWATT-HOUR OF ENERGY?

A. When the projected annual revenue requirements of the ten new assets, net of tax credits, are divided by the energy they are expected to produce, the average cost to customers per MWh over the 17 years between 2024 and 2040 is expected to be $53/MWh. The lowest cost year in that period is projected to be $47/MWh.

The ten new assets are: the seven resources obtained through the 2021 RFPs set out in Table 5, plus three other PPA resources that went online in 2021 or that will go online in 2022: the 20 MW Wytheville, 20 MW Leatherwood, and the 15 MW

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Depot solar facilities. A diverse portfolio such as this would be representative of what APCo would expect if it sought a large amount of renewable capacity needed to replace some or all of the Plants' capacity (assuming it could even find and get approval for that amount of capacity by 2028, which is doubtful).

Q. DOES RENEWABLE ENERGY CERTIFICATE VALUE INFLUENCE NEW RESOURCE COSTS, INCLUDING PPA COSTS?

A. Yes, and the magnitude of that influence is growing of late. All of these ten renewable assets come with renewable energy certificates (RECs), which have cash value in REC trading markets in addition to the value of the energy itself. PJM Tier 1 RECs traded as high as $24.50/MWh in January 2022. In the two VCEA portfolios on which I based my analysis in this proceeding, RECs were assumed to be priced at between $27 and $32 per MWh between 2023 and 2031 (VCEA Report Figure 8).

In recent years, many PJM states and neighboring states in the Northeast have established renewable energy mandates, and corporations are making substantial renewable energy pledges. This has created high demand for renewables and their RECs, which has led to difficulty getting resources sited, interconnected, approved, and built in time to meet growing compliance targets. In February 2022, PJM publicly acknowledged the backlog it is facing in getting new projects moved through the interconnection queue, and announced it was seeking to implement a two-year moratorium on new interconnection requests. All of the above has driven up REC prices and PPA prices.

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APCo has a requirement to either self-generate or purchase and retire RECs in order to comply with the VCEA, and thus RECs are required by APCo when it seeks new resources. For the PPA assets, this REC value can push up the PPA price to an amount well above the cost the developer incurs to build and operate the assets themselves. RECs are separately priced in some renewable PPAs, and buried in a combined energy/REC price in others, so it isn't always clear what the REC value is, but it's clearly a factor developers consider in pricing assets offered into RFPs for both owned assets and PPAs. Either way, the REC value that rational profit seeking developers attempt to capture in pricing their product will cause the price of new resources to be higher than the cost of asset itself.

IV. IMPACTS OF THE VCEA ON THE PLANTS

Q. DOES THE VCEA REQUIRE THE PLANTS TO RETIRE?

A. No. The Plants are located outside of Virginia, and thus are not required to be retired by any certain date by the VCEA.

Q. WHAT IMPACT DO THE VCEA'S NEW RESOURCE PETITION REQUIREMENTS HAVE ON THE ANALYSIS OF THE ECONOMICS OF THE ELG INVESTMENT AND THE PLANTS' CONTINUED OPERATIONS?

A. The VCEA resource petition mandates have very little impact on an evaluation of the ELG investment, or the need for the Plants in general. The law states that APCo must meet RPS requirements and petition the Commission for approval of certain resources. The petition requirements that are applicable in time to impact the ELG decision are 400 MW of wind or solar by 2027 and 25 MW of storage by 2025. The

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next interim petition requirement after the 2027 requirement is 200 additional MW of wind or solar by 2030 and 125 additional MW of storage by 2030. Any resources added for VCEA compliance after the 2027 requirement would be irrelevant to the decision regarding how to replace the Plants' capacity, as that decision would have already been made.

Table 21 in the VCEA Report shows the UCAP provided by the additions that APCo plans to add to achieve VCEA compliance through 2040. In that VCEA portfolio, only the minimum resources needed for VCEA compliance (assuming they are cheaper than RECs) were added. The Company is not projected to need capacity to maintain compliance with the PJM capacity requirement until 2040. That resource plan included an assumed amount of distributed generation (labeled New DG) built on the APCo system, which is not mandated by the VCEA. As shown in the 2028 column on the line labeled Total Additions (Firm and Degraded), the total UCAP added by 2028 from all resources is expected to be 298 MW, which is less than half of the UCAP capacity of the smallest unit at Amos, which is 742 MW. Looking further out, it takes until 2035 for the total UCAP of all resources planned for VCEA compliance to total more than 742 MW. This demonstrates that capacity provided by the new resources planned for VCEA compliance are less than the amount of capacity needed to offset even the smallest unit of the Plants until 13 years from now.

220320001

Q. DO THE VCEA'S RENEWABLE ENERGY REQUIREMENTS HAVE AN IMPACT ON THE ANALYSIS OF THE ECONOMICS OF THE ELG INVESTMENT, OR THE VALUE OF THE PLANTS IN GENERAL?

A. The economics of the Plants are impacted by the VCEA requirements as reflected in the Company's Fundamental forecasts, which assume a full build-out of VCEA resources in PJM and Virginia's participation in RGGI. Regarding APCo specifically, the renewable energy targets in the VCEA mandate that a percentage of the Company's Virginia jurisdictional energy load be met from qualifying resources or RECs. That percentage increases through time before reaching 100% by 2050. As the requirement is a percentage of load, not a percentage of energy generated by the Company's resources, the law does not restrict how much the Plants can run. As long as the Company has enough of a combination of REC purchases and qualifying renewable generation to meet the percent of Virginia load targets, the Company will be in compliance, regardless of how much or how little its fossil plants run. Even if the VCEA compliance requirement was qualifying energy or RECs of 100% of Virginia load at some point before the Plants retire, any generation produced by the Plants will be sold off-system into the PJM market, generating value for customers despite not being needed to serve internal load.

220220001

V. TRANSMISSION CONSIDERATIONS

Q. COULD RETIREMENT OF THE PLANTS CREATE THE NEED TO INVEST IN THE BULK HIGH VOLTAGE TRANSMISSION SYSTEM?

A. Yes. AEP's transmission planning organization performed high level studies while the Company was initially evaluating whether to make the CCR and ELG investments at the Plants. Those studies indicated that retiring the Plants in 2028 could result in the need for between $100-$200 million of upgrades to the high voltage transmission system to prevent violations to both thermal and voltage reliability standards. This was factored into the economic analysis that supported making the investments.

Q. DID YOU INCLUDE POTENTIAL TRANSMISSION COSTS IN THE ANALYSIS SUPPORTING THIS PETITION?

A. No, I did not include transmission costs in this analysis because the Plants will not be retiring in 2028. I also did not include an assumption of interconnection costs in the cost of the replacement assets, beyond routine interconnection costs assumed in the generic resources. Based on the interconnection costs of adding the 498 MW of resources currently under development, the costs of getting enough transmission for the thousands of nameplate MW needed to replace Virginia's half of the Plants could be $50-$100 million depending on the locations of replacement capacity. This would raise the costs of replacing the Plants above what I have presented here.

VI. CLINCH RIVER RGGI COMPLIANCE

Q. PLEASE DESCRIBE THE RGGI COMPLIANCE COSTS RELATED TO THE CLINCH RIVER PLANT.

A. Clinch River is located in Virginia, and thus is subject to RGGI compliance costs due to Virginia's participation in RGGI. As discussed in her testimony, Company witness Castle has included an estimate of these compliance costs in his calculation of the revenue requirement of the E-RAC rider. These costs have been deferred (not collected from customers) to date. As a generator located in PJM, Clinch River only dispatches when it is economic compared to the other resources that have been offered into PJM to meet load in a given hour. When APCo offers the unit for sale into the PJM energy market, the offered price includes the cost of any RGGI allowances that APCo would need to purchase to allow Clinch River to run. PJM would only dispatch Clinch if its offer price was lower than the marginal energy price. As a result, any RGGI-related costs are offset by energy revenues received when the energy is sold. Customers have already received the fuel cost of service reduction from these revenues, and therefore it is appropriate for APCo to recover those costs in the E-RAC revenue requirement.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APCo Exhibit No. ___
Witness: JFM
Schedule 1

AMERICAN ELECTRIC POWER

BOUNDLESS ENERGY

American Electric Power
1051 E Cary Street, Suite 1100
Richmond, Virginia 23219
AEP.com

January 7, 2022

By Electronic Filing

Hon. Bernard J. Logan, Clerk
State Corporation Commission
Document Control Center
1300 East Main Street
Richmond, Virginia 23219

Noelle J. Coates
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Re: Petition of Appalachian Power Company
For approval of its 2021 RPS Plan
under § 56-585.5 of the Code of Virginia
and related requests
Case No. PUR-2021-00206

Dear Mr. Logan:

Enclosed for filing is Corrected Attachment 1, the 2021 RPS Plan, to the Petition that was filed in the above-referenced case on December 30, 2021. After the filing of the 2021 RPS Plan, the Company noted that Tables 22 and 23 contained incorrect information, which has been corrected in this version. In addition, the Plan's original Appendix B had two tables numbered 29, which has also been corrected and all tables past Table 29 have been renumbered. Lastly, the information in Appendix C has been removed, as it was inadvertently included in the report.

Sincerely,

Noelle J. Coates

Enclosure

cc: William H. Chambliss, Esq.
Kiva B. Pierce, Esq.
C. Meade Browder, Jr., Esq.

APCo Exhibit No. ___
Witness: JFM
Schedule 1

2021-00206
12/30/2021

APPALACHIAN POWER

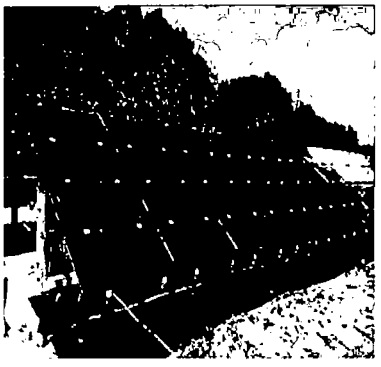
An AEP Company

BOUNDLESS ENERGY

RENEWABLE PORTFOLIO STANDARD PLAN

CASE NO. PUR-2021-00206

December 30, 2021



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1.0 Virginia Clean Economy Act Compliance Plan Overview

Consistent with the requirements of Virginia Code Section 56.585.5.D.4, Appalachian Power Company (Appalachian, APCo, or the Company) submits the second of its annual plans to meet the requirements in the Virginia Clean Economy Act (VCEA).

This year's report includes six separate VCEA compliant plans for informational purposes. Descriptions of the six Portfolios are provided in Table 1. Four of the plans, Portfolios 1-4, assume only the minimum level of renewable resources needed to meet the annual VCEA energy targets are added. These plans were prepared under varying scenarios in which the Company's two coal plants were retired in either 2028 or 2040, and replaced with either a combination of renewable and gas fired resources or 100% renewable resources. The fifth plan (Portfolio 5) was prepared under the assumption that 1,000 MW of additional wind above the minimum VCEA requirements is available and can be added based on favorable economics in time to capture production tax credits before they expire in 2026. The sixth plan (Portfolio 6) is a sensitivity case prepared as a result of a requirement in the Commission's order on the Company's 2020 VCEA filing,[1] in which future wind resources are assumed to have a capacity factor that is consistent with the Company's current wind PPA resources.

TABLE 1: PORTFOLIO DESCRIPTIONS

Portfolios					
1	**2**	**3**	**4**	**5**	**6**
RGGI Only CO2 2040 AM & MNTR Ret. Gas Options Available	RGGI to $15 CO2 2040 AM & MNTR Ret. No Gas Option Available	RGGI Only CO2 2028 AM & MNTR Ret. Gas Options Available	RGGI to $15 CO2 2028 AM & MNTR Ret. No Gas Option Available	RGGI to $15 CO2 2040 AM & MNTR Ret. No Gas Option Available Higher Wind Limits	RGGI to $15 CO2 2040 AM & MNTR Ret. No Gas Option Available Current Wind Project Cap Factors

For the purposes of this report, the Company's base case assumption is that the coal plants will operate through 2040 and fossil fueled resources will not be used to replace them at that time. Portfolio 2 presents that scenario and will be referred to in this report as the VCEA Plan or the Plan. Nevertheless, APCo intends to issue Request for Proposals (RFPs) in the near

[1] Final Order at 5, *Commonwealth of Virginia, ex rel. State Corporation Commission Ex Parte: Establishing 2020 RPS Proceeding for Appalachian Power Company*, Case No. PUR-2020-00135, Doc. Con. Cen. No. 210440238 (April 30, 2021) ("Order on 2020 Filing").

term based on Portfolio 5, and seek approval of those resources based on the results of APCo's economic analyses. The Company's 2021 VCEA Plan includes a geographically varied portfolio of storage, solar and wind resources, both Company and third party owned, as well as market REC purchases. In the filing associated with this Plan, the Company is seeking a prudency determination of the acquisition of one 150 MW solar facility and the agreements to purchase the output of three solar facilities via power purchase agreements (PPAs) totaling approximately 89 MW; approval to recover the costs of 50 MW of owned West Virginia solar and 204 MW of Illinois wind resources. In addition, APCo is seeking cost recovery for RECs associated with 40 MW of Virginia solar contracted through its Cogen/SPP rate schedule; 15 MW of contracted solar located in Virginia; 5 MW owned solar in Virginia; as well as market REC purchases necessary for annual compliance.

The Company developed these VCEA compliant plans in a way that is similar to how Integrated Resource Plans are developed, using the same general methods, commodity price forecasts, optimization software, load forecasts, and resource cost assumptions. The amount and timing of the resource additions were determined with Plexos® optimization software, adjusted as needed to include resource additions that were necessary to meet certain annual requirements associated with energy efficiency targets and Virginia-domiciled renewable and storage.

In addition to determining the type and timing of resource additions, this report provides an estimate for the rate impacts associated with compliance, consistent with the Commission's requirement in the Order on the 2020 Filing.

1.1 VCEA Expected Resource Additions

APCo issued a series of RFPs for renewable resources and RECs in 2021 to meet the VCEA requirements and is seeking approval in both Virginia and West Virginia for several projects that resulted from that process. It is assumed for purposes of this Plan that both Virginia and West Virginia commissions will approve those investments and that each retail jurisdiction will receive its allocated share of costs and attributes. All other identified renewable resource additions are assumed to accrue exclusively to Virginia retail customers.

In the short term, APCo expects to acquire or contract for 498 MW of resources. These specific resources, which are the subject of the petition filed simultaneously with this report, are shown in Table 2.

TABLE 2 APCO PLANNED NEAR-TERM RESOURCE ADDITIONS

Facility	Nameplate Capacity MW	Owned / PPA	State	Resource Type	Operation
Firefly	150.0	Owned	Virginia	Solar	July 2024-June 2059
Amherst*	4.9	Owned	Virginia	Solar	Jan 2023 - Dec 2057
Horsepen	20.0	PPA	Virginia	Solar	Jan 2025 - Dec 2054
Dogwood*	18.9	PPA	Virginia	Solar	Jan 2025 - Dec 2054
Sun Ridge	50.0	PPA	Virginia	Solar	Jan 2025 - Dec 2054
Virginia Domiciled	**243.8**				
Top Hat	204.0	Owned	Illinois	Wind	Jan 2025 - Dec 2054
Bedington	50.0	Owned	West Virginia	Solar	Oct 2023 - Sep 2058
TOTAL	**498**				

*Distribution Resource

In addition, the Company expects the Depot (15 MW) and Wytheville (20 MW) solar facilities to be operational in late 2021-early 2022. The Leatherwood (20 MW) solar facility was placed in-service in September 2021. All of the renewable attributes of the Leatherwood and Wytheville facilities, which are PURPA projects, are being attributed to Virginia. Finally, the Company is proposing to add approximately 8 MW of energy storage for the purposes of improving reliability along its Glade Station – White Top circuit.

The RFP issued for RECs in May 2021 resulted in one bid. The Company elected not to pursue this bid based on its economic analysis, and will continue to issue RFPs for RECs from time to time to evaluate the cost effectiveness and level of availability of REC contracts as a compliance option.

As shown in Table 3 below, the Company will satisfy the 2023 interim wind and solar requirements of Section 56-585.5 D.1 by petitioning the Commission for approval to acquire approximately 155 MW of owned Virginia-domiciled solar facilities (Firefly and Amherst), and approximately 144 MW of contracted, third-party owned, Virginia-domiciled solar facilities (Wytheville, Leatherwood, Depot, Horsepen, Sun Ridge, and Dogwood). Progress towards the Virginia-domiciled resources that will be used for compliance with the 2023 petition requirement are listed in Table 3.

TABLE 3: APCO PROGRESS TOWARDS 56-585.5 D. WIND/SOLAR REQUIREMENTS

56-585.5.D Requirement	PPA	Owned	Total
YE 2023	70	130	200
YE 2027	140	260	400
YE 2030	210	390	600
2021 Plan	144	155	299

The VCEA section 56-585.5 E also contains interim storage resource requirements. See Table 4 for the Company's Progress towards these requirements. The Company expects to solicit bids for qualifying storage resources in a future RFP in 2022.

TABLE 4: APCO PROGRESS TOWARDS 56-585.5 E. STORAGE REQUIREMENTS

56-585.5.E Requirement	PPA	Owned	Total
YE 2025	9	16	25
YE 2030	53	98	150
YE 2035	140	260	400
2021 Plan	0	0	0

1.2 Virginia Clean Economy Act Near-Term Compliance

The Company met the RPS requirements of Section 56-585.5 C for 2021 largely with its current supply of renewable resources. In Table 5, the Company has prepared a projection of its expected position in terms of VCEA qualifying energy production versus each year's energy targets through 2025. Given the assumed production of the existing and planned energy resources, the Company projects a deficit in each year. It is anticipated this deficit will be addressed through the tactical purchase of RECs, when market conditions are favorable.

TABLE 5: APCO NEAR TERM VCEA ENERGY COMPLIANCE

Projected REC production and forecast requirments (MWh)

	2021	2022	2023	2024	2025
Current Resources					
Hydro - owned	478,739	478,739	478,739	478,739	478,739
Hydro (PPA)	70,366	70,366	70,366	70,366	70,366
Bluff Point Wind (PPA)	189,720	189,720	189,720	189,720	189,720
Camp Grove Wind (PPA)	99,893	99,893	99,893	99,893	99,893
Fowler Ridge (PPA)	114,235	114,235	114,235	114,235	114,235
Leatherwood (PPA)	13,039	45,153	44,927	44,703	44,479
Sub-total Current Resources	965,993	998,107	997,881	997,656	997,433
Projected Resources					
Wytheville (PPA)	0	42,968	42,753	42,539	42,327
Depot (PPA)	0	13,285	15,475	15,398	15,321
Amherst - owned	0	314	5,290	5,264	5,237
Horsepen (PPA)					21,765
Dogwood (PPA)					16,446
Sun Ridge (PPA)					58,200
Top Hat - owned					381,979
Firefly - owned				111,428	167,142
Bedington - owned			10,962	52,225	51,964
Subtotal - Projected Resources	0	56,567	74,481	226,854	760,381
Total - Current and Projected	965,993	1,054,674	1,072,361	1,224,510	1,757,814
less APCo Renewable Riders	(80,342)	(80,342)	(80,342)	(80,342)	(80,342)
Production Available for Compliance	885,651	974,332	992,019	1,144,168	1,677,472
Virginia Retail Load (forecast)(MWh)	15,040,556	15,017,019	15,002,519	14,989,673	14,998,772
RPS % Requirement	6%	7%	8%	10%	14%
RPS REC Requirement	902,433	1,051,191	1,200,202	1,498,967	2,099,828
REC Deficit	(16,783)	(76,859)	(208,182)	(354,799)	(422,356)
Cumulative REC Surplus/(Deficit)		(93,642)	(301,824)	(656,623)	(1,078,979)

Embedded Jurisdictional Split	0.501
New Asset Split	0.501

	2021	2022	2023	2024	2025
Requirement	902,433	1,051,191	1,200,202	1,498,967	2,099,828
WV Approves	871,923	953,166	959,959	1,002,627	1,657,979
Only Virgina Approves	965,993	1,054,674	1,072,361	1,224,510	1,757,814

1.3 APCo's Coal Units

The Company is required to make certain environmental investments in its two coal plants (2,930 MW Amos, St. Albans, WV; 1,336 MW Mountaineer, New Haven, WV) in order for them to operate past 2028. In Case No. PUR-2020-00258, the Virginia SCC did not approve cost recovery for the Virginia jurisdictional share of the investment necessary to comply with the Effluent Limitation Guidelines (ELG) rule. As a result, the Company modeled two sets of scenarios: one with the two plants retiring at the end of 2028 and one with the plants retiring in 2040. During the performance of the analyses in this report, the Public Service Commission of West Virginia (WVPSC) ordered (Case No. 20-1040-E-CN) APCo to proceed with the investments necessary to keep the plants operational past 2028 and held that West Virginia customers will, if necessary, pay for the entire investment. There are unresolved issues associated with the sharing of capacity and energy benefits of these plants between the states if the Virginia SCC ultimately denies cost recovery of the ELG investment and the coal plants remain operational past 2028. For the purposes of discussion of the VCEA Plan (Portfolio 2) in this report, it is assumed that Virginia will continue to have the benefit of the two coal plants through 2040.

1.4 Environmental Justice

Appalachian is committed to the tenets of the Commonwealth's Policy on Environmental Justice and considers it in all prospective transactions for renewable resources. Identification and remediation of potential concerns are made during the RFP process, as discussed in the petition. Because Environmental Justice is specific to the communities immediately surrounding resources, meaningful screening can only be accomplished once potential sites have been identified. The Plexos® selected resource additions identified in this Plan are generic in nature and are not site specific and thus cannot be evaluated for potential Environmental Justice issues.

1.5 Reliability Impacts

Through Plexos®, the Company models reliability at a system level by ensuring that sufficient resources are available to meet customer load based on the hourly profile of both load and resources. Because the Company is a member of PJM, Plexos® has the option to fill energy deficits in any specific hour with market purchases. At this time, the Company expects that supply of energy from PJM will be available through at least 2030 when needed with pricing

based upon scarcity. The Company will continue to evaluate and identify potential reliability concerns and mitigation as renewable penetration increases in APCo's service territory, Virginia, and PJM.

2.0 VCEA Summary

In 2020, the General Assembly passed the VCEA, which was signed into law by Governor Northam. The VCEA is a transformative law that seeks to end carbon dioxide emissions from the electric utility industry in Virginia.[2]

2.1 VCEA Requirements

There are four primary requirements of the VCEA related to resource acquisition:

1. Annual RPS requirement. For APCo, this requirement is reproduced in Table 6 and begins at 6% in 2021 and escalates to 100% by 2050.

TABLE 6: APCO VCEA RPS REQUIREMENTS BY YEAR

Year	APCo RPS Requirement (%)	Year	APCo RPS Requirement (%)
2021	6	2036	53
2022	7	2037	53
2023	8	2038	57
2024	10	2039	61
2025	14	2040	65
2026	17	2041	68
2027	20	2042	71
2028	24	2043	74
2029	27	2044	77
2030	30	2045	80
2031	33	2046	84
2032	36	2047	88
2033	39	2048	92
2034	42	2049	96
2035	45	2050 and thereafter	100%

2. Development of Virginia domiciled solar and wind resources. APCo is required to petition the Commission for 600 MW solar or wind resources by December 31, 2030, with interim targets beginning December 31, 2023; 35% of those resources are required to be contracted via PPA. The Company is using nameplate capacity to determine compliance with these requirements.

[2] Appalachian is a "Phase I" utility as defined in Section 56.585.1. A.1. of the Code of Virginia. As such, this report will refer to the requirements in the VCEA that only apply to Appalachian.

3. Development of Energy Storage resources. By December 31, 2035, the VCEA requires APCo to have petitioned the Commission for necessary approvals to construct or acquire 400 MW of energy storage capacity, or more with Commission approval. These resources must meet the same 35% PPA requirement that applies to the Virginia domiciled solar and wind resources. Further, 10% of the battery installations are required to be behind the meter (BTM) installations.

   The Commission opened Case No. PUR-2020-00120 to establish rules and regulations for the required addition of storage and subsequently issued regulations to determine the appropriate timing of storage additions on December 18, 2020. The Company is working to identify the preferred location and size of storage resources, and will issue an RFP in 2022 for storage resources. See Table 7 for those interim storage addition minimums[3].

TABLE 7: VCEA REQUIRED STORAGE ADDITIONS

Date	New Storage Additions (MW)	Cumulative Storage Additions (MW)
12-31-2025	25	25
12-31-2030	125	150
12-31-2035	250	400

4. Energy Efficiency requirement. APCo must implement energy efficiency measures that achieve energy savings equivalent to at least 2% of the Company's 2019 retail sales by 2025. The VCEA also specifies that the Commission shall establish new EE requirements for the period of 2026 to 2028, and for every three year period thereafter. Due to the uncertain nature of any future proceeding regarding the efficacy or cost-effectiveness of additional EE, the amount of EE requirements set by the Commission was assumed to remain constant beyond 2025, with any additional EE in future years only being selected for economic purposes.

[3] Order for Notice and Comment, *Commonwealth of Virginia, ex rel., State Corporation Commission Ex Parte: In the matter of establishing rules and regulations pursuant to §56-585.5 E 5 of the Code of Virginia related to the deployment of energy storage*, Case No. PUR-2020-00120, Doc. Con. Cen. No. 200910238 (Sept. 11, 2020).

2.1.1 Commission Filing Requirements

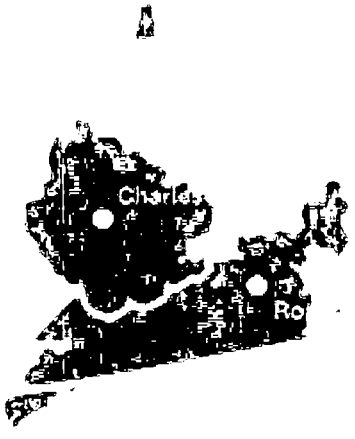
In the Attachment to its July 10, 2020 *Order Establishing 2020 RPS Proceedings*, the Commission set forth certain filing requirements. In addition, in the Order on the 2020 Filing, the Commission imposed certain requirements for this 2021 VCEA filing. The requirements of each of these orders, along with a description of where they are addressed in this report, are contained in Appendix E.

3.0 APCo Company Summary and Assumptions Overview

3.1 Overview of APCo

APCo's customers are retail and sales-for-resale (wholesale) customers located in the states of Virginia, West Virginia and Tennessee (see Figure 1). Currently, APCo serves nearly 1 million customers, with nearly 540,000 of those customers being in Virginia. The peak load requirement of APCo's total retail and wholesale customers is seasonal in nature, with distinctive peaks occurring in the summer and winter seasons. APCo's all-time highest recorded peak demand was 8,708 MW, which occurred in February 2015, and the highest recorded summer peak was 6,755 MW, which occurred in August 2007. The most recent (summer 2021 and winter 2020/21) actual APCo summer and winter peak demands were 5,348 MW and 5,975 MW, occurring on August 24, 2021 and February 8, 2021, respectively.

FIGURE 1: APCO'S SERVICE TERRITORY



3.2 APCo's existing resources

APCo serves its customers through owned generation resources and PPAs for renewable resources. See Table 8 and Table 9 for a summary of these owned and contracted resources, respectively.

TABLE 8: APCO OWNED GENERATION RESOURCES

Plant	Capacity [MW[1]]	No. of Units	Location	Fuel	First Unit Commissioned	Retirement Date
John E. Amos	2930	3	Winfield, WV	Coal	1971	2040*
Mountaineer	1305	1	New Haven, WV	Coal	1980	2040
Ceredo	450	6	Ceredo, WV	Natural Gas	2001	2041
Clinch River	455	2	Carbo, VA	Natural Gas	1958	2025
Dresden	570	3	Dresden, OH	Natural Gas	2012	2047
Buck	1.5	3	Ivanhoe, VA	Hydro	1912	2024
Byllesby	4.2	4	Byllesby, VA	Hydro	1912	2024
Claytor	75.5	4	Radford, VA	Hydro	1939	2041
Leesville	50	2	Leesville, VA	Hydro	1964	2040
London	6.5	3	Montgomery, WV	Hydro	1935	2044
Marmet	5.8	3	Marmet, WV	Hydro	1935	2044
Niagara	2.4	2	Roanoke, VA	Hydro	1906	2024
Smith Mountain	585	5	Penhook, VA	Hydro	1965	2040
Winfield	10	3	Winfield, WV	Hydro	1938	2044
TOTAL	**1310.9**	**32**				

[1] Nameplate rating. For capacity planning purposes, PJM UCAP ratings are used.

*Retirement date for planning purposes. May differ from retirement dates for depreciation purposes

TABLE 9: APCO CONTRACTED GENERATION RESOURCES

Facility	Nameplate Capacity MW	State	Resource Type	Contract Expiration
Ohio Valley Electric Corporation	332	Ohio	Coal	2040
Summersville I and II	80	West Virginia	Hydro	2027
Bluff Point	120	Indiana	Wind	2037
Camp Grove	75	Illinois	Wind	2028
Beech Ridge	101	West Virginia	Wind	2030
Fowler Ridge III	99	Indiana	Wind	2029
Grand Ridge II and III	101	Illinois	Wind	2029
Depot Solar	15	Virginia	Solar	2041
Wytheville*	20	Virginia	Solar	2036
Leatherwood*	20	Virginia	Solar	2036
TOTAL	**963**			
*Behind the Meter Resources				

3.3 Key Modeling Assumptions

Key assumptions included in the VCEA Plan

1. Appalachian Power operates in both Virginia and West Virginia and is subject to regulation in both states, with resource acquisition determinations made by regulators

in both states and resource costs allocated between the jurisdictions. The Company assumes, for the purposes of this Plan, that all of the specific resources in Table 4 will be approved by both Virginia and West Virginia. Subsequent renewable resources will accrue entirely to Virginia retail customers. There is not currently a renewable portfolio standard in place in West Virginia.

2. The Company's base case assumption is that Amos and Mountaineer coal-fired plants will run through 2040 consistent with the WVPSC's order in Case No. 20-1040-E-CN. After 2040, the Company has assumed, in the VCEA Plan, that capacity shortfalls will be met with a combination of renewable generators and energy storage. In other cases where the Company modeled fossil additions for informational purposes, it is understood that those resources would necessarily be located outside of Virginia.
3. The Company will sell the REC bank that it accumulated through the end of the Voluntary RPS in 2020 during 2021 for the benefit of customers that were subject to the voluntary RPS. As a consequence, the Company's starting REC position for the VCEA is zero.
4. RECs were made available to the Plexos® model as a resource option that could be selected if they were a less costly VCEA compliance option than other renewable resources, based on an assumed REC price curve. Projected RECs in excess of any one year's VCEA energy requirement were assumed to be sold the following year in order to reduce overall compliance costs.
5. Any capacity additions resulting in excess capacity above the Company's minimum PJM UCAP capacity requirement were modeled to be sold to either the PJM capacity market or to a third party under a bilateral purchased power agreement beginning in 2026, at the Company's fundamental PJM capacity price forecast.
6. The Company's existing renewable resources are contributing to the VCEA renewable energy goals. Existing renewable resources are allocated based on the ratio of APCo Virginia retail load (including Public Authority and Commonwealth customers) to total company load, which is estimated to be 50.1%. Existing contracts are modeled as ending on their expiration date and are not expected to be renewed.

3.4 APCo Load Forecast

The APCo load forecast was developed by the American Electric Power Service Corporation (AEPSC) Economic Forecasting organization and completed in June 2021.[4] The load forecast is the culmination of a series of underlying forecasts that build upon each other. The economic forecast provided by Moody's Analytics is used to develop the customer forecast,

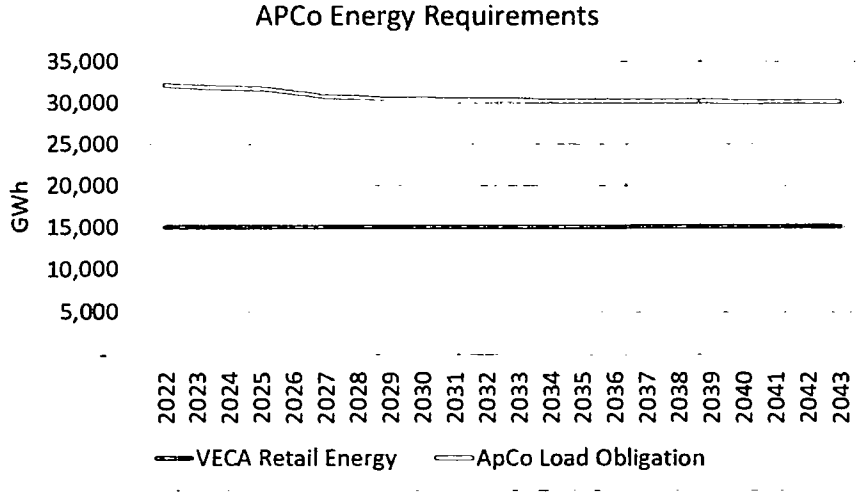
[4] The load forecasts (as well as the historical loads) integral to this Plan reflect the traditional concept of internal load, i.e., the load that is directly connected to the utility's transmission and distribution system and that is provided with bundled generation and transmission service by the utility. Such load serves as the starting point for the load forecasts used for generation planning. Internal load is a subset of *connected load*, which also includes directly connected load for which the utility serves only as a transmission provider. Connected load serves as the starting point for the load forecasts used for transmission planning.

which is then used to develop the sales forecast, which is ultimately used to develop the peak load and internal energy requirements forecast.

Over the next 15-year period (2022-2036),[5] APCo's service territory is expected to see population to decline at 0.3% per year and non-farm employment growth 0.3% per year, and APCo is projected to see its customer count decline by 0.1% over this period. Over the same forecast period, APCo's retail sales are projected to decline at 0.2% per year, with growth expected from the industrial class (+0.2% per year) while the residential class is projected to decline at a compounded annual growth rate (CAGR) of 0.4% per year. Finally, APCo's internal energy is expected to decline by 0.4% per year and peak demand is expected to decline by 0.6% per year through 2036. For this forecast, it has been assumed that APCo's current wholesale customers will not renew their contracts beyond the current contract expiration dates, resulting in removal of their load from the forecast.

Figure 2 shows both the total load forecast for APCo and the Virginia retail sales applicable to the VCEA. The Company understands "retail" as defined in the Code to include the Public Authority and Commonwealth customers in Virginia, for the purposes of determining VCEA RPS requirements. These forecasted retail sales along with the annual VCEA energy targets provided a key input into the development of the proposed VCEA Plan.

FIGURE 2: APCO ENERGY REQUIREMENTS



3.5 The Fundamentals Forecast

The Fundamentals Forecast is a long-term, weather-normalized commodity market forecast principally based upon the assumptions contained in the Energy Information Administration's Annual Energy Outlook (AEO). It is provided to AEPSC and all AEP operating companies for purposes such as resource planning, capital improvement analyses, fixed asset impairment accounting, and others. These projections cover the electricity market within the Eastern Interconnect, the Electric Reliability Council of Texas, and the Western Electricity Coordinating Council. The Fundamentals Forecast includes, among other factors: 1) hourly, monthly and annual regional power prices (in both nominal and real dollars); 2) prices for various qualities of coals; 3) monthly and annual locational natural gas prices, including the benchmark Henry Hub; 4) nuclear fuel prices; 5) SO_2, NO_x, and CO_2 burden values; 6) locational implied heat rates; 7) electric generation capacity values; 8) renewable energy subsidies; and 9) inflation factors; 10) VCEA compliance for Virginia utilities among others.

Table 10 below describes the Fundamentals Forecast components, which are sourced directly from the EIA AEO, from third party energy consultancies, or were sourced internally. As the EIA AEO does not provide the granularity for most regulatory applications, the Aurora energy market simulation model was utilized to create a reasonable proxy for the EIA AEO while providing the level of detail necessary for downstream consumption.

TABLE 10: FUNDAMENTALS FORECAST COMPONENTS

Forecast Components	EIA	Other	Source
Economy; Inflation/GDP deflators	✓		EIA Reference case
Generating Reserve Margins		✓	RTO Requirements
Electric Load		✓	AEP Load Forecasting
Electric Load shapes		✓	AEP Fundamentals
Solar/Wind production shapes by area		✓	NREL
Coal; Delivered price to EIA regions	✓	✓	EIA Reference case FOB prices + AEP Fundamentals
Natural gas price; Henry Hub	✓		EIA Reference case
Natural gas price; Locational values	✓	✓	EIA Reference case - Henry Hub + AEP Fundamentals
Natural gas supply; Lower 48 production	✓		EIA Reference case
Natural gas demand (incl. losses)	✓		EIA Reference case
Natural gas; net pipeline/LNG exports	✓		EIA Reference case
Oil price, WTI	✓		EIA Reference case
Fuel Oil price; locational values	✓	✓	EIA Reference case - WTI + AEP Fundamentals
Uranium prices		✓	AEP Fundamentals
Other Fuel(Biofuel, etc...)	✓		EIA Reference case
New gen unit options and capital costs	✓		EIA Reference case
Existing gen units	✓		EIA Reference case
Announced new gen units	✓		EIA Reference case
Aged-out retirements of existing gen units	✓		EIA Reference case
Gen unit maintenance schedule		✓	AEP Fundamentals
Gen unit outages		✓	AEP Fundamentals
Unit-level emission rates; CO_2, SO_2, NO_x		✓	US EPA CEMS data
Application of a CO_2 burden		✓	AEP Environmental
REC		✓	AEP Regulatory Forecast
PTC	✓		EIA Reference case
ITC	✓		EIA Reference case
State-mandated Renewable Portfolio Standards		✓	AEP Environmental
Reporting parameters; Peak/Off-Peak/NERC Holidays		✓	PJM/SPP/other RTO and/or internal guidelines
Transmission/links between Zones		✓	AEP Fundamentals

The Fundamentals Forecasts incorporates requirements of the Virginia Clean Energy Act and the Regional Greenhouse Gas Initiative (RGGI) for both APCo and Dominion:

- Including Virginia in the RGGI, applying RGGI CO_2 prices through 2027 before switching to an assumption of a higher $15/metric ton national standard in 2028
- Applying the Virginia RPS program to Phase I and Phase II utilities within the state
- Retiring all fossil units named in the VCEA law by stated retirement dates
- Retiring all remaining Phase I fossil units by 2050 and Phase II fossil units by 2045
- Including the resource additions required for Dominion under the VCEA based upon the Company's understanding of those requirements

The Aurora model iteratively generates zonal, but not company-specific, long-term capacity expansion plans, annual energy dispatch, fuel burns and emission totals from inputs including fuel, load, emissions, and capital costs, among others. Ultimately, Aurora creates a weather-normalized, long-term forecast of the market in which a utility would be operating. AEPSC also has ample energy market research information available for its reference, which includes third-party consultants, industry groups, governmental agencies, trade press, investment community, AEP-internal expertise, various stakeholders, and others. The Aurora model is widely used by utilities for integrated resource and transmission planning, power cost analysis

and detailed generator evaluation. The database includes approximately 25,000 electric generating facilities in the contiguous United States, Canada, and Baja Mexico. These generating facilities include wind, solar, biomass, nuclear, coal, natural gas, and oil. A licensed online data provider, ABB Velocity Suite, provides up-to-date information on markets, entities and transactions along with the operating characteristics of each generating facility, which are subsequently exported to the Aurora model.

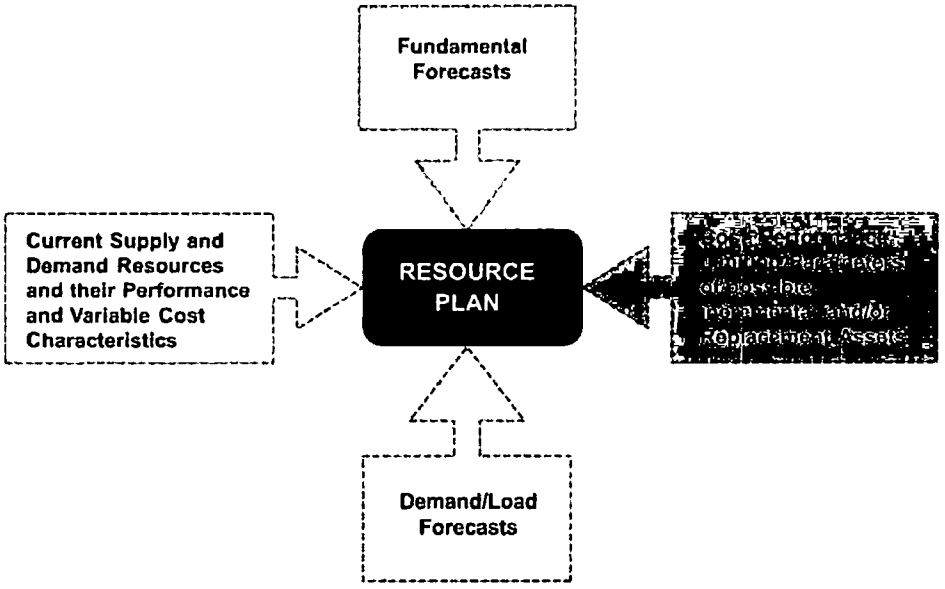
The annual results from each scenario developed are shown in Appendix A and include on-peak and off-peak energy prices, natural gas prices, coal prices, CO_2 prices and capacity prices.

3.6 Determining Compliant VCEA Plans

For the purposes of modeling compliance with the VCEA, APCo used a process nearly identical to its typical IRP process, which used the Plexos® model to address the gap between resource needs and current resources, while also including minimums related to the requirements established under the VCEA for energy from renewable resources, energy savings from energy efficiency resources and capacity from energy storage resources.

Given the cost and performance parameters around sets of potentially available proxy resources–both supply and demand side–and a scenario of economic conditions that include long-term fuel prices, capacity costs, energy costs, emission-based pricing proxies including CO_2, as well as projections of energy usage and peak demand, Plexos® will return the optimal suite of proxy resources (portfolio) that meet the resource need. Portfolios created under similar pricing scenarios may be ranked on the basis of cost, or the net present value of the resulting stream of revenue requirements. The least cost option is considered the optimum portfolio for that unique input parameter scenario.

FIGURE 3: RESOURCE PLANNING DIAGRAM



4.0 Supply- and Demand-side Resource Options

Supply-side resource options including natural gas base/intermediate and peaking generating technologies and intermittent renewable resources including large-scale solar, wind and battery storage were selectively made available in different scenarios to develop compliant plans.[6] To reduce the computational problem size within Plexos®, the number of alternatives explicitly modeled was reduced through an economic screening process that analyzed various supply options and developed a quantitative comparison levelized over technologies life cycle. It is important to note that alternative technologies with comparable cost and performance characteristics, subject to limitations included in Section 56-585.5, can ultimately be substituted, should technological or market-based profile changes warrant.

Table 11 includes a summary of the technologies made available to the model, depending upon scenario, and their associated performance parameters. These generation technologies were intended to represent reasonable proxies for each capacity type (base-load, intermediate, peaking). Subsequent substitution of specific technologies could occur in any later plan, based on emerging economic or non-economic factors not yet identified.

Other generation resource technologies were not made available to Plexos® due to their respective costs, and to improve modeling process time. Technologies such as natural gas resources with carbon capture and storage, hydrogen-capable combustion turbines, long duration storage, and small modular nuclear reactors were evaluated and found not to be competitive on cost when compared to the resource types shown in Table 11 which were made available to Plexos®, APCo will continue to monitor developments in these and other technologies and including cost, availability, and the availability of federal tax credits, which could make these resources more attractive options in the future.

[6] The Company referred to the EIA ANNUAL ENERGY OUTLOOK 2020 report (https://www.eia.gov/outlooks/aeo/pdf/aeo2020.pdf) and the associated EIA Capital Cost and Performance Characteristic Estimate for Utility Scale Electric Power Generating Technologies (https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf) to inform the analysis process.

TABLE 11: GENERATION TECHNOLOGY OPTIONS (2021$)

AEP System

New Generation Technologies

Key Supply-Side Resource Option Assumptions (a)(b)(d)

Type	Capability (MW) (e) Std. ISO	Summer	Winter	Installed Cost (d,f) ($/kW)	Capacity Factor (%)	LCOE (g) ($/MWh)
Base Load						
COMB TURBINE H CLASS, 1100-MW COMBINED CYCLE (c)	1,030	1,010	1,070	1,100	75	55.5
COMB TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT, 430 MW (c)	420	410	440	1,200	75	58.9
Peaking						
COMB TURBINE F CLASS, 240-MW SIMPLE CYCLE (c)	230	230	250	800	25	95.0
COMB TURBINES AERODERIVATIVE, 100-MW SIMPLE CYCLE (c)	110	100	110	1,300	25	128.4
INTERNAL COMBUSTION ENGINES, 20 MW (c)	20	20	20	2,100	25	173.9
Intermittent						
BATTERY ENERGY STORAGE SYSTEM, 50 MW / 200 MWH (c)	50	50	50	1,472	25	156.7
SOLAR PHOTOVOLTAIC WITH BATTERY ENERGY STORAGE SYSTEM, 150 MWx200 MWh (h)	150	150	150	2,041	20	101.7
ONSHORE WIND, LARGE PLANT FOOTPRINT, 200 MW (i)	200	200	200	1,505	35	40.3
SOLAR PHOTOVOLTAIC, 150 MWAC (h)	150	150	150	1,469	24	57.1

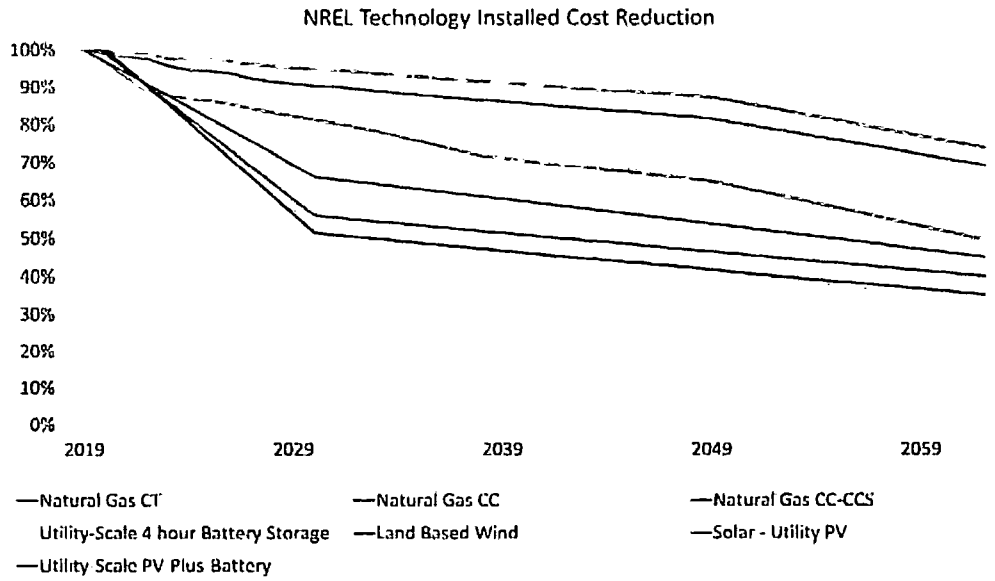
Notes:
(a) Costs and performance data informed by EIA report Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies (Feb 2020)
(b) Installed cost, capability and heat rate numbers have been rounded
(c) All costs in 2021 dollars, except as noted. Costs adjustments made based on EIA report Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2020 - Region 11 (PJMW)
(d) $/kW costs are based on summer capability
(e) All Capabilities adjusted by the Performance Adjustment Factors defined in the reference report (a)
(f) Total Plant Investment Cost w/AFUDC (AEP rate of 6.41%,site rating $/kW)
(g) Levelized cost of energy based on capacity factors shown in table
(h) Dollars are in 2023 informed by ApCo RFP
(i) Dollars are in 2023 informed by Bloomberg New Energy Finance's (BNEF) 2H 2020 U.S. Renewable Energy Market Outlook

For this analysis, the Company adopted "learning curve" forecasts published by the National Renewable Energy Laboratory (NREL) in its 2021 Annual Technology Baseline (ATB)[7] for capital costs for all resource types and for wind and solar O&M costs. The notion behind learning curve forecasts is that over time real costs will come down due to economies of scale, technology improvements, manufacturing improvements, and other factors. NREL forecasts that overnight installed capital costs will decline over time for all of these resource options. These effects of the cost reduction rates as a percentage of 2019 price are illustrated in Figure 4 and applied to the technology installed cost forecasts used in the Plexos® modeling. For a table of the overnight installed cost per technology in 2019 real dollar terms with the NREL learning rates, please see Appendix E: Overnight Installed Cost of Technologies in 2019 Real Dollars ($/kW) The Company then applied a forecasted inflation rate to these real dollar

[7] https://atb.nrel.gov/

amounts to convert them to the nominal dollars over the 30 year forecast period, for the purposes of determining the actual future installation costs for each resource type.

FIGURE 4: NREL CAPITAL COST LEARNING CURVES (2019$)



4.1 Power Purchase Agreement (PPA) Options

Consistent with the requirements in Section 56-585.5.D.4, the Plan reflects, in the aggregate and over its duration, a 35% PPA – 65% ownership split for the Virginia jurisdictional share of new Solar and Wind resources. The modeling attempted to maintain approximately this ownership to PPA ratio over a period of years, not in each individual year. In practice, the amount of PPA versus owned wind and solar added in any one year will be the result of competitive solicitations subject to regulatory approval.

PPA resource costs were informed from the results of the RFPs APCo issued in 2021. The PPA bids in response to those RFPs were on average 8% less expensive than owned asset bids. This difference was used as an initial proxy for this analysis to determine the levelized PPA costs relative to levelized owned costs for solar, wind and hybrid solar resources and are not reflective of long-term pricing differences including tax credit effects. This does not necessarily reflect the results of future RFPs and does not include other factors both explicit and implicit regarding ownership benefits. Actual owned and PPA resource costs will be identified in future solicitations for specific resources and may depend on multiple factors including federal tax policy.

4.2 Baseload & Peaking Resource Options

For Baseload resources, the Company modeled two natural gas combined cycle configurations shown in Table 11, the multi-shaft 1,100 MW resource and the single shaft, 430 MW resource. For Peaking resource options, the Company modeled the three resources including a 240 MW combustion turbine (CT), a 105 MW aero-derivative engine (AD) and a 20 MW Reciprocating Internal Combustion Engine (RICE).

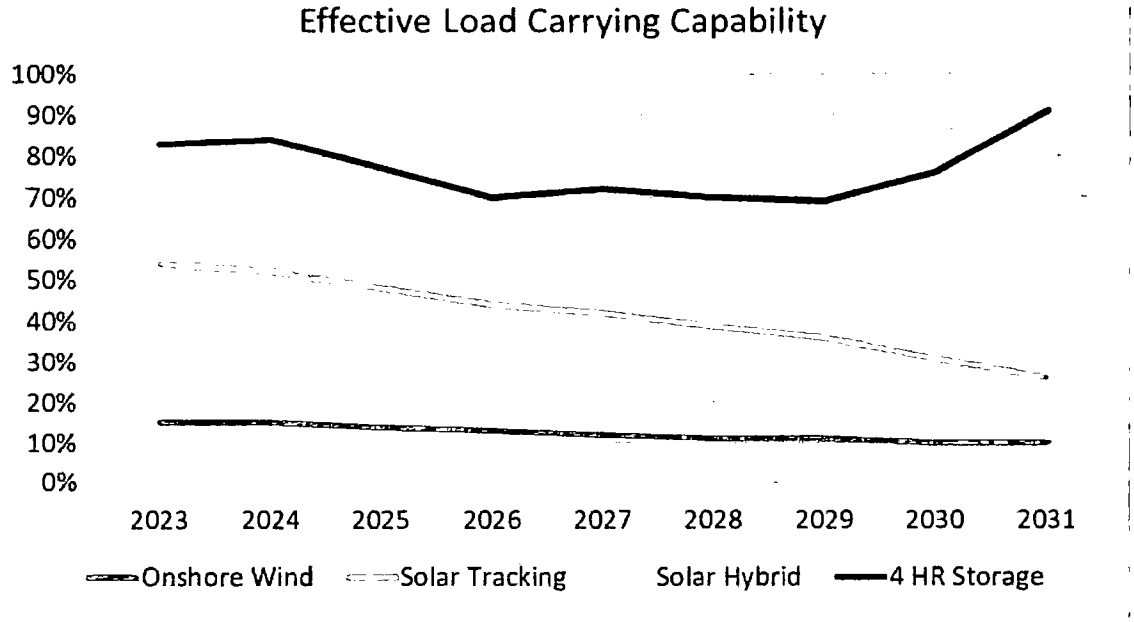
4.3 Intermittent and Renewable Resource Options

Various intermittent and renewable generating technologies were available for selection by the model, with constraints for each year equivalent to the requirements of the VCEA for Scenarios 1-4. Development of these resources continue to grow as advancements in both solar photovoltaics and wind turbine manufacturing have reduced both installed and ongoing costs.

Renewable energy resources, because of their intermittent nature, typically provide more energy value than capacity value, and PJM continues to refine its guidance on the Effective Load Carrying Capability (ELCC) for intermittent resources. In general, under the current PJM draft guidance, as intermittent resources continue to increase in relation to the total of all PJM resources, the planning capacity credit of new renewable resources added to the system will decline. The Company referred to PJM's July 2021 ELCC Report[8] to inform the plan for intermittent resource contributions to the Company's capacity obligations. A summary chart of the ELCC levels assumed in this plan is shown in Figure 5. PJM's July 2021 ELCC Report did not produce projections beyond 2031. For the Company's analysis, the 2031 ELCC values were held constant until the end of the planning horizon.

[8] https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-report-for-july-2021-results.ashx

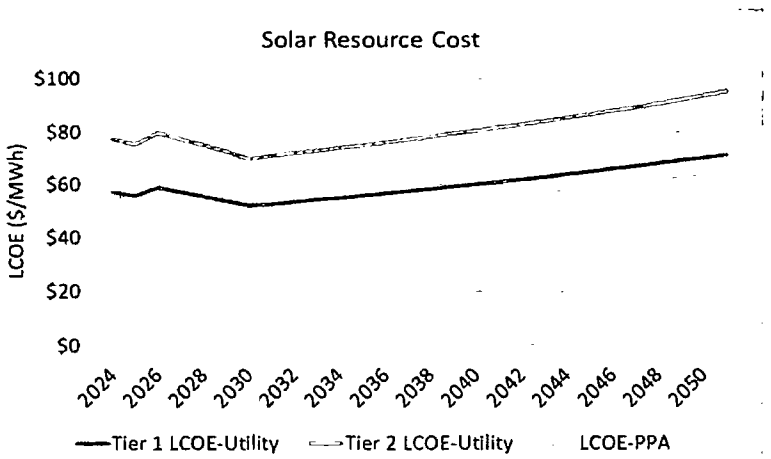
FIGURE 5: PJM EFFECTIVE LOAD CARRYING CAPABILITY (ELCC)



4.3.1 Solar

Large-scale solar resources were available starting in 2025. The Company relied on information from the RFP of owned assets for APCo to model prospective owned solar costs for assets to be placed in service in early 2025. Tier 1 build cost was based upon the top bid in the RFP and Tier 2 based upon the average of bids excluding winning bid. Figure 6 illustrates the forecasted Utility Tier 1, Tier 2, and PPA Solar levelized cost of energy (LCOE) through time. The costs included in these estimates include all costs that would be expected, including a return on rate base, depreciation, land leases, operations and maintenance expense, property taxes, insurance, asset retirement costs, and normalization of the solar investment tax credit (ITC). The property tax and land lease assumptions are tailored to this analysis based on the Company's experience with tax rates in its service territory, and from evaluating specific resources located in both Virginia and in other PJM states.

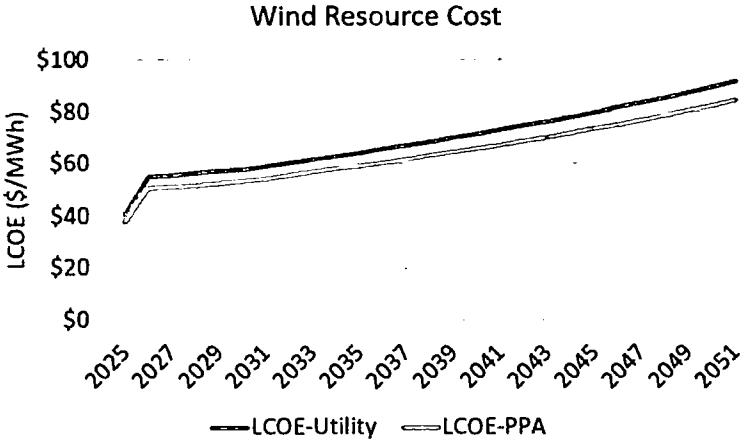
FIGURE 6: SOLAR RESOURCE LCOE



4.3.2 Large-Scale Wind

For Portfolios 1-5, the Company assumed a 35% capacity factor for the new wind resource. Additionally, the Company prepared Portfolio 6 in which the wind capacity factors were assumed to be equivalent to historical 30.4% capacity factor of APCo's existing wind resources. The build cost was based on Bloomberg New Energy Finance's (BNEF) 2H 2020 U.S. Renewable Energy Market Outlook. Figure 7 illustrates the forecasted Utility and PPA Wind LCOEs. The increase from 2025 to 2026 in this figure is due to the expiration of the currently available wind Federal production tax credits. Increases after 2026 are inflation driven.

FIGURE 7: WIND RESOURCE LCOE



4.3.3 Energy Storage

The stand-alone Energy Storage resource modeled in this plan is a Lithium-ion storage technology and has a nameplate rating of 50 MW/200 MWh, with a round trip efficiency of

82.3%. The modeling of Energy Storage utilized the values shown in Table 12, with the nameplate rating adjusted from 50 MW to 25 MW to align with the storage levels in the Commission's order regarding the interim requirements. A Storage PPA option was not modeled as separate resource from an owned storage resource, under the assumption that the cost of the solar resource included in the model represents a blend of owned and PPA. Both PPA and owned storage resources will be considered in future RFPs.

4.3.4 Hybrid Solar / Storage

Hybrid Solar systems include a Solar PV plant with a 4 hour closed loop battery storage system associated with it. For this analysis, a 150 MW_{ac} solar plant was modeled, coupled with a 50 MW (200 MWh) Li-Ion Battery Energy Storage system.

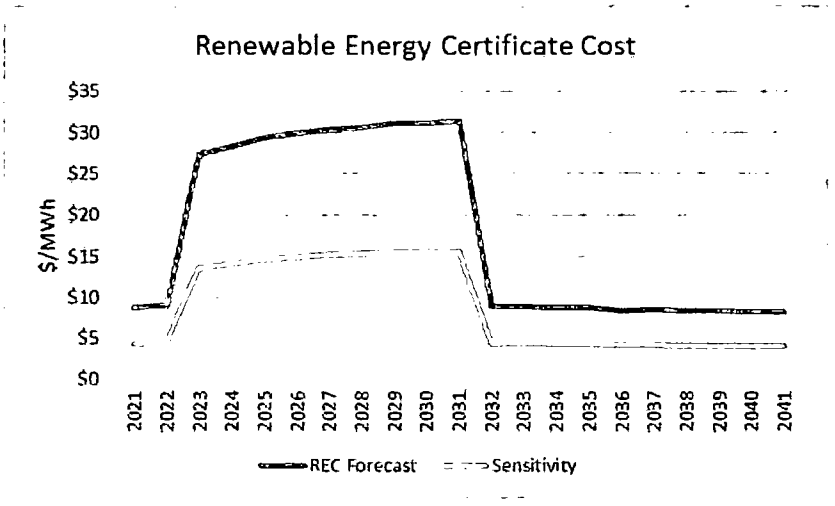
4.3.5 Renewable Energy Certificates (RECs)

The Company included RECs as a RPS energy compliance option in the Plexos® modeling, allowing the model to choose whether to build physical resources or purchase RECs based on economics. In this analysis a 150 MW block of utility solar with an assumed ~350 GWh set the size for a single REC addition in the model. The first year when RECs could be added was assumed to be 2025. A third party forecast provided by S&P Global[9], as shown in Figure 8, was used for the base REC price forecast in all portfolios. The number of RECs selected by the model in each portfolio is presented in Appendix B. Higher and lower priced REC sensitivity cases were also prepared.

A lower priced REC sensitivity case was also prepared, based on an assumption that RECs would be available of 50% of the cost of the base REC forecast curve. That price curve is also shown in Figure 8. The results of that sensitivity analysis are presented in Section 5.

[9] S&P Global, SPGlobalMI_RECForecast_2021Q2_06302031, available by subscription.

FIGURE 8: REC PRICE FORECAST



4.3.6 Annual and Cumulative Resource Limits

For each portfolio, annual and cumulative intermittent and renewable resource limits were determined based on simultaneous consideration of multiple regulatory requirements. All six portfolios are VCEA-compliant. Different limits were necessarily applied to each portfolio based on the unique assumptions of each portfolio, such as the assumed retirement date of Amos and Mountaineer, as well as whether gas-fired options were available. Table 12 contains a summary of the limits for the wind, solar, storage, and REC options included in the modeling for each portfolio.

TABLE 12: NEW RESOURCE LIMITATIONS

New Resource Assumptions							
Resource Type	**First Year Available**	**Life**	**Portfolio 1,2,6**	**Portfolio 3 &4**	**Portfolio 5**	**Individual Technology Total**	**Cumulative Technology Total**
Solar PPA	1/1/2025	35 years	150 MW/yr	300 MW/yr	150 MW/yr	900 MW	3,150 MW
Solar Utility T1		35 years	300 MW/yr	600 MW/yr	300 MW/yr	2,100 MW	
Solar Utility T2		35 years	150 MW/yr	300 MW/yr	150 MW/yr		
Solar Hybrid		35 years	150 MW Block 450 MW/yr			1,050 MW	
Wind PPA Limits	1/1/2026	30 years	100 MW/yr	300 MW/yr	100 MW/yr	350 MW Total	950 MW
Wind Owned Limits	1/1/2026	30 years	200 MW/yr	600 MW/yr	-	600 MW Total	
Wind Owned Limits	1/1/2026	30 years	- - - - -	- - - - -	2026 1,200 MW 2028 2,600 MW 2030 3,600 MW 2032 4,600 MW 2035 5,000 MW	5,000 MW Total	5,350 MW
Renewable Energy Certificates	1/1/2025	5 years	20 Blocks/yr			~7,000 GWh	~7,000 GWh
Stand Alone Storage	1/1/2025	10 years	2,500 MW/yr			12,500 MW	12,500 MW
NG 240 MW Combustion Turbine	1/1/2026	30 years	P1 unlimited P2 N/A	P3 unlimited P4 N/A	N/A	Unlimited	Unlimited
NG 1,100 MW Combined Cycle	1/1/2026	30 years	P1 unlimited P2 N/A	P3 unlimited P4 N/A	N/A	Unlimited	Unlimited

The primary regulatory constraints considered in setting the annual and cumulative resource limits were 1) PJM minimum capacity requirements; 2) VCEA annual Virginia-jurisdictional renewable energy targets; 3) VCEA 35% wind and solar PPA requirements; and 4) near term (prior to 2030) VCEA wind, solar, and storage new resource requirements. All of these constraints must be applied simultaneously. Compliance with the minimum obligations under any one of these requirements, such as the VCEA annual energy targets, could and did lead to substantial over-compliance with other requirements, such as PJM's minimum capacity requirement, in some portfolios. In addition, to the extent possible, the Company spread out resource additions gradually over time, rather than all at once, to help mitigate near-term rate increases that can result from adding required resources. This can result in the addition of resources earlier than the year in which one of these regulatory obligations requires them. Finally, there are practical limits regarding the absolute levels of cost-effective renewable capacity that are available in Virginia and more broadly across PJM.

The timing of the assumed retirement of Amos and Mountaineer also impacted the resource limitations. This resulted in higher annual wind and solar limits in Portfolios 3 and 4 than in Portfolios 1 and 2 in order to allow more resources to be constructed during the period prior to Amos and Mountaineer retiring in 2028. This constraint also resulted in a high annual limit for storage resources in all portfolios in order to allow enough storage to be selected for its capacity to replace a substantial share of the capacity that would be lost when Amos and

Mountaineer retire. This also drives a high cumulative lifetime storage limit, if storage is selected again at the end of its 10-year useful life, if the model deemed it to be the most economic option available.

Lastly, the near-term availability of Virginia domiciled wind and solar resources was considered. Based on the numbers of bids received of each resource type in the two RFP's issued in 2021, solar resources are expected to be more widely available than wind, and the quantity of wind MW available in Virginia could be quite limited. As a result, higher limits were allowed for solar than wind.

By choosing these limits for the various scenarios, the Company is not expressing an opinion regarding whether these levels of resources are in fact available, or whether adding that level of a given resource is desired. The assumption that 2,500 MW of storage could be added to a Company the size of APCo in any one year, or even cumulatively prior to 2030, is particularly aggressive. These limits are simply an attempt to give the model enough available capacity and energy options to meet the necessary PJM and VCEA requirements in all years of the analysis from a portfolio of all of the available resource types under each scenario.

4.4 Demand-Side Resource Options

4.4.1 Energy Efficiency

The Company included both Residential and Commercial/Industrial energy efficiency bundles as demand-side resource options to consider. Table 13 shows the Residential Bundles cost and potential by year, and Table 14 shows the Commercial/Industrial Bundles included in the model.

TABLE 13: RESIDENTIAL EE BUNDLES

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2022-2026	Yearly Potential Savings (MWh) 2027-2031	Yearly Potential Savings (MWh) 2032-2036	Yearly Potential Savings (MWh) 2037-2041	Bundle Life
Thermal Shell - AP	$0.21	6,621	2,794	3,120	2,824	10
Thermal Shell - HAP	$0.31	20,514	54	0	0	10
Heating/Cooling - AP	$0.68	49,323	7,365	0	0	18
Heating/Cooling - HAP	$0.96	7,576	0	0	0	18
Water Heating - AP	$0.24	34,877	11,711	13,000	6,265	14
Water Heating - HAP	$0.35	82,827	10,498	10,391	0	14
Appliances - AP	$0.22	33,242	3,018	3,133	2,460	13
Appliances - HAP	$0.31	7,449	0	0	0	13
Lighting - AP	$0.08	1,669	0	0	0	31
Lighting - HAP	$0.13	1,103	0	0	0	30
Behavioral Programs	$0.04	23,137	0	0	0	2

TABLE 14: COMMERCIAL EE BUNDLES

Bundle	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2022-2026	Yearly Potential Savings (MWh) 2027-2031	Yearly Potential Savings (MWh) 2032-2036	Yearly Potential Savings (MWh) 2037-2041	Bundle Life
Heat Pump - AP	$9.00	2,985	0	0	0	15
Heat Pump - HAP	$13.49	199	0	0	0	15
HVAC Equipment - AP	$0.16	2,718	0	0	0	15
HVAC Equipment - HAP	$0.24	1,624	0	0	0	15
Indoor Screw-In Lighting - AP	$0.01	2,345	0	0	0	6
Indoor Screw-In Lighting - HAP	$0.02	995	0	0	0	6
Indoor HID/Fluor. Lighting - AP	$0.11	15,646	1,409	0	0	14
Indoor HID/Fluor. Lighting - HAP	$0.16	1,738	0	0	0	14
Outdoor Lighting - AP	$0.38	3,946	567	0	0	15
Outdoor Lighting - HAP	$0.57	4,384	0	0	0	15

4.4.2 Demand Response

The Company included one Demand Response resource option to be considered, which is based on a Residential Bring-Your-Own-Thermostat program. Table 15 shows the characteristics of this resource.

TABLE 15: APCO DEMAND RESPONSE

Sector	Participants	Demand Savings (kW)	Energy Savings (kWh)	Enrollment Cost	Annual Cost	Total First Year Cost	Service Life (Years)
Residential	2,500	3,375	70,000	$165,000	$950,500	$1,115,500	7

4.4.3 Volt VAR Optimization

The Company included Volt VAR Optimization (VVO), which represents a form of voltage control that allows the grid to operate more efficiently as a resource option. VVO sensors and intelligent controllers monitor load flow characteristics and direct controls on capacitor and voltage regulating equipment in order to optimize power factor and voltage levels. Power factor is the ratio of real or active power (MW) to apparent power (MVA), and is a characteristic of electric power flow that is controlled to optimize power flow on an electric network. Power factor optimization also improves energy efficiency by reducing losses on the system. VVO enables Conservation Voltage Reduction (CVR) on a utility's system. CVR is a process by which the utility systematically reduces voltages in its distribution network, resulting in a proportional reduction of load on the network. Voltage optimization can allow a reduction of system voltage that still maintains minimum levels needed by customers, thereby allowing customers to use less energy without any changes in behavior or appliance efficiencies.

Although there are no "embedded" incremental VVO load reduction impacts implicit in the load forecast, VVO has been modeled as a unique EE resource. Table 16 below shows the resource characteristics of the VVO resources made available to the model in all portfolios.

TABLE 16: VVO RESOURCES

Tranche	No. of Circuits	Capital Investment	Annual O&M	Demand Reduction (kW)	Energy Reduction (MWh)
1	36	$12,600,000	$378,000	11,172	45,996
2	36	$12,600,000	$378,000	9,639	39,684
3	36	$12,600,000	$378,000	8,799	36,227
4	36	$12,600,000	$378,000	8,298	34,163
5	36	$12,600,000	$378,000	7,826	32,222
6	36	$12,600,000	$378,000	7,458	30,705
7	36	$12,600,000	$378,000	7,126	29,340
8	36	$12,600,000	$378,000	6,884	28,343
9	36	$12,600,000	$378,000	6,629	27,292
10	36	$12,600,000	$378,000	6,435	26,493
11	36	$12,600,000	$378,000	6,186	25,470
12	36	$12,600,000	$378,000	5,909	24,329
13	36	$12,600,000	$378,000	5,849	24,081
14	36	$12,600,000	$378,000	5,473	22,532

4.4.4 Distributed Generation

The Company included both the capacity and energy associated with Distributed Generation in all six portfolios. Figure 9 shows the cumulative nameplate DG MW forecasted to be installed. For capacity planning purposes, the Company referred to the PJM ELCC report discussed in Section 4.3, beginning at 38% of the nameplate value in 2023. The associated energy produced from this customer-owned DG was assumed to not be part of the Company's achievement of the VCEA RPS requirement.

Attachment 46

Electricity Data Browser

Explore the new Beta version with expanded plant level data for water cooling and emissions.

Change data set

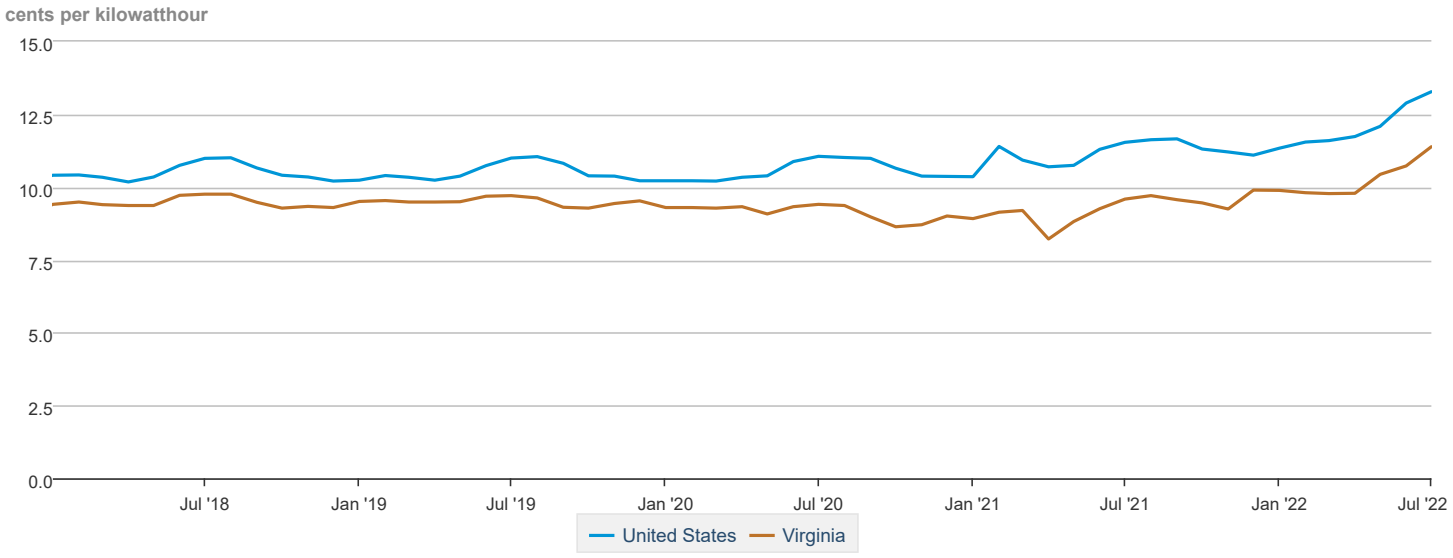
Average retail price of electricity

OR

View a pre-generated report

Choose a report

Average retail price of electricity, monthly



Data source: U.S. Energy Information Administration

CHART INDEXING OPTIONS: None | Index to start as percent | Index to start as value

Change data set

Average retail price of electricity

OR

View a pre-generated report

Choose a report

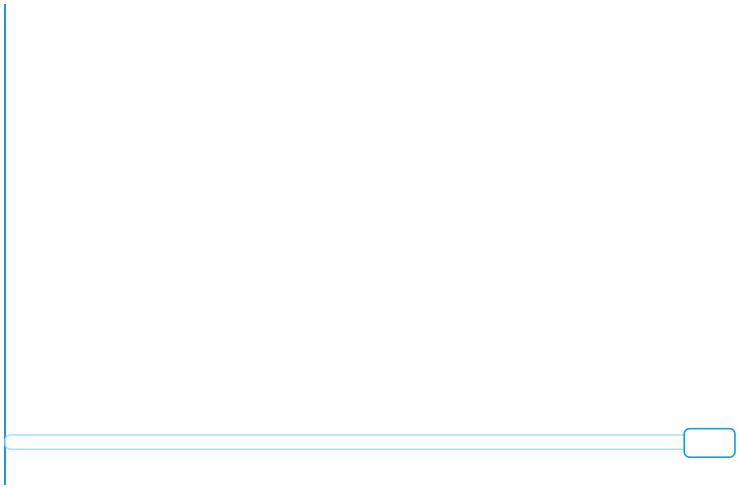
FILTER/ORDER | ANALYSIS | Time-series | Column | Map | HELP | DOWNLOAD

Pin | API

Jan 2018 — Jul 2022

Annual | Quarterly | Monthly

	Apr 2022	May 2022	Jun 2022	Jul 2022
Average retail price of electricity (cents per kilowatthour)				
All sectors				
United States	11.74	12.09	12.89	13.28
South Atlantic				
Virginia	9.79	10.44	10.73	11.39



NM = Not meaningful due to large relative standard error. Show relative standard errors expressed as percent in parenthesis: ☐

Terms and definitions

Attachment 47

220510071

Virginia State Corporation Commission
eFiling CASE Document Cover Sheet

Case Number (if already assigned)	PUR-2022-00070
Case Name (if known)	Petition of Virginia Electric and Power Company for authority to suspend a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia and for alternate recovery mechanism of certain compliance costs
Document Type	APLA
Document Description Summary	Petition of Virginia Electric and Power Company
Total Number of Pages	10
Submission ID	24762
eFiling Date Stamp	5/5/2022 10:07:31AM

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May 5, 2022

BY ELECTRONIC DELIVERY

Mr. Bernard Logan, Clerk
State Corporation Commission
c/o Document Control Center
Tyler Building – First Floor
1300 East Main Street
Richmond, Virginia 23219

Petition of Virginia Electric and Power Company for authority to suspend a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia and for alternate recovery mechanism of certain compliance costs
Case No. PUR-2022-00070

Dear Mr. Logan:

Please find enclosed for electronic filing in the above-captioned proceeding the *Petition of Virginia Electric and Power Company for authority to suspend a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia and for alternate recovery mechanism of certain compliance costs.*

Please do not hesitate to contact me if you have any questions in regard to the enclosed.

Highest regards,

/s/ Elaine S. Ryan

Elaine S. Ryan

Enclosures

cc: William H. Chambliss, Esq.
C. Meade Browder, Jr., Esq.
Paul E. Pfeffer, Esq.
David J. DePippo, Esq.
Joseph K. Reid, III, Esq.
Timothy D. Patterson, Esq.

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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PETITION OF	)	
	)	
VIRGINIA ELECTRIC AND POWER COMPANY	)	
	)	Case No. PUR-2022-00070
For authority to suspend a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia, and for alternate recovery mechanism of certain compliance costs	)	

PETITION OF VIRGINIA ELECTRIC AND POWER COMPANY FOR SUSPENSION OF RIDER RGGI AND FOR ALTERNATE RECOVERY MECHANISM OF CERTAIN COMPLIANCE COSTS

Pursuant to § 56-585.1 A 5 e ("Subsection A 5 e") of the Code of Virginia ("Va. Code") and Rule 5 VAC 5-20-80 of the State Corporation Commission of Virginia's ("Commission") Rules of Practice and Procedure, Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company"), by counsel, hereby petitions the Commission to suspend effective July 1, 2022, its rate adjustment clause ("RAC" or "Rider"), designated Rider RGGI, that was approved in Case No. PUR-2020-00169 to recover costs related to the purchase of allowances through the Regional Greenhouse Gas Initiative ("RGGI") market-based trading program for carbon dioxide ("CO_2") emissions.[1] Further, the Company proposes that RGGI compliance costs incurred up through July 31, 2022, which are not actually recovered prior to the suspension of the Rider, be alternatively recovered through the utility's rates for generation services (base rates) in effect during the period incurred. The Company's petition ("Petition") is driven by the anticipated withdrawal of the Commonwealth from the RGGI program and the interests of its

[1] *Petition of Virginia Electric and Power Company For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia,* Case No PUR-2020-00169, Order Approving Rate Adjustment Clause at 11 (Aug. 4, 2021); Order on Reconsideration at 2 (Nov. 17, 2021).

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customers in reducing RAC-related charges. In support of its Petition, the Company respectfully shows as follows:

GENERAL INFORMATION

1. Dominion Energy Virginia is a public service corporation organized under the laws of the Commonwealth of Virginia furnishing electric service to the public within its certificated service territory. The Company also supplies electric service to non-jurisdictional customers in Virginia and to the public in portions of North Carolina. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public for compensation. The Company is also a public utility under the Federal Power Act, and certain of its operations are subject to the jurisdiction of the Federal Energy Regulatory Commission. The Company is an operating subsidiary of Dominion Energy, Inc.

2. The Company's address is:

Virginia Electric and Power Company
120 Tredegar Street
Richmond, Virginia 23219

3. The names, addresses, and telephone numbers of the attorneys for the Company are:

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BACKGROUND

4. RGGI is a regional multi-state market-based program designed to impact CO_2 emissions from the power sector under which CO_2 emission allowances are obtained by covered power generators through quarterly auctions. Member states participate voluntarily in the program, and Virginia has been a participating state in the RGGI program since January 1, 2021.

5. In May 2019, the Virginia Department of Environmental Quality ("DEQ") issued a final rule establishing a state carbon regulation program facilitating participation in RGGI (the "DEQ Carbon Rule" or "Rule"). The DEQ Carbon Rule capped CO_2 emissions for Virginia at 27.1 million short tons for calendar year 2021 and decreases the emissions cap annually by approximately 3%. Emission sources subject to the Rule are required to obtain and surrender a CO_2 emission allowance for every short ton of CO_2 emitted during a control period.

6. The Company owns regulated emissions sources, so it must comply with RGGI as long as Virginia participates in the program.

7. Va. Code § 56-585.1 A 5 e permits cost recovery related to compliance with RGGI through an approved RAC pursuant to this subdivision. The recovery of RGGI compliance costs through a RAC is at the utility's election. On August 4, 2021, in Case No. PUR-2020-00169 ("2020 Rider RGGI Proceeding"), the Commission issued its Order Approving Rate Adjustment Clause ("Rider RGGI Order"), approving Rider RGGI to be effective for usage on and after September 1, 2021.[2] The Rider RGGI Order approved the recovery of compliance

[2] *Petition of Virginia Electric and Power Company For approval of a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia*, Case No PUR-2020-00169, Order Approving Rate Adjustment Clause at 11 (Aug. 4, 2021) (the "2020 Rider RGGI Proceeding").

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costs projected for the period January 1, 2021 (the initial compliance obligation date) through July 31, 2022. The establishment of Rider RGGI increased the monthly bill of a residential customer using 1,000 kilowatt-hours per month by approximately $2.39.[3]

8. Subsequently, the Commission suspended the Rider RGGI Order on August 25, 2021, pending consideration of a Petition for Reconsideration or Clarification. On November 17, 2021, by its Order on Reconsideration, the Commission lifted the suspension of the Rider RGGI Order without modification of its initial order. On November 29, 2021, Appalachian Voices filed a Notice of Appeal, and the case is currently pending before the Supreme Court of Virginia.

9. On December 6, 2021, the Company filed its first annual update filing in Case No. PUR-2021-00281, in which the Company requested a revenue requirement of $323,411,000 for a Rate Year beginning September 1, 2022.[4] As proposed, this update filing would have increased the monthly bill of a residential customer using 1,000 kilowatt-hours per month by an additional $1.98, for a total Rider RGGI bill impact on the typical bill of a residential customer of $4.37.

10. On December 8, 2021, then-Governor-elect Glenn Youngkin announced that he intended to withdraw Virginia from RGGI. Due to uncertainty surrounding the timeline for the Commonwealth's participation in RGGI, as well as the compliance requirements and associated costs for the September 1, 2022 through August 31, 2023 rate year, on January 10, 2022, the Company filed a motion to withdraw its application in the 2021 Rider RGGI Proceeding ("Withdrawal Motion").[5] On April 1, 2022, the Commission issued an Order granting the

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[3] Rider RGGI Order at 2.

[4] *Petition of Virginia Electric and Power Company, For revision of a rate adjustment clause: Rider RGGI, pursuant to § 56-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2021-00281, Rider RGGI Annual Update Filing (Dec. 6, 2021) (the "2021 Rider RGGI Proceeding").

[5] *Petition of Virginia Electric and Power Company, For revision of a rate adjustment clause: Rider RGGI, pursuant to § 56-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2021-00281, Motion to Withdraw Application (Jan. 10, 2022).

Withdrawal Motion and continuing the matter.[6] The Order Granting Motion further directs the Company to file a status update on Rider RGGI on or about July 1, 2022, including any motion to continue the currently-approved RAC, and to file an update to Rider RGGI on or before January 1, 2023.

11. Rider RGGI as approved in the 2020 Rider RGGI Proceeding remains in effect. The forecasted net unrecovered balance as of July 31, 2022, is $178 million, comprised of approximately $260 million actual and projected compliance costs, offset by approximately $82 million of actual and projected recoveries.[7]

RECENT DEVELOPMENTS

12. On January 15, 2022, Governor Youngkin issued Executive Order Number Nine ("Executive Order Nine"), directing the Director of the DEQ, in coordination with the Secretary of Natural and Historic Resources, to take certain actions to "re-evaluate Virginia's participation in the Regional Greenhouse Gas Initiative and immediately begin regulatory processes to end it."[8]

13. On March 11, 2022, as directed by Executive Order Nine, the DEQ issued a report ("DEQ Report")[9] that presents a path for Virginia to end its participation in RGGI "upon the conclusion of an appropriate legislative or regulatory process." Specifically, the DEQ Report

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[6] *Petition of Virginia Electric and Power Company, For revision of a rate adjustment clause: Rider RGGI, pursuant to § 56-585.1 A 5 e of the Code of Virginia*, Case No. PUR-2021-00281, Order Granting Motion (Apr. 1, 2022).

[7] In Case No. PUR-2020-00169, the Company projected compliance costs for the period January 1, 2021 - July 31, 2022 of approximately $168 million. However, the RGGI auction prices for emissions allowances have significantly exceeded prior forecasts, resulting in a revised forecasted cost of RGGI compliance during this period of approximately $260 million. In the ordinary course, the under-recovery of costs during the rate year would be addressed in a future Rider RGGI update and true-up proceeding.

[8] *Commonwealth of Virginia Office of the Governor,* Executive Order Number Nine (2022), "Protecting Ratepayers from the Rising Cost of Living due to the Regional Greenhouse Gas Initiative" (Jan. 15, 2022), *available at* https://www.governor.virginia.gov/media/governorvirginiagov/governor-of-virginia/pdf/eo/EO-9-RGGI.pdf.

[9] *Department of Environmental Quality*, Letter to Secretary of Natural and Historic Resources (Mar. 11, 2022), *available at* https://www.deq.virginia.gov/home/showpublisheddocument/13813/637829669069026180.

includes the following:

- A draft emergency regulation ("Emergency Regulation"), along with a brief description of the process for promulgating an emergency regulation under Va. Code § 2.2-4011, including a draft letter to the Attorney General asking for his approval as required by that statute;

- A brief description of the process and timetable for turning an emergency regulation into a permanent regulation under the Administrative Process Act, including a draft Notice of Intended Regulatory Action (NOIRA) to commence that process; and

- A draft letter for [the Governor's] signature notifying RGGI, Inc., of the Governor's intent of withdrawing the Commonwealth from the RGGI program.

PETITION TO SUSPEND RIDER RGGI AND FOR ALTERNATE RECOVERY MECHANISM OF CERTAIN COMPLIANCE COSTS

14. To date, the Company has elected to recover its RGGI compliance costs through a RAC as permitted under Subsection A 5 e. The currently approved Rider RGGI went into effect on January 1, 2022, to recover actual and projected compliance costs for the period January 1, 2021 (the start of the Company's RGGI compliance obligation), through July 31, 2022 (the end of the initial Rider RGGI Rate Year as filed).[10]

15. Based on currently available information and assumptions, the Emergency Regulation could become effective as early as July 2022, which would eliminate the Company's RGGI compliance obligations.

16. In anticipation of these planned actions to withdraw Virginia from RGGI, and in order to provide customers with rate relief as promptly as possible, the Company requests that

[10] While the Company requested a rate year of August 1, 2021 – July 31, 2022, the Rider RGGI Order approved Rider RGGI effective September 1, 2021. Further, due to the suspension of the Rider RGGI Order by the Order for Reconsideration, Rider RGGI was delayed in its implementation until January 1, 2022.

the Commission suspend Rider RGGI effective July 1, 2022,[11] and that its rate be correspondingly reset to $0.00/kWh as of that time. Suspension of the RAC will immediately reduce the typical residential customer bill by approximately $2.39 per month, with greater reductions for higher energy consumers in the residential, as well as commercial and industrial classes.

17. The Company projects that it will have recovered approximately $82 million in RGGI compliance costs through the Rider RGGI during the period January 1, 2022 to June 30, 2022, and that approximately $178 million in prudently incurred compliance costs up through July 31, 2022 (the assumed date of RGGI withdrawal for purposes of this Petition) will remain unrecovered. Rather than recovering such costs through the RGGI RAC, the Company is proposing to recover those costs through the Company's existing rates for generation services (base rates) during the period in which they were incurred. As such, customers would see no incremental increase in future bills to recover those costs.[12]

18. Good cause exists to grant the Company's Petition. Based on current information and assumptions, it is reasonable to anticipate that Virginia will withdraw from the RGGI compact. Suspending Rider RGGI will provide an immediate, material reduction to customer bills given this assumption. Likewise, the Company's voluntary election alternately to recover approximately $178 million in unrecovered RGGI compliance costs through existing base rates will prevent future incremental rate increases. The Company believes that these actions are particularly in the public interest given current geopolitical and market conditions beyond its

[11] The Company requests to suspend the Rider RGGI rate on the first day of the month that is at least fifteen days following the date of any Commission order approving the Petition. Therefore, in order to implement the suspension effective July 1, 2022, the Company requests a Commission order on or before June 15, 2022.
[12] While the Commission has approved necessary costs to comply with RGGI through Rider RGGI, and the Company maintains that such costs have been prudently incurred, it recognizes that the prudence of any such costs recovered through base rates may be subject to further Commission review in the Company's 2024 triennial review proceeding pursuant to Va. Code § 56-585.1 A 3.

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control which are driving increases in the costs to be recovered from customers of fuel commodities necessary to produce electric energy.

19. The Company acknowledges that its presumed compliance obligation termination date of July 31, 2022, while based on reasonable assumptions, is indefinite. In the event the Commonwealth has not withdrawn from RGGI via an emergency regulation by this date, and compliance costs extend beyond this time, the Company reserves its right under Subsection A 5 e to petition for resumption of Rider RGGI and recovery of any costs incurred to meet its compliance obligations on or after August 1, 2022, as may be approved by the Commission, and requests that the Commission hold this docket open for further proceedings as future events concerning the Commonwealth's participation in RGGI develop.

20. Should the Commission grant the Company's requested relief in this Petition, the Company further requests the Commission issue an Order modifying, as appropriate, its Order Granting Approval in Case No. PUR-2021-00281.

CONCLUSION

WHEREFORE, Dominion Energy Virginia respectfully requests that the Commission issue an Order that (i) grants authority to suspend the approved Rider RGGI effective July 1, 2022; (ii) resets the Rider RGGI rate to $0.00/kWh; (iii) approves the Company's election to alternately recover unrecovered RGGI compliance costs through its rates for generation services, as opposed to Rider RGGI, as described herein; (iv) holds this docket open for future proceedings; and (v) grants such other relief as deemed appropriate and necessary.

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Respectfully submitted,

VIRGINIA ELECTRIC AND POWER COMPANY

By: */s/ Elaine S. Ryan*
Counsel

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Counsel for Virginia Electric and Power Company

May 5, 2022

Attachment 48

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, JUNE 15, 2022

SCC-CLERK'S OFFICE
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2022 JUN 15 A 11: 35

220630078

PETITION OF
VIRGINIA ELECTRIC AND POWER COMPANY

Case No. PUR-2022-00070

For authority to suspend a rate adjustment clause, designated Rider RGGI, under § 56-585.1 A 5 e of the Code of Virginia, and for alternate recovery mechanism of certain compliance costs

ORDER GRANTING PETITION

On May 5, 2022, Virginia Electric and Power Company ("DEV" or the "Company") petitioned the State Corporation Commission ("Commission") to suspend, effective July 1, 2022, its rate adjustment clause ("RAC" or "Rider"), designated Rider RGGI, that was approved in Case No. PUR-2020-00169 ("Petition"). The Rider recovers the Company's costs related to the purchase of allowances through the Regional Greenhouse Gas Initiative ("RGGI") market-based trading program for carbon dioxide emissions.

In Case No. PUR-2020-00169, the Commission approved projected allowance costs of $167,759,000 for the period ending July 31, 2022, subject to true-up for the actual costs subsequently approved by the Commission for that period. As a result, those costs are currently being recovered through the Projected Cost Recovery Factor for Rider RGGI.

In its Petition, the Company proposes that RGGI compliance costs incurred up through July 31, 2022, which are not actually recovered prior to the suspension of the Rider, be alternatively recovered through the utility's rates for generation services (base rates) in effect during the period incurred. The Petition states that it is driven by the Commonwealth's

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anticipated withdrawal from the RGGI program and the interests of the Company's customers in reducing RAC-related charges.[1]

The Company requests that the Commission suspend Rider RGGI effective July 1, 2022, and that the Projected Cost Recovery Factor be correspondingly reset to $0.00 per kilowatt-hour ("kWh") as of that date.[2] The Company states that suspension of the RAC will immediately reduce the monthly bill of a residential customer bill using 1,000 kWh per month by approximately $2.39 per month, with greater reductions for higher energy consumers in the residential, as well as commercial and industrial classes.[3]

In sum, DEV has requested in its Petition that the Commission issue an Order that (i) grants authority to suspend the approved Rider RGGI effective July 1, 2022; (ii) resets the Rider RGGI rate to $0.00/kWh; (iii) approves the Company's election to alternately recover unrecovered RGGI compliance costs through its rates for generation services, as opposed to Rider RGGI, as described in the Petition; (iv) holds this docket open for future proceedings; and (v) grants such other relief as deemed appropriate and necessary.[4]

On May 13, 2022, the Commission issued an Order Expediting Response and Reply that invited interested entities to file a response to DEV's Petition and DEV to file a reply. On May 19, 2022, responses were filed by Commission Staff ("Staff"), the Office of the Attorney General, Division of Consumer Counsel ("Consumer Counsel") and Appalachian Voices. On May 24, 2022, DEV filed its reply.

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[1] Petition at 1, 2.

[2] Because the Commission has yet to approve actual allowance costs for this period under Rider RGGI, the Actual Cost True-Up Factor is currently set at $0.00/kWh.

[3] *Id.* at 6, 7.

[4] *Id.* at 8.

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NOW THE COMMISSION, upon consideration of the Company's Petition and the responses and reply thereto, finds as follows. Staff, Consumer Counsel, and Appalachian Voices did not oppose the Company's request to suspend Rider RGGI. The Commission finds Rider RGGI shall be suspended, and the Rider RGGI Projected Cost Recovery Factor shall be reset to $0.00/kWh, effective July 1, 2022.

With respect to the projected approximately $178 million in accrued but unrecovered RGGI compliance costs as of July 31, 2022, DEV requested the Commission approve the Company's election to alternately recover unrecovered RGGI compliance costs through its rates for generation services, as opposed to Rider RGGI, as described in the Petition.[5] DEV acknowledges that the prudence of any such costs recovered through base rates may be subject to further Commission review in the Company's 2024 triennial review proceeding, just as any other element of the cost of service.[6] We approve DEV's request to recover pre-July 31, 2022 RGGI costs through both Rider RGGI and base rates (subject to further review in the Rider RGGI actual cost true-up as referenced in Ordering Paragraph (5), and in the Company's 2024 triennial review proceeding). Finally, the Commission finds that Consumer Counsel and Appalachian Voices' recommendations related to RGGI costs incurred after July 31, 2022, and financing costs associated therewith,[7] are beyond the scope of the instant proceeding and decline to adopt them at this time.

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[5] DEV clarified in its reply that it is proposing immediate recognition and recovery of these costs over the periods that they were actually incurred in 2021 and 2022 and "[t]he costs would be expensed against base revenues in 2021 and 2022, and thus treated as fully recovered by July 1, 2022." DEV Reply at 2. Accordingly, DEV asserts there would be no financing costs associated with these compliance costs. *Id.*

[6] *Id.*

[7] Consumer Counsel Response at 2; Appalachian Voices Response at 6.

Accordingly, IT IS ORDERED THAT:

(1) The Petition is granted as set forth herein.

(2) Rider RGGI is suspended and reset to $0.00/kWh, effective July 1, 2022.

(3) RGGI compliance costs that are incurred up through July 31, 2022 (and ultimately approved by the Commission), and which have not been recovered prior to the suspension of the Rider, may be recovered through the utility's base rates for generation services in effect during the period incurred.

(4) DEV forthwith shall file revised tariffs with the Clerk of the Commission and with the Commission's Division of Public Utility Regulation and Utility Accounting and Finance, consistent with this Order. The Clerk of the Commission shall retain such filings for public inspection in person and on the Commission's website: scc.virginia/pages/Case-Information.

(5) This docket shall remain open for future proceedings, including but not limited to the actual cost true-up proceeding to review incurred allowance costs (currently estimated to be approximately $82 million) that have been recovered through Rider RGGI, as required in the Order Approving Rate Adjustment Clause issued in Case No. PUR-2020-00169.

(6) This matter is continued.

A COPY hereof shall be sent electronically by the Clerk of the Commission to all persons on the official Service Lists in this matter, and in Case Nos. PUR-2021-00281 and PUR-2020-00169. The service lists are available from the Clerk of the Commission.