Amanda B. "Mandy" Tornabene
Vice President – Environmental Services
Dominion Energy Services, Inc.

5000 Dominion Boulevard, Glen Allen, VA 23060
DominionEnergy.com

By electronic delivery: Karen.sabasteanski@deq.virginia.gov

March 5, 2019

Ms. Karen Sabasteanski
Policy Analyst
Office of Air Regulatory Affairs
Department of Environmental Quality
P.O. Box 1105
Richmond, Virginia 23218

RE: Notice of Re-Proposed Rulemaking: 9VAC5-140. Regulation for Emissions Trading Programs

Dear Ms. Sabasteanski:

Dominion Energy is submitting the following comments on the Department of Environmental Quality's (DEQ) re-proposed rule, published in the February 4, 2019 *Virginia Register*[1], to regulate carbon dioxide (CO_2) emissions from fossil fuel fired electric power generating facilities in Virginia. This regulatory action is a re-proposed version of the Agency's initial proposed regulation, issued in January 2018, to establish a state-level CO_2 cap-and-trade program under 9 VAC 5-140 Part VII (Regulations for Emissions Trading) that would be linked to the northeast Regional Greenhouse Gas Initiative (RGGI) trading program.

Dominion Energy is one of the nation's largest producers and transporters of energy, with a portfolio of approximately 31,000 megawatts of diverse electric generation capacity in 10 states, 15,000 miles of natural gas gathering, storage, transmission and distribution pipeline and 93,600 miles of electric transmission and distribution lines. A significant portion of Dominion Energy's electric generation is located in Virginia, including four carbon-free nuclear units, one of the nation's largest portfolios of renewable biomass generation, four of the most modern combined cycle natural gas facilities in the United States, the largest hydroelectric pumped storage power plant in the world and a rapidly growing portfolio of large-scale solar generation.

The Company is already a leader in reducing greenhouse gas (GHG) emissions and began its transition to a less carbon-intensive generation fleet well in advance of the Clean Power Plan (CPP). Between 2000 and 2017, Dominion Energy reduced carbon emissions from its units serving Virginia by over 10 million tons of CO_2 (26 percent), while the amount of power we produced increased by 14 percent. The emission intensity (emissions per megawatt hours of energy produced) decreased by 35 percent over the same period. This is due, in large part, to the

[1] See *VA Register* Notice at http://register.dls.virginia.gov/details.aspx?id=6770

closure, sale or conversion to natural gas and biomass of 12 coal-fired units, the company's four nuclear units that operate in Virginia, its growing fleet of highly efficient natural gas-fueled power stations, and its growing portfolio of renewable energy.

The Company will continue to move toward cleaner, more efficient, and lower emitting ways of generating, delivering, storing, and transporting energy. In 2018, we placed into reserve about 400 MW of coal-fired generation and plan to retire two additional coal units at the Yorktown Power Station. New electric power generators, like our highly efficient Warren, Brunswick and Greensville natural gas-fired power stations, continue our long-term trend toward cleaner, less carbon-intensive electric generation. In the past five years, we have invested $3.5 billion in renewable generation and grown our solar fleet in Virginia and North Carolina from zero to approximately 1,700 megawatts in service, in construction, or under development with a goal of adding 3,000 megawatts of solar and wind energy by 2022. In November 2018, we received approval of an offshore wind pilot project – the second such project in the United States and the first to be owned by an electric utility. Dominion Energy operates several hydropower facilities and is one of the nation's largest generators of electricity using renewable biomass. The company also is evaluating pumped storage utilizing renewable energy as all or part of its power source in the coal field region of the state as supported by Virginia legislation.[2] In addition, the Company recently announced an industry-leading initiative to reduce methane emissions from its natural gas infrastructure by 50 percent over the next decade, based on 2010 levels. The initiative will prevent more than 430,000 metric tons of methane from entering the atmosphere. This voluntary initiative builds on the significant progress Dominion Energy has made in reducing methane emissions over the last decade, which prevented more than 180,000 metric tons of methane from entering the atmosphere.

RGGI is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap and reduce CO_2 emissions from the electric power sector. The RGGI states began implementing the regional carbon cap-and-trade program in 2009 and have set annually declining emission cap levels through 2030.

Dominion Energy's electric generating units operate in the PJM Interconnection, LLC (PJM), which is the regional transmission organization that operates the wholesale electric grid in parts of the Midwest and the mid-Atlantic region including Virginia, North Carolina, West Virginia and Pennsylvania. To date, Maryland and Delaware are the only states participating in the RGGI program that are part of PJM. New Jersey has announced its intention to rejoin the RGGI program and has commenced a regulatory process that, once completed, would begin implementing the program in January 2020.

Dominion Energy submitted extensive comments on the initial proposal which was based on a baseline carbon cap of 33 to 34 million tons in 2020. Key issues and concerns identified in the comments included:

---

[2] See http://lis.virginia.gov/cgi-bin/legp604.exe?171+ful+CHAP0820.

- Virginia's linkage to RGGI will encourage lower cost electricity imports from out-of-state sources that are more carbon-intensive, resulting in a significant increase in power imports while highly efficient and lower emitting NGCCs in Virginia will run less.
- Reductions in carbon emissions in Virginia, as a result of the increased use of imported power, will be offset by emission increases elsewhere within the North American Electric Reliability Corporation (NERC) Eastern Interconnect (EI) which includes all of PJM and the RGGI region.
- Increased imports of more carbon-intensive power will increase the carbon footprint per customer in Virginia and expose Virginia customers to increased power price volatility from the energy market.
- Linking to RGGI could impose significant additional cost to Virginia customers during the 2020-2030 period.

Under the revised proposal, the initial (year 2020) Virginia base budget of CO_2 emission allowances is reduced by 15 percent from 33-34 million tons to 28 million tons. According to DEQ, the reduced starting cap is based on revised modeling assuming lower electricity demand in most RGGI states, lower than previously modeled natural gas prices, the inclusion of up to 5,000 MW of renewable energy and significant energy efficiency investments by regulated utilities in Virginia by way of the 2018 Grid Transformation and Security Act (GTSA) and significant clean energy deployment in the RGGI states. DEQ projects minimal cost impacts to Virginia electric customers based on an analysis of monthly electricity bills for Virginia residential, commercial and industrial consumers performed by the Analysis Group.

Summary of Comments on Re-Proposed Regulation

We remain concerned that the Commonwealth's linkage to the RGGI program through the Virginia carbon proposal with its now significantly lower proposed starting emissions cap would disadvantage Virginia generation relative to other states and result in an undue burden on its customers with no real mitigation of GHG emissions regionally.

- DEQ's own modeling shows that emission decreases within the RGGI program region (including VA) are largely offset by equivalent emission increases outside of the RGGI program in PJM and the EI.
- Power imports with implementation of the RGGI program in Virginia still increase significantly relative to the reference case (RGGI not implemented in Virginia).
- The State Corporation Commission (SCC) review of DEQ modeling assumptions indicates that DEQ has significantly underestimated the potential cost impact to Virginia electricity customers.
- Modeling demonstrates that Virginia generators will need to purchase additional allowances over and above the amount allocated by DEQ under the program in order to comply with the RGGI requirements. The revenue from the purchases of these additional allowances will flow to other RGGI states while the cost of compliance will be borne by Virginia electricity customers.

For these reasons, DEQ should defer reducing the Virginia cap from the levels initially proposed in January 2018 and reassess the need to do so in accordance with the next RGGI program review. In addition, DEQ should defer any further reductions of the emissions cap beyond 2030 until such time that the RGGI states collectively determine that further reductions of the regional cap are necessary.

We also provide comment on several additional issues:

- DEQ should provide additional regulatory language to clarify and provide for the exemption of emissions from the biomass portion of fuel for fossil fuel-fired units that co-fire with biomass.
- DEQ should expand the scope of eligible offset projects to include Virginia-based carbon offset projects. DEQ should also expand the scope of eligible projects in general to include and incentivize carbon reductions in other sectors of the economy.
- We also offer several administrative-type suggestions, including modifying certain 2019-based deadlines in the regulation that will occur prior to the regulation becoming final and effective.

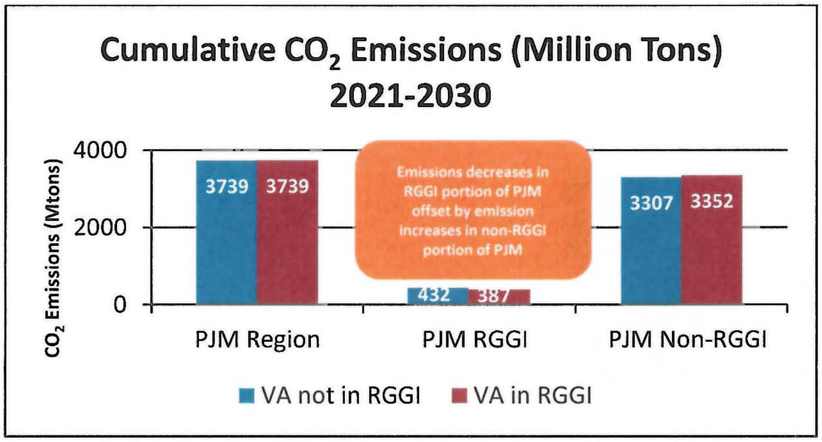
Detailed Comments

1. **Virginia linking to the RGGI program does not reduce emissions regionally.**

   DEQ's modeling results indicate that Virginia entering the RGGI program in 2020 with a statewide emissions cap at the reduced levels proposed and imposing RGGI's approximate 3% per year cap reduction to achieve a 30% emission reduction over the period 2020 – 2030 does not result in overall carbon emission reductions in the EI or PJM regions by 2030. The analysis shows, when comparing emissions in the reference case where Virginia is not linked to the RGGI program with emissions in the policy case where Virginia is linked to RGGI, that emissions reductions achieved in Virginia and the RGGI program are largely offset by emissions increases in the non-RGGI portions of the EI and PJM regions.

   Cumulatively, over the period 2021-2030, emissions in the portion of the PJM region subject to RGGI are reduced by about 45 million tons, but increase by the same amount in the non-RGGI portion of PJM (see Figure 1 below). In the EI region, as a whole, cumulative emissions over the 10-year period are only reduced by 3 million tons - with about a 57-million tons reduction in the RGGI portion of the EI offset by a 54-million ton increase in the remainder of the EI outside of the RGGI program. Since modeling information provided for incremental generation was confined to the RGGI states only and not provided for the states outside of the RGGI region, it is difficult to determine whether the minimal carbon emission reductions modeled for the entire EI region were the result of the RGGI program or the result of "natural" retirement of older coal plants in the region.

Figure 1. Cumulative CO_2 Emissions Comparison (2021-2030) – Virginia in RGGI



Source: VA DEQ November 2018 IPM Reference Case and Policy Case Results @ https://www.deq.virginia.gov/Programs/Air/GreenhouseGasPlan.aspx

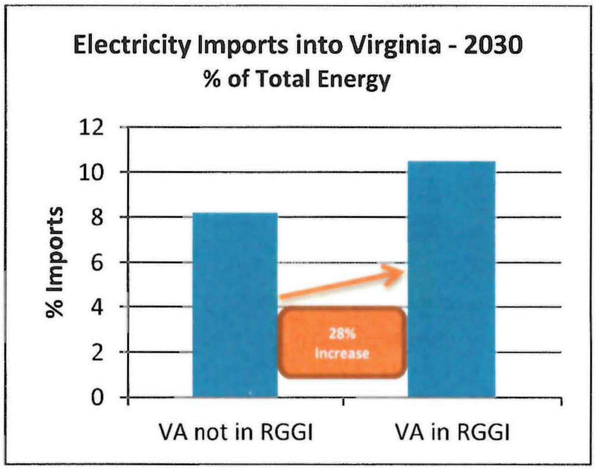
DEQ's modeling did not include New Jersey joining RGGI in its Policy case. New Jersey plans to rejoin RGGI and, like Virginia, the New Jersey Department of Environmental Protection (DEP) has proposed a regulation to begin implementing the RGGI model rule beginning in 2020. Modeling that the DEP has performed, that includes both New Jersey and Virginia in RGGI, shows generally similar results with emission reductions achieved in the RGGI states mostly offset by emissions increases outside of the region. The modeling showed only about a 0.6 percent reduction in emissions across the entire PJM region comparing the policy case to the reference case[3].

2. **The program will result in a significant increase in power imports.**

If Virginia joins RGGI, the projected increase in emissions in states outside of the RGGI program suggests emissions leakage will occur as a result of increased energy imports from more carbon-intensive energy sources in states that are not part of the RGGI program. This is borne out by modeling results that show significant increases in power imports into Virginia. With Virginia linked to RGGI, net energy imports into Virginia by 2030 increase by about 28 percent with approximately 8.2 percent of total net generation from imported power under the case with no carbon regulations in Virginia to about 10.5 percent of total net generation from imported power for the case with Virginia linked to RGGI (see Figure 2 below).

[3] See NJ DEP CO_2 Budget Trading Reference Case and Policy Case Modeling Results @ https://www.state.nj.us/dep/aqes/rggi.html#/

Figure 2. Electricity Imports into Virginia in 2030



Source: VA DEQ November 2018 IPM Reference Case and Policy Case Results @ https://www.deq.virginia.gov/Programs/Air/GreenhouseGasPlan.aspx

DEQ's latest proposed rule includes an updating output-based allowance allocation approach that it believes will incentivize utilization of NGCC resources as a means to counter leakage. Under this approach, allowances are allocated annually to affected generating units based on generation output (megawatt hours of operation) averaged over the previous three-year period. However, while an updating output-based allocation approach may be more favorable to NGCC units since they emits much less carbon per unit of output (relative to coal-fired units), it does not address leakage. Natural gas-fired units in Virginia will still be subject to a CO_2 cost adder that units outside of the carbon constrained program will not be subject to. Thus, the effect of RGGI-equivalent reduction requirements in Virginia is likely to limit the dispatch of highly efficient and lower emitting NGCC facilities in Virginia and encourage the dispatch of higher emitting resources and increased emissions in neighboring states outside of the RGGI region.

This will increase the carbon intensity of the electricity used by Virginia customers. Virginia's carbon footprint from electric power generation is already significantly cleaner than many of its neighboring states and PJM as a whole (see Appendix A). With the federal Clean Power Plan (CPP) currently stayed and proposed to be replaced with the Affordable Clean Energy (ACE) rule, few states outside of the northeast RGGI program and along the west coast have or is proceeding with definitive carbon regulations. This includes all of the remaining states that are part of PJM (except Maryland and Delaware which are part of RGGI.

In the PJM Interconnect, units are dispatched based on "Replacement Cost" of the variable components required to run the unit. This is known as economic dispatch. The variable components include fuel and emission allowances, such as RGGI allowances. The "Replacement Cost" changes are based on the market value of the type of fuel used in a unit and the market value of the emission allowance. Dominion Energy does not choose when to operate its units, but instead, units are called upon by PJM. If Dominion Energy units are above the target price for the day, other units, generally less controlled and more carbon intensive, will be called upon and operated to meet the PJM load demand due to their ability to operate at a lower cost. PJM does not take environmental impact into account when dispatching units. When Virginia units bid into the electric market, their bids will incorporate a RGGI-based carbon cost that bids from other PJM resources outside of the RGGI program will not have. As a result, Virginia generators will be economically disadvantaged (less competitive), resulting in increased imports dispatched into Virginia. Coupled with the possible forced retirement and/or curtailment of fossil fuel-fired resources, this raises reliability concerns with increased dependence on out-of-state, more carbon-intensive power to meet Virginia's energy needs.

3. **DEQ has underestimated the potential cost impacts to Virginia electricity customers.**

As noted above, DEQ used an outside consultant, the Analysis Group, to perform an analysis of monthly electricity bills for Virginia residential, commercial and industrial consumers. The results, which were summarized in a PowerPoint presentation posted on DEQ's website, projects that electricity bills will be lower with Virginia participating in RGGI. According to the study, higher firm power prices under the cap-and-trade program are more than offset by projected revenue from the sale of CO_2 emission allowances that are passed (by assumption) on to consumers.

The Virginia Department of Planning and Budget (DPB) reviewed the study and largely concluded that it lacked the resources to verify the model or its assumptions[4]. DPB further suggested that the assumption should be reviewed by the State Corporation Commission (SCC).

Although not in direct response to DPB's suggestion, the SCC conducted a review of the DEQ/Analysis Group cost impact study and performed its own analysis[5][6]. SCC estimates the total cost to Dominion Energy's customers to be $3.3 billion for Virginia linking to RGGI or $5.9 billion for Virginia joining RGGI over the 2020-2030 timeframe. Based on SCC's analysis, typical residential customer bills are estimated to increase by $7 to $12 per month over the 2019-2043 study period, with an average $6.95 per month (averaged over the 25-year period in constant dollars) with Virginia linking to RGGI. These costs are significantly higher than the minimal impact estimated by DEQ. The SCC states that RGGI compliance increases the dispatch cost of fossil generation making it less competitive. This causes such generation to run less or be taken out of service. The SCC further explains that the DEQ/Analysis Group study modeled Dominion Energy Virginia and Appalachian Power (AEP) as deregulated utilities in a competitive market with merchant power plants. While much of the power generated in the RGGI states is supplied by merchant power, most of the power generation in Virginia is owned and

[4] See): http://www.townhall.virginia.gov/l/GetFile.cfm?File=1\4818\8476\EIA_DEQ_8476_v1.pdf

[5] Letter from William F. Stephens, Director Division of Public Utility Regulation, State Corporation Commission to Delegate Terry Kilgore, Virginia House of Delegates (January 29, 2019).

[6] Letter from William F. Stephens, Director Division of Public Utility Regulation, State Corporation Commission to Delegate Charles D. Poindexter, Virginia House of Delegates (February 27, 2019).

operated by regulated utilities and the cost of compliance is borne by customers. The SCC also identified that the Analysis Group applied a low discount rate for the weighted cost of capital projects that may be needed to replace generation from early retirements and therefore understated the cost of future capital investments by Virginia utilities.

4. **Virginia participating in RGGI will impose additional cost to Virginia customers with no environmental benefit regionally. In addition, compliance with RGGI will shift revenue from Virginia to other RGGI states.**

Virginia linking to or joining RGGI will impose significant additional cost to Virginia electricity customers while achieving minimal, insignificant emission reductions regionally. It will encourage lower cost electricity imports from out-of-state sources that are more carbon-intensive. Reductions in carbon emissions in Virginia and the RGGI region will be offset by emission increases elsewhere within the non-RGGI portion of PJM and the EI.

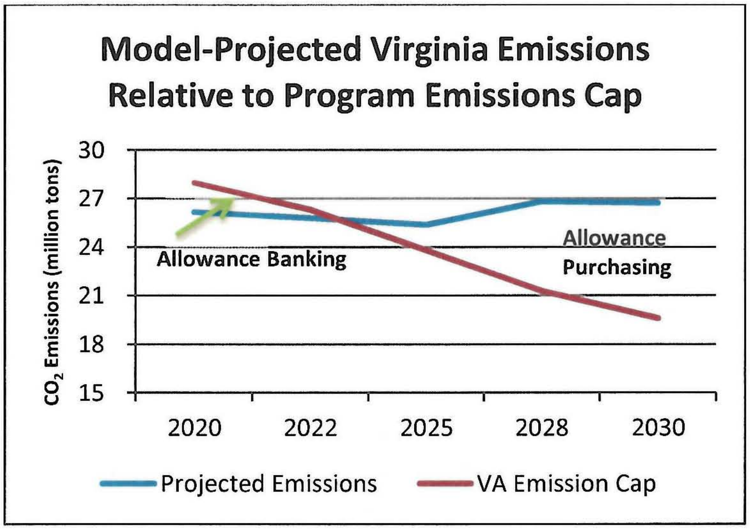
DEQ's modeling also shows that although about a 5 percent reduction in Virginia CO_2 emissions is achieved cumulatively over the 2020-2030 period, emissions through much of the 10-year period are projected to be above the state-level emission cap. This implies that compliance with the program will require allowance purchases over and above the amount of allowances DEQ will allocate to Virginia sources (as shown illustratively in Figure 3 below). The revenue from the purchases of these additional allowances will flow to other RGGI states while the cost of compliance will be borne by Virginia electricity customers.

The Company has modeled the RGGI impacts to Virginia customers in the 2018 IRP proceeding filed May 2018. As seen on pages 108-109 of the Company's 2018 IRP[7], the cost increase to Virginia customers if the Company *links* to RGGI is over $1.5 billion net present value which equates to a monthly average rate increase of $4.10. *Joining* RGGI would increase cost to Virginia customers to over $4 billion net present value which would equate to a monthly average rate increase of $6.83. This modeling was based on the DEQ's initially proposed 33-34 million ton baseline emissions cap, which has now been reduced by 15% down to 28 million tons. Although the analysis did not include specific elements of the GTSA, which was not final at the time modeling assumptions for the 2018 IRP were "locked in", it did include over 4.5 GW of new solar and offshore wind – an amount that is comparable to the renewable build specified in the GTSA.

---

[7] See www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf

Figure 3. Model-Projected Virginia Emissions Relative to Program Emissions Cap



Source: VA DEQ November 2018 IPM Reference Case and Policy Case Results @ https://www.deq.virginia.gov/Programs/Air/GreenhouseGasPlan.aspx

5. **DEQ should defer any decision to modify the originally proposed 2020 baseline emissions cap at this time.**

As previously mentioned, part of DEQ's explanation for the reduced baseline emissions cap includes the incorporation and assumption of the deployment of additional clean energy programs in other RGGI states. DEQ does not provide a description or any detailed information regarding these programs and the extent of additional emission reductions they may achieve. It therefore is difficult to assess how much of a driver these programs served in the decision to lower the Virginia baseline cap. Nevertheless, it does raise question as to why such programs served as drivers for DEQ to adjust the Virginia baseline cap while no additional adjustments will be made to the emission caps in the other RGGI states within which these very programs will be implemented. To the extent that the future, planned deployment of clean energy programs in other RGGI states are deemed influential in establishing Virginia's 2020 baseline budget, it is logical to assume that the planned implementation of the GTSA in Virginia likewise could factor into the future budgets of the other RGGI states. This suggests that any modifications to RGGI state budgets attributed to these various state clean energy programs should be spread across the entire RGGI region and not just limited to Virginia.

An additional consideration regarding DEQ's proposal to reduce the baseline cap is that RGGI re-assesses its program every four years based on historical performance. Since 2009, RGGI has conducted two program reviews, one in 2012 and one in 2016/2017. Both of these reviews have resulted in a reduction/lowering of going-forward CO_2 emission caps for the RGGI region. The 2016/2017 program review led to the RGGI states' decision to increase the annual reduction of the regional emission cap beginning in 2021 from the current 2.5 percent-per-year rate to 3 percent-per-year through 2030. The next assessment period is scheduled to occur in 2021, which is only one year after Virginia would begin its participation in RGGI under the Virginia RGGI Program. This means that the significantly reduced Virginia cap identified in the re-proposed rule may be re-negotiated as early as 2021 with other member RGGI states.

In addition to the annual 3 percent-per-year reduction, the RGGI model rule includes two elements that can reduce the regional cap even further. These include (1) a "banked allowance adjustment", to be determined in 2021 and applied over the period 2021-2025, based on the size of the allowance bank amassed across the current RGGI region over the period 2018-2020; and (2) a new Emissions Containment Reserve (ECR) mechanism that would allow the RGGI states to withhold an amount of allowances up to 10 percent of the statewide emissions budget from offer in the RGGI auction if the auction clearing price falls below the ERC trigger price.

The Virginia carbon proposal includes both of these RGGI elements that would further reduce the Virginia emissions cap beyond the 3 percent per year reduction already imposed. In fact, DEQ's modeling projects an adjustment (reduction) of 75 million tons to the RGGI regional cap over the 2021-2025 period from the "banked allowance" adjustment provision. (NJ DEP modeling shows an adjustment (reduction) of 93 million tons with both Virginia and New Jersey in the program.) In our comments filed in response to DEQ's initial proposal, we requested DEQ explain and justify adjusting the Virginia state emission cap on the basis of banked allowances amassed over the period 2018-2020 (prior to Virginia's linking to the RGGI program) by affected entities in other RGGI states that Virginia affected sources will not have (be holding) since Virginia entities will not become subject to an emissions cap or required to hold allowances until 2020. We therefore advocated that proposed provisions to adjust emissions caps and/or withhold allowances based on the volume of banked allowances should be delayed in the Virginia rule to provide time for a nascent Virginia carbon market to mature. We believe these issues are even more pertinent with the proposed reduced cap.

Given these issues and uncertainties, DEQ should defer any decision to modify the originally proposed 2020 baseline emissions cap at this time. To the extent DEQ moves forward with a Virginia cap-and-trade program, it should proceed on the basis of the 33 to 34 million ton range in the original proposal. An evaluation as to whether adjustments are necessary can be performed during the next RGGI program review (expected to begin in 2021) at which time the impacts of the additional clean energy measures and programs expected to be implemented in the RGGI states including the GTSA in Virginia can be used to inform the effectiveness of the RGGI regional cap as a whole.

6. **DEQ should defer any further reduction of the emissions budget beyond 2030.**

The revised proposal includes a new provision, specified in 9 VAC 5-140-6190.C, that requires DEQ to review the cap in 2030 and recommend "appropriate adjustments" for post-2030 years. Absent any adjustment, the cap will be reduced (by default) by an additional 840,000 tons/year each year beginning in 2031. This provision is premature and unnecessary. As noted previously, the RGGI states conduct a review of the program every four years. On this schedule, subsequent reviews of the program will be conducted in the 2021, 2025 and 2029 timeframe at which time the effectiveness of the regional program and assessments as to whether "appropriate adjustments" are necessary will be made. In fact, the RGGI states themselves note that the re-proposed regulation specifying the additional reductions to the Virginia budget between 2030 and 2040 is inconsistent with the RGGI model rule and that the periodic RGGI program review is the appropriate vehicle to effect changes to the RGGI regional long-term cap trajectory[8]. In addition, existing Va. Code 2.2-4017 (APA) requires agencies to review regulations every four years. For these reasons, subsection 9 VAC 5-140-6190.C should be stricken. At a minimum, the provision establishing the default 840,000 ton per year additional reduction beyond 2030 should be removed.

7. **As allowed in the RGGI model rule, the biomass exemption should also apply to emissions from the biomass portion of fuel for fossil fuel-fired units that co-fire with biomass.**

As explained in our previous comments, we strongly support DEQ's proposal not to impose any compliance obligations upon units that use biomass as their primary fuel. No emissions attributed to biomass firing should require allowances. This would be consistent with EPA's approach in developing the CPP, which did not include biomass generation in establishing the baseline and state emission reduction targets and did not require biomass units to hold emission allowances under the mass-based model trading rules or surrender emission rate credits (ERCs) under the rate-based model trading rules.

This compliance exemption should also apply to the emissions apportioned to the burning of biomass for fossil fuel-fired units that are co-fired with biomass, such as Dominion Energy's Virginia City Hybrid Energy Center (VCHEC). Whether a unit burns biomass as its primary fuel or co-fires biomass with fossil fuel, the emissions from biomass should be treated the same. Under the rule, as currently proposed, a fossil fuel-fired unit that co-fires with biomass would be obligated to hold allowances for all of its emissions (fossil fuel and biomass-based).

In its Public Notice of action to re-propose the rule, DEQ seeks comment on whether 9 VAC 5-140-6050.C.1 should be amended to specify that the total CO_2 emissions related to CO_2 allowances only includes emissions resulting from the combustion of fossil fuel and whether such an amendment to the standard requirements would provide clarity and consistency with the fossil fuel focus of ED-11.

The proposed regulation, in 9 VAC 5-140-6020 C, defines "fossil fuel" and "fossil fuel-fired" as follows:

> *"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.*

The regulation defines a CO_2 budget unit as follows:

[8] See RGGI states' comments submitted to Virginia DEQ – February 21, 2019 at https://www.rggi.org/sites/default/files/Uploads/Participation/2019_02_21_Virginia_Re-Proposed_Comments.pdf

"CO_2 budget unit" means a unit that is subject to the CO_2 Budget Trading Program requirements under 9VAC5-140-6040.

The applicability provisions are defined in 9 VAC 5-140-6040.A:

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.

The regulatory requirements for units subject to the rule are established in 9 VAC 5-140-6050.C . The regulatory text, as currently proposed, would require any unit that meets the definition of a fossil fuel-fired unit and a CO_2 budget unit defined in 9 VAC 5-140-6020.C and the applicability provisions of 9 VAC 5-140-6040.A to hold CO_2 allowances in an amount no less than the total CO_2 emissions from the source or unit as follows:

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 for the 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. (emphasis added)

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 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. (emphasis added)

Thus, a fossil fuel-fired unit that co-fired with biomass (a non- fossil fuel), such as the unit at VCHEC, and meets the applicability criteria of the rule and thus the definition of a CO_2 budget unit would be required to hold allowances for all of its CO_2 emissions including emissions attributed to burning biomass.

VCHEC is a 610-MW electric generating station in Wise County, Virginia that burns waste coal and co-fires with biomass (it can co-fire with biomass up to 20% of its capacity or 122 MW) as part of its fuel stream using "circulating fluidized bed (CFB)" technology. CFB is proven clean-coal technology that also enables the using of run-of-mine coal, waste coal, and renewable energy sources such as waste wood. CFB technology combined with modern post-combustion controls yields low emissions of sulfur dioxide, nitrogen oxide, particulate matter and mercury. In June 2008, the Virginia State Air Pollution Control Board directed the DEQ to incorporate a provision (Condition 26) in the facility's Prevention of Significant Deterioration (PSD) air permit to construct and operate in accordance with 9 VAC 5-80 Article 8 establishing a timetable for biomass utilization at the facility. According to DEQ, the Board chose this approach "in order to promote further reductions in sulfur dioxide emissions and show a reduction in carbon emissions, since biomass is considered a biogenic, carbon-neutral material".[9] Requiring VCHEC to now hold allowances under a state carbon program for emissions resulting from the burning of biomass fuel in compliance with an air permit provision established specifically to address carbon is counterintuitive.

As currently proposed, the regulation would require VCHEC to hold approximately 8 percent more allowances than would be required if the rule did not apply to the emissions from biomass. This percentage will increase over the next several years since the air permit requires a stepwise increase in the percentage of biomass fuel up to a minimum of 10 percent. This will add to the cost of dispatching the unit, which will have direct cost impacts to customers.

Requiring fossil units that co-fire with biomass to hold allowances would also be inconsistent with the existing RGGI program which only regulates fossil fuel-fired units.

For these reasons, we believe clarifying language is needed to assure that the limitation of applicability to emissions from fossil fuel would apply to a unit that meets the definition of a fossil fuel-fired unit but co-fires with biomass and that such a unit would not be required to hold CO2 allowances for emissions associated with the burning of biomass (a non-fossil fuel). Accordingly, DEQ should include in a final regulation the clarifying amended language it brought before the Board in September 2018 (shown in brackets below) in <u>both</u> 9 VAC 5-140-6050.C.1 and C.2 to preserve the intent of ED-11.

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 <u>[that have been generated as a result of combusting fossil fuel]</u> *for the 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 <u>[that have been generated as a result of combusting fossil fuel]</u> *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.*

[9] Letter from Dallas R. Sizemore (Regional Director, Virginia DEQ) to James K. Martin (Vice President, Virginia Electric and Power Company), June 30, 2008.

8. We support DEQ's proposed recognition of offsets awarded by other RGGI states. However, DEQ should expand the scope of eligible projects to include Virginia-based carbon offset projects.

Dominion supports DEQ's proposal to recognize CO_2 offset allowances awarded by other participating states. However, we recommend that DEQ clarify in the applicable regulatory language that it will recognize offset allowances awarded by a RGGI state even if the underlying project is located in another state. Further, we urge DEQ to expand the scope of eligible projects to include Virginia-based projects that meet the offset eligibility requirements of the RGGI model rule, as well as SF_6 reduction projects and electrification projects. These steps are necessary to ensure that the cap-and-trade program realizes the potential for offset projects to provide environmental and economic benefits to the state while containing compliance costs.

a. DEQ should clarify the proposed regulatory language regarding use of CO_2 offset allowances from other participating states.

We support the proposal's recognition of CO_2 offset allowances from other participating states. However, the operative language of the re-proposed regulation is ambiguous. It refers to CO_2 offset allowances "generated by" other participating states.[10] This formulation could be misread to limit eligibility to allowances only from projects that are actually located in other participating states. We recommend that the provision refer instead to CO_2 offset allowances "*awarded by*" other participating states. This alternative language more accurately tracks the language of the offset process as outlined in the RGGI Model Rule and in the regulations promulgated by other participating states.[11] Further, it makes clear that DEQ will recognize CO_2 offset allowances awarded by a participating state, even if the underlying project is located in another state. The RGGI Model Rule has authorized a pathway for awarding CO_2 offset allowances in such circumstances. The process, which has been adopted in the regulations of other participating states, involves entering into a memorandum of understanding with the non-participating state.[12]

b. The exclusion of Virginia-based offset projects disincentivizes entities to participate in climate mitigation.

The re-proposed regulation includes the establishment of an arbitrary restraint on offsets in the proposed program. It would deny the opportunity for projects located in Virginia to earn CO_2 offset allowances.

To be clear, under the proposed approach, Virginia-based projects not only could not apply to Virginia for CO_2 offset allowances, they also could *not* apply for CO_2 offset allowances from *other* RGGI participating states. Under the RGGI Model Rule and the corresponding regulations promulgated by other participating states, a project is only eligible to receive CO_2 offset allowances from the state in which the majority of reductions occur.[13] Accordingly, if DEQ were to finalize the re-proposed regulation

[10] Re-proposed Regulation at 9VAC5-140-6020 (definition of "CO_2 allowance").
[11] *See, e.g.,* RGGI Model Rule, XX-1.2 (definition of "CO_2 allowance").
[12] *Id.*, XX-10.3(a)(2)(i).
[13] *Id.*, XX-10.3(a)(2)(ii).

in its current form, a Virginia-based project could not apply to Maryland, Delaware, New Jersey or any other RGGI participating states that award CO_2 offset allowances to projects. Rather, the door would be closed to Virginia-based offset projects, including projects that could otherwise meet the eligibility criteria of the RGGI program.

We urge DEQ to revisit this approach and open the door to worthy projects from Virginia. By making it possible for projects in the state to earn offset allowances, DEQ would make it possible for a greater number and variety of Virginia entities to participate in the Commonwealth's efforts to address climate change. DEQ could tap the ingenuity of more Virginians. The program would provide incentives for mitigation activities and technological innovation across additional sectors, including the agriculture, manufacturing, and transportation sectors.

c. DEQ should allow for projects deemed eligible under the RGGI model rule, including agricultural manure management projects.

At a minimum, DEQ should allow for projects deemed eligible under the RGGI model rule. This includes agricultural manure management projects. In particular, there is great potential for offset projects in Virginia's agricultural sector, including projects that capture waste methane from hog farms and convert it into renewable natural gas (RNG) that can heat homes and provide power to local businesses. By capturing methane that would otherwise be released into the atmosphere, the use of RNG leads to a significant reduction in methane emissions, a potent greenhouse gas, from the agriculture and energy industries.

In addition, as discussed in greater detail below, there is significant opportunity in Virginia and other states to achieve additional emission reductions through projects that reduce SF_6 in the transmission and distribution sector and projects that electrify the transportation sector.

d. Offsets ensure that the cap-and-trade program can continue to deliver expected environmental benefits by moderating compliance costs through expanding the universe of carbon-reducing compliance.

Allowing Virginia projects to earn CO_2 offset allowances and allowing a CO_2 budget source the flexibility to meet a limited portion of its compliance obligation with offset allowances also would moderate the costs of compliance with the program and the resulting impacts on ratepayers and consumers. Offset projects expand the universe of emission reduction activities that can be used for compliance, including activities that could have a lower per-ton cost than measures implemented at CO_2 budget sources.

The compliance cost flexibility offered by offsets will be important in the RGGI program as its stringency increases. In the past, offsets have played only a small role in the RGGI program. However, the RGGI states, including Virginia, have committed to emissions caps in 2020 and beyond that are significantly more ambitious than the caps that have applied to date. Already, the RGGI allowance market is adjusting to this expected trajectory of more stringent limits. The first RGGI allowance auction in 2017 had a clearing price of $3.00. By the December

2018 auction, the clearing price was $5.35, a 78% increase.[14] Another indicator of the growing demand for RGGI compliance instruments can be found in the futures market. The RGGI market monitor has determined that the overall volume of futures trading in the third quarter of 2018 was up 55% from the previous quarter, and 36% higher than the third quarter of the previous year.[15] The market monitor also found that options trades in the third quarter of 2018 had strike prices at $4.50 for December 2018 options, rising to $6.00 for December 2019 options.[16] And these trades pre-dated DEQ's proposal to substantially tighten the emissions cap for Virginia. In other words, all indicators point to rising prices for allowances, and therefore higher compliance costs. These are conditions for which offset projects would provide a significant cost-mitigating influence.

These conditions suggest that demand for compliance instruments in the RGGI program could increasingly approach the demand in jurisdictions participating in the Western Climate Initiative, i.e., California and Quebec. In those jurisdictions, ambitious emissions caps have yielded significant demand for offset credits, even though (1) the economy-wide scope of the cap-and-trade program means that regulated entities can draw on reductions from multiple sectors; and (2) there are strict limits on the amount of offset credits that regulated entities can use for compliance. California's compliance offset program alone has approved over 370 projects and issued over 140 million offset credits.[17] Without those credits, allowance prices (and resulting compliance costs) in California would have been significantly higher. In 2010, the California Air Resources Board (CARB) modeled how the state's cap-and-trade program would perform by 2020 under various scenarios, including a case in which the cap-and-trade program did not allow the use of offsets.[18] CARB's modeling found that the allowance price in 2020 under its base case (the cap-and-trade program with offsets) would be $25/tCO_2e$. In the case of the cap-and-trade program without offsets, the price was $148/tCO_2e$.[19] The experience in the Western Climate Initiative makes clear that there are significant risks to imposing arbitrary limits on the scope of offset projects that can generate CO_2 offset allowances.

Importantly, offsets are a cost containment mechanism that ensures that the cap-and-trade program can continue to deliver expected environmental benefits. Offsets are an important complement to the Cost Containment Reserve (CCR), an element of the RGGI model rule and the proposed Virginia rule established to contain compliance cost through a mechanism designed to help prevent allowance prices from exceeding

---

[14] See https://www.rggi.org/Auctions/Auction-Results/Prices-Volumes.
[15] https://www.rggi.org/sites/default/files/Uploads/Market-Monitor/Quarterly-Reports/MM_Secondary_Market_Report_2018_Q3.pdf, at p. 3.
[16] *Id.* at p. 11. These trades pre-dated DEQ's proposal to substantially lower the emissions cap for Virginia.
[17] ARB Offset Credits Issued, https://www.arb.ca.gov/cc/capandtrade/offsets/issuance/arb_offset_credit_issuance_table.pdf (Last Updated: January 23, 2019).
[18] CARB, Updated Economic Analysis of California's Climate Change Scoping Plan: Staff Report to the Air Resources Board (March 24, 2010), available at https://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf.
[19] *Id.*, p. 40 (Table 16).

unreasonable and unmanageable levels. The CCR achieves this aim by making additional allowances available in the RGGI allowance auction at the CCR trigger price thereby increasing the emissions cap in response to a price spike. By contrast, the offsets mechanism contains costs by expanding the universe of *emission reductions* that can be used for compliance purposes, *without* increasing the emissions cap. The two cost containment mechanisms can work well together. By making it possible for a CO_2 budget source to use CO_2 offset allowances to meet a portion of its compliance obligation, the program makes it less likely that allowance prices will spike to the level of the trigger price and thereby relax the emissions cap. In other words, offsets can ensure that activation of the CCR is the last resort that it should be.

e. **Excluding Virginia-based offset projects will deny Virginia the environmental and economic benefits such projects can deliver.**

Denying eligibility to state-based projects would not only jeopardize the cost containment benefits of offsets; it would also deny Virginia other important benefits delivered by offset projects. These include air and water quality improvements as well as new jobs.

Indeed, DEQ's proposed approach is the inverse of the approach adopted in Western Climate Initiative jurisdictions. In California, the state not only authorizes offset credits for both in-state and qualifying out-of-state projects, it mandates that at least half of the credits that a covered entity submits for compliance come from projects that provide "direct environmental benefits in the state."[20] Cap-and-trade legislation under consideration in Oregon has a similar preference for projects providing in-state environmental benefits.[21] By contrast, DEQ's proposed approach effectively establishes a preference for *other* states to enjoy these co-benefits. We urge DEQ to make it possible for Virginia to realize the co-benefits of high quality, in-state offset projects.

f. **DEQ has sufficient legal authority and administrative capacity to implement an offsets program.**

In its response to comments on the revised proposal, DEQ said that one of the reasons not to promulgate rules and procedures to award offset allowances to Virginia projects is that an offset program is "complex" to manage.[22] Yet, DEQ already has long experience with offsets programs. The General Assembly expressly authorized DEQ to assess and issue credits to offset projects, and DEQ has exercised this authority for many years in the context of the federal Clean Air Act.[23] Given this experience, DEQ is certainly no less capable of managing a CO_2 offsets program than

---

[20] AB 398, Sec. 4(c)(2)(E).
[21] Or. HB 2020, (introduced Feb. 20, 2019), Sec. 19(2)(a), available at https://olis.leg.state.or.us/liz/2019R1/Downloads/MeasureDocument/HB2020/Introduced (last visited Feb. 22, 2019).
[22] DEQ, Town Hall Agency Background Document, Form TH-02, available at http://www.townhall.virginia.gov/L/GetFile.cfm?File=1\4818\8476\AgencyStatement_DEQ_8476_v2.pdf, at p. 24 (justifying a restrictive approach on offsets based on "the uncertainty of any benefits associated with a complex offset program").
[23] 9VAC5-80-2120.

the seven other RGGI participating states that have agreed to review in-state projects.[24] New Jersey intends to join their ranks. The New Jersey Department of Environmental Protection (NJDEP) has proposed regulations under which New Jersey projects would be eligible for offset credits.[25] In the preamble to its proposed rule, NJDEP emphasizes that "offset projects outside the capped electric generation sector will provide greater compliance flexibility to CO_2 budget sources."[26] There is no good reason for Virginia to be an outlier among participating states.

To address any complexities, DEQ can draw on the extensive experience of California and other jurisdictions that have managed carbon offset programs. As noted above, CARB has reviewed and approved nearly 370 projects. CARB has expanded its administrative reach by using private, non-profit offset project "registries" to do some of the initial work of project documentation review.[27]

For these reasons, there are no meaningful legal or administrative barriers to DEQ adopting and implementing rules and procedures for review of Virginia-based offset projects.

g. DEQ should expand the scope of eligible offset projects to include SF_6 offset projects.

Given the increasing stringency of the Virginia emission caps and the RGGI program as a whole, we urge DEQ to expand the scope of eligible offset projects to include projects that reduce sulfur hexafluoride (SF_6) in the electricity transmission and distribution sector. Such projects reduce highly potent greenhouse gas emissions not otherwise covered by RGGI emission caps. According to the United Nations, the global warming potential of SF_6 is 23,900 times as great as carbon dioxide over a 100-year period.[28] Once emitted, SF_6 remains in the atmosphere for 3,200 years.[29]

Entities in the power sector do not have legal requirements to reduce SF_6 emissions, and there are no meaningful economic gains from such projects. Accordingly, such activities meet the "additionality" criteria for offset projects. SF_6 reduction projects

---

[24] *See* R.C.S.A. 22a-174-31a – Greenhouse Gas Emission Offset Projects (Connecticut); D.A.C. Title 7 section 1147 – CO_2 Budget Trading Program Regulations (Delaware); DEP Chapter 156 – CO_2 Budget Trading Program Regulations (Maine); COMAR Title 26 Subtitle 9 – Maryland CO_2 Budget Trading Program Rules (Maryland); Chapter Env-A 4700 – Carbon Dioxide Offset Projects (New Hampshire); 250-RICR-120-05-46 – CO_2 Budget Trading Program (Rhode Island); and Vermont CO_2 Budget Trading Program Regulations (Subchapter X) (Vermont).
[25] *See* Proposed N.J.A.C. 7:27C-010.3 (published Dec. 17, 2018), available at https://www.state.nj.us/dep/aqes/docs/rggi_co2_trading_proposal_with_disclaimer.pdf.
[26] *Id.* at p. 54.
[27] CARB, Offset Project Registries, available at https://www.arb.ca.gov/cc/capandtrade/offsets/registries/registries.htm (last visited Feb 16, 2019).
[28] https://unfccc.int/process/transparency-and-reporting/greenhouse-gas-data/greenhouse-gas-data-unfccc/global-warming-potentials.
[29] U.S. Environmental Protection Agency, "Overview of SF6 Emissions Sources and Reduction Options in Electric Power Systems" (August 2018), available at https://www.epa.gov/sites/production/files/2018-08/documents/12183_sf6_partnership_overview_v20_release_508.pdf, at p. 4.

are well understood, with well-established methodologies for measurement and verification.[30]

An earlier version of the RGGI Model Rule included SF_6 projects on the list of eligible project types. However, the project type subsequently was delisted. This decision was attributed to an absence of project applications; but, as discussed above, the RGGI program historically had such lenient emission caps that there was minimal demand for offset projects of any kind. In addition, the RGGI rules and procedures for SF_6 projects imposed excessive administrative burdens.[31] The combination of low demand and high administrative costs discouraged the development of SF_6 projects for RGGI purposes. As discussed above, however, there is every reason to expect substantially greater demand for offsets in the RGGI states in the future, which provides a reason for DEQ to revisit and streamline the rules and procedures for SF_6 projects.

h. DEQ should expand the scope of eligible offset projects to include projects that contribute to electrification of the transportation sector.

We also urge DEQ to establish the eligibility of projects that reduce CO_2 emissions in the transportation sector through electrification, including development of charging infrastructure.

Across the United States, transportation sector CO_2 emissions now exceed those from the power sector, and are continuing to increase.[32] Rising transportation sector emissions complicate the efforts of Virginia and other states to achieve climate policy objectives.[33] A number of studies have concluded that it will only be possible to achieve decarbonization objectives for the transportation sector through electrification of much of the sector.[34] Electrification, in turn, will only be possible through a build out of charging infrastructure. Electric vehicles are becoming an attractive choice for more consumers; however, potential buyers identify the lack of charging stations as a major obstacle.[35]

---

[30] *See, e.g., id.*
[31] *See* Comments of ConEdison on the June 27, 2017 RGGI Stakeholder Meeting (July 7, 2017), available at https://www.rggi.org/sites/default/files/Uploads/Program-Review/6-27-2017/Comments/ConEdison_Comments.pdf, at p. 1 (observing that the New York State Department of Environmental Conservation required a project sponsor to file ten forms with its consistency application and eight forms with the annual monitoring and verification submission – each of which must be reviewed and verified by an independent entity).
[32] U.S. Energy Information Administration, Power Sector Carbon Dioxide Emissions Fall Below Transportation Sector Emissions (Dec. 19, 2017), available at https://www.eia.gov/todayinenergy/detail.php?id=34192.
[33] B. Storrow, "Emissions: Cars Threaten Climate Goals in Blue States," E&E News (Apr. 17, 2018) ("The policy innovation at the state level has largely been focused on power and not on comprehensive solutions," said John Larsen, an analyst at the Rhodium Group. "Tackling emissions outside the power sector is required if states are going to continue to lead.")
[34] *See, e.g.,* The White House, Mid-Century Strategy for Deep Decarbonization (Nov. 2016), *available at* https://unfccc.int/files/focus/long-term_strategies/application/pdf/mid_century_strategy_report-final_red.pdf.
[35] Mark Singer, National Renewable Energy Laboratory, Consumer Views on Plug-in Electric Vehicles– National Benchmark Report (2016), http://www.afdc.energy.gov/uploads/publication/consumer_views_pev_benchmark.pdf.

State incentives can play a key role in this necessary build-out of charging infrastructure.[36] Furthermore, utilities are well positioned to lift the market for charging infrastructure off the ground. Utilities can offer experience with infrastructure development, the benefits of grid coordination, expertise with customer pricing models with the grid, and experience developing services for disadvantaged communities.[37] For these reasons, we recommend DEQ create a market-based incentive for charging station development by owners of CO_2 budget sources in the form of CO_2 offset allowances. The CO_2 offset allowances would correspond to the CO_2 emission reductions attributable to the electricity provided by the station to electric vehicles, which would displace the use of higher carbon-intensity gasoline that conventional vehicles would otherwise use.[38] This incentive mechanism would give Virginia a jump start on its development of policies under the Transportation & Climate Initiative.

9. **DEQ needs to provide more clarification as to how the allowance allocation and consignment auction process will be implemented.**

In its current form, the proposed regulation is confusing and unclear as to how the CO_2 allowance allocation process and interaction with the RGGI auction will be implemented.

First, the regulation proposes to allocate allowances to the CO2 budget units in two different subsections of Article 5 as follows:

> *9 VAC 5-140-6190.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 and 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 an allowance to be used for compliance purposes* (emphasis added).

> *9 VAC 5-140-6215.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 CO_2 conditional allowances equal to the CO_2 base budget.* (emphasis added)

[36] *See* National Conference of State Legislators, State Efforts to Promote Hybrid and Electric Vehicles (Sep. 26, 2017), available at http://www.ncsl.org/research/energy/state-electric-vehicle-incentives-state-chart.aspx#action (last visited Feb. 14, 2019); Center for American Progress, Investing in Charging Infrastructure for Plug-In Electric Vehicles: How to Accelerate Deployment (July 30, 2018), available at https://www.americanprogress.org/issues/green/reports/2018/07/30/454084/investing-charging-infrastructure-plug-electric-vehicles/ (last visited Feb. 14, 2019).
[37] *See* M.J. Bradley & Associates and Georgetown Climate Law Center, Utility Investment in Electric Vehicle Charging Infrastructure: Key Regulatory Consideration (Nov. 2017), available at https://www.georgetownclimate.org/files/report/GCC-MJBA_Utility-Investment-in-EV-Charging-Infrastructure.pdf.
[38] One example of a potential methodology for awarding offset credits to such a project has been established under the auspices of the Verified Carbon Standard. *See* Verified Carbon Standard, Methodology for Electric Vehicle Charging Systems (Apr. 2018), available at http://verra.org/wp-content/uploads/2018/05/Methodology-for-Electric-Vehicle-Charging-Systems.pdf.

Under 9 VAC 5-140-6190.B, the CO2 budget unit would be required to consign the allowances to an auction. This requirement is also specified in 9 VAC 5-140-6430, which states that

> *"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 shall become a CO_2 allowance."* (emphasis added)

As noted in comments submitted in response to DEQ's initial proposal, we strongly support the use of a consignment auction approach as it reflects DEQ's intended approach to allocate allowances to the affected generation units affected by the rule. However, proposed regulatory text elsewhere appears to suggest that CO2 allowances would be allocated to an "agent" (which is undefined, but presumably would be the RGGI auction). Subsection 9 VAC 5-140-6210.H specifies that:

> *1. By May 1, 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 May 1, 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 April 1, 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 May 1, 2021, and May 1 of every subsequent year thereafter, the department will submit to its agent the CO_2 allowance allocations for the applicable control period in accordance with 9VAC5-140-6215 A and B.* (emphasis added)

It is not clear whether the "submittal to its agent" refers to a direct allocation of a CO_2 allowance or whether the provision is providing a means for DEQ to submit to the auction agent an amount of "actual allowances" to assure a necessary supply of allowances are available such that "conditional" allowances (allocated to affected generating units) can be converted to "actual allowances" that can be used by affected entities for compliance purposes. DEQ needs to provide more clarification as to how the allowance allocation and consignment auction process will be implemented. DEQ should also explain why subsections H.1 and H.2 refer to the submission of "conditional allowances" while subsection H.3 refers to "allowances".

It is also unclear why allowances for the 2021 interim control period are submitted to the agent in the 50/50 percent fashion specified in subsection H.2 while subsection H.3 would allow for full submittal of annual allowances in all subsequent years thereafter – even for interim control period years. To allow for a consistent approach for submitting allowances to the agent that would provide for submission prior to a subsequent control period, we suggest subsections H.2 and H.3 be modified as follows:

> *2. By May 1, 2020, the department will submit to its agent the ~~conditional~~ allowance allocations in accordance with 9VAC5-140-6215 A and B, for the 2021 control period. ~~By April 1, 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 May 1, 2021, and May 1 of every subsequent year thereafter, the department will submit to its agent the CO_2 allowance allocations for the [subsequent] ~~applicable~~ control period in accordance with 9VAC5-140-6215 A and B.*

10. The deadline for initial generation output submittals must be extended.

The deadline specified in 9 VAC 5-140-6215.C.1 for affected entities to submit initial generation output data (2016-2018) to DEQ for the initial 2020 allocation determination needs to be extended. The March 1, 2019 submittal date, which precedes even the deadline to submit comments on this re-proposal, will certainly precede any date for which the regulation, if finalized, would become effective. At a minimum, the submittal deadline for initial generation output data should be changed to 60 days after the effective date of the regulation.

11. An extension is needed for the timing of DEQ submittal of allowances for the initial (2020) compliance period into the program auction.

The May 1, 2019 deadline for DEQ to submit to the auction agent conditional allowance allocations for the initial 2020 control period, specified in 9 VAC 5-1400-6210.H.1, also must be extended. It is unlikely that the proposed regulation will be final and effective before May 1, 2019, and DEQ will need adequate time to determine the allocations for the 2020 interim control period once it receives the required initial generation output data from affected entities. Accordingly, the deadline should be set at least 60 days after the deadline for submittal of the initial generation output data specified in 9 VAC 5-140-6215.C.1 (amended, as suggested above).

12. A correction to the regulatory text in 9 VAC 5-140-6420.A.2 is needed to provide the intended citation to the conditions that would trigger the Cost Containment Reserve (CCR).

We believe the change (insertion) highlighted below (in brackets) is needed in 9 VAC 5-140-6420.A.2, which specifies the number of CO_2 Cost Containment Reserve (CCR) allowances that would be offered for sale during an auction, in order to provide the intended citation to the conditions that would trigger the CCR provisions.

> *The number of CO_2 allowances that will be offered for sale at the auction if the condition of [B].1 of this subsection is met:*

Conclusion

In conclusion, we remain concerned that the Commonwealth's linkage to the RGGI program through the Virginia carbon proposal with its now significantly lower proposed starting emissions cap would disadvantage Virginia generation relative to other states and result in an undue burden on its customers with no real mitigation of GHG emissions regionally. DEQ should defer reducing the Virginia cap from the levels initially proposed in January 2018 and reassess the need to do so in accordance with the next RGGI program review. DEQ also should defer any further reductions of the emissions cap beyond 2030 until such time that the RGGI states collectively determine that further reductions of the regional cap are necessary.

In addition, regardless of the baseline cap ultimately established, DEQ should provide regulatory language to clarify that a unit meeting the definition of a fossil fuel-fired unit that co-fires with biomass would not be required to hold CO_2 allowances for emissions associated with the burning of biomass. The regulation should also expand the scope of eligible offset projects to include Virginia-based projects including projects that incentivize and achieve greenhouse gas emission reductions from other sectors of the economy.

Thank you for this opportunity to provide comment. We appreciate your consideration of these matters. Dominion Energy plans to continue our efforts to provide cleaner energy to our customers, and we look forward to working with you as we undertake these efforts. If you have any questions, please contact me at 804-273-2998, (Amanda.B.Tornabene@dominionenergy.com), Lisa Messinger at 804-273-2792 (Lisa.C.Messinger@dominionenergy.com) or Lenny Dupuis at 804-273-3022, (Leonard.Dupuis@dominionenergy.com).

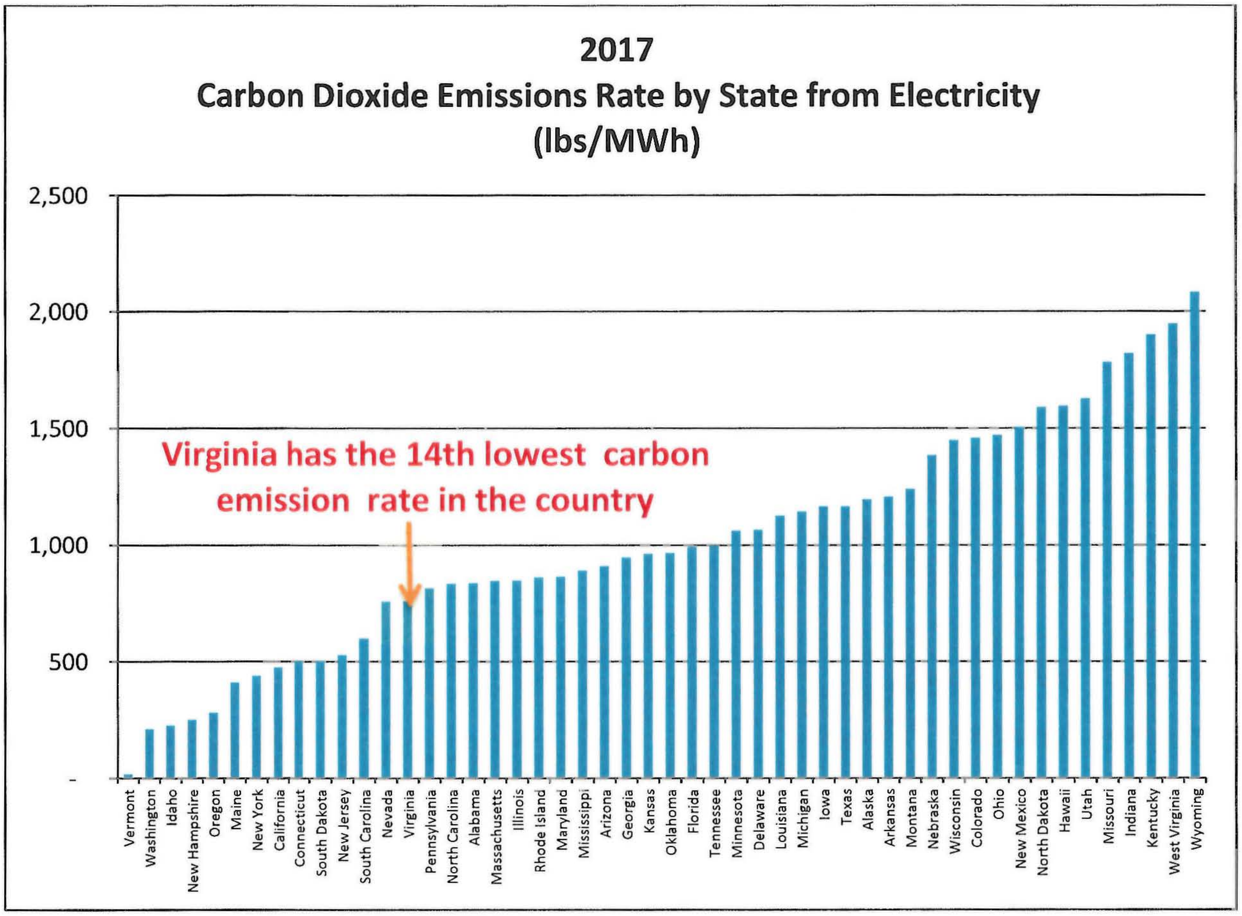
Sincerely,

Lisa C. Messinger

Amanda B. Tornabene for

Ecc: Mr. David K. Paylor (DEQ)
Mr. Michael S. Dowd (DEQ)
Mr. Thomas Ballou (DEQ)
Ms. Angela Conrad (DEQ)

Appendix A



Note: State intensity rankings charted from lowest to highest emitters
Source: Energy Information Administration (EIA) – State Electricity Profiles at https://www.eia.gov/electricity/state/