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Comments of the Virginia Manufacturers Association on Re-proposed Regulation for Emissions Trading Programs (Rev. C17)
9 V.A.C. 5-140-6010 through 9 V.A.C. 5-140-6440
35 Va. Reg. 1404 (Feb. 4, 2019)

I. Introduction

On behalf of its member companies, the Virginia Manufacturers Association (VMA) submits the following comments on the re-proposal by the State Air Pollution Control Board (the Board) to adopt regulations to reduce and cap carbon dioxide (CO2) emissions from fossil fuel-fired electric generating facilities through emissions trading programs (the Re-proposed Rule).[1]

Since 1922, the VMA has served as Industry's Advocate.™ Our mission is to create the best business environment in the United States for world-class advanced technology businesses to manufacture and headquarter their companies for maximum productivity and profitability. VMA is committed to environmental excellence.

Several member companies intend to file separate comments on the Re-proposed Rule. We urge the Virginia Department of Environmental Quality (DEQ) and the Board to carefully consider VMA's comments and the comments of our member companies on this crucial rulemaking that is poised to permanently change the manufacturing landscape in the Commonwealth.

At the outset, VMA insists that DEQ and the Board consider why the proposed CO2 emissions cap-and-trade program is even necessary. CO2 emissions in Virginia have plummeted without such a program. In February 2019, the U.S. Energy Information Administration (EIA) published data indicating that Virginia's CO2 emissions

[1] 35 Va. Reg. 1404 (Feb. 4, 2019).

have decreased 20.0% from 2005 to 2016, the last year tallied.[2] In fact, reductions in CO2 have been greater in Virginia than the following RGGI states: Connecticut, Delaware, New Hampshire, New Jersey, Rhode Island, and Vermont.[3] RGGI member states also saw CO2 decreases for this time period, but these data suggest that CO2 in Virginia can be reduced without a punitive cap and trade mechanism. The carbon footprint in Virginia is expected to continue this downward trend. The aggressive suite of national and state environmental regulations will continue to take effect and encourage growth of renewable energy in the Commonwealth.

VMA will discuss the negative impacts of the Re-proposed Rule on Virginia's current manufacturers and positioning as the home to future manufacturers. Given that carbon emissions are decreasing *without* the Re-proposed Rule, there is no justification for the damaging impact of the Re-proposed Rule on manufacturers and the increased costs of the Re-proposed Rule to manufacturers, residential and commercial electricity customers.

II. Brief Synopsis of VMA's Comments on the Original Proposed Regulation

On April 9, 2018, VMA commented and opposed the original proposal to adopt regulations to reduce and cap CO2 emissions from fossil fuel-fired electric generating facilities.[4] VMA incorporates those comments by reference.[5] We summarize and underscore the most important points from those comments in this Section II.

1. Contrary to Virginia's historical approach, the proposed regulations are more stringent than federally required.

The Board should adhere to this long-standing Virginia approach, eschew the regulation of CO2 emissions as proposed, and leave any such regulation to the appropriate time and approach determined for the nation by Congress and the U.S. Environmental Protection Agency (EPA).

2. Neither the Board nor the DEQ has provided a rationale for the need for regulations that are more stringent than federally required pursuant to Va. Code § 10.1-1308.A.

There are no federal CO2 requirements. Clearly, the proposed regulations are more stringent than federally required. DEQ must provide a rationale for the *need*, not just the debatable social desirability, for the more stringent requirements in the Re-proposed Rule. This has not happened to-date, even after the re-proposal.

3. The proposed regulations are not cost-effective.

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[2] *See* EIA, Table 2, State energy-related carbon dioxide emissions by year, adjusted (2005-2016), dated February 2019.
[3] *Id.*
[4] 9 VAC 5-140, Part VII, 34 Va. Reg. 924 (Jan. 8, 2018).
[5] Please see VMA's comments on the original proposal as Attachment A.

As originally proposed, the regulations were not cost-effective. The cost burden far exceeded any purported benefits from the proposed regulations. As discussed herein, the Re-proposed Rule is even less cost-effective than the original proposal.

4. The purported benefits of the Cap and Trade regulations are unsubstantiated and illusory.

The administrative record for the proposed rulemaking is devoid of the necessary scientific data or other information to support the conclusion that the proposed CO2 emissions cap-and-trade program in Virginia would have benefit, such as any real, perceptible effect on the severity of storms, storm surges, or flooding in Virginia. In fact, the Virginia Department of Budget and Planning (DPB) acknowledged that it is not possible to quantify benefits to Virginia in its original Economic Impact Analysis.[6] Virginians would receive no real benefit from the proposed or re-proposed regulations.

5. Undesirable emissions "leakage" will happen, resulting in no overall CO2 emission reductions in the region.

Virginia will likely import electricity from out-of-state fossil fuel-fired generating facilities in response to higher costs, thereby reducing electricity generation in the Commonwealth. The analysis conducted by ICF[7] supports the conclusion that the proposed CO2 emissions cap-and-trade program would significantly increase the import of electricity into Virginia from out of state facilities. Virginians would pay higher energy costs, but overall national CO2 emissions would not be reduced.

6. The increasing CO2 concentration in the atmosphere is a global phenomenon that requires a global, or at least national, approach.

If regulation of CO2 emissions in the United States is needed to address climate change, then regulation must be undertaken and applied uniformly throughout the country, not state-by-state or locality-by-locality.

7. Any adverse effects of climate change in Virginia would be better addressed through comprehensive resiliency planning and implementation.

Virginia should develop and implement cost-effective programs to address the perceived effects of climate change in Virginia. The costs of a CO2 emissions cap-and-

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[6] The DPB stated: "The U.S. Environmental Protection Agency (EPA) and other federal agencies use estimates of the social cost of carbon (SC-CO2) to value the climate impacts of regulatory rulemakings. The SC-CO2 is a measure, in dollars, of the long-term damage done by a ton of CO2 emissions in a given year. This dollar figure also represents the value of damages avoided for a reduction of a ton of CO2 emissions in a given year (i.e. the benefit of a CO2 reduction). It should be noted that the federal model estimates of the social cost of carbon are for the world overall. Thus, it is not possible to quantify the Virginia-specific benefits." (Footnotes omitted.)

[7] ICF is a contractor hired by the Georgetown Climate Center to analyze the potential impacts of Virginia's participation in Regional Greenhouse Gas Initiative, Inc. (RGGI).

trade program imposed on Virginia's citizens and businesses would be much better spent directly on resiliency infrastructure or programs recommended by former Governor McAuliffe's Governor's Climate Change and Resiliency Update Commission that will have a tangible impact on communities in the Commonwealth.

8. The costs of the proposed CO2 emissions Cap and Trade regulations outweigh any purported benefits.

Virginia's citizens and businesses will experience a significant increase in electricity costs, as a result, of the proposed cap and trade program. However, this cost is not justified since the program does not provide any direct or measurable benefit to Virginians.

9. The proposed Cap and Trade program will have a significant adverse effect on manufacturing in Virginia.

Virginia is ranked among the most competitive southern states for manufacturing. However, this preeminent competitive position will be severely jeopardized by increasing energy costs in the Commonwealth.[8] The increased cost of operation will diminish Virginia's advantage over the Southeastern and Midwestern states against which the Commonwealth competes for new and expanded industry. The Re-Proposed Rule places Virginia's competitive profile at further risk, as discussed in more detail herein.

10. The Cap and Trade regulations impose a carbon tax.

Originally, the proposed CO2 emissions cap-and-trade program in Virginia was supposed to operate to return revenue generated by the auction of conditional allowances consigned by a regulated Virginia source to that source owner, less RGGI's administrative fees. If this return does not happen, the regulations will essentially operate as a carbon tax. However, the General Assembly cannot constitutionally delegate its taxing power to an unelected entity, whether the Board, DEQ or RGGI. The Virginia Constitution and case law are quite clear on these matters. In *Marshall v. Northern Virginia Transportation Authority*, 275 Va. 419, 657 S.E. 2d 71 (2008), the Virginia Supreme Court affirmed that taxes must be imposed only by a majority of the elected representatives of a legislative body, with the votes cast by the elected representatives being duly recorded. VMA made this comment in its first set of comments and reiterates this concern, particularly in light of the recent budget amendment.[9]

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[8] Cato Institute Working Paper: A Review of the Regional Greenhouse Gas Initiative, Aug. 10, 2017, pp. 8-10. The Cato Institute study found that from 2007 (pre-RGGI) to 2014 the economies of the five non-RGGI comparison states grew 2.5 times faster than the RGGI states. It is clear that even as the economy was recovering from the recession of 2008, industry was leaving the RGGI states.

[9] The Virginia General Assembly amended the budget to state: "Any revenues generated through participation in any regional climate change compact, including but not limited to the Regional Greenhouse Gas Initiative and the Transportation Climate Initiative, shall be deposited in the general fund and shall not be transferred to any other entity as a condition of such compact nor shall such funds be

11. CO2 emissions from Virginia sources are declining rapidly anyway.

CO2 emissions in Virginia are dropping because citizens and businesses are becoming more energy efficient, and governments are subsidizing more renewable energy sources. Virginia is already among the nation's leaders in reducing CO2 emissions. Virginia is reducing its carbon footprint at a rate much faster than the nation as a whole, and comparable to the RGGI states even without a costly CO2 emissions cap and trade program.

12. Renewable energy generation is rapidly expanding in Virginia even without the proposed CO2 emissions cap-and-trade program.

Virginia's electric utilities are strongly committed to expanding the role of renewable energy in power generation. Virginia's electric utilities are moving rapidly to greatly expand generation from renewable resources. Virginia is already among the nation's leading states in this regard. A costly program capping CO2 emissions is unnecessary to promote the continued growth of renewable energy generation in the Commonwealth, especially when considering the statutory requirements of SB966 (2018).[10]

13. Forcing owner/operators of electric generating units in Virginia to consign their allowances to RGGI for general auction constitutes an illegal "taking."

If the Board adopts the proposed CO2 cap-and-trade program and fails to allocate allowances necessary for those facilities to generate electricity, that failure would deprive those entities of their ability to operate. Such takings are prohibited by the U.S and Virginia Constitutions.

14. By compelling owner/operators of electric generating units in Virginia to consign allowances issued to them to RGGI for auction under RGGI's sole control, the Board would be attempting to enter an interstate compact without authorization by the Virginia General Assembly and the U.S. Congress.

Virginia is a member of numerous interstate and regional compacts. An essential feature of every one of these interstate compacts is specific authorization by the U.S. Congress and confirmation by the Virginia General Assembly. "Linking" to RGGI by compelling the consignment of allowances to RGGI for general auction would constitute an unauthorized compact with the RGGI states. Attempting to do so would exceed the authority of the Board.

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expended for any projects or programs without the express approval of the General Assembly as evidenced by an appropriation of such funds in a general Appropriation Act." Va HB 1700, 2019 General Assembly Session (Item 4-2.02 #1h).

[10] SB 966 (2018) is entitled "Electric utility regulation; grid modernization, energy efficiency."

15. VMA also previously commented on many specific aspects of the original Proposal:

- Retain proposed applicability provisions for CO2 emission sources, which includes the Industrial Exemption.
- Fossil fuel-fired units that serve electrical generators smaller than 25 MWe should not be subject to the regulations.
- Industrial facilities should not be included in the proposed CO2 emissions cap and trade program at all.
- Expanding the reach of the CO2 emissions cap and trade program beyond the electric power generation sector would exceed the Governor's mandate to the Board, and there is no basis for doing so.
- Virginia's industrial facilities and electric generation utilities are not similarly situated to comply with CO2 emissions cap-and-trade requirements.
- The regulations should specify that to qualify for the industrial facility exemption, at least one third of the electricity and heat generated on-site can be exported off-site so as to clarify the lack of a "primary use" of energy definition.
- The proposed regulations should exclude CO2 emissions from the combustion of non-fossil fuels.
- The Board should not adopt a CO2 emissions cap-and-trade program that entails a direct auction of allowances by the DEQ.

III. VMA Strongly Opposes the Re-Proposed CO2 Cap and Trade Regulation.

VMA opposes the Re-proposed CO2 Cap and Trade Regulation for the following specific reasons.

A. DEQ's cost impact analysis wrongly and illegally obfuscates Virginia's regulatory review process. The State Corporation Commission (SCC) projects substantial cost increases for Dominion Energy's customers.

The original proposed CO2 Cap and Trade rule included a CO2 allowance budget of either 33 or 34 million tons. The Re-proposed Rule reduces the CO2 allowance budget to 28 million tons. DEQ originally calculated significant cost increases to Dominion Energy's customers. These cost projections estimated that costs to industrial customers would increase from 0.5% to 1.1% annually. The chief assumptions made in this analysis were:

1. Natural gas prices would increase slightly;
2. Future demand would increase substantially; and
3. Some additional solar will be added, but not the 5,000 MW included in the 2018 Grid Transformation and Security Act (GTSA) policy goals.

These assumptions were derived from the Dominion Energy IRP in place at the time. Dominion Energy is now in the process of revising its IRP, thus preventing the economic analysis of the Re-proposed CO2 Cap and Trade rule from using IRP assumptions. The original analysis assumed that any revenue from selling allowances in the RGGI market or to third parties will be returned to customers. It is important to distinguish this revenue from the flow back that regulated utilities will receive as reimbursement for the purchase of the consigned allowances.

DEQ now analyzes a 28 million ton allowance budget scenario and predicts no cost increase for any Dominion Energy customers. The DEQ cost analysis adopted by DEQ predicts no rate increases because it is based on indefensible assumptions. DEQ never explains why the original analysis was abandoned, except to state "things can change a lot in a year" and to "foster better integration into RGGI." Better integration into RGGI can only mean that RGGI wants fewer allowances auctioned in its market to minimize dilution and resulting allowance price decreases. The DEQ cost study assumes that:

1. The reimbursement of consignment auction costs will be passed to customers.
2. The policy goals in 2018 GTSA are in place by 2030.
   A. 5,000 MWs of solar,
   B. 30 MWs of battery storage, and
   C. $870 MM of spending on energy efficiency programs (the most tenuous of the three).
3. Renewable generation offsets generation from affected units.
4. Further reduction in natural gas prices.
5. Demand reductions because demand is down in other RGGI states.
6. 12-18% reductions in firm power price projections from the prices modeled in 2017.

On the first point, there is nothing in the Re-proposed Rule that requires cost flow back from the consignment auction to regulated utilities to flow down to customers. In fact, there is no mechanism in the Re-proposed Rule for how the flow back to the regulated utilities will work, let alone the flow down to the customers. Obviously, this assumption must be removed from the analysis. The removal of this assumption alone will result in a projection of substantial increased costs to industrial and residential consumers. These costs are significant to Virginia manufacturers.

The SCC performed its own study and provided a summary of the study to Delegate Kilgore and to VMA[11]. The SCC does make DEQ's assumption of full implementation of the 2018 GTSA's policy goals of 5,000 MWs of solar, 30 MWs of battery storage and $870 million spending on energy efficiency programs. The SCC analysis does not assume the flow back of consignment auction costs to customers. The SCC testified before a subcommittee of the Virginia House Labor and Commerce Committee, on January 24, 2019, that the flow back will be returned to customers "one

[11] Please see Attachments B and C.

way or another ultimately," but this assumes that in a future rate proceeding before the SCC, the flow back will be credited to customers. There is no basis to predict whether, how or when this will happen.

The SCC concludes that the total cost to Dominion Energy from 2020 to 2030 will increase $3.3 billion if only linked to RGGI and $5.9 billion if Virginia joins RGGI. Experience informs our members that a substantial portion of these increased costs will be passed to industrial customers. DEQ must adopt the SCC analysis. Areas of difference are mainly, that:

1. Even if the full GTSA policy goals are implemented, renewables will not necessarily offset generation from Virginia fossil fuel units. Virginia is a member of PJM,[12] which dispatches units over a large region. Additional renewables are likely to displace older, higher cost units in other states.
2. These renewables and fossil fuel units are two different types of generation and are not interchangeable. Solar is intermittent, and fossil fuel is continuous.
3. The DEQ analysis assumes that natural gas prices will decrease below the very low current prices. DEQ only cites general EIA analyses over decades to support this assumption.
4. The DEQ analysis assumes demand will reduce in Virginia because demand is down in other RGGI states. No Virginia demand analysis is made. Demand in RGGI states appears to decrease because RGGI raised the cost of generation, and electricity is now imported into these states.
5. The DEQ analysis also assumes that firm power price projections from the prices modeled in 2017 will drop 12% to 28% from 2020 to 2030. No explanation supporting this assumption is given.

In a letter dated February 27, 2019, from William F. Stephens, Director of the State Corporation Commission, Division of Public Utility Regulation to Delegate Charles D. Poindexter (Poindexter Letter),[13] the SCC provided a detailed analysis of the DEQ cost analysis. The SCC found DEQ's conclusion that there would be no rate impact of the Re-proposed Rule to be completely incorrect. As noted, the SCC concluded that the costs to Dominion Energy will be $3.3 billion if Virginia only links (e.g., consignment) to RGGI. If Virginia joins RGGI, the cost will be $5.9 billion.

The SCC finds that the most significant mistake that DEQ makes is to misunderstand Dominion Energy's operation and rate structure. DEQ's analysis treats Dominion Energy as only a buyer of electricity and effectively a merchant company with only shareholders to bear costs. In doing so, DEQ ignores the fact that Dominion Energy is an integrated utility, with substantial generation to serve customer load. Obviously, the allowance structure is designed to increase the cost of generation by

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[12] PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

[13] Please see the Poindexter Letter at Attachment D.

reducing allowance allocations by three percent a year. Customers will pay for the increased operating costs for fossil fuel units to continue to run. Furthermore, these costs will be borne by the customers whether the units run or not. None of these costs are included in the DEQ analysis.

The SCC models show that Chesterfield Units 5 and 6 and Clover Units 1 and 2 will be forced to retire prematurely (2022 and 2025, respectively).[14] Dominion Energy's customers will pay for the retired units and will also pay for the construction of 1,500 MWs that must be built earlier than anticipated to replace the retired units and meet PJM capacity requirements. Thus, Virginia customers effectively pay twice for the same 1,500 MWs of generation.

As noted above, even if the 2018 GTSA policy goals are achieved, Dominion Energy will not meet its CO2 emissions reduction goals. The additional renewables, battery capacity and efficiency projects will displace the least efficient, highest cost units in PJM. These are not Dominion Energy units. Dominion Energy is still likely to have to prematurely retire 1,500 MWs of coal and replace those MWs with natural gas to meet PJM's capacity needs.

DEQ also modeled a CO2 emissions allowance price that is lower than the Emissions Containment Reserve (ECR) trigger price. The Re-proposed Rule and the RGGI market establish the ECR trigger price to act as the market floor for allowance prices. If the allowance price drops below the ECR trigger price, then allowances are removed from the market until the price moves up. DEQ's allowance cost assumption that the CO2 emissions allowances will always clear at a price lower than the ECR trigger price requires explanation, as the ECR mechanism in the RGGI model rule and incorporated in the Re-Proposal is designed to prevent this pricing assumption from happening.

In its analysis, DEQ assumed a 2.1% discount rate. The SCC assumed 6.31% discount rate, which reflects Dominion Energy's after tax weighted average cost of capital. DEQ's use of the lower discount rate understates the true costs of future capital investments. The SCC's use of the 6.31% discount rate reflects Dominion Energy's actual cost of funding large capital projects. Again, DEQ makes a fundamentally flawed assumption that understates the actual cost of the Re-proposed Rule.

None of these DEQ assumptions are supported by actual analysis of the Virginia energy landscape, and DEQ does not attempt to provide any insight. At this point, the record is incomplete, because the actual cost impact of the Re-proposed Rule is not included. The fact that the DEQ analysis did not capture any of these costs, more than demonstrates that it cannot be the basis for the Rule.

DEQ must withdraw the Rule and adopt the SCC cost analysis. Without accurate cost data, an accurate cost-benefit analysis cannot be made. The public is denied the

[14] Without the CO2 Cap and Trade program, Chesterfield Units 5 and 6 would retire in 2034 and 2039 respectively. Clover Units 1 and 2 would retire in 2034 and 2051.

right to notice and comment on the Rule. Making false assumptions to achieve an inaccurate cost impact is unacceptable and skirts the Joint Legislative Audit & Review Commission review process. Only re-issuing the proposal again with an accurate cost analysis will meet notice and comment requirements and allow the Board to make an informed decision.

B. The Industrial Exemption Must Stay Intact, Should be Clarified, and Should Broadly Apply To All Existing and Future Industrial Source Electric Generating Units.

DEQ's Re-proposed Rule has narrowed the industrial exemption in several ways, which will have significant, negative repercussions on existing manufacturers and future manufacturers considering Virginia for a site. The Re-proposed Rule provides this mark-up for the industrial unit exemption. Below is a comparison against the original proposal that demonstrates the additional qualifications in the underlined text that a manufacturer must now meet to be exempt:

> B. Exempt from the requirements of this part is any fossil fuel [~~power generating unit located at individual facility that generates electricity and heat from fossil fuel for the primary use of operation of the facility~~ CO_2 budget source located at or adjacent to and physically interconnected with a manufacturing facility that: (i) supplies less than or equal to 10% of its annual gross electrical generation to the electric grid, or (ii) supplies less than or equal to 15% of its annual total useful energy to an entity other than a manufacturing facility in the Commonwealth, provided that the CO_2 budget source had, prior to January 1, 2019, supplied both non-electric thermal energy to a manufacturing facility and 15% or less of its annual total useful energy to an entity other than a manufacturing facility. Such unit shall have a permit containing the applicable restriction under subdivision (i) or (ii) of this subsection.

1. The Exemption Inappropriately Narrows the Sources that are Defined as "Fossil Fuel CO2 Budget Sources," which Can Qualify for the Industrial Exemption.

The Re-Proposal revises the definition of "fossil fuel-fired CO2 budget source" to change the amount of fuel comprised of fossil fuel from 10% to 5%. The present definition states:

> "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 [~~10%~~ 5.0%] of the annual heat input on a Btu basis during any year.[15]

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[15] 35 Va. Reg. 1401, 1413 (Feb. 4, 2019).

This revision places manufacturing plants at risk of becoming subject to the Rule without any CO_2 allowance allocations. VMA urges DEQ to retain the 10% fossil fuel combustion threshold. Non-fossil fired fuel units require some amount of fossil fuel as a backup fuel and for periods of startup, shutdown, and for flame stability. These units are traditionally operated well below 10% fossil fuel. However, they do typically vary from year-to-year in the 3-7% range. By lowering the threshold to 5%, DEQ could be creating a situation where units might be subject to the standards one year and not another. Retaining the 10% fossil fuel combustion in this definition is essential to keep operational flexibility intact for these units and not unnecessarily creating confusion over applicability to the Rule. The Re-Proposal must allow more flexibility for combusting other environmentally-friendly fuels, while continuing to retain the Industrial Exemption for those units.

2. The Exemption's New Sunset Date of January 1, 2019 Will Freeze Virginia's Manufacturing Footprint.

VMA sees the Re-Proposal as overly restricting manufacturing growth in Virginia. As VMA articulated in its original comments, Virginia has a $112.3 billion economic output from its robust manufacturing sector[16] and has prospered from a strong competitive position. VMA's original comments focused on the damage to that position due to the increase in electricity costs expected from a cap and trade rule.

Now, the Re-Proposal goes much further. It overtly clips Virginia's upward trajectory to continue as a prosperous manufacturing state by forcing new manufacturing sources to comply with this CO_2 cap and trade rule. Specifically, the Re-Proposal diverges from the original rule by providing that the Exemption only applies to sources that meet the Exemption requirements prior to January 1, 2019. The Re-proposed Rule grandfathers existing sources, but any new facility, whether built by an existing company or new company operating in the Commonwealth, will have to contend with the CO_2 cap and trade rule.

The result of further narrowing the Industrial Exemption is clear. New manufacturers will choose to locate facilities requiring an electric generating unit greater than 25 MWe in another state. A decline in manufacturing has already been measured in other RGGI states. The decline in manufacturing in RGGI states can be seen by comparing the industrial electricity demand. RGGI states' demand fell 17 percent in comparison with non-RGGI comparison states that fell only 3 percent.[17] We note that although CO_2 may be reduced locally by having fewer manufacturing sources in the RGGI states, those CO_2 emissions are simply occurring in non-RGGI states. This is not the solution to global CO_2 emissions.

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[16] Virginia Economic Development Partnership, Economic Impact of Virginia's Manufacturing Sector, 2018.

[17] *See* Cato Institute Working Paper: A Review of the Regional Greenhouse Gas Initiative, Aug. 10, 2017. For further discussion, please see VMA comments on the original proposal, attached, in Section III.C.5.b.

The damage to the manufacturing sector is tangible. The Virginia Economic Development Partnership provides "cost of doing business" as a primary consideration for businesses looking to enter the state. That cost is composed of the cost of electricity, to be impacted by the Re-Proposal, as well as the cost of regulatory compliance. The Re-proposed Rule will cause industry members considering a Virginia siting to choose less expensive siting choices outside of the Commonwealth.

Putting Virginia at a competitive disadvantage for attracting larger manufacturers is completely contrary to the supposed goals of the Governor to bring more manufacturers to the Commonwealth, increase jobs, and enhance the Virginia economy. It is also contrary to VMA's mission to foster the best business environment to maximize productivity and profitability in the Commonwealth. For these reasons, VMA strongly advocates for the removal of the January 1, 2019 grandfathering clause from the Industrial Exemption. All manufacturers, regardless of when they come to Virginia, should be able to use the Exemption.

3. The Industrial Exemption and Related Definitions Lack Clarity, which will lead to multiple interpretations and confusion in implementation.

VMA has identified a number of areas in which the Industrial Exemption and related definitions are not clear. VMA recommends the following revisions to the Exemption:

- The Industrial Exemption should clarify that it applies on a facility-basis, not on a unit-basis. We believe that the Exemption is intended by DEQ to apply on a facility basis given that the Exemption refers to exempting any "CO2 budget source located at or adjacent to and physically interconnected with a manufacturing facility." The Re-proposed Rule defines a "CO2 budget source" as "one or more budget units," contemplating that a source can include more than one unit. However, since the term CO2 budget source is used in multiple contexts throughout the Rule, clarification is needed to ensure the Exemption's consistent application. We recommend that the Exemption substitute "source" for "CO2 budget source" because "source" is defined in the Re-Proposal as "a source with multiple units."[18]

- The Industrial Exemption should provide the specific units of measure for "Total Useful Energy and "Annual Net Electrical Generation." The Industrial Exemption provides a calculation to determine annual net electrical generation. The Exemption does not apply when a source

[18] 35 Va. Reg. at 1415.

supplies more than 10% of its annual net electrical generation to the electric grid. That calculation in the Exemption should be clarified to note that the sales, purchases, and generation should be expressed in megawatts (MWs). The Exemption also requires that the source supply less than 15% of its annual total useful energy to another entity. "Total useful energy" is defined as "the sum of gross electrical generation and useful net thermal energy."[19] We recommend that the definition of "total useful energy" and "useful net thermal energy" also be expressed in megawatts for consistency.

- The Industrial Exemption does not provide a clear mechanism for determining the timing for applicability. We suggest that Exemption applicability should be determined on an annual basis at the end of the calendar year to dictate applicability for the following calendar year. For example, if an industrial source exceeds the 10% annual net electrical generation to the electric grid requirement, as determined using data from January 1 to December 31, then that source would not retain the Exemption for the next calendar year.

- The Re-Proposal Rule Definitions and the Industrial Exemption do not clearly state whether a non-exempt source would need allowances for CO2 emissions from non-fossil fuel combustion. Given that the Re-Proposal does not provide allowances for non-fossil fuel CO2 emissions, the Re-proposal should clarify that these emissions are excluded. Treatment of CO2 emissions from biogenic sources should not depart from federal and internationally accepted accounting protocols. The changes to the definition of "CO2 allowance" should be reversed. Previously, the definition of CO2 allowance included a clarification that the allowance is an authorization "to emit up to one ton of CO2 that has been generated as a result of combusting fossil fuel . . ." The underlined phrase should be re-inserted into this definition to clarify that the Re-proposal does not require that allowances must be obtained for CO2 emissions from non-fossil fuels. Any redundancy perceived in making this change is outweighed by the risk of different regulatory interpretations on this important point.

- The Re-Proposed Rule should clarify how permitting will be handled for existing industrial units, and the Rule should not require exempt facilities to go through permit modifications. The language in the Industrial Exemption requires qualifying facilities to obtain a permit. Since this is an Exemption to the regulation that DEQ wants to include in facility operating permits, DEQ should ensure that the facility is not required to pay the permit modification fee for such inclusion. DEQ could elect to incorporate this language as an administrative change.

[19] *Id.*

Further, DEQ should provide some guidance to facilities as to how it intends to facilitate inclusion of this language into existing permits.

C. The Re-proposed Rule is vague on how the allowance auction will work.

The Re-proposed Rule includes a number of provisions from the RGGI model rule but does not provide adequate detail on how the auction will work in Virginia. Although many revisions to original proposed rule supposedly better reflect the provisions of the RGGI model rule, they do not clarify how RGGI will run the auction and integrate with participants and customers. Among the missing details are:

- How the CO2 allowances will be consigned and auctioned?
- How will the reimbursement of consigned allowance auction costs be returned to regulated entities?
- Will the reimbursed consigned allowance auction costs flow down to customers? If so, how?
- How will auction prices be set?
- Will there be a mechanism for sales of excess allowance to third parties?

These omissions are not de minimis. Failure to provide these details violates the Administrative Process Act (APA) because, without these details, there can be no real opportunity for notice and comment. This fact is reinforced by comments filed by RGGI making the same observation. It is arbitrary and capricious to not include the actual requirements of the rule in the proposed rule. The lack of the opportunity for notice and comment cannot be cured through guidance or by a cross-reference. DEQ must withdraw the Rule and revise it to provide adequate detail to allow the regulated community to understand all of the requirements of the Rule and adequately comment.

D. The Re-proposed Rule Substantively Departs from the RGGI Model Rule by specifying Virginia's Base CO2 Reductions from 2030 to 2040, creating a Track Inconsistent with other RGGI States.

Without any basis, the Board and DEQ have departed from the RGGI 2017 Model Rule by committing Virginia's program to continued reductions in CO2 allowances from 2030 "and each year thereafter."[20] This revision has no legal or practical basis and further, it is unclear whether further reductions in CO2 allowances and, therefore, in the state budget cap, will be necessary in 2031.

The RGGI States have already provided comments on the Re-proposed Rule that disapprove of this inconsistency with the 2017 Model Rule. RGGI has an interest in the full compatibility of Virginia's program design with the other RGGI states. To address future caps, RGGI has set forth a periodic RGGI

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[20] 35 Va. Reg. 1404, 1423 (Feb. 4. 2019) (9 VAC 5-140-6210).

program review process for the participating states to consider the appropriate future trajectories by consensus.

Even though VMA strongly disapproves of Virginia's steps to enter the RGGI program, if Virginia pursues this path, Virginia's plan should be compatible with the RGGI model rule. The CO2 allowance budgets that were added for 2030 and beyond must be struck for these reasons.

E. DEQ does not have the authority to regulate CO2.

DEQ bases its authority to adopt a CO2 cap and trade program upon an Attorney General opinion (Opinion). This Opinion actually provides DEQ with no authority to issue the Re-proposed Rule.[21] The basis of the Opinion is that CO2 fits within the definition of "air pollution" under Virginia law and regulations. The Opinion assumes that because the Board has the authority to regulate air pollutants, it can legally adopt this Rule, which significantly reduces CO2 emissions through a Virginia market-based program linked to RGGI.

The Opinion bases its opinion that CO2 is an air pollutant, which the Board has the authority to regulate, on two arguments. First, the Opinion states that Green House Gases, which include CO2, are currently regulated by the Clean Air Act's (CAA), Prevention of Significant Deterioration (PSD) program, which is administrated by the Board. Second, it opines that there is a "growing consensus" among scientists that CO2 contributes to elevated global temperatures that maybe harmful to the welfare of people, animals, and property.

The CAA PSD program does not provide the Board with the authority to regulate CO2. In 2014, the U.S. Supreme Court held in *UARG v. EPA,* that neither EPA nor states have authority under the National Ambient Air Quality Standards (NAAQS) to regulate CO2.[22] Likewise, the *UARG v. EPA* decision held that CO2 is not a pollutant that can be regulated alone under the PSD program. The decision found that CO2 cannot be regulated under the NAAQS because it has potential global impacts, not state impacts. The NAAQS are administered on a state-by-state basis. The *UARG* decision is clearly on point and nullifies the Opinion and the Board's authority to issue the Re-proposed Rule.

The Board's own regulations extend the application of the *UARG* decision. The Board can only regulate air pollutants subject to NAAQS and specific emissions limits. 9 VAC 5-10-20. A CO2 cap and trade program is neither part of Virginia's NAAQS program or a specific emissions limit.

Air Board statute 10.1–1308 still limits DEQ's ability to issue any regulations more stringent than federal requirements without providing notice to the appropriate

[21] Letter from Attorney General Herring to Delegate Toscano, May 12, 2017.
[22] *UARG v. EPA*, 573 U.S. 302 (2014).

standing committee of the General Assembly. No such notice has been made. While at this point EPA is not directly regulating CO2 emissions, the Affordable Clean Energy Rule (ACE) will regulate CO2 under CAA Section 111(d). The ACE rule is expected to be issued soon. Once ACE is issued, Section 10.1–1308 will clearly apply to the Re-proposed Rule, and notice requirements must be satisfied.

IV. VMA's Recommendations.

VMA strongly supports DEQ withdrawing the cap and trade rule permanently for the reasons stated herein. If DEQ is unwilling to abandon the notion of joining RGGI, VMA requests DEQ to withdraw the Rule and re-propose it, with an accurate cost analysis, and the following: (1) A robust Industrial Exemption covering *all* present and future Virginia manufacturers; (2) The necessary clarifications requested in these comments; and (3) Additional details so it is clear how the program will work. The new revised rule will need to be re-proposed to provide for adequate notice and comment on these significant details, especially the real cost of regulation to Virginia's businesses and citizens.

Attachment – A

April 9, 2018

BY ELECTRONIC AND U.S. MAIL
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Comments of the Virginia Manufacturers Association on proposed regulations to reduce and cap carbon dioxide (CO_2) emissions from fossil fuel-fired electric generating facilities 9 VAC 5-140, Part VII, 34 Va. Reg. 924 (Jan. 8, 2018)

I. Introduction

On behalf of its member companies, the Virginia Manufacturers Association ("VMA") hereby submits the following comments on the proposal by the State Air Pollution Control Board ("the Board") to adopt regulations to reduce and cap carbon dioxide ("CO_2") emissions from fossil fuel-fired electric generating facilities. 9 VAC 5-140, Part VII, 34 *Va. Reg.* 924 (Jan. 8, 2018).

Since 1922 the Virginia Manufacturers Association has served as Industry's Advocate.™ Our mission is to create the best business environment in the United States for world-class advanced technology businesses to manufacture and headquarter their companies for maximum productivity and profitability. VMA is committed to environmental excellence and submits these comments on behalf of its member companies, but several member companies intend to file separate comments on the proposed regulations. We urge the Virginia Department of Environmental Quality ("DEQ") and the Board to carefully consider VMA's comments and the comments of our member companies on this critically important rulemaking.

At the outset, it should be noted that the proposed CO_2 emissions cap-and-trade program is not necessary to reduce the carbon footprint of Virginia. Virginia's energy-related CO_2 emissions fell by 16.3 percent from 2000 to 2015 without such regulation.

II. Brief Synopsis of the Proposed Regulations

In the Agency Background Document published on the Virginia Town Hall Web site, DEQ summarized the proposed regulations as follows:

> 1. The primary purpose of the regulation is to implement a declining cap on carbon emissions. The administrative means of accomplishing this will be effected by linking Virginia to RGGI ["Regional Greenhouse Gas Initiative"], which is an established emissions trading program. An allowance will be issued for each ton of carbon emitted by an electricity generating facility. The company must then decide if it will reduce carbon emissions and sell the resulting additional allowances, or if it will not reduce carbon emissions and make up the difference with purchased allowances. The proposal includes two options on the base budgets, 33 million tons and 34 million tons, which will determine, based on a 3% annual reduction, the annual budgets and allocations for future years.[1]
> 2. The mechanism for determining the cost of allowances will be a consignment auction.
> 3. A cost containment reserve allowance will be offered for sale at an auction for the purpose of containing the cost of CO_2 allowances in the event of higher than anticipated emission reduction costs. An emission containment reserve allowance will be withheld from sale at an auction for the purpose of additional emission reduction in the event of lower than anticipated emission reduction costs.
> 4. Monitoring, recording, and recordkeeping requirements will be implemented to track compliance.
> 5. Conditional allowances will be allocated to the Department of Mines, Minerals and Energy (DMME) in order to assist the department for the abatement and control of air pollution, specifically, CO2.

The proposed regulations would establish a CO_2 emissions cap-and-trade program in Virginia. As described by DEQ, the regulations would set an initial state-wide cap for CO_2 emissions from electric generating facilities, allocate emission "allowances" to those facilities, and require those allowances to be consigned to the Regional Greenhouse Gas Initiative ("RGGI") for auction. RGGI describes itself as follows:

> The Regional Greenhouse Gas Initiative (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 power sector CO_2 emissions.[2]

[1] Although DEQ's description speaks in terms of "carbon emissions," the emissions cap will be in tons of carbon dioxide, not carbon.

[2] New Jersey participated as a RGGI member from 2009 to 2011.

RGGI is composed of individual CO_2 Budget Trading Programs in each participating state. Through independent regulations, based on the RGGI Model Rule, each state's CO_2 Budget Trading Program limits emissions of CO_2 from electric power plants, issues CO_2 allowances and establishes participation in regional CO_2 allowance auctions.

RGGI is the first mandatory, market-based CO_2 emissions reduction program in the United States. Within the RGGI states, fossil-fuel-fired electric power generators with a capacity of 25 megawatts (MW) or greater ("regulated sources") are required to hold allowances equal to their CO_2 emissions over a three-year control period.

A CO_2 allowance represents a limited authorization to emit one short ton of CO_2 from a regulated source, as issued by a participating state. Regulated power plants can use a CO_2 allowance issued by any participating state to demonstrate compliance in any state. They may acquire allowances by purchasing them at regional auctions, or through secondary markets.

III. General Comments on the Proposed Regulations

VMA has the following general comments on the proposed regulations. Comments on specific aspects of the proposed regulations follow.

A. Contrary to Virginia's historical approach, the proposed regulations are more stringent than federally required.

For years it has been the policy of the Commonwealth to eschew the imposition of regulatory requirements on its citizens and businesses "which are more restrictive than applicable federal requirements" unless a cogent showing of necessity supports a more stringent Virginia rule. This principle is codified in the Virginia Air Pollution Control Law. *See* Va. Code § 10.1-1308.A: ". . . a description of provisions of any proposed regulation which are more restrictive than applicable federal requirements, together with the reason why the more restrictive provisions are needed, shall be provided to the standing committee of each house of the General Assembly to which matters relating to the content of the regulation are most properly referable." Furthermore, the Virginia Administrative Process Act establishes a procedure whereby the General Assembly reviews regulations during the promulgation or final adoption process. Va. Code § 2.2-4014. For regulations that are more restrictive than applicable federal requirements, the General Assembly has the opportunity to judge whether such regulations are truly "necessary" in the Commonwealth. VMA believes the Board should adhere to this long-standing Virginia approach, eschew the regulation of carbon dioxide emissions as proposed, and leave any such regulation to the appropriate time and approach determined for the nation by Congress and the U.S. Environmental Protection Agency ("EPA").

B. Neither the Board nor the DEQ has provided a rationale for the need for regulations that are more stringent than federally required.

In publishing its Agency Background Document for the proposed regulations, DEQ failed to meet the Virginia Town Hall requirement to identify and explain requirements more restrictive than federally required. The instructions in the Town Hall form for Agency Background Documents state:

> Please identify and describe any requirement of the proposal which is more restrictive than applicable federal requirements. Include a rationale for the need for the more restrictive requirements. If there are no applicable federal requirements or no requirements that exceed applicable federal requirements, include a statement to that effect.

DEQ's response to this directive was the statement: "There are no applicable federal requirements." Since there are no applicable federal requirements, the proposed regulations are without question more stringent than federally required. Thus, DEQ (the Board) must provide a rationale for the ***need***, not just the debatable social desirability, for the more stringent requirements in the proposed regulations. VMA submits that DEQ failed to provide a cogent need for the proposed regulations in the Agency Background Document (or elsewhere) because there is no such ***need***, and the Board will be unable to provide the General Assembly "with the reason why the more restrictive provisions are needed" in Virginia as required by Va. Code § 10.1-1308.A.

C. The proposed regulations are not cost-effective.

Cost-effectiveness is a fundamental premise for good environmental regulation. When government burdens its citizens by regulation, the benefits from the regulation should outweigh the burdens. The Board's proposed CO_2 emissions cap-and-trade regulations fail this basic premise. The proposed regulations are not cost-effective. The cost burden far exceeds any purported benefits from the proposed regulations.

1. The purported benefits of the proposed regulations are unsubstantiated and illusory.

In his Executive Order 57 ("EO-57"), then-Governor McAuliffe stated:

> 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.

Again in his Executive Directive 11 ("ED-11"), then-Governor McAuliffe stated:

> 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.

In discussing the purpose of the proposed regulations, both in the Agency Background Document and in the preamble to the proposed regulations, DEQ quotes then-Governor McAuliffe's EO-57 and ED-11. In EO-57 and ED-11, then-Governor McAuliffe revealed the ulterior, *i.e.*, non-environmental, motive for mandating a CO_2 emissions cap-and-trade program in Virginia – "to grow the clean energy economy" and " to make clean energy a pillar of our future economic growth and a meaningful part of our energy portfolio." ED-11 notes an increase in "the number of solar jobs in Virginia" and the increase in "revenue for energy efficiency businesses in Virginia." While expanding jobs and increasing business revenues in Virginia are certainly laudable goals, it is a misuse of governmental authority to use environmental regulation for these non-environmental purposes. There are other, more appropriate governmental authorities and programs, *e.g.*, through economic development initiatives and programs, to accomplish these economic goals.

It appears from the statements in EO-57, ED-11, DEQ's Agency Background Document, and the preamble to the proposed regulations that the environmental benefit envisioned from the regulation of CO_2 emissions from electric generating facilities in Virginia is the mitigation of the risks to Virginians from climate change, *e.g.*, "increasingly fierce storms, severe flooding, and other extreme weather events" and "rising storm surges and flooding" in Virginia's coastal areas. The administrative record for the proposed rulemaking is devoid of the necessary scientific data or other information to support the conclusion that the proposed CO_2 emissions cap-and-trade program in Virginia would have any real, perceptible effect on the severity of storms, storm surges, or flooding in Virginia.

In the preamble to the proposed regulations, DEQ presented a chart of "Health Benefits of Incidental Reductions in SO_2 and NOx." The rationale is that regulating emissions of CO_2 would have the "incidental" benefit of reducing emissions of sulfur dioxide ("SO_2") and nitrogen oxides ("NOx"). However, there are numerous other air regulatory authorities and programs addressing emissions of SO_2 and NOx, including their own cap-and-trade programs. Thus, if additional regulation of SO_2 or NOx is deemed necessary, there are other, more appropriate regulatory programs to directly address this necessity. Virginia does not have to resort to CO_2 regulation to indirectly address concerns with SO_2 or NOx emissions. More specifically, the Board cannot say the proposed regulations are needed to address emissions of SO_2 or NOx. Incidental reductions in SO_2 and NOx provide no rationale for imposing the proposed CO_2 emissions cap-and-trade program in Virginia.

The Virginia Department of Budget and Planning ("DPB") provided an Economic Impact Analysis of the proposed regulations. In discussing the purported benefits of reducing CO_2 emissions, DPB stated:

> The U.S. Environmental Protection Agency (EPA) and other federal agencies use estimates of the social cost of carbon (SC-CO_2) to value the climate impacts of regulatory rulemakings. The SC-CO_2 is a measure, in dollars, of the long-term damage done by a ton of CO_2 emissions in a given year. This dollar figure also represents the value of damages avoided for a reduction of a ton of CO_2 emissions in a given year (i.e. the benefit of a CO_2 reduction). It should be noted that the federal model estimates of the social cost of carbon are for the world overall. Thus it is not possible to quantify the Virginia-specific benefits. (Footnotes omitted.)

There is a fundamental reason why any such "value of damages avoided" in Virginia is impossible to quantify. The effect, if any, of reducing CO_2 emissions from Virginia's electric power sector on the severity of storms, storm surges, or flooding in Virginia would be negligible at best.[3] The proposed regulations would provide no measurable environmental benefit to the citizens of Virginia. In short, Virginians would receive no real benefit from the proposed regulations.

2. In response to higher costs and reduced electricity generation, Virginia will likely import electricity from out-of-state fossil fuel-fired generating facilities.

[3] The Congressional Research Service reached a similar conclusion regarding CO_2 emission reductions from the RGGI states: "RGGI's aggregate emissions rank in the top 20 among all nations. But from a practical standpoint, the RGGI program's contribution to *directly* reducing the global accumulation of GHG emissions in the atmosphere is arguably negligible." CRS, "The Regional Greenhouse Gas Initiative: Lessons Learned and Issues for Congress," May 16, 2017, Summary and p. 17.

When the proposed CO_2 emissions cap-and-trade program raises the cost of electricity generated by facilities within the Commonwealth, Virginia's electric utilities may well find it economical to buy power on the grid generated from out-of-state facilities unburdened by cap-and-trade regulation. This creates the problem of "emissions leakage." Virginia is a member of the PJM regional transmission organization ("RTO"). PJM serves all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, West Virginia, and the District of Columbia. (Maryland and Delaware are the only RGGI states in the PJM RTO.) This collection of states in PJM gives Virginia's utilities ready access to electricity generated by fossil fuel-fired units that are not limited by a CO_2 emissions cap-and-trade program. RGGI states buy large amounts of power generated out-of-state.[4]

The analysis conducted by ICF[5] supports the conclusion that the proposed CO_2 emissions cap-and-trade program would significantly increase the import of electricity into Virginia from out of state facilities. Using the DEQ's assumptions, ICF predicts that from 2023 to 2030 electricity usage in Virginia will increase from approximately 130 TWh (terawatt hours) to approximately 145 TWh. All of this increase will be imported electricity under the proposed CO_2 emissions cap-and-trade program whereas less than half of this increase would be imports without such a program.[6]

It is clear that CO_2 emissions "leakage" would easily compensate for the mandated reductions in CO_2 emissions within Virginia. While Virginians would pay higher energy costs, overall CO_2 emissions would not be reduced by Virginia's cap-and-trade restrictions.

3. The increasing CO_2 concentration in the atmosphere is a global phenomenon that requires a global approach.[7]

If reducing the global concentration of atmospheric CO_2 is the goal, the entire world must participate in the effort. Virginia could reduce emissions of CO_2 from its fossil fuel-fired electric generating facilities, but any such reduction would be swamped by the massive amount of CO_2 emissions from China alone. In 2015, China generated over 11 billion tons of CO_2 from fossil fuel combustion for electricity and industrial power generation. For comparison, the Board's proposed cap-and-trade regulations would reduce CO_2 emissions from Virginia by approximately 10-11 million tons/year in 2030. While coal-fired electricity generation in China, the world's largest coal consumer, is expected to remain flat through 2040, natural gas-fired energy generation is projected to increase substantially. In fact, worldwide energy-related CO_2 emissions, approximately 38 billion tons in 2017, are projected to grow an average 0.6%/year

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[4] RGGI member states experienced a 34% increase in imported electricity after RGGI was established. CRS, "The Regional Greenhouse Gas Initiative: Lessons Learned and Issues for Congress," May 16, 2017, p. 14.

[5] ICF is a contractor hired by the Georgetown Climate Center to analyze the potential impacts of Virginia's participation in RGGI.

[6] ICF, Virginia Reference and Policy Scenario Overview, Webinar presentation, Oct. 20, 2017, p. 18.

[7] Information presented in this section of VMA's comments is derived primarily from the U.S. Energy Information Administration's "International Energy Outlook 2017."

until 2040. Thus, while the proposed regulations would reduce CO_2 emissions from Virginia's fossil fuel-fired electric generating facilities by roughly 10-11 million tons/year in 2030, worldwide CO_2 emissions will have increased by over 2 billion tons/year.

Reducing the global concentration of atmospheric CO_2 would take a concerted effort by the United States, China, and the rest of the world's nations. Climate change and reduction of greenhouse gas emissions are global issues. Climate change is not a local phenomenon and to the extent man can craft a "solution" to climate change by reducing carbon dioxide emissions, that solution cannot be accomplished by disjointed state and local approaches. VMA believes that if any regulation of carbon dioxide emissions in the United States is deemed necessary and prudent to address climate change, that regulation must be undertaken and applied uniformly throughout the country, not state by state or locality by locality.

4. Any adverse effects of climate change in Virginia would be better addressed through comprehensive resiliency planning and implementation.

In 2014, then-Governor McAuliffe established the Governor's Climate Change and Resiliency Update Commission. This Commission was directed to develop up to five actionable recommendations and submit those recommendations in a report to the Governor. The Commission conducted its last meeting in August 2015 and generated a report summarizing its deliberations and presenting its recommendations to the Governor. From a broader list of recommendations the Commission's workgroups narrowed the recommendations down to a total of thirteen that were presented to the full Commission and subsequently voted on by the membership. The top five recommendations resulting from the voting are as follows:

1. Establish a Climate Change and Resilience Resource Center and/or Clearinghouse;
2. Create a New Virginia Bank for Energy and Resilience;
3. Set a Renewable Energy Procurement Target for Commonwealth Agencies;
4. Adopt a Zero Emission Vehicle Program; and
5. Leverage Federal Funding to Make Coastal Communities, Southside, and Southwest Models of Resilience.[8]

VMA believes this is the type of effort Virginia should be undertaking to address any concerns with the effects of climate change in Virginia. Rather than impose burdensome and costly CO_2 emissions cap-and-trade requirements, Virginia should develop and implement direct, cost-effective programs to address the perceived effects of climate change in Virginia. The costs of a CO_2 emissions cap-and-trade program imposed on Virginia's citizens and businesses would be much better spent directly on resiliency programs and initiatives that will have a tangible impact in communities in the Commonwealth.

[8] Notably, the Commission's recommendations did not include a CO_2 emissions cap-and-trade program.

5. The costs of the proposed CO_2 emissions cap-and-trade regulations outweigh any purported benefits.

a. Virginia's citizens and businesses will experience a significant increase in electricity costs as a result of the proposed cap-and-trade program.

In its Economic Impact Analysis, DPB notes that the proposed regulations likely would increase electricity costs for Virginia's citizens and businesses by no more than 1.1 percent ($2015) by 2031, the year after the maximum CO_2 emission reduction has been achieved.[9] However, a recent study by the Cato Institute showed that electricity costs in the RGGI states rose by 4.6 percent between 2007 (pre-RGGI) and 2015. This increase was 64 percent higher than the increase in electricity costs in a sampling of five non-RGGI states.[10] As the data from the RGGI states show, adoption of the proposed CO_2 emissions cap-and-trade program will add millions of dollars per year to the electric bills of the citizens and business of Virginia.

b. The proposed cap-and-trade program will have a significant adverse effect on manufacturing in Virginia.

Virginia has a robust $43 billion manufacturing sector. The Commonwealth is ranked as the fourth most competitive state in overall manufacturing competitiveness in the nation, trailing only Minnesota, Utah, and Iowa.[11] Moreover, Virginia is ranked the most competitive southern state for manufacturing. However, this preeminent competitive position would be severely jeopardized by increasing energy costs in the Commonwealth.

The Cato Institute study (cited above) found that from 2007 (pre-RGGI) to 2014 the economies of the five non-RGGI comparison states grew 2.5 times faster than the RGGI states. That study noted that data from the U.S. Bureau of Economic Analysis show that during the same period the RGGI states lost 35 percent of energy intensive businesses (primary metals, food processing, paper products, petroleum refining, and chemicals), whereas the five non-RGGI comparison states only lost 4 percent.[12] While the non-RGGI comparison states' overall goods production grew by over 15 percent, the RGGI states lost 13 percent of overall goods production. This decline is reflected in industrial electricity demand with the RGGI states falling 17 percent

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9 DPB relied on conclusions developed by ICF, a contractor hired by the Georgetown Climate Center to analyze the potential impacts of Virginia's participation in RGGI. DPB states it did not conduct an independent analysis to verify ICF's conclusions.

10 Cato Institute Working Paper: A Review of the Regional Greenhouse Gas Initiative, Aug. 10, 2017, pp. 6-7. The non-RGGI comparison states were Illinois, Ohio, Oregon, Pennsylvania and Texas, all of which, like the RGGI states, have deregulated their electric power sector.

11 Virginia Industry Foundation: A Virginia Vision for a More Competitive Manufacturing Future, October 2017. The study evaluated five weighted metrics: Business Climate (30%), Workforce (25%), Infrastructure (20%), Innovation (15%), and Economic Strength (10%).

12 Cato Institute Working Paper: A Review of the Regional Greenhouse Gas Initiative, Aug. 10, 2017, pp. 8-10.

while non-RGGI comparison states only fell 3 percent. The greater decline in energy demand in the RGGI states cannot be attributed to greater energy efficiency in those states. In fact, the RGGI states improved by 9.6 percent, while the non-RGGI comparison states improved by 11.5 percent. Rather it is clear that even as the economy was recovering from the recession of 2008, industry was leaving the RGGI states.

If the proposed CO_2 emissions cap-and-trade program is enacted in Virginia, electricity costs for the Commonwealth's manufacturing facilities will undoubtedly increase, by as much as 4-5 percent by 2031.[13] This increased cost of operation will diminish Virginia's advantage over the Southeastern and Midwestern states against which the Commonwealth competes for new and expanded industry. If Virginia participates in RGGI, we can expect the same fate for our industry that the RGGI states have experienced – industry, especially energy intensive industry, will go elsewhere where the costs of energy are lower.

In conclusion, the proposed CO_2 emissions cap-and-trade program will impose significant costs on Virginia's economy, especially its manufacturing sector, but the proposed program would provide no real benefit to Virginians. Accordingly, the proposed regulations lack any semblance of cost-effectiveness. VMA believes principles of good governance compel the rejection of this proposal.

D. The proposed regulations impose a "carbon tax" and cede this tax authority to RGGI.

The proposed regulations envision a process whereby "conditional allowances" (one allowance equals one ton of CO_2 emissions) are allocated by DEQ to regulated sources. Then those regulated sources are compelled to consign the conditional allowances to RGGI for auction. Regulated sources throughout Virginia and the RGGI states can bid on the allowances. Historically, RGGI states have taken the auction revenue and used it for a variety of purposes, one of which is not related at all to the goal of reducing CO_2 emissions. RGGI states (in aggregate) allocated auction revenues as follows:

- 42% for energy efficiency;
- 11% for electricity bill assistance;
- 9% for GHG abatement;
- 8% for clean and renewable energy;
- 8% for state budget reduction;
- 4% for administration; and
- 1% for RGGI, Inc. [14]

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[13] *Id.*, pp. 6-7.
[14] CRS, "The Regional Greenhouse Gas Initiative: Lessons Learned and Issues for Congress," May 16, 2017, p. 12.

Note that 8 percent of the revenue was used "for state budget reduction." That money was used just like any other tax revenue that goes into the state's general coffers.

The proposed CO_2 emissions cap-and-trade program in Virginia is supposed to operate somewhat differently. Revenue generated by the auction of conditional allowances consigned by a regulated Virginia source is supposed to be returned to that source owner, less RGGI's administrative fees. DEQ has indicated the revenue received by owners of regulated electric utilities will "flow to rate payers pursuant to State Corporation Commission (SCC) requirements."[15] However, at this juncture we have no idea that will actually happen or to what purposes the revenue would be put.

The provisions in the proposed regulations governing the allocation and auction of CO_2 emission allowances, whether conducted by DEQ (under the Board's authority) or RGGI, are designed to produce revenue to fund energy efficiency programs, resiliency infrastructure, and other state and local government purposes. The overlay of the additional cost imposed by the proposed auction of CO_2 emission allowances constitutes in essence an additional tax on the citizens and businesses of Virginia. And the magnitude of that tax will not be set by Virginia; it will be set by RGGI, an extra-territorial, non-governmental entity.

The Virginia General Assembly may by special act delegate the power of taxation to any county, city, town, or regional government. See Va. Const. art. VII, § 2. However, the General Assembly cannot constitutionally delegate its taxing power to an unelected entity, whether the Board, DEQ or RGGI.

The Virginia Constitution and case law are quite clear on these matters. In *Marshall v. Northern Virginia Transp. Authority*, 275 Va. 419, 657 S.E. 2d 71 (2008), the Virginia Supreme Court affirmed that taxes must be imposed only by a majority of the elected representatives of a legislative body, with the votes cast by the elected representatives being duly recorded. The court noted that the Constitutional constraints which the citizens of Virginia have placed upon the General Assembly regarding the imposition of taxes would be rendered meaningless if the General Assembly were permitted to avoid compliance with these constraints by delegating the decisional authority whether to impose taxes. Further, although the Constitution does not explicitly prohibit the delegation of such decisional authority concerning the imposition of taxes, that delegation is prohibited by necessary implication, and the General Assembly may not delegate its taxing power to a non-elected body. Thus, the Virginia Constitution prohibits ceding tax power to the Board, DEQ or RGGI.

E. The proposed CO_2 emissions cap-and-trade program is unnecessary. CO_2 emissions from Virginia sources are declining rapidly anyway.

[15] DEQ presentation to the Board, Nov. 16, 2017.

1. CO_2 emissions in Virginia are dropping because citizens and businesses are becoming more energy efficient.[16]

Virginia's per capita energy use fell from a recent peak of 346 million BTUs per person in 2005 to 292 million BTUs in 2013 and 2014. There have been some fluctuations along the way, including drops caused by decreased economic activity during the years of the Great Recession (2007-2009), as well as minor ticks upward in both 2010 and 2013. Virginia's 2014 rate is lower than the national average of 309 million BTUs and ranked Virginia 21st among US states for energy consumption. Another way of gauging energy consumption is to compare usage rates to annual state GDP. Virginia's consumption rates have dropped from 6.6 thousand BTUs per GDP dollar in 2005 to 5.7 thousand BTUs in 2014. This amount was lower than the national average of 6.2 thousand BTUs per GDP dollar, as well as peer states Tennessee (8.1 thousand BTUs) and North Carolina (5.8 thousand BTUs), and ranked the Commonwealth 18th best in the country.

2. Virginia is already among the nation's leaders in reducing CO_2 emissions.

The decrease in energy consumption translates into a pronounced decrease in CO_2 emission from the Commonwealth. Virginia's energy related CO_2 emissions fell by 16.3 percent from 2000 to 2015. For comparison, the RGGI states averaged a 17.1 percent decrease and the entire nation experienced a 10.3 drop in CO_2 emissions.[17] Virginia already generates a relatively low amount of energy-related greenhouse gases per capita from electrical power generation, transportation, heating/cooling, and industrial processes. Virginia's CO_2 emissions decreased from 15.9 metric tons per person in 2005 to 12.5 metric tons in 2014.[18] This level was substantially better than the national average of 17.0 metric tons per capita and ranked 13th best in the country. It's clear that Virginia is reducing its carbon footprint at a rate much better than the nation as a whole and comparable to the RGGI states even without a costly CO_2 emissions cap-and-trade program.

3. Renewable energy generation is rapidly expanding in Virginia even without the proposed CO_2 emissions cap-and-trade program.

Virginia's electric utilities are strongly committed to expanding the role of renewable energy in power generation. For example, Dominion Energy currently has solar facilities capable of producing approximately 744 MW of power either operational or under development

[16] Information presented in this section is derived from Virginia Performs, http://vaperforms.virginia.gov/indicators/naturalResources/energy.php.

[17] U.S. Energy Information Administration: Energy-Related Carbon Dioxide Emissions by State, 2000-2015, Jan. 22, 2018, Table 1.

[18] Virginia Performs, http://vaperforms.virginia.gov/indicators/naturalResources/energy.php.

in Virginia. These facilities will provide enough energy at peak solar output to power more than 186,000 homes. This represents tremendous growth over the company's Virginia solar capacity at the end of 2014, when only four small facilities with total output of just 1.18 MW were operational.[19] Old Dominion Electric Cooperative ("ODEC") currently has approximately 300MW of renewable energy generation capacity. ODEC plans to add 70 MW of solar generation in the next five years.[20]

As the cost of solar photovoltaic technology continues to decrease, solar-powered electric generation is growing rapidly in Virginia. According to data from the Solar Energy Industries Association ("SEIA"), Virginia's total solar capacity of 619.5 MW at the end of 2017 ranked 17th among the states. The Commonwealth's total solar capacity greatly exceeded that of many nearby states, including South Carolina (510.5 MW), Tennessee (247.2 MW), Kentucky (31.9 MW) and West Virginia (6.5 MW). Additionally, SEIA data indicate that Virginia's solar generation fleet grew by 381.3 MW in 2017 alone. Virginia ranked 10th among the nation last year in adding solar capacity.[21]

Dominion Energy's 2017 Integrated Resource Plan ("IRP") for meeting the long-term energy needs of its customers indicates this massive expansion of solar capacity will continue. All of the scenarios presented in the 2017 IRP call for the addition of at least 3,200 MW of additional solar capacity to the company's generating fleet serving Virginia customers by 2032 and at least 5,280 MW of additional solar capacity by the conclusion of a longer, 25-year study period concluding in 2042. Dominion Energy's IRP notes that "solar energy will play a major role in meeting the energy needs of (the company's) customers in the future. Solar technology is now cost-competitive with other more traditional forms of generation."[22]

Dominion Energy is also moving forward with a test-bed project that could help pave the way for more extensive development of offshore wind energy as a generating resource. The project will consist of two 6-MW turbines and will become the mid-Atlantic's first offshore wind project in a federal lease area. The facility will provide critical information that could help achieve the cost reductions and technology improvements needed for more extensive wind development off Virginia's Atlantic coast. Larger-scale deployment of turbines in an adjacent 112,800-acre site leased by Dominion Energy from the federal Bureau of Ocean Energy Management could potentially produce up to 2,000 MW of electricity – enough to power a half-million homes.[23]

Senate Bill 966, enacted by the 2018 session of the Virginia General Assembly and signed into law by Governor Northam, states that construction or purchase by Virginia electric utilities of solar and wind-powered facilities capable of producing up to 5,000 MW of electricity at maximum output is "in the public interest." The provisions of this legislation are to be

[19] See https://sites.wp.odu.edu/virginiasolarpathways/wp-content/uploads/sites/3538/2017/12/Virginia-Solar-Pathways-Project-Report-2017.pdf.
[20] See http://www.odec.com/3dissue/ODECSustainabilityReport2017/html5/index.html?page=1&noflash.
[21] See https://seia.org/states-map and individual SEIA state fact sheets.
[22] See https://www.dominionenergy.com/library/domcom/pdfs/corporate/2017-irp-cover-letter-va.pdf.
[23] See https://www.dominionenergy.com/about-us/making-energy/renewables/wind/coastal-virginia-offshore-wind.

liberally construed by the Virginia State Corporation Commission ("SCC") when reviewing applications for construction of such facilities.

In sum, it is clear that Virginia's electric utilities are moving rapidly to greatly expand generation from renewable resources. Virginia is already among the nation's leading states in this regard. A costly program capping CO_2 emissions is unnecessary to promote the continued rapid growth of renewable energy generation in the Commonwealth.

F. Forcing owner/operators of electric generating units in Virginia to consign their allowances to RGGI for general auction constitutes an illegal "taking."

Virginia's electric utilities have billions of dollars invested in assets that serve the public good and generate returns for investors. If the Board adopts the proposed CO_2 cap-and-trade program and fails to allocate allowances necessary for those facilities to generate electricity, that failure would deprive those entities of their ability to operate. In essence the government would be taking the value of those electric generating assets from Virginia's utilities without compelling public need and just compensation.

Similarly, if the Board allocates sufficient allowances for Virginia's utilities to operate but then forces them to consign those allowances to RGGI for potential purchase by someone else, the Board again would be in essence taking valuable allowances away from these companies without compelling public need and just compensation. Such "takings" are prohibited by the U.S and Virginia Constitutions.

G. By compelling owner/operators of electric generating units in Virginia to consign allowances issued to them to RGGI for auction under RGGI's sole control, the Board would be attempting to enter into an interstate compact without authorization by the Virginia General Assembly and the U.S. Congress.

Article I, Section 10 of the U.S. Constitution states, in relevant part: "No state shall, without the consent of Congress . . . enter into any agreement or compact with another state . . . ." Linking a Virginia CO_2 cap-and-trade program to RGGI for the general auction of allowances would make Virginia a party to a multi-state compact without confirmation by the Virginia General Assembly and approval by the U.S. Congress. Virginia is a member of numerous interstate and regional compacts.[24] An essential feature of every one of these interstate compacts is specific authorization by the U.S. Congress and confirmation by the Virginia General Assembly. "Linking" to RGGI by compelling the consignment of allowances

[24] For a listing of all of the interstate compacts to which Virginia is a party see https://law.lis.virginia.gov/compacts/compilation-of-compacts-and-related-records-and-reports/.

to RGGI for general auction would constitute an unauthorized compact with the RGGI states. Attempting to do so would exceed the authority of the Board.[25]

IV. Comments on Specific Aspects of the Proposed Regulations

A. If the Board adopts the proposed regulations, it should retain the proposed applicability provisions.

The applicability provisions of the proposed regulations, 9 VAC 5-140-6040, specify those CO_2 emission sources that would become subject to the cap-and-trade program:

> 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 power generating unit owned by an individual facility and located at that individual facility that generates electricity and heat from fossil fuel for the primary use of operation of the facility.

If the Board adopts the proposed regulations, VMA urges the Board to retain these applicability provisions with some additional clarification.

1. Fossil fuel-fired units that serve electrical generators smaller than 25 MWe should not be subject to the regulations.

A critical aspect of subsection A above is the word "an." In order for a fossil fuel-fired unit, *e.g.*, a boiler, to be subject to the regulations, it must provide energy to, *i.e.*, "serve," "*an* electricity generator with a nameplate capacity equal to or greater than 25 MWe."[26] As VMA understands it, this means that a facility with a boiler that "serves" multiple electrical generators, none of which has a nameplate capacity of 25 MWe or greater, would not be subject to the regulations even if the combined electrical output of the generators exceeds 25 MWe. This is important to Virginia manufacturers that have multiple, smaller generators at their facilities. The VMA believes this important aspect of the applicability provision in subsection A must be retained should the Board decide to adopt the proposed regulations.

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[25] When states want to cooperate on environmental matters, they can enter into a multi-state compact to do so, but only through authorization by the U.S. Congress. For example, the Interstate Environmental Commission, a compact of New York, New Jersey and Connecticut, was formed in 1936 with the consent of Congress. See http://www.iec-nynjct.org/about.who.htm.

[26] "MWe" is electrical output in megawatts.

2. Industrial facilities should not be included in the proposed CO_2 emissions cap-and-trade program.

Subsection B quoted above clearly exempts from the regulations any "facility that generates electricity and heat from fossil fuel for the primary use of operation of the facility." If the Board adopts the proposed regulations, VMA urges the Board to retain the industrial facility exemption in subsection B.

a. Expanding the reach of the CO_2 emissions cap-and-trade program beyond the electric power generation sector would exceed the Governor's mandate to the Board.

Executive Directive 11 speaks in terms of "electric power facilities." Executive Order 57, leading directly to ED-11, speaks in terms of "power plants," "the electric sector," "electric companies," and "electric utilities." This makes it clear that the mandate from then-Governor McAuliffe was for the Board to propose a CO_2 emissions cap-and-trade program tied to RGGI that would apply to units and facilities whose primary, if not exclusive, purpose is the generation of electricity for sale ultimately to the public. These "power plants" are owned and operated by "electric companies" in "the electric sector" of Virginia's economy. Industrial facilities, like those owned and operated by members of the VMA, are not "power plants" owned by "electric companies" and operating in "the electric sector." In short, industrial facilities lay clearly outside the scope and intent of EO-57 and ED-11. Accordingly, the Board should retain the current approach to exclude industrial facilities from the reach of the proposed CO_2 emissions cap-and-trade program.

b. Virginia's industrial facilities and electric utilities are not similarly situated to comply with CO_2 emissions cap-and-trade requirements.

Many industrial facilities in Virginia do not have multiple locations with different energy generating capacities to provide flexibility in meeting a mandated CO_2 emissions cap. They have only one facility and are not able to shift emissions allocations between facilities and between generating technologies. Virginia's electric utilities have multiple units and multiple generating technologies which allow them to find the least expensive means to reduce CO_2 emissions.

Utility power producers are in the business of building alternative power generation sources while manufacturers are not. It is much easier for utility power producers to shift their mix of generation to renewable power sources. In many cases, sites with renewable power generation are already developed. Electric utilities have economies of scale and may purchase larger and a greater number of alternative generation units. The power needs of Virginia's manufacturers are generally much smaller.

Electric utilities are better able to pass their costs on to their customers than Virginia's manufacturers. Virginia's manufacturers do not have a captive customer base. They compete worldwide for business from customers who are acutely price sensitive. Large capital expenditures for alternative energy generation technologies would increase the price of their products and damage their market position. Electric utility revenues are not affected by these global market demands.

c. There is no basis for expanding the scope of the proposed CO_2 emissions cap-and-trade program to include industrial facilities.

Emissions from industrial sources comprise only 11.3 percent of Virginia's CO_2 emissions.[27] Thus, expanding a cap-and-trade program to Virginia's manufacturing sector would impose significant costs but result in only a small reduction in Virginia's CO_2 emissions. The Board should avoid the significant adverse effects on Virginia's businesses when it would yield only insignificant additional CO_2 emission reductions. In any event, should the Board decide to expand the scope of the CO_2 cap-and-trade program to include industrial facilities, the Board would have to rewrite and re-propose a new set of regulations. Simple revisions to the current proposed regulations would not suffice.

d. The regulations should specify that in order to qualify for the industrial facility exemption, no more than one third of the electricity and heat generated on site can be exported off site.

The proposed regulations do not contain a definition of the term "primary use" in Subsection B of 9 VAC 5-140-6040. The dictionary sense of "primary" would allow a facility to "export" just under 50 percent of the electricity and heat generated from fossil fuels on site and still qualify for the industrial facility exemption in subsection B. The reality of manufacturing operations in Virginia is that no manufacturing facility comes anywhere close to exporting 50 percent of the energy generated on site. However, VMA believes the regulations should provide Virginia's manufacturing facilities an ample margin of flexibility to export valuable energy when it is not all needed on site. Thus, VMA recommends that "primary use" be defined to mean that in order to qualify for the industrial facility exemption, no more than one third of the power generated on site, in the form of electricity and heat, can be exported off site. This approach is based on the cogeneration exclusion in Virginia's former CAIR rules. For example, 9 VAC 5-140-1040.B.1.a(2) (repealed) excludes cogeneration units provided they do not supply more than

[27] U.S. Energy Information Administration: Energy-Related Carbon Dioxide Emissions by State, 2000-2015, Jan, 22, 2018, Table 4.

one third of the unit's potential electrical output capacity to any utility power distribution system for sale. Accordingly, VMA advocates defining primary use on site to mean that no more than one third of the industrial unit's power output (in the form of electricity and heat) can be exported off site.

B. The proposed regulations should exclude CO_2 emissions from the combustion of biomass.

The proposed regulations are intended to reduce CO_2 from fossil fuel-fired electric generating units. The proposed regulations define "fossil fuel" as "natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material." 9 VAC 5-140-6020.C. This definition does not include biomass because biomass is not a "fossil" fuel.[28] Accordingly, the proposed CO_2 cap-and-trade program should not include CO_2 emissions generated from the combustion of biomass.

The proposed CO_2 emissions cap-and-trade program would apply to "any fossil fuel-fired unit that serves an electricity generator with a nameplate capacity equal to or greater than 25 MWe." 9 VAC 5-80-6040.A. "Fossil fuel-fired" is defined to mean "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 10% of the annual heat input on a Btu basis during any year." 9 VAC 5-140-6020.C. This means a combustion unit that burns 89 percent biomass and 11 percent fossil fuel could be subject to the proposed CO_2 emissions cap-and-trade program. But that is inappropriate since in such a case, approximately 89 percent of the CO_2 emissions from the unit would be from the combustion of biomass, not a fossil fuel. VMA believes the proposed definition of "fossil fuel-fired" should be revised to clearly exclude CO_2 emissions from the combustion of any biomass based fuel. This approach would be consistent with the RGGI program's approach to biomass CO_2 emissions.[29]

C. The Board should not adopt a CO_2 emissions cap-and-trade program that entails a direct auction of allowances by the DEQ.

If the Board adopts a CO_2 cap-and-trade program in Virginia, emission allowances should be allocated as proposed. Allowances should be distributed without cost to the owner/operators of the electric generating units that will be constrained by the emissions cap. Direct auction of the allowances by DEQ with the revenue collected by the state would constitute

[28] According to the American Forest & Paper Association, biomass combustion is "CO_2 neutral." Thus, overall, biomass combustion does not contribute to an increase in the global atmospheric CO_2 concentration. For a fuller explanation of biomass CO_2 neutrality, see http://www.afandpa.org/issues/issues-group/carbon-neutrality-of-biomass.

[29] "CO_2 emissions from eligible biomass reduce the total CO_2 allowance compliance obligation of the emitting unit. Emissions from eligible biomass should be deducted from the regional total of CO_2 emissions for purposes of calculating emissions from CO_2 budget sources subject to RGGI CO_2 allowance compliance obligations." See https://www.rggi.org/allowance-tracking/emissions.

a tax that is not authorized by the Virginia General Assembly. Moreover, such a direct auction would greatly increase the cost of the program to the citizens and businesses of the Commonwealth. VMA believes the imposition of the costs of a direct auction of allowances by DEQ would severely jeopardize the competitiveness of manufacturers and other businesses in the Commonwealth.

Attachment – B

William F. Stephens
Director
(804) 371-9611
FAX (804) 371-9350

COMMONWEALTH OF VIRGINIA

PO Box 1197
Richmond, Virginia 23218-1197

STATE CORPORATION COMMISSION
Division of Public Utility Regulation

January 29, 2019

Delegate Terry G. Kilgore
Virginia House of Delegates
Pocahontas Building
900 East Main Street
Richmond, Virginia 23219

Dear Delegate Kilgore:

This letter is in response to your request for additional cost information associated with Staff's estimate of Regional Greenhouse Gas Initiative ("RGGI") related customer bill impacts. Staff calculates the total cost to Dominion Energy Virginia's ("DEV's") customers to be $3.3 billion or $5.9 billion, respectively, for linking to RGGI or joining RGGI over the 2020-2030 timeframe. The Staff estimates that a typical residential customer's bill would increase by $7 to $12 per month.

Staff's RGGI analysis used the PLEXOS® computer model to simulate RGGI compliance for DEV using the following key assumptions:

- Staff used the price floor for carbon emission allowances published by RGGI;

- Staff used a discount rate of 6.31% which represents DEV's most recent weighted average cost of capital used in proceedings before the Commission;

- Staff modeled DEV as a vertically integrated utility, meaning that DEV owns generation resources. Dominion's customers continue to pay for DEV's generation resources whether a unit runs or not or is taken out of service due to RGGI compliance;

- Staff assumed that 5,000 megawatts ("MWs") of solar, 30 MW of battery storage, and $870 million of spending on energy efficiency programs, consistent with the mandates contained in the 2018 Grid Transformation and Security Act ("2018 GTSA" or "SB966") are implemented; and

- Staff used a RGGI CO_2 emissions cap for Virginia of 28 million tons beginning in 2020 which decreases 3% per year through 2030, as proposed in Virginia State Air Pollution Control Board regulations currently under review.

By way of background, RGGI is a "cap and trade" market mechanism designed to cap and reduce CO_2 emissions from the power sector. RGGI compliance increases the dispatch cost of fossil fuel generation thereby making it less competitive. As a result, such generation will run less or be taken out of service leading to reductions in fossil fuel generation and CO_2 emissions. The emissions cap decreases each year. If the owner of one or more generation facilities exceeds its cap in a given year, then the generation owner must purchase offsetting CO_2 emissions allowances.

RGGI is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Much of the power in these states is supplied by merchant generators. In Virginia, the regulated utility owns the generation and, therefore, the cost of these allowances falls on the regulated utility which will seek to recover its RGGI compliance costs from its customers.

If you have any other questions or need additional assistance, please contact me or Greg Abbott who testified in front of the subcommittee at 804-371-9611.

Respectfully,

William Stephens

Attachment – C

KEN SCHRAD
DIRECTOR

ANGELA P. BOWSER
DEPUTY DIRECTOR

COMMONWEALTH OF VIRGINIA

PHONE: (804) 371-9141

http://www.scc.virginia.gov

STATE CORPORATION COMMISSION
INFORMATION RESOURCES
P.O. BOX 1197, RICHMOND, VIRGINIA 23218-1197

February 14, 2019

John (Jay) M. Holloway III
Williams Mullen
200 South 10th Street, Suite 1600
Richmond, VA 23219

By- Email

RE: Public records in the State Corporation Commission's possession regarding DEQ's proposed CO2 Cap & Trade rule

Jay:

As previously advised, the availability of SCC records is governed by Virginia Code Section 12.1-19. Any records associated with your request would, pursuant to that statute, be a regulatory record of the Commission.

There is no public record regarding your February 11, 2019 request.

It is the practice of SCC staff to be prepared to answer questions it may receive at legislative committee meetings regarding legislation under consideration by the Virginia General Assembly.

In preparing for bills that addressed Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI), Commission staff made an estimate of the potential monthly impact on a typical residential customer of Dominion Energy Virginia (DEV).

Staff's estimate, requiring certain assumptions, was based on the following:

- Staff used the published RGGI floor prices for carbon emission allowances.

- Staff used a discount rate of 6.31 percent which represents DEV's most recent actual weighted average cost of capital used in proceedings before the Commission.

- Staff modeled DEV as a vertically integrated utility, meaning that DEV owns generation resources. Dominion's customers continue to pay for DEV's generation resources whether a unit runs or not or is taken out of service due to RGGI compliance. Staff estimated that RGGI will result in several units being retired prematurely. This alone could impose an additional $1.3 billion of costs on customers to replace those units.

- Staff assumed that 5,000 megawatts ("MWs") of solar, 30 MW of battery storage, and $870 million of spending on energy efficiency programs, consistent with the mandates contained in the 2018 Grid Transformation and Security Act ("2018 GTSA" or "SB966") are implemented.

- Staff used a RGGI CO_2 emissions cap for Virginia of 28 million tons beginning in 2020 which decreases 3 percent per year through 2030, as proposed in Virginia State Air Pollution Control Board regulations currently under review.

Based on those assumptions, staff calculates the total cost to DEV's customers to be $3.3 billion or $5.9 billion, respectively, for linking to RGGI or joining RGGI over the 2020-2030 timeframe.

Finally, you asked about a Commission letter provided in response to an information request from Delegate Terry G. Kilgore. The Commission regularly receives direct inquiries or information requests from members of the General Assembly. The long-standing practice of the Commission is to treat such communications as confidential. Thus, the public availability of such communications would be at the discretion of the state lawmaker who requested the information.

Sincerely,

Kenneth J. Schrad

Attachment – D

COMMONWEALTH OF VIRGINIA

William F. Stephens
Director
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PO Box 1197
Richmond, Virginia 23218-1197

STATE CORPORATION COMMISSION

Division of Public Utility Regulation

February 27, 2019

Delegate Charles D. Poindexter
Virginia House of Delegates
Post Office Box 117
Glade Hill, Virginia 24092

Dear Delegate Poindexter:

I am responding to your letter dated February 15, 2019 requesting SCC Staff responses to questions you raise concerning proposed regulations capping CO2 emissions from the Commonwealth's regulated electric power plants. These proposed regulations concern the Commonwealth linking to the Regional Greenhouse Gas Initiative ("RGGI").

Enclosed for your review is a document that the SCC Staff recently prepared at the request of the Virginia Department of Environmental Quality ("DEQ") to explain the methodology and assumptions used by SCC Staff. The document provides SCC Staff analysis supporting our bill impact estimates that a typical monthly residential bill for Dominion Energy Virginia ("DEV") will increase between $7 and $12 depending on whether Virginia *links* to RGGI or *joins* RGGI.

Answers to your specific questions and requests for information, to the extent that the SCC Staff can provide them, are detailed below:

1. CO2 annual emissions from 2009 through 2018 for:
   a. The Commonwealth's regulated electric power plants.
   b. All other unregulated sources of CO2.

   Inasmuch as the SCC does not regulate or track historic CO2 emissions for either regulated electric power plants or unregulated sources of CO2, we do not maintain any data relative to carbon emissions. The DEQ has regulatory authority relative to environmental issues in the Commonwealth and is the appropriate source of emissions data.

2. The forecast of CO_2 emissions beginning in 2019 under the latest integrated resource plans for regulated electric power plants.

   DEV's 2018 Integrated Resource Plan ("IRP") (not approved by the Commission as filed) incorporated the initial proposed CO_2 emissions cap for Virginia of 34 million tons rather than the currently proposed 28 million tons. The SCC Staff believes it would be more relevant to provide the CO_2 emissions forecast modeled in the SCC Staff's RGGI analysis which used the current proposed cap of 28 million tons. This CO_2 forecast is enclosed.

3. The annual CO_2 emissions allowed through 2040:
   a. Under the original DEQ proposal (34 million ton 2020 budget base, 3% reductions per year, no reductions beyond 2030).
   b. Under the new re-proposal using a 28 million ton 2020 budget, 3% reductions per year through 2030, and annual reductions of 840,000 tons per year from 2031 to 2040.

   The requested information is enclosed.

4. An estimate of the annual cost of the "allowance fees" purchased through 2040 to be passed through to consumers based on the minimum price and double the minimum price.

   See page 14 of the enclosed document. The SCC Staff's analysis estimated the annual cost of the allowance fees through 2030 based on the RGGI Emission Containment Reserve trigger prices. RGGI has not published any prices beyond 2030.

5. An estimate of the plants that would be shutdown to comply with the emission caps and the change in natural gas deliveries as a result.

   The SCC Staff's analysis concludes that linking to RGGI will result in the premature retirements of DEV'S Chesterfield Units 5 and 6 and Clover Units 1 and 2. Since these are coal units, there are no related impacts to natural gas deliveries.

6. An estimate of the capacity and emissions from the plants required to provide power when solar and wind plants are not able to supply the power demand.

   DEV's units are dispatched by the PJM Interconnection, LLC ("PJM"). PJM dispatches power generation from a mix of nuclear, coal, gas, and renewable generating units owned by PJM member utilities (including DEV) operating in *the PJM Interconnection.*[1] *When individual solar and wind plants in Virginia or elsewhere in the Interconnection are not available for any reason (forced outages, weather, etc.), the power these units would have furnished will be supplied from the mix of other available generation plants (of all types) located throughout the PJM footprint. Further, if additional generation is needed to meet load during a time of high demand within the Interconnection, PJM simply dispatches from the mix of generation then available to meet load requirements. Consequently, the information requested in this question cannot be provided because of the way in which PJM dispatches the generation of its member utilities.*

7. Evaluation of the proposal using the SCC's standard analysis including the Ratepayer Impact Measure. Please provide estimates of the residential, commercial and industrial rates from 2020 through 2040 assuming no return of allowance revenue to consumers as was contemplated in legislation defeated in the General assembly.

   See pages 7-8 of the enclosed document. Staff only provides a high-level bill impact for a typical DEV residential customer. Determining actual rate impacts by year through 2040 for all of DEV's rate classes is beyond the scope of the RGGI analysis that the SCC Staff performed. DEV has very complex non-residential rate structures and many different non-residential rate classes. This fact coupled with the wide diversity of customers within these classes makes such an analysis extraordinarily complex. Additionally, we would have little confidence in the results of such an analysis.

8. Estimates of the amount of power purchased annually from the PJM grid during the 2020-2040 cap regime.

   As a member of PJM, DEV purchases 100% of the power it consumes from PJM and it sells 100% of the power its generating units produce into PJM. Staff's estimate of total sales to PJM, purchases from PJM, and net purchases in excess of sales is enclosed.

9. Experience from other RGGI states between 2007 and 2016 shows an increase in imports of power from other states in the PJM grid as in-state power generation falls because of allowance prices. There was also a significant loss of in-state production of energy intense goods that shifted to other states. What is the SCC estimate of carbon dioxide emission shifting from these two causes? Shouldn't the estimates be included as costs to the RGGI program?

[1] The PJM Interconnection coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Any changes to imported power from PJM and changes in the dispatch of DEV's fossil fuel units is captured in Staff's RGGI analysis. The SCC Staff has not estimated loss of in-state production of energy intense goods as its analysis was limited to the costs of providing electricity and related customer bill impacts of RGGI compliance.

10. The estimates of the Cost Containment Reserve (CCR) allowance price and the Emission Containment Reserve (ECR) trigger price appear to be based on the discredited Social Cost of Carbon proposed by the Obama Administration. Can you confirm how these two prices were developed?

    The SCC Staff cannot confirm how the Cost Containment Reserve allowance price or the Emission Containment Reserve price were calculated or what formed the basis of those calculations.

If you have any other questions or need additional assistance, please contact me or Greg Abbott at 804-371-9611.

Respectfully,

William Stephens

Enclosures

SCC STAFF RGGI ANALYSIS FORECAST OF CARBON EMISSIONS FOR DEV

CARBON (TONS)

	No CO2 Base	No CO2 GTSA	RGGI Link GTSA
2018	28,858,477	28,858,477	28,858,477
2019	29,215,747	29,115,197	29,131,044
2020	30,036,685	29,524,359	26,488,641
2021	28,923,203	28,115,865	25,240,860
2022	29,334,792	28,142,628	25,715,612
2023	30,096,952	28,727,137	25,617,605
2024	29,921,839	28,181,266	24,970,901
2025	30,180,823	27,732,939	24,767,813
2026	29,619,643	26,607,941	24,441,398
2027	31,179,184	27,965,381	26,013,263
2028	30,336,483	26,499,684	22,956,099
2029	31,132,829	27,318,300	24,424,271
2030	30,346,024	26,771,111	22,877,523
2031	30,570,478	26,680,186	22,772,674
2032	29,637,821	26,180,204	21,024,971
2033	32,369,828	28,661,945	24,088,127
2034	30,600,303	27,648,989	22,098,659
2035	33,227,067	30,240,431	25,135,606
2036	33,420,559	31,065,660	25,469,431
2037	33,999,904	31,546,764	25,456,153
2038	34,245,693	32,175,343	26,035,008
2039	34,420,443	32,567,542	26,056,592
2040	34,732,142	32,999,597	25,935,143
2041	34,829,607	33,261,042	25,987,079
2042	35,529,933	34,017,314	26,302,759
2043	35,746,249	34,374,286	26,629,909

ANNUAL CO2 EMISSIONS ALLOWED THROUGH 2040
UNDER ORIGINAL DEQ PROPOSAL AND UNDER THE CURRENT PROPOSAL

	Orginal Proposal VA RGGI Carbon Cap (tons)	Current Proposal VA RGGI Carbon Cap (tons)
2020	34,000,000	28,000,000
2021	32,980,000	27,160,000
2022	31,960,000	26,320,000
2023	30,940,000	25,480,000
2024	29,920,000	24,640,000
2025	28,900,000	23,800,000
2026	27,880,000	22,960,000
2027	26,860,000	22,120,000
2028	25,840,000	21,280,000
2029	24,820,000	20,440,000
2030	23,800,000	19,600,000
2031	23,800,000	18,760,000
2032	23,800,000	17,920,000
2033	23,800,000	17,080,000
2034	23,800,000	16,240,000
2035	23,800,000	15,400,000
2036	23,800,000	14,560,000
2037	23,800,000	13,720,000
2038	23,800,000	12,880,000
2039	23,800,000	12,040,000
2040	23,800,000	11,200,000

SCC STAFF RGGI ANALYSIS
Estimates of Power Sold/Purchased from PJM
MWh

	DEV Generation Sold to PJM	DEV Purchases From PJM	DEV Net Sales/(Purchases)
2020	84,946,957	91,974,332	(7,027,375)
2021	82,986,266	92,615,967	(9,629,700)
2022	84,770,240	93,916,547	(9,146,308)
2023	85,905,419	94,430,313	(8,524,894)
2024	86,027,330	95,435,557	(9,408,227)
2025	87,602,035	95,744,298	(8,142,263)
2026	87,976,157	96,594,919	(8,618,762)
2027	91,051,456	97,601,148	(6,549,692)
2028	87,455,638	99,209,840	(11,754,202)
2029	90,679,958	100,122,207	(9,442,249)
2030	87,330,556	100,912,249	(13,581,694)
2031	88,331,501	102,148,066	(13,816,565)
2032	85,999,274	103,926,366	(17,927,093)
2033	90,965,316	104,641,500	(13,676,184)
2034	87,611,827	105,542,792	(17,930,965)
2035	92,829,185	106,656,182	(13,826,997)
2036	92,587,585	107,698,643	(15,111,058)
2037	92,749,240	108,571,202	(15,821,962)
2038	92,911,607	109,593,016	(16,681,409)
2039	92,426,410	110,518,918	(18,092,508)
2040	91,812,715	111,554,353	(19,741,638)

SCC STAFF ANALYSIS OF CUSTOMER BILL IMPACTS OF VIRGINIA PARTICIPATING IN RGGI
February 21, 2019

EXECUTIVE SUMMARY

During the 2019 Virginia General Assembly session, bills were introduced regarding Virginia's participation in the Regional Greenhouse Gas Initiative (RGGI). Using currently available information and applying certain assumptions, the Staff of the State Corporation Commission ("SCC") made estimates of the potential cost and rate impacts of *joining* or *linking* to RGGI. This document was prepared at the request of the Virginia Department of Environmental Quality ("DEQ") to explain the method and assumptions used by SCC Staff which produced these estimates.

Since DEQ's proposed RGGI rule envisions Virginia linking to RGGI, this document will address the implications of Virginia linking to RGGI. SCC Staff estimates the total cost to Dominion Energy Virginia ("DEV") of linking to RGGI to be about $3.3 billion. SCC Staff estimates the total cost to DEV of joining RGGI to be about $5.9 billion. SCC Staff estimates that linking to RGGI will *increase* the typical DEV ("DEV") residential customer's monthly bill by an average of $6.95 from $120.52 to $127.48 over the 25-year study period.[1]

DEQ estimates that the typical monthly bill for a residential customer served by DEV will *decrease* by an average of $0.54 over the 2020-2030 time period. Given that RGGI is a government imposed cap and trade mechanism designed to impose a carbon tax on the use of fossil fuel generation, and given that DEV owns a significant portfolio of coal and natural gas generation units, the SCC Staff finds DEQ's projection of falling customer bills to be counterintuitive.

DEQ modeled DEV as if it was solely a purchaser of electricity from the grid. In contrast, SCC Staff modeled DEV's actual market structure as a vertically integrated utility that owns fossil fuel generation resources. SCC Staff correctly modeled DEV as both a purchaser of electricity from the grid and as a seller of electricity into the grid.

Chesterfield Units 5 and 6 and Clover Units 1 and 2 are forced into retirement prematurely under SCC Staff's modeling. These units must be paid for by DEV's customers whether the units operate or not. Furthermore, as a member of the PJM Interconnection, LLC ("PJM"), DEV is required to meet PJM's capacity obligation. SCC Staff's analysis shows that approximately 1,500 MWs of capacity will have to be constructed earlier than would otherwise be the case to replace the 4 retired units. DEV's customers essentially pay twice. First, they must pay for the 4 retired units for capacity that they will no longer receive due to RGGI. Secondly, they must pay for the costs of new capacity constructed sooner than otherwise necessary to replace these retired units.

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[1] Given that SCC Staff used a 25-year study period, this should be viewed as the average increase in the typical residential customer's monthly bill (averaged over the 25-year period in constant dollars). Thus, these bill impacts will likely be lower than $6.95 in the beginning of the study period and higher than that amount at the end of the study period. Measured in future inflated dollars, these average bill impacts will likely be greater than $6.95 over the 25-year period.

SCC STAFF ANALYSIS OF CUSTOMER BILL IMPACTS

OF VIRGINIA PARTICIPATING IN RGGI

February 21, 2019

Q. What is the SCC Staff's understanding of the Regional Greenhouse Gas Initiative ("RGGI")?

A. RGGI is a "cap and trade" market mechanism to cap and reduce CO_2 emissions from the electric power sector. It is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. The number of allowances, or "cap," is ratcheted down each year. Each of the RGGI member states is allocated the number of CO_2 emissions allowances corresponding to its share of the overall RGGI cap. Generally, each member state must submit its CO_2 emissions allowances for sale in the RGGI auction with the revenues received from these sales flowing back to each state. Fossil fuel electric power generators with a capacity of 25 megawatts ("MWs") or greater are required to hold allowances equal to their CO_2 emissions. The required offsetting CO_2 emissions allowances must be purchased by each fossil fuel generator. The Virginia Department of Environmental Quality ("DEQ") proposes to link to RGGI and its allowance auction system by way of a "consignment auction." Essentially, RGGI levies a carbon tax on fossil fuel generation, payable by electric generators in each RGGI state, with the goal of making fossil fuel generation less competitive, thus leading to reductions in fossil fuel generation and corresponding reductions in CO_2 emissions.

Q. What is the SCC Staff's understanding of DEQ's estimate of the bill impact on a typical residential customer under RGGI?

A. DEQ estimates that the typical monthly bill for a residential customer served by Dominion Energy Virginia ("DEV") will decrease by an average of $0.54 over the 2020-2030 time period. Given that RGGI is a government imposed cap and trade mechanism designed to impose additional costs on the use of fossil fuel generation, and given that DEV owns a significant portfolio of coal and natural gas generation units, the SCC Staff finds DEQ's projection of falling customer bills to be counterintuitive.

Q. Has the SCC Staff separately analyzed the cost and rate impacts of Virginia participating in RGGI?

A. Yes. SCC Staff estimates that RGGI will impose costs on DEV's customers. SCC Staff estimates that a typical monthly residential bill will see an average increase between $7 and $12, over the 2019-2043 time period, depending on whether Virginia ***links*** to RGGI or ***joins*** RGGI. SCC Staff estimates the total cost of linking to RGGI to be about $3.3 billion. SCC Staff estimates the total cost of joining RGGI to be about $5.9 billion.

Since DEQ's proposed RGGI rule envisions Virginia linking to RGGI, the remainder of this document will address the implications of Virginia linking to RGGI.[2]

Q. Why is the SCC Staff's bill impact of linking to RGGI higher than the bill impact calculated by DEQ?

A. As will be discussed in more detail later in this document, the most important difference between SCC Staff and DEQ is the market structure that was used in the modeling. DEQ modeled DEV as a deregulated utility and Virginia as a deregulated market. As a result, DEQ modeled DEV as if it was solely a purchaser of electricity from the grid. In contrast, SCC Staff modeled DEV's actual market structure as a vertically integrated utility that owns fossil fuel generation resources. SCC Staff correctly modeled DEV as both a purchaser of electricity from the grid and as a seller of electricity into the grid.

The deregulated market approach modeled by DEQ is consistent with the market structure that exists in all other RGGI member states except Vermont. It does not, however, reflect the market reality that exists in Virginia, and it is not appropriate to use this market structure to measure customer bill impacts of RGGI compliance for Virginians. Simply put, DEQ's model assumes that DEV does not own fossil fuel generation units that will be impacted by the new Virginia RGGI CO_2 regulations. However, DEV does own fossil fuel generation units and its customers will pay for the increased operating costs of the fossil fuel units that continue to run. Furthermore, DEV's customers will pay for these units whether the units are run or not.

[2] SCC Staff modeling assumed that if Virginia links to RGGI, 95% of the revenues received through the sale of CO_2 emissions allowances in the RGGI auctions would flow back to customers though the utilities to offset customer bill impacts. There are a variety of ways that emissions allowances revenues could serve to reduce DEV's customer bills. SCC Staff's analysis assumes that these revenues will benefit customers in one way or another.

Q. The 2018 Grid Transformation and Security Act ("2018 GTSA" or "SB966") contained several policy objectives[3] for DEV to potentially achieve by 2028 including: (1) the construction and/or purchase of 5,000 MWs of solar/wind generation capacity; (2) $870 million of proposed spending on energy efficiency programs; and (3) the construction of 30 MWs of battery storage. Will achieving these policy objectives alone result in DEV meeting its CO_2 emissions reductions targets under RGGI?

A. No. Determining the impact of 2018 GTSA policy goals must be done in the context of DEVs' membership and participation in the PJM Interconnection, LLC ("PJM") energy and capacity markets.[4]

PJM dispatches generation based on the economics of each individual unit. The addition of 5,000 MWs of solar/wind resources in Virginia, 30 MWs of battery storage, and $870 million of spending on energy efficiency will displace generation from the least efficient and highest cost generating units in the PJM footprint.[5] These units will most likely be aging coal and/or natural gas generating units. These fossil fuel generating units, while located within PJM, may or may not be in Virginia.[6] As a result, even if DEV achieves all of the 2018 GTSA's policy objectives described above, it may nevertheless be required to (i) prematurely retire currently operational coal generation units to meet RGGI CO_2 emissions reduction goals, and (ii) concurrently construct new natural gas fired generating units in order to meet its generation capacity obligation in PJM.

Q. Please provide the results of the SCC Staff's model simulations of Virginia linking to RGGI.

A. The SCC Staff's analysis[7] used the PLEXOS®[8] model to simulate several different scenarios as follows:

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[3] SB966 also included the policy goals of grid modernization, the undergrounding of transmission lines, and the undergrounding of tap lines.

[4] PJM coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. For purposes of generation unit dispatch, the utilities in these states operate together as one large utility system.

[5] Likewise, the construction of renewable facilities or the implementation of energy efficiency measures in other PJM states may lead to less CO_2 emissions in Virginia.

[6] For example, the construction of additional solar facilities in Virginia may lead to the retirement of a coal unit in West Virginia or Ohio.

[7] DEV owns the PLEXOS® software and performed the model runs contained in this document at the direction of the SCC Staff.

[8] The PLEXOS® Integrated Energy model is a power market simulation software that uses mathematical programming and stochastic optimization techniques and is widely used by electric utilities including both DEV and Appalachian Power Company in Virginia.

1. A base scenario which represents a least cost plan for DEV to meet its customers' electricity requirements and that assumes that Virginia does not participate in RGGI;

2. A GTSA scenario in which the model is required to select the 5,000 MWs of solar/wind, 30 MWs of battery storage, and $870 million of energy efficiency contained in the 2018 GTSA and which also assumes that Virginia does not participate in RGGI; and

3. A GTSA-RGGI scenario in which the model is required to select the 5,000 MWs of solar/wind, 30 MWs of battery storage, and $870 million of energy efficiency contained in the 2018 GTSA and which also assumes that Virginia links to RGGI.

The model results showing the resulting DEV generating unit build plans and the net present value ("NPV") costs under each scenario are presented below:

	Base No RGGI		GTSA No RGGI		GTSA RGGI Link	
	Renewable MWs	Fossil MWs	Renewable MWs	Fossil MWs	Renewable MWs	Fossil MWs
2020	-	-	480	-	480	-
2021	80	-	491	-	491	-
2022	-	458	480	458	480	458
2023	-	458	480	458	480	458
2024	-	458	480	458	480	458
2025	-	458	480	-	480	458
2026	-	458	480	-	480	458
2027	-	458	480	-	480	458
2028	-	-	480	-	480	-
2029	-	458	480	-	480	458
2030	-	-	160	458	160	-
2031	-	-	-	-	-	-
2032	-	458	-	458	80	458
2033	-	458	-	-	480	-
Total	**80**	**4,122**	**4,971**	**2,290**	**5,531**	**3,664**
2034	480	-	-	458	-	458
2035	480	-	320	-	80	-
2036	160	-	-	458	-	458
2037	-	458	-	-	160	-
2038	160	-	-	458	-	-
2039	-	-	-	-	-	-
2040	-	458	-	458	-	-
2041	-	-	-	-	-	-
2042	-	458	-	458	-	-
2043	-	-	-	-	-	-
Total	**1,360**	**5,496**	**5,291**	**4,580**	**5,771**	**4,580**

NPV ($B) $26.75	$27.54	$29.95

Q. What are the differences in the build plans under each scenario?

A. SCC Staff utilized a 25-year study period, which is the standard study period used by the State Corporation Commission ("Commission") to evaluate utility Integrated Resource Plans and utility applications for Certificates of Public Convenience and Necessity for the construction of utility proposed generation projects. In all three scenarios, the model selected the nuclear license extensions for the Surry and North Anna nuclear units on a cost optimization basis. All three scenarios under SCC Staff's modeling also include the retirements of all current cold reserve generating units[9] and Possum Point Unit 5. Under the GTSA-RGGI scenario, the additional retirements of Chesterfield Units 5 and 6 in 2022 and Clover Units 1 and 2 in 2025 are required as the added costs of purchasing the required offsetting CO_2 emissions allowances for these units make them uneconomic. The cost implications of these premature retirements will be discussed later in this document.

Q. Based on the SCC Staff's model results, what is the incremental cost of linking to RGGI?

A. Assuming the generation and energy efficiency related components contained in the 2018 GTSA are implemented, SCC Staff estimates that linking to RGGI will impose an incremental additional NPV cost of $2.41 billion[10] ($29.95 billion minus $27.54 billion) over the 25-year study period.

Q. How did the SCC Staff develop its estimate of a $7 typical residential customer bill impact for linking to RGGI?

A. First, SCC Staff developed a ratio of the NPV cost of the GTSA-No RGGI scenario divided by the NPV cost of the Base–No RGGI scenario. SCC Staff then applied this ratio to the base generation, generation rate adjustment clauses ("RACs"), and fuel factor portion of the current typical residential customer's monthly bill to determine the bill impact of the generation and energy efficiency-related components of the 2018 GTSA. SCC Staff estimates that the generation and energy efficiency-related components of the 2018 GTSA will increase the typical residential customer's monthly bill by $2.28 from $118.24 to $120.52.

SCC Staff then developed a ratio of the NPV cost of the GTSA-RGGI Link scenario divided by the NPV cost of the GTSA-No RGGI scenario. This ratio was applied to the

[9] The following units were placed in cold reserve status during 2018: Bellemeade 1, Bremo 3 & 4, Mecklenberg 1 & 2, Pittsylvania 1, Chesterfield 3 & 4, and Possum Point 3 & 4, representing 1,292 MW of generating capacity.
[10] This is equivalent to approximately $3.3 billion in nominal dollars.

base generation, generation RACs, and fuel factor components of the estimated typical residential customer's monthly bill described above for the generation and energy efficiency-related components 2018 GTSA. SCC Staff estimates that linking to RGGI will increase the typical residential customer's monthly bill by an average of \$6.95 from \$120.52 to \$127.48 over the 25-year study period.[11]

Q. Identify the key assumptions the SCC Staff used in its RGGI bill analysis for DEV customers.

A. Some of the key assumptions are as follows:

- SCC Staff used a RGGI CO_2 emissions cap for Virginia of 28 million tons beginning in 2020 which decreases 3% per year through 2030, as proposed in Virginia State Air Pollution Control Board regulations currently under review.

- SCC Staff modeled DEV as the vertically integrated utility that it is, i.e., a utility that owns generation resources – and whose customers will pay for these units regardless of whether they are run or not;

- SCC Staff used the CO_2 emission containment reserve ("ECR") trigger price floor for CO_2 emission allowances published by RGGI;

- SCC Staff used a discount rate of 6.31%, which represents DEV's after tax weighted average cost of capital used in its most recent Integrated Resource Plan proceeding before the Commission; and

- SCC Staff assumed that 5,000 MWs of solar, 30 MWs of battery storage, and \$870 million of spending on energy efficiency programs, consistent with the 2018 GTSA, are built or implemented.

- SCC Staff's analysis reflects the Commission's findings in its December 7, 2018 Order in Case No. PUR-2018-00065 regarding DEV's 2018 Integrated Resource Plan. Namely, Staff's analysis used: (1) the coincident peak PJM load and energy forecast scaled down to the DEV load serving entity level; and (2) a capacity factor of 23% for solar generating resources.

[11] Given that SCC Staff used a 25-year study period, this should be viewed as the average increase in the typical residential customer's monthly bill (averaged over the 25-year period in constant dollars). Thus, these bill impacts will likely be lower than \$6.95 in the beginning of the study period and higher than that amount at the end of the study period. Measured in future inflated dollars, these average bill impacts will likely be greater than \$6.95 over the 25-year period.

Q. Why is the SCC Staff's bill impact of participating in RGGI higher than the bill impact calculated by DEQ?

A. SCC Staff's customer bill impacts showing an increase to customer bills significantly differs from DEQ's estimates of RGGI compliance resulting in lower customer bills. This is due to differing modeling assumptions. Some of DEQ's key assumptions are as follows:

- DEQ modeled DEV as if it were a deregulated utility that does not own generation resources operating in a deregulated competitive energy market. Thus, DEQ omitted the customer bill impact of increased fuel costs and prematurely retiring generating units and of additional costs to operate DEV's fossil fuel generating units that continue to run;

- DEQ used CO_2 emission allowance prices that are lower than the ECR trigger price for carbon emission allowances published by RGGI;

- DEQ used a discount rate of 2.1%;

- DEQ assumed that the generation and energy efficiency-related policy objectives contained in the 2018 GTSA are implemented.

The impact of these key DEQ assumptions is discussed below.

Q. What is the practical effect of DEQ using a CO_2 emission allowance price that is lower than the RGGI ECR trigger price floor for carbon emission allowances published by RGGI?

A. To the extent that the carbon emission allowance prices are lower, this will result in a lower cost estimate for RGGI compliance and lower typical bill impacts. A comparison of DEQ's CO_2 emission allowance prices, the RGGI ECR trigger price floor, and the RGGI CO_2 cost containment reserve ("CCR") trigger price ceiling is shown below.

	RGGI ECR Trigger Price Floor	RGGI CCR Trigger Price Ceiling	DEQ Price
2020	$6.00	$10.77	N/A
2021	$6.00	$13.00	N/A
2022	$6.42	$13.91	$4.01
2023	$6.87	$14.88	N/A
2024	$7.35	$15.92	N/A
2025	$7.86	$17.03	$4.55
2026	$8.41	$18.22	N/A
2027	$9.00	$19.50	N/A
2028	$9.63	$20.87	$5.18
2029	$10.30	$22.33	N/A
2030	$11.02	$23.89	$5.65

Q. Please explain why SCC Staff views the RGGI ECR trigger price as a floor and the RGGI CCR trigger price as a ceiling.

A. The RGGI ECR and CCR trigger prices establish a range of CO_2 emissions allowance prices which represent the policy goals of RGGI. These trigger prices should be viewed as a "soft" price floor and a "soft" price ceiling. Actual prices for CO_2 emissions allowances can clear at a price below the ECR trigger price or above the CCR trigger price in any given year. However, if the auction price clears below the ECR trigger price, RGGI will remove CO_2 emissions allowances from future auctions to force prices back above the ECR trigger price floor. Similarly, if the auction price clears above the CCR trigger price, then RGGI would inject additional CO_2 emissions allowances into the market to force prices back below the CCR trigger price ceiling.

Q. Does the SCC Staff view DEQ's assumed CO_2 emissions allowance prices to be too low?

A. Not necessarily. Historically, CO_2 emissions allowances have cleared the RGGI auction at relatively low prices. DEQ is assuming that this will continue to be the case in the future. In addition, as mentioned above, the RGGI market can clear at a price below the ECR trigger price. However, when estimating the costs of RGGI compliance going forward for Virginia, SCC Staff believes it is more realistic to use CO_2 emissions allowance prices that are consistent with RGGI's allowance price trigger mechanisms described above. SCC Staff used the ECR trigger price floor which SCC Staff views as being a conservative assumption.

Q. What is the practical effect of DEQ using a discount rate lower than DEV's weighted average cost of capital?

A. Using a lower discount rate understates the true costs of future capital investments. The Commission has consistently used DEV's weighted average cost of capital in evaluating CPCN applications for proposed generation and transmission projects. This is appropriate because it reflects DEV's actual costs of raising capital for these large capital projects.

Q. What is the practical effect of DEQ modeling DEV as if it were a deregulated utility that does not own generation resources operating in a deregulated competitive energy market?

A. Virginia is unique compared to the RGGI member states which are fully deregulated. Local Distribution Companies ("LDCs") in those deregulated states do not own generation assets. All generation is provided by merchant generators selling into the grid. All power consumed by the LDCs is purchased from the grid or through bilateral power purchase agreements with merchant generators.

In contrast, DEV is a vertically integrated utility that owns generation, transmission, and distribution resources. The LDCs in other RGGI states are purchasers of electricity from the grid. DEV is both a purchaser of electricity from the grid and a producer of electricity sold into the grid. DEV's ownership of generation resources is a key factor that must be considered in any RGGI analysis and it appears that DEQ did not fully consider this factor.

Q. Focusing on the impacts of RGGI on DEV as a purchaser of electricity, explain how DEQ calculated customer bill impacts.

A. DEQ calculates the incremental increase of PJM Interconnection, LLC ("PJM") power prices assuming that Virginia links to RGGI. DEQ then multiplies this incremental increase in cost per kilowatt-hour ("kWh") by the average monthly bill usage to arrive at the bill increase cost of RGGI compliance. DEQ then adjusts this bill impact by subtracting the expected pro-rata share of the RGGI CO_2 emissions allowance revenues that DEV will receive from the sale of CO_2 emissions allowances in the RGGI auction. It appears that DEQ's estimate of RGGI CO_2 emissions allowance revenues is greater than the increase in PJM power prices which results in DEQ's estimate of falling customer bills under RGGI.

Q. Does the SCC Staff agree that Virginia linking to RGGI will put upward pressure on PJM energy prices?

A. Yes. SCC Staff estimates that Virginia linking to RGGI will cause PJM power prices to increase by an average of $0.44 per megawatt hour ("MWh") over the 2020 to 2030 time period. Hourly PJM energy prices are determined by the marginal unit that clears the market each hour. The imposition of additional costs on Virginia fossil fuel units for the required offsetting CO_2 emissions allowances under RGGI will generally lead to higher cost marginal units setting the hourly PJM energy price, thus putting upward pressure on PJM energy prices.

Q. Does the SCC Staff agree that Virginia linking to RGGI will result in DEV receiving revenues from the sale of CO_2 emissions allowances into the RGGI auctions?

A. Yes, the table below shows SCC Staff's estimate of expected revenues from the sale of CO_2 emissions allowances. SCC Staff assumed that DEV would be allocated 70% of the Virginia total. SCC Staff further assumed that 5% of this total would go to the Virginia Department of Mines, Minerals and Energy ("DMME").[12]

[12] 5% of the revenues will go to DMME to defray the costs of oversight and implementation of Virginia's participation in RGGI.

	VA RGGI Carbon Cap (tons)	DEV Carbon Cap 70% of VA	DEV Cap @ 95% (tons)	RGGI ECR Prices	RGGI Allowance Revenues
	(a)	(b)	(c)	(d)	(e) = (c) x (d)
2020	28,000,000	19,600,000	18,620,000	$6.00	$111,720,000
2021	27,160,000	19,012,000	18,061,400	$6.00	$108,368,400
2022	26,320,000	18,424,000	17,502,800	$6.42	$112,367,976
2023	25,480,000	17,836,000	16,944,200	$6.87	$116,406,654
2024	24,640,000	17,248,000	16,385,600	$7.35	$120,434,160
2025	23,800,000	16,660,000	15,827,000	$7.86	$124,400,220
2026	22,960,000	16,072,000	15,268,400	$8.41	$128,407,244
2027	22,120,000	15,484,000	14,709,800	$9.00	$132,388,200
2028	21,280,000	14,896,000	14,151,200	$9.63	$136,276,056
2029	20,440,000	14,308,000	13,592,600	$10.30	$140,003,780
2030	19,600,000	13,720,000	13,034,000	$11.02	$143,634,680

Q. What is missing from DEQ's RGGI cost analysis?

A. As mentioned earlier, SCC Staff modeled DEV as a vertically integrated utility that owns a portfolio of fossil fuel generation resources. DEV is both a purchaser of power from the PJM market and a seller of power into the PJM market. DEQ's RGGI cost analysis does not include the costs of the CO_2 emissions allowances that DEV must purchase for each of its fossil fuel units. These costs will flow back to customers and increase customer bills. The cost of CO_2 emissions allowances will impact customers in two different ways.

First, many of DEV's fossil fuel units will continue to clear the PJM energy and capacity markets and will continue to run. However, given that these units will now have a higher unit dispatch cost, these units will return far less value back to the customer through the fuel factor.[13]

Secondly, Chesterfield Units 5 and 6 and Clover Units 1 and 2 are forced into retirement prematurely under SCC Staff's modeling. These units must be paid for by DEV's customers whether the units run or not.

[13] For a hypothetical example, if the unit dispatch cost for a fossil fuel unit is $30/MWh without RGGI and the PJM energy price is $33/MWh, then this unit will provide $3/MWh of value back to DEV's customers for every MWh sold into PJM. If the unit dispatch cost is increased to $32.50/MWh under RGGI reflecting the costs to the utility of the required offsetting CO_2 emissions allowances, then this unit will still run but it will now only provide $0.50/MWh of value back to the customer. The DEV fuel factor will increase to recover the $2.50/MWh of required RGGI costs under this hypothetical example.

Q. Why must customers pay for these prematurely retired units?

A. As a regulated utility, DEV has a legal obligation to provide service to every customer in its service area. When these units were approved for construction, they formed a necessary part of the generation "fleet" used to supply power to customers; thus, under the regulatory framework, the utility is entitled to recover the entire cost.

Q. What happens to the unrecovered costs of prematurely retired units in DEQ's analysis?

A. DEQ treated all generation units as merchant generators. As such, the shareholders of the entities that own the retiring fossil fuel unit would bear these unrecovered costs. Similarly, even for fossil fuel units that continue to run, DEQ's analysis assumes that the cost of the required offsetting CO_2 emissions allowances will be borne by the shareholders of the entities that own the affected fossil fuel generating units. That is, DEQ assumes that these shareholders will earn a lower profit as a result. In reality, since DEV owns the fossil fuel generating units, the cost of the required offsetting CO_2 emissions allowances will be collected from DEV's customers most likely through a higher fuel factor than would otherwise be the case.

Q. What are the costs that DEV will incur under RGGI for its fossil fuel units that will continue to run under RGGI?

A. SCC Staff estimated these costs to be the product of the expected CO_2 emissions (tons) for the GTSA-RGGI Link scenario and the ECR trigger price. This is presented in the table below.

	RGGI ECR Prices	RGGI/GTSA DEV Carbon Output (tons)	RGGI Allowance Costs
	(a)	(b)	(c) = (a) x (b)
2020	$6.00	26,488,641	158,931,846
2021	$6.00	25,240,860	151,445,160
2022	$6.42	25,715,612	165,094,229
2023	$6.87	25,617,605	175,992,946
2024	$7.35	24,970,901	183,536,122
2025	$7.86	24,767,813	194,675,010
2026	$8.41	24,441,398	205,552,157
2027	$9.00	26,013,263	234,119,367
2028	$9.63	22,956,099	221,067,233
2029	$10.30	24,424,271	251,569,991
2030	$11.02	22,877,523	252,110,303

Q. How would including the costs of CO_2 emissions allowances for DEV's fossil fuel units that will continue to run impact DEQ's RGGI cost analysis?

A. This is displayed in the table below.

	DEV Energy Consumed (MWh)	RGGI PJM Energy Price Increase ($/MWh)	Increased Cost of Purchased Energy	DEV RGGI Allowance Revenues	DEQ RGGI Cost Analysis	DEV RGGI Allowance Costs	SCC Staff RGGI Cost Analysis
	(a)	(b)	(c) = (a) x (b)	(d)	(e) = (c) - (d)	(f)	(g) = (c) - (d) + (f)
2020	88,217,000	$0.44	$38,534,790	$111,720,000	($73,185,210)	$158,931,846	$85,746,636
2021	88,602,520	$0.44	$38,703,192	$108,368,400	($69,665,208)	$151,445,160	$81,779,952
2022	89,374,730	$0.44	$39,040,507	$112,367,976	($73,327,469)	$165,094,229	$91,766,760
2023	89,917,040	$0.44	$39,277,398	$116,406,654	($77,129,256)	$175,992,946	$98,863,690
2024	90,556,640	$0.44	$39,556,787	$120,434,160	($80,877,373)	$183,536,122	$102,658,749
2025	90,793,260	$0.44	$39,660,147	$124,400,220	($84,740,073)	$194,675,010	$109,934,937
2026	91,353,920	$0.44	$39,905,053	$128,407,244	($88,502,191)	$205,552,157	$117,049,966
2027	92,017,840	$0.44	$40,195,066	$132,388,200	($92,193,134)	$234,119,367	$141,926,233
2028	93,082,110	$0.44	$40,659,958	$136,276,056	($95,616,098)	$221,067,233	$125,451,135
2029	94,001,280	$0.44	$41,061,468	$140,003,780	($98,942,312)	$251,569,991	$152,627,680
2030	94,927,940	$0.44	$41,466,250	$143,634,680	($102,168,430)	$252,110,303	$149,941,874

The table above is based on SCC Staff's RGGI model outputs for the GTSA-RGGI Link scenario. Applying DEQ's methodology shows a net cost reduction as the revenues received from the sale of CO_2 emissions allowances is greater than the increased cost of purchased power in all years. However, DEQ's methodology fails to include the required purchases of CO_2 emissions allowances to cover the CO_2 emissions from DEV's fossil fuel units that continue to run. SCC Staff's methodology includes those costs and results in a net cost increase in all years. The costs of the required CO_2 emissions allowances will increase the dispatch costs of DEV's fossil fuel units, which will cause these units to provide less value back to DEV's customers. This will be seen on customers' bills as an increase in the fuel factor. This increase in the fuel factor is captured in the SCC Staff's estimate of a $6.95 increase in the typical residential customer's bill.

It should be noted that DEQ's analysis stops at 2030 (11 years). However, RGGI will continue to impose costs beyond 2030. SCC Staff's analysis includes the costs of RGGI compliance over a 25-year study period, as discussed above.

It is important to note that the table above does not include the costs associated with DEV's fossil fuel units that are forced to retire prematurely nor the increased fuel costs from dispatch changes.

Q. What additional costs are imposed on DEV's customers from Chesterfield Units 5 and 6 and Clover Units 1 and 2 retiring prematurely?

A. SCC Staff's RGGI analysis shows that Chesterfield Units 5 and 6 and Clover Units 1 and 2 are forced into early retirement in 2022 and 2025, respectively. These 4 units have a combined capacity of nearly 1,500 MWs. These units are forced into retirement prematurely because the increase in their dispatch costs from including the costs of CO_2 emissions allowances under RGGI make them no longer competitive in the PJM power market.

Chesterfield Units 5 and 6 would retire in 2034 and 2039, respectively, without RGGI. Likewise, Clover Units 1 and 2 would retire in 2050 and 2051, respectively, without RGGI. Thus, RGGI will result in these units retiring between 12 and 26 years early.

The combined end of year 2018 net book value for DEV of these 4 units is $781 million.[14] The entire $781 million will be collected from DEV's customers.[15]

Furthermore, as a member of PJM, DEV is required to meet PJM's capacity obligation. SCC Staff's analysis shows that approximately 1,500 MWs of capacity will have to be constructed earlier than would otherwise be the case to replace the 4 retired units. Under the SCC Staff's modeling results, most of this will be natural gas-powered combustion turbine units (1,376 MWs), with the remainder being additional solar units (560 MWs nameplate).[16] SCC Staff estimates that this replacement capacity will cost approximately $1.3 billion, excluding financing costs and a profit margin. This investment will also be collected from DEV's customers.

[14] Chesterfield Units 5 and 6 have a net book value of $626,986,555. Clover Units 1 and 2 have a net book value of $307,710,398. DEV has a 50% ownership in Clover Units 1 and 2. The remaining 50%, or $153,855,199, is owned by ODEC. SCC Staff has not performed an analysis of the customer bill impacts on Electric Cooperative customers in Virginia due to the premature retirement of Clover Units 1 and 2.

[15] In addition, there are lost property taxes and lost jobs implications associated with these 4 units retiring prematurely. SCC Staff's analysis did not attempt to capture or quantify these impacts.

[16] 560 MWs of nameplate solar capacity translates into about 129 MWs for purposes of meeting the PJM capacity obligation.

DEV's customers essentially pay twice. First, they must pay for the capacity of the retired units for capacity that they will no longer receive due to RGGI. Secondly, they must pay for the costs of new capacity constructed sooner than otherwise necessary to replace these retired units.

The costs of the units required to replace the capacity of the prematurely retired units will most likely be recovered through future RAC's. These bill impacts of these new RACs are captured in the SCC Staff's estimate of a $6.95 increase in the typical residential customer's bill.