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

April 9, 2018

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

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

Dear Ms. Sabasteanski:

Dominion Energy is submitting the following comments on the Department of Environmental Quality's (DEQ) proposed rule, published in the January 8, 2018 *Virginia Register*[1], to regulate carbon dioxide (CO_2) emissions from fossil fuel fired electric power generating facilities in Virginia. The proposed action is pursuant to former Governor McAuliffe's Executive Directive 11 (ED-11) requiring DEQ to develop a regulation that (i) ensures that Virginia is "trading-ready" to allow for the use of market-based mechanisms and the trading of CO_2 allowances through a multi-state trading program, and (ii) establishes abatement mechanisms that provide for a corresponding level of stringency to CO_2 limits imposed in other states with such limits. DEQ proposes to meet this directive by establishing a state-level CO_2 cap-and-trade program under 9 VAC 5-140 Part VII (Regulations for Emissions Trading) that would be linked to the northeast Regional Greenhouse Gas Initiative (RGGI) trading program.

Dominion Energy is one of the nation's largest producers and transporters of energy, with a portfolio of approximately 26,000 megawatts of generation, 15,000 miles of natural gas transmission, gathering and storage pipeline and 6,600 miles of electric transmission lines. The majority of Dominion Energy's electric generation is located in Virginia, including four carbon-free nuclear units, one of the nation's largest portfolios of renewable biomass generation, three of the most modern combined cycle natural gas facilities in the United States (with a fourth state of the art facility under construction), and a rapidly growing portfolio of large-scale solar generation.

The Company is already a leader in reducing greenhouse gas (GHG) emissions and began its transition to a less carbon-intensive generation fleet well in advance of the Clean Power Plan

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

(CPP). Between 2000 and 2017, Dominion Energy's carbon intensity for units serving Virginia decreased by 35 percent, while the amount of power we produced increased by 14 percent. This is due, in large part, to the closure, sale or conversion to natural gas and biomass of 12 coal-fired units, the company's four nuclear units that operate in Virginia, its growing fleet of highly efficient natural gas-fueled power stations, and its growing portfolio of renewable energy.

The Company will continue to move toward cleaner, more efficient, and lower emitting ways of generating, delivering, storing, and transporting energy. We plan to close or place into reserve another 720 MW of coal-fired generation over the next year. New electric power generators, like our highly efficient Brunswick and Greensville power stations, continue our long-term trend toward cleaner, less carbon-intensive electric generation. The company's investment in solar energy in Virginia and North Carolina during just the past two years is approaching $1 billion in projects with 1,350 MW of new solar in service, under construction or proposed. In addition, Dominion Energy operates several hydropower facilities and is one of the nation's largest generators of electricity using renewable biomass. The company also announced an offshore wind demonstration project and is evaluating pumped storage utilizing renewable energy as all or part of its power source in the coal field region of the state as supported by Virginia legislation.[2]

At a time of significant uncertainty in federal policy, we remain committed to transitioning to cleaner, less carbon-intensive electric generation. Dominion Energy actively participated in providing input to the Governor's Executive Order 57 (EO 57) Climate Work Group established in June 2016 and in the Technical Advisory Panel (TAP) process in the summer of 2017, established to solicit input in the development of state carbon regulations pursuant to the process and directive set by ED-11.

We offer the following comments on the Virginia carbon proposal:

Overarching Principles of a Carbon Mitigation Program

To the extent the Commonwealth pursues establishing a statewide emissions cap, we generally support the concept of designing a program that would allow for emissions trading and would position the program to be "trading-ready". We also find that the following key features are essential to designing a reasonable and workable program to address carbon emissions:

- The program should be designed to achieve desired environmental goals of reducing carbon emissions not only in Virginia, but regionally as well. The program should encourage the growth of cleaner, lower and zero-emitting generation in Virginia, commensurate with the Grid Transformation and Security Act of 2018,[3] which finds 5,500 MW of new solar and wind in Virginia in the public interest, as opposed to encouraging the increase in the dispatch of higher emitting generation in neighboring states/regions. It must recognize the benefit of reducing purchased power from out of state and its impact on the environment, the Virginia economy and Virginia jobs. A scenario that would shift generation and increase emissions in neighboring states and

[2] See http://lis.virginia.gov/cgi-bin/legp604.exe?171+ful+CHAP0820.
[3] See https://lis.virginia.gov/cgi-bin/legp604.exe?181+ful+CHAP0296

regions not subject to carbon constraints in the name of reducing emissions in Virginia will impose economic burden on Virginia customers with no environmental gain.

- The program must establish a representative baseline that effectively accounts for the emissions serving Virginia customer energy needs (electric consumption) from which to determine and measure emissions reduction goals. This should account for emissions from in state generation sources as well as emissions from purchased power.
- Any Virginia reduction plan should evaluate and set emission goals and realistic implementation timelines that will provide needed time for the ramp-up of new renewables, energy efficiency programs, and infrastructure improvements in order to maintain the state's fuel diversity and goal to become more energy independent;
- The program should also be designed to recognize the critical role of extending the operation of Virginia's existing fleet of carbon-free nuclear generation and the critical role of natural gas as the lowest cost, cleanest and most reliable form of dispatchable generation to complement the integration of renewables to the electric grid.
- It should also recognize and account for the role and opportunity that the electrification of other sectors of the economy, such as transportation and cities, can play to reduce carbon emissions economy wide in the Commonwealth and must not hinder the growth of electric vehicles with inflexible CO_2 limits.
- A goal should be to create a flexible program with multi-year emission averaging and other measures so that reductions can be achieved in the most cost-effective manner.
- The program should also provide for a means to address electric system reliability or adverse rate impacts.

In addition, as was recognized in design of the federal CPP promulgated by the Obama Administration, fuel switching from coal to natural gas is an essential part of lowering carbon emissions from electric generating facilities. Virginia's ability to continue the environmental gains from this strategy while maintaining reliable electricity service depends on adequate natural gas pipeline capacity. The Atlantic Coast Pipeline is a much needed addition to Virginia's energy infrastructure and ability to achieve its carbon goals. The current situation in New England, where the region has long been plagued by high electricity prices due in significant part to pipeline constraints and has been forced to import liquefied natural gas from Russia, should serve as an important policy lesson on the need for adequate pipeline capacity.

Summary of Key Issues and Concerns Regarding the Virginia Carbon Proposal

While the Company is committed to its ongoing transition to cleaner and lower carbon emitting resources, we are concerned that the Commonwealth's linkage to the RGGI program through the Virginia carbon proposal would disadvantage Virginia generation relative to other states and result in an undue burden on its customers with no real mitigation of GHG emissions regionally.

Modeling performed for Dominion Energy shows that:

- Virginia's linkage to RGGI will encourage lower cost electricity imports from out-of-state sources that are more carbon-intensive. The program will result in a significant increase in power imports while highly efficient and lower emitting NGCCs in Virginia will run less.

- Reductions in carbon emissions in Virginia, as a result of the increased use of imported power, will be offset by emission increases elsewhere within the North American Electric Reliability Corporation (NERC) Eastern Interconnect (EI) which includes all of PJM and the RGGI region.
- Increased imports of more carbon-intensive power will result in the carbon footprint per customer in Virginia increasing by about 5.7% by 2030.
- Linking to RGGI could impose over $500 million in additional cost to Virginia customers during the 2020-2030 period.

The 5,500 MW of renewables supported under the Grid Transformation and Security Act of 2018, if approved and constructed, will, to some degree, mitigate power imports and costs.

To the extent the Commonwealth proceeds with the proposed linkage to RGGI, we offer the following comments on the proposed design elements of the program:

- We do not support the proposed baseline (2020) caps of 33 or 34 million tons, which were based on model projections. Annual CO_2 emissions for Virginia units that would be covered under the Virginia carbon cap were about 35.3 million tons in 2016. Fundamentals-based models, while useful for evaluating the impacts of various policy strategies, should not be used to set the program emissions baseline. Rather, an emissions baseline should be established using historic emission levels including allowance for historic variations in emission levels due to year-to-year differences in weather patterns and fuel prices. This approach would be consistent with how other allowance programs, including RGGI, have established initial program baselines.
- Applicability should be consistent with other established emission reduction programs for EGUs and based on a 25-MW threshold as proposed.
- Units that burn biomass as their primary fuel should be exempt as proposed. As allowed in the RGGI model rule, an exemption should also apply to emissions from the biomass portion of fuel for fossil units that co-fire with biomass.
- With respect to auctioning of emission allowances under a trading program, legislation is required for the Board to designate use of revenue associated with a trading program. Absent such authority, DEQ could not proceed with directly conducting an allowance auction or collect revenue from an auction. The consignment auction approach provides a mechanism for the rule to proceed. Accordingly, to the extent the regulations link to RGGI via auction, we would support the proposed consignment approach with auction proceeds returned to the generators as opposed to a direct auction by DEQ where revenue would be deposited in state coffers. An approach where allowances are allocated to the generators is more cost-effective to customers.
- The proposed RGGI cap adjustment mechanisms and limitations on banking, including the Emissions Containment Reserve (ECR), should not be implemented in a nascent Virginia allowance market. Virginia affected sources will not be carrying any banked allowances during the initial compliance period. Accordingly, DEQ should allow the Virginia market to mature before applying any mechanism that would artificially reduce

and further tighten the emission cap and increase compliance costs by driving up the allowance price.

- DEQ should defer implementation of the Virginia program to 2021 to align with RGGI's 3-year compliance cycle.
- The program should allow offsets to encourage and advance emission reductions from other sectors of the economy, particularly those whose de-carbonization will be driven by electrification, such as the transportation sector.

Comments on the Commonwealth's Proposed Linkage to RGGI

1. **The proposed program will significantly increase power imports. Reduced emissions in Virginia will be offset by out-of-state emission increases.**

Carbon leakage occurs when a reduction in emissions of greenhouse gases within a state is offset by an increase in emissions of greenhouse gases outside the state as a direct result of a policy to cap emission in the state. For Virginia, carbon leakage means that the climate mitigation policy is less effective and more costly in containing emission levels. This should be a legitimate concern to carbon policy-makers.

Any program setting carbon emission targets for electric generating units must accommodate for the dynamics of power generated outside of and imported into Virginia. The program baseline and targets must reflect and account for the fact that Virginia is a net importer of energy from more carbon-intensive out-of-state resources. The program also must be designed to incent the expansion of lower-emitting cleaner generation in the state to address energy needs as envisioned in the Grid Transformation and Security Act of 2018, and reduce imports of electricity in accordance with state energy policy. Encouraging the expansion of highly efficient natural gas-fired combined cycle and renewable energy resources, including solar, wind and pumped storage, within the Commonwealth will grow the state's economy and lower emissions by decreasing reliance on more carbon-intensive power imported from other states.

Virginia's carbon footprint from electric power generation is already significantly cleaner than many of its neighboring states (see Appendix A). We are concerned that setting a stringent cap on already cleaner generation in Virginia absent a similar level of reductions from neighboring states or a mechanism to address potential leakage from neighboring states would increase the cost burden to Virginia generators. Such a situation would likely encourage lower cost electricity imports from out-of-state sources that are more carbon-intensive and not subject to a carbon cost adder. This could result in the unintended consequence of curtailing or limiting the dispatch of highly efficient and lower emitting natural gas combined cycle (NGCC) facilities in Virginia and encouraging the dispatch of higher emitting resources in neighboring states. With the federal CPP currently stayed and under administrative review, few states outside of the northeast Regional Greenhouse Gas Initiative (RGGI) program and along the west coast have or are proceeding with definitive carbon regulations. This includes all of the remaining states that are part of the PJM Interconnection, LLC (except Maryland and Delaware which are part of RGGI), which is the regional transmission organization that operates the wholesale electric grid in the mid-Atlantic region including Virginia, North Carolina and West Virginia.

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

These concerns are borne out by modeling sensitivity analyses. The following are based on forecasts from sensitivity cases requested by Dominion Energy and performed by ICF. They do not represent ICF's Reference Case view. In support of the Company's 2018 Integrated Resource Plan (IRP), ICF provided Dominion Energy with forecasts for a case where Virginia joins RGGI and a case where Virginia does not join RGGI (no CO_2 rule). Both cases assume no CO_2 program at the federal level. Further, both cases assume that New Jersey rejoins and participates in RGGI beginning in 2020. (New Jersey has recently announced its intent to rejoin the RGGI program.) In addition, the modeling did not include the Grid Transformation and Security Act of 2018 since it had not been signed into law at the time. Although the proposed regulation would not involve Virginia directly "joining" RGGI, the rule as proposed is designed to link to the RGGI program by way of a consignment auction of program CO_2 emission allowances, a level and timeline of emission reductions equivalent in stringency to RGGI, and provisions implementing the RGGI model rule. The region ICF modeled covered the U.S. and Canada, including the North American Electric Reliability Corporation (NERC) Eastern Interconnect (EI) which includes all of PJM and the RGGI region.

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

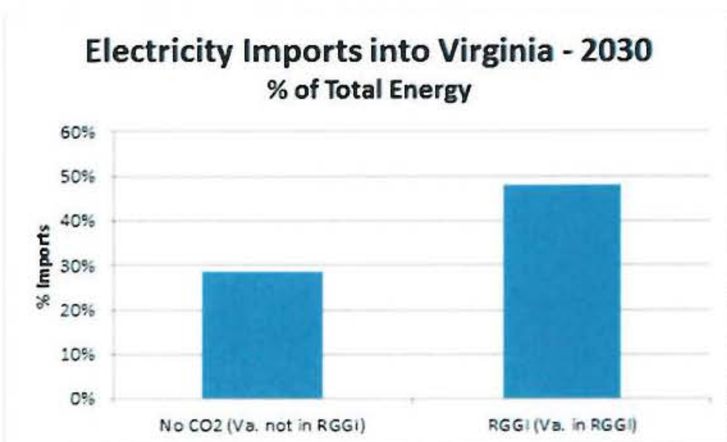
The modeling results indicate that Virginia entering the RGGI program in 2020 with a statewide emissions cap at the levels proposed and imposing RGGI's approximate 3% per year cap reduction to achieve a 30% emission reduction over the period 2020 – 2030 does not result in overall carbon emission reductions in the EI or PJM regions by 2030. Emissions in the entire EI in 2030 are about 10 million tons higher than emissions in 2020 and about 3 million tons higher in the PJM region during the same period. The analysis shows that for the most part emissions reductions achieved in the RGGI region are offset by emissions increases in the non-RGGI portions of the EI region. Cumulatively, over the period 2020-2030, emissions in the portion of the EI subject to

RGGI are reduced by about 75 million tons, but increase by almost 90 million tons in the non-RGGI portion of the EI. In the RGGI region, emission decreases over the period 2020-2030 with Virginia linked to RGGI are driven by emission reductions in Virginia – emissions in the non-Virginia portion of RGGI actually increase.

b. As proposed, the program will result in a significant increase in power imports while highly efficient and lower emitting NGCCs in Virginia will run less.

The modeling results also show significant increases in net energy imports (GWh) in Virginia (based on annual retail sales of electricity) with Virginia linked to RGGI, increasing from about 28% under the case with no carbon regulations in Virginia to 48% for the case with Virginia linked to RGGI (see Figure 1 below). At the same time, the weighted average capacity factor for NGCC facilities in Virginia is projected to decrease by almost 50% between 2020 and 2030 under the RGGI case. (Capacity factor is the ratio of the time a unit actually operates compared to the amount of time is was available to operate.) We note that DEQ modeling of Virginia linking with the RGGI program showed similar increases in power imports under both policy scenarios evaluated relative to the case with no carbon regulations in Virginia. DEQ has proposed an updating output-based allowance allocation approach that it believes will incentivize utilization of NGCC resources as a means to counter leakage. However, while an updating output-based allocation approach may be more favorable to NGCC units (relative to coal-fired units), it does not address leakage. Natural gas-fired units in Virginia will still be subject to a CO_2 cost adder that units outside of the carbon constrained region will not be subject to. Thus, the effect of RGGI-equivalent reduction requirements in Virginia is likely to limit the dispatch of highly efficient and lower emitting NGCC facilities in Virginia and encourage the dispatch of higher emitting resources and increased emissions in neighboring states outside of the RGGI region.

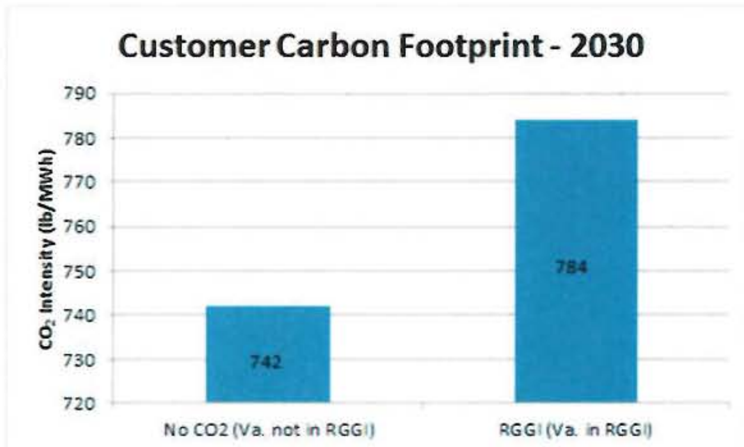
Figure 1. Electricity Imports into Virginia in 2030



c. Increased imports of more carbon-intensive power will result in the carbon footprint per customer in Virginia increasing by about 5.7% by 2030.

Average carbon intensity in 2030 of electricity (imports and in state generation) serving Virginia with the state not joining RGGI is projected to be 742 lbs/MWh in 2030; the carbon intensity increases to 784 lbs/MWh if Virginia joins RGGI (see Figure 2 below). This is a 5.7% **increase** in carbon intensity of the electricity used by Virginia customers – largely due to increased electricity imports into Virginia, which have a higher carbon intensity than in-state generation (see Appendix A).

Figure 2. Customer Carbon Footprint in 2030



2. Linking to RGGI could cost Virginia customers over $500 million over 2020-2030.

Based on the ICF modeling, linking to RGGI is projected to cost Virginia customers about $530 million over the period 2020-2030 (significantly less than actually joining RGGI). This includes cost for carbon emission allowances plus increased imported power cost adjusted for reduction in total production cost for Virginia.

The modeling indicates that Virginia linking to RGGI will lower allowance prices thereby lowering the cost of carbon compliance in other RGGI states, subsidized, in part, by Virginia electricity customers. Should Virginia join or link to RGGI, customers in the RGGI states outside of Virginia will incur $876 Million less in cost related to RGGI allowance purchases for the period 2020-2030 than the RGGI states would incur without Virginia joining RGGI.

Additional costs related to carbon reductions isolated to the state and stranded investments for forced closures will be borne by customers whose electricity is provided by the Company. With the majority of the PJM region not subject to carbon regulations, the energy market will favor non-Virginia generating units to supply energy, making Virginia units less competitive. This will advantage licensed competitive service providers (CSPs) that cover load through power purchases from non-Virginia-based resources. Additionally, unless these costs are non-bypassable by state code, larger energy customers that have the ability under retail choice (§ 56-577) to purchase energy from a licensed CSP may find that CSPs can provide more attractive pricing and can avoid the costs related to carbon reductions. To the extent larger customers migrate to CSPs, remaining customers will bear the cost for compliance with the state carbon program.

Comments on the Proposed Emissions Baseline and Cap

1. **Neither of the proposed baseline 2020 emission caps is practical. At a minimum, the baseline cap should be no lower than current emission levels.**

   DEQ is requesting comment on two different alternatives for the baseline emissions cap in 2020 (33 million tons vs 34 million tons), both of which are based on reference case modeling projections performed for DEQ by ICF, Inc. using the Integrated Planning Model (IPM). The 33 million ton cap case uses assumptions from Dominion Energy's 2017 IRP[4] (provided to ICF by DEQ); the 34 million ton cap is based on RGGI assumptions.

   Traditionally, an IRP is a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period, taking into account many variables such as weather, predicted fuel prices, regulatory risks, etc. IRPs therefore depict a suggested portfolio expansion at the "instant" in time at which they are published (a snapshot in time) and tend to change on an annual basis. While utility IRPs may be used to provide guidance to states in setting overall long-term goals, their purpose is ***not*** to establish specific emission standards or regulatory requirements.

   Fundamentals-based models, such as the IPM model, while useful for evaluating the impacts of various policy strategies, should not be used to set the program emissions baseline for the very policies being analyzed. Rather, an emissions baseline should be established on historic emission levels including allowance for historic variations in emission levels due to year-to-year differences in weather patterns and fuel prices. For example, for the initial RGGI emissions cap determination in 2005, RGGI designers set the 2009 emissions cap about 4% above the average emission levels observed between 2000 and 2002. Historical data have also been used by EPA in establishing baseline emission levels for various emissions trading programs including the Cross State Air Pollution Rule (CSAPR) and the NOx SIP Call.

   2016 emissions for Virginia units that would be covered under the Virginia carbon proposal were about 35.3 million tons. An analysis of statewide emissions from electric generating units in Virginia over the last 20 years shows an average annual emission level of about 35 million tons with about a ± 10 percent CO_2 emission volatility. Average emissions over the 2014-2016 period were about 34.3 million tons. Applying a 10 percent margin to account for variability would provide for a baseline cap of over 37.5 million tons. Applying the same 4 percent margin used in setting the initial RGGI cap would yield a baseline level of about 35.7

[4] See material provided by DEQ from October 20, 2017 webinar hosted by the Georgetown Climate Center at http://deq.state.va.us/Programs/Air/GreenhouseGasPlan.aspx.

tons. Accordingly, we believe the 2020 baseline should be set between 35.7 and 37.5 million tons to provide a margin to account for potential year-to-year fluctuations in weather patterns and fuel price volatility. (We note that this analysis does not include emissions from new generation projects, such as Dominion Energy's Greensville and the Panda Stonewall NGCC facilities, which have already received air permits well in advance of this regulatory process, are under construction and will become operational prior to 2020, and will be subject to the Virginia carbon rule. Dominion Energy's Greensville facility, with capacity in excess of 1,300 MW, will operate some of the most efficient NGCC units with the most stringent GHG limits in the country.)

The modeling performed for DEQ by ICF projects almost 1,100 MW of additional coal-fired capacity retirements by 2020 in the Virginia assumptions case and over 1,500 MW of coal capacity retirements by 2020 in the RGGI case. Unit retirements, whether model-projected, announced or planned for implementation prior to the start (baseline) date of the program should not be reflected in or used to set the baseline. Efforts to reduce emissions by way of unit retirements implemented in advance of the program baseline date should be rewarded and applicable toward compliance under the program and not penalized by applying these early actions toward a further reduction to the program's baseline level.

The data record utilized also must include the emissions from all units covered under the program, including units at which CO_2 emissions are not measured by continuous emissions monitoring systems (CEMS). Coupled with the ability to credit reductions that occur prior to 2020, this would create a more fair and equitable approach.

In addition, the state's 2020 baseline and its reduction targets thereafter should not be based on a presumption that energy efficiency potential based on policies in neighboring states can be repeated and achieved in Virginia. Dominion Energy continually works to achieve operating efficiencies in our existing generating units to obtain more output with fewer emissions. In addition, since 2010, we have offered a number of end-use energy savings programs to our customers. As reported in our 2017 Integrated Resource Plan (Case No. PUR-2017-00051), these programs have already achieved a substantial amount of energy savings; however, some of these existing programs are due to expire within the next two years or less. Implementation of future programs is strictly subject to approval by the Virginia State Corporation Commission, which is not within the Company's control. Dominion Energy has filed approximately 36 replacement and new programs for approval by the Commission. To date, about two-thirds of the proposed programs have been approved.

While there remains potential for energy savings from consumer-side energy efficiency programs - and we remain committed to expanding participation in the current programs and offering consumers more choices to achieve energy savings - this expansion is subject to state laws and regulations governing their approval. It should also be noted that the ultimate success of these energy efficiency programs is strongly affected by the degree to which customers choose to participate. Consumer acceptance is not guaranteed. Regardless of the success of energy efficiency programs, utilities must nevertheless be prepared to still serve their native load. Accordingly, the state emissions target should be based on well thought out and reasonable expectations of achievable energy savings and the compliance timelines must provide adequate time for the development, approval and implementation of any energy efficiency programs deemed necessary to achieve such objectives.

2. **The 2030 cap should be no more stringent than what would have been imposed in a state plan under the CPP.**

   At a minimum, the Virginia cap should not be more stringent than levels that would have been imposed under the EPA's CPP. Although the intent of the Governor's directive is to set Virginia on a path to regulating carbon in the absence of federal action and the uncertainty about the future of the CPP, it does not, nor should it compel the state to establish emission targets equivalent to or below levels that would have been imposed under the CPP (which was approximately 27.8 million tons in 2030 including both existing and new sources). As we have previously indicated in past comments on the CPP, we believe that the mass-based carbon emissions target EPA established under the CPP underestimated potential future growth to meet energy demand and was the most costly compliance alternative identified in the Company's 2017 IRP. Although established at the state-level, the limits required under the CPP presumed and envisioned a robust nationwide emissions trading program. Virginia should not impose more stringent emission reduction requirements to address a global environmental issue while other surrounding states we compete with economically have no established emission reduction goals or requirements. The caps imposed under the Virginia carbon proposal should not be more stringent than the levels that would have been imposed under the CPP.

3. **RGGI's next model review will begin just as Virginia is linking to the program, introducing uncertainty to the 2020 – 2030 cap as proposed.**

   An additional consideration regarding Virginia's participation in the RGGI program is that RGGI re-assesses its program every four years based on historical performance. Since 2009, RGGI has conducted two program reviews, one in 2012 and one in 2016/2017. Both of these reviews have resulted in a reduction/lowering of going-forward CO_2 emission caps for the RGGI region. The next assessment period is scheduled to occur in 2021, which is only one year after Virginia would begin its participation in RGGI under the Virginia RGGI Program. This means that Virginia cap identified in the current Virginia RGGI Program through 2030 may be re-negotiated in 2021 with other member RGGI states and may be different than what is currently proposed. Effectively, Virginia's entrance into RGGI—whether directly or through the Virginia RGGI Program—creates just two years (i.e. 2020 and 2021) of "certain" CO_2 limitations. Based on RGGI's two prior re-assessments, the CO_2 cap will likely be different than what is currently proposed, which increases uncertainty in electric utility planning.

Comments on the Proposed Design Elements of the Virginia Carbon Proposal

1. **Applicability should be consistent with other established emission reduction programs for EGUs and based on a 25-MW threshold as proposed.**

   In terms of affected EGU's subject to compliance obligations, we support DEQ's proposal to limit compliance applicability only to fossil fuel-fired electric generating units that are greater than or equal to 25 MW. Small combustion turbines and boilers below this threshold should not be subject to compliance obligations under the program. This is consistent with many existing federal and state-level EGU-based emission reduction programs including EPA's Acid Rain Program (ARP), the Cross-State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standard (MATS) rule and the northeast RGGI program's model rule.

2. **Units that burn biomass as their primary fuel should be exempt as proposed. As allowed in the RGGI model rule, an exemption should also apply to emissions from the biomass portion of fuel for fossil units that co-fire with biomass.**

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

In 2013, Dominion Energy made significant investments to convert three 51 MW coal-fired units to 100 percent biomass. Close proximity to an ample supply of waste wood biomass as well as EPA's "carbon-neutral" policy for permitting were key economic drivers for these projects. Given Dominion Energy's significant investment in renewable wood waste biomass, it is important for our customers that biomass emissions remain exempt as proposed. Any departure from EPA's prior treatment of biomass as carbon neutral or action that eliminates the use of this fuel as a creditable compliance option could raise compliance costs for states like Virginia which has already invested ratepayer money to generate electricity using this renewable fuel.

This compliance exemption should also apply to the emissions apportioned to the burning of biomass for fossil fuel-fired units that are co-fired with biomass, such as Dominion Energy's Virginia City Hybrid Energy Center (VCHEC). Under the rule, as currently proposed, a fossil fuel-fired unit that co-fires with biomass would be obligated to hold allowances for all of its emissions (fossil fuel and biomass-based). As proposed, this requirement is a disincentive for a coal-fired power plant to reduce its carbon emissions.

VCHEC is a 600-MW electric generating station in Wise County, Virginia that burns waste coal and co-fires with biomass (it can co-fire with biomass up to 20% of its capacity or 117 MW) as part of its fuel stream using a technology called "circulating fluidized bed (CFB)". Advanced CFB is proven clean-coal technology that also enables the using of run-of-mine coal, waste coal and renewable energy sources, such as wood waste. CFB technology combined with modern post-combustion controls has low emissions of sulfur dioxide, nitrogen oxide, particulate matter and mercury. In June 2008, the Virginia State Air Pollution Control Board directed the DEQ to incorporate a provision (Condition 26) in the facility's Prevention of Significant Deterioration (PSD) air permit to construct and operate in accordance with 9 VAC 5-80 Article 8 establishing a timetable for biomass utilization at the facility. According to DEQ, the Board chose this approach "in order to promote further reductions in sulfur dioxide emissions and show a reduction in carbon emissions, since biomass is considered a biogenic, carbon-neutral material".[5] Requiring VCHEC to now hold allowances under a state carbon program for emissions resulting from the burning of biomass fuel in compliance with an air permit provision established specifically to address carbon is counterintuitive.

Requiring fossil units that co-fire with biomass to hold allowances would also be inconsistent with the existing RGGI program which only regulates fossil fuel fired units and provides explicit calculations to subtract CO_2 emissions from biomass from multi-fuel fired units. To regulate biogenic emissions would be a significant departure from the existing RGGI program. It would set a precedent that would put Virginia's forest owners and biomass-related renewable energy investments at risk, while also creating unnecessary complexity in the program. Absent definitive alternate carbon neutrality guidance and policy from the federal level, the Virginia program should retain the exemption for biomass units as proposed and additionally should exclude CO_2 emissions from biomass from fossil fuel-fired units that co-fire with biomass.

To the extent that the final regulation requires biomass units to hold allowances, the state CO_2 emissions budget must be adjusted (increased) accordingly to assure that the emissions from these facilities are included in the baseline.

3. Comments on the proposed consignment auction approach

DEQ proposes to link the Virginia carbon program to RGGI by way of a consignment auction. Under this approach, DEQ would allocate a pool of allowances, called "conditional allowances" to each generating unit. These "conditional allowances" would need to be consigned over to the RGGI auction and clear the RGGI market in order to be converted to "conventional" allowances that can be used for compliance purposes. Revenue generated through the sale of the allowances in the RGGI auction (based on the auction clearing price) would be returned to the generators. DEQ explains that the purpose of the consignment auction is to ensure that the Virginia program allowances enter the RGGI market and that the auction proceeds are collected and redistributed directly to the generators since additional legislation would be required for the Board to establish a carbon trading program that involved money being directly paid to DEQ and/or DEQ redistributing the proceeds of such an auction[6].

Dominion Energy supports this approach but we note that the proposal does not provide specific details of the auction process and how revenue will be handled and transferred. The rule mentions that such revenue transfers will be done "in accordance with procedures established by the department'' (DEQ). Clarity is needed as to how the Virginia allowances,

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

[6] Pursuant to Article X, Section 7 of the Virginia Constitution, proceeds of an auction paid to DEQ would be "revenue of the Commonwealth" and thus must be paid into the State treasury. Under that same section, payment of money out of the State treasury requires appropriation by the General Assembly.

which are proposed to be allocated annually, will be merged with the RGGI auctions, which are conducted quarterly.

a. Legislative authority is required for the Board to conduct an auction and designate the use of revenue associated with a trading program.

DEQ has requested comment as to the potential for DEQ to directly auction allowances. As noted above, additional legislation is required for the Board to designate use of revenue associated with a trading program. Absent such authority, DEQ could not proceed with directly conducting an allowance auction or collect revenue from an auction. The consignment auction approach could provide a mechanism for the rule to proceed. Accordingly, to the extent the regulations link to RGGI via auction, we support the proposed consignment approach with auction proceeds returned to the generators as opposed to a direct auction by DEQ where revenue would be deposited in state coffers. Direct auctioning would increase the stringency and cost of the program by forcing generators to purchase allowances they otherwise would have been allocated. EGUs would effectively have to pay twice to reduce emissions – first to reduce emissions from affected EGUs or to develop new low-emitting generation and second to obtain allowances to cover their remaining emissions. Modeling scenarios performed by ICF with Virginia joining RGGI with the auction proceeds returned to the state projected costs to the customer that are three times higher than costs estimated under the consignment auction approach proposed under the Virginia program.

b. We support the proposed allocation of allowances to generators based on either historic generation or emissions data.

We support the proposal to allocate most allowances to affected EGUs (generators) using either historic generation (output based) or emissions data. This approach is reasonable, consistent with many of EPA's other emissions trading programs, such as the ARP and the CSAPR, and will help to minimize compliance and electricity customer costs. Allocating allowances directly to affected EGUs who have a clear financial interest in complying with the rule will create a more reliable, predictable, and manageable system. Direct allocations to non-affected entities, such as LSEs, could have the effect of increasing the stringency of the emissions cap by forcing affected sources to acquire allowances they otherwise would have been allocated, and under the proposed consignment auction approach, would have the opportunity to recover cost through auction revenue returned to the generator. This would increase the cost of compliance for affected EGUs and therefore the impacts to electricity rate-payers.

c. Virginia should advocate that RGGI expand its current 25% bidding limitation.

RGGI's quarterly allowance auctions have a restriction/limit as to how many allowances a single entity can bid (25% of the initial offering of CO_2 allowances in the auction). If Virginia participates in the RGGI auction program, such a limitation might not make it possible for all the compliance entities in the program to rely strictly on the auction to acquire their necessary allowances and they may be forced to go elsewhere (secondary market) to get sufficient allowances needed to comply. This bidding limitation has not been an issue to date in RGGI because there has not been a single entity requiring enough allowances to possibly hit the 25% limit. Virginia should advocate that RGGI amend this rule by expanding the size of the bid limitation by any one entity such that every entity has the possibility of relying on the auction for compliance.

4. Comments on the proposed allowance allocation methodology

The DEQ proposes to allocate an initial set of allowances (vintage 2020) to existing sources (units that are operational before January 1, 2020) in May 2019 based on average annual 2016-2018 generation output (mwhrs). Post 2020 allocations would be allocated in 3-year blocks, beginning with allocations for 2021 – 2023 in May 2020, and updated every 3 years, based on the 3 previous years of generation output. New sources (operational after Jan 1, 2020) would not receive allowances until they have amassed 3 years of output data. There is no set aside proposed for new sources.

a. We support the proposed 3-year updating allocation cycle.

In terms of the frequency of updating allocations, the proposed schedule would be consistent and coincident with the current RGGI and the three year compliance cycle proposed under the Virginia carbon program. Given the proposed three-year compliance approach, an updating frequency of less than 3 years (including annually) is not workable and should not be considered. In addition, a unit that retires should not be required to give back allowances it has already been allocated. The allocation approach should provide a reasonable lag time between unit retirements and the discontinued allocation of allowances to those units, an approach EPA has allowed under trading programs such as the CSAPR. The proposed updating allocation methodology will effectively transition retired units out of the allocation cycle without "requiring" units to give back allowances.

With respect to the baseline (average output over the previous three-year period) for determining a unit's pro-rata share of the state total budget, we suggest DEQ use the average of the three highest years over the previous five-year period. This approach, which is consistent with other successful emissions trading programs such as CSAPR, would provide additional flexibility to assure a baseline representative of a unit's normal/expected operations and filter out, for example, years when a unit experienced a prolonged outage or other factors contributing to atypical utilization.

b. The rule must provide a mechanism for providing allocations to units that meet the definition of an existing unit but do not have three years of historical operational data.

The rule does not address how an existing (pre-2020) source with less than 3 years of output data will be allocated allowances. For example, a unit that becomes operational anytime between 2016 and 2018 will not have 3 full years of operational data used to determine the initial 2020 allocations. Furthermore, a unit that does not come on line until sometime in 2018 and is operating in ramp-up mode will not have operational data that is adequately representative of the unit's full-scale operation. The rule must provide a mechanism for providing allocations to units that meet the definition of an existing unit but do not have three years of historical operational data. In such cases, the allocation determination should exclude years during which the unit does not have a full year of operational data. In cases where a unit does not have a full year of operational data over the 2016-2018 time period, the allocation could be based on an estimate of projected annual operation with a requirement that the source give back any unused allowances for redistribution to existing sources.

c. The proposal to allocate 5% of the allowance budget to DMME will require legislative approval.

Under the proposal, five percent of the statewide budget would be set aside and allocated to the Department of Mines, Minerals and Energy (DMME). These allowances would be consigned for auction by the holder of a public contract with DMME to assist the department in the "abatement and control of air pollution". However, the proposal provides no details as to how the revenues obtained from the sale of these allowances in the RGGI auction would be used. The allowances and proceeds allocated to DMME to administer the program are revenues of the Commonwealth and cannot be paid to DMME but rather would have to go into the State Treasury. DMME would only be allowed to use funds appropriated by the General Assembly to cover administrative and other costs.

d. To the extent the 5% allowance set aside for DMME is to be used to advance energy efficiency projects, both demand side and supply side energy efficiency improvement programs should be eligible.

Although not explicitly stated in the proposal, DEQ has indicated elsewhere its intent to, at least in part, direct the five percent set aside allocated to the DMME for use to encourage energy efficiency projects. To the extent the set aside is directed toward incentivizing energy efficiency, both demand side and supply-side energy efficiency improvement programs, including voltage optimization and other electricity transmission and distribution efficiency improvements, should be eligible for any revenues dispersed by way of this mechanism. In addition, eligibility should be expanded to include a variety of programs that help reduce carbon emissions such as infrastructure to enhance the growth of electric vehicles (EVs) in the Commonwealth.

5. The proposed RGGI cap adjustment mechanisms and limitations on banking should not be implemented in a nascent Virginia allowance market.

The Virginia carbon proposal would immediately implement two elements of the RGGI model rule that reduce the emissions cap directly based on the size of the regional banked allowance pool or by withholding the sale of allowances if the allowance price is too low. The first element would be an adjustment (reduction) to the Virginia cap that would be determined in 2021 based on the size of the allowance bank amassed across the current RGGI region over the period 2018-2020. This provision would reduce the emissions cap, beyond the 3 percent per year reduction already imposed, in each year over the period 2021 through 2025. The second element adopts RGGI's new ECR mechanism that would allow DEQ to withhold an amount of allowances up to 10 percent of the statewide emissions budget from offer in the consignment auction if the RGGI auction clearing price falls below the ERC trigger price.

In terms of the proposed cap adjustment provision, DEQ must explain and justify adjusting the Virginia state emission cap on the basis of banked allowances amassed over the period 2018-2020 (prior to Virginia's linking to the RGGI program) by affected entities in other RGGI states that Virginia affected sources will not have (be holding) since Virginia entities will not become subject to an emissions cap or required to hold allowances until 2020. RGGI states were not subject to such adjustments through the first two RGGI 3-year compliance periods. The initial allowance bank-based adjustments were first applied to the 2015 RGGI cap following the 2009-2011 and 2012-2014 compliance periods. As a practical matter, banking should be unlimited. At a minimum, proposed provisions to adjust emissions caps and/or withhold allowances based on volume of banked allowances should be delayed in the Virginia rule to provide time for a nascent Virginia carbon market to mature.

Similarly, there is no justification for applying the RGGI ECR mechanism at the inception of the Virginia program. Virginia affected sources will not be carrying any banked allowances during the initial compliance period. Under the RGGI model rule, states have discretion whether to implement the ECR mechanism. We note that New Hampshire and Maine do not intend to implement this new RGGI mechanism. Accordingly, DEQ should allow the nascent Virginia market to mature before applying any mechanism that would artificially reduce and further tighten the emission cap and increase compliance costs by driving up the allowance price.

Another concern with these adjustment mechanisms is that the allowance bank will be drawn so that compliance entities will eventually be compelled to purchase allowances from non-compliance entities to obtain enough allowances to comply with the ever-reducing caps. This will be further complicated by the ECR that will function to reduce the bank of allowances. When compliance entities are required to purchase allowances from noncompliance entities, it is likely that the cost of allowances will increase as noncompliance entities seek a return on their investments, which increases compliance costs.

We support unlimited banking of allowances in a mass-based program and the use of banked allowances across compliance periods. Accordingly and for the reasons explained above, we do not believe the proposed adjustment provisions should be incorporated into the Virginia carbon program without further evaluation of whether such adjustments are necessary. Applying adjustments and restrictions to the unlimited use of allowance banking would complicate and limit the very emissions trading system that the RGGI states have praised for its success in the past and relies upon to provide compliance flexibility and minimize compliance costs.

6. We support the proposed 3-year compliance true-up provisions.

The RGGI program has from its inception in 2009 allowed for a multi-year compliance true-up (surrender of allowances) timeline. For the first six years of the program, affected entities were required to demonstrate compliance (with an allowance "true-up") on a three-year cycle. Beginning in 2015 with the implementation of RGGI's 2012 Program Review, the program was modified to a tiered three-year compliance obligation. This current tiered three-year compliance obligation will be maintained under the revised RGGI program and model rule (based on RGGI's 2016 Program Review) that takes effect beginning in 2021. This essentially allows for a smooth transition for RGGI compliance entities into the next phase of the RGGI program with a new three-year compliance true-up (2021-2023) following the last three-year compliance true-up (2018-2020) under the current phase.

DEQ proposes to implement a similar tiered three-year compliance approach for the Virginia carbon program. We generally support a multi-year compliance approach as it affords compliance entities flexibility in meeting compliance obligations. We note that the EPA's CPP also allowed for a three-year compliance true-up. To the extent that the Virginia program would link to the RGGI program, aligning compliance true-up requirements with compatible three-year compliance cycles in RGGI makes sense.

7. DEQ should defer implementation of the Virginia carbon program to 2021 to align with RGGI 3-year compliance cycle.

With the Virginia carbon program starting in 2020, as currently proposed, the regulation would impose a one-year initial compliance timeline (to address 2020 emissions) before converting to a three-year compliance cycle. DEQ explains that initial 2020 allocations and a one-year compliance true-up obligation is needed to align the Virginia program with RGGI's current 3-year compliance cycle. This single year compliance requirement places a burden on Virginia generators that no other compliance entities in the RGGI program have. In order to address this issue, DEQ should defer the implementation of the Virginia carbon program until 2021. This would fully align the compliance obligations under the Virginia program with RGGI's current three-year cycle and provide a smoother transition to linking with the RGGI allowance system.

8. We support the adoption of RGGI's Cost Containment Reserve as a safety valve mechanism to avert potential reliability issues.

We support the proposed adoption of the RGGI Cost Containment Reserve (CCR) which would provide a pool of additional allowances for sale in the consignment auction if the costs of compliance (allowances) exceed a certain threshold. Such a mechanism is needed to address unexpected scenarios and to address potential adverse impacts on electric system reliability, and could also offer affected entities protection in terms of not being penalized for fewer emission reductions resulting from the unpredictable performance of renewable generation units.

9. The program should allow offsets to encourage and advance emission reductions from other sectors of the economy.

At a minimum, the regulation should include the same type of offsets allowed under the RGGI model rule. These include landfill methane capture and destruction, sequestration of carbon due to forestation, improved forest management or avoided conversion, and avoided methane emissions from agricultural manure management operations.

The regulation should be expanded to allow offsets that will encourage and advance the reduction of emissions from electrification of other sectors of the economy, such as transportation. Accordingly, electric vehicles (EVs) and charger installations should be allowed to generate offsets as well as using the auction revenues (from the 5% DMME set aside) to incent their adoption. In 2016, more carbon emissions came from the transportation sector than the power sector. This last happened in the late 1970's. To achieve deeper decarbonization, emissions from the transportation sector must be reduced.

In addition, the regulation should allow reductions in emissions from sulfur hexafluoride (SF_6), one of the most potent GHGs. This offset category was eliminated from the revised RGGI model rule simply on the basis that, to date, there had been no SF_6 projects finalized in any of the RGGI states. One of the possible reasons for this in the past have been may be the overall low RGGI allowance prices coupled with an abundant supply of RGGI allowances rendering the administration costs of applying for such offsets undesirable. However, the significantly more stringent RGGI cap and new mechanisms designed to minimize the allowance bank and drive the allowance price higher may make these offset projects more attractive and viable going forward.

10. Tables 140-5A and 140-5B in 9VAC5-140-6210 should reflect that the allowances listed are in million tons.

Table 140-5A (CCR Allowances from 2021 Forward) in 9VAC5-140-6210.D.2 and Table 140-5B (ECR Allowances from 2021 Forward) in 9VAC5-140-6210.E.2 should be corrected to reflect that the annual number of CCR and ECR allowances listed are in million tons.

Conclusion

In conclusion, we've had a long-term trend towards cleaner generation at Dominion Energy. This has led to a 35 percent reduction in carbon intensity since 2000 for units serving Virginia. As reflected in our 2017 IRP and long-term planning, we expect to see that continue, notwithstanding the significant policy uncertainty at the federal level.

As noted in these comments, however, we have concerns that these and future in-state reduction efforts may be offset by lower cost electricity imports from out-of-state sources that are more carbon-intensive under the Virginia carbon proposal. The program should encourage the growth of cleaner, lower and zero-emitting generation in Virginia commensurate with the Grid Transformation and Security Act of 2018.

We also believe that the program's emissions baseline or starting point should be more representative of actual current emissions and not based on model predictions. Unit retirements and other efforts to reduce emissions implemented in advance of the program baseline date should be rewarded and applicable toward compliance under the program and not penalized by applying these early actions toward a further reduction to the program's baseline level.

We remain committed to working with our regulators and all stakeholders toward a workable carbon reduction program and policies here in Virginia that provide reasonable reduction timelines, flexible compliance options and keep fuel diversity, reliability and costs to customers top of mind. Accordingly, we welcome the opportunity to actively engage in further discussion of ways to address these and other issues that we have identified in these comments.

Thank you for this opportunity to provide comment. If you have any questions, please contact me at 804-819-2420, (Pamela.Faggert@dominionenergy.com) or Lenny Dupuis at 804-273-3022, (Leonard.Dupuis@dominionenergy.com).

Sincerely,

Pamela F. Faggert

Pamela F. Faggert

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

Appendix A

PJM Region - State CO_2 Emissions from Electric Generation (2016)

State	CO_2 (thousand metric tons)	Net Generation (MWh)	CO_2 Intensity (lb/MWh)	Intensity Rank
Kentucky	72,433	80,273,501	1,985	2
West Virginia	68,473	75,942,968	1,984	3
Indiana	85,393	101,759,059	1,846	4
Ohio	81,618	118,922,078	1,510	10
Michigan	58,644	112,121,790	1,151	20
Tennessee	39,927	79,340,633	1,107	22
Maryland	18,578	37,166,687	1,100	23
Delaware	4,363	8,731,261	1,099	24
North Carolina	52,492	130,779,157	883	34
Pennsylvania	85,041	215,066,509	870	36
Virginia	**36,566**	**92,554,876**	**869**	**37**
Illinois	72,226	187,441,635	848	38
New Jersey	21,108	77,611,403	598	41

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