Report on Appendix A-1 of the Virginia Energy Plan: Impacts of Proposed Regulations under Section 111(d) of the Clean Air Act

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Executive Summary

Virginia faces a set of complicated choices about how best to comply with new federal rules limiting emissions of greenhouse gases from power plants in the state. In order to solve this problem in a fair and efficient manner, the state will need careful and even-handed analysis of its obligations and opportunities. One early report on this issue came in a study carried out by the Center for Coal and Energy Research (CCER) at Virginia Tech for the Department of Mines Minerals and Energy.[1] Unfortunately, this report is deeply flawed and could lead the public policy debate down an unproductive path. The report contains a number of large errors including a double counting of costs that overstates compliance costs by half. The study establishes an incorrect baseline for calculating the costs of changes needed for compliance. The study fails to provide even-handed treatment of uncertainties, emphasizing only those uncertainties that serve to overstate compliance costs. Finally, the study focuses its analysis only on unrealistic, high-cost options for compliance, while giving only the most cursory and dismissive treatment of the options that most observers believe will form the core of cost-effective compliance options. In short, the report is almost certainly worse than no study at all because it misstates likely costs, analyzes irrelevant options, and gives short shrift to the cases that really matter.

The report:

- ***D*ouble counts compliance costs by about $400 million annually because the authors added together two different estimates of compliance costs.** It's like going to two car repair shops for bids on fixing your brakes and then adding the different bids together to get the total cost of the repairs. (See page 23)
- ***O*verstates expected fossil fuel generation by at least 5,800 gigawatt hours per year by underestimating the likely use of renewable fuels and energy conservation.**
    - The report fails to acknowledge the energy conservation goals in other parts of the state energy plan and assumes that there will be no additional energy conservation efforts in the state after 2012. Even the very modest plans

[1] The economic analysis was performed by Chmura Economics and Analytics.

proposed by Dominion Virginia Power result in savings on the order of 3,000 gigawatt hours per year by 2030. Following the Virginia Energy Plan would have added even more savings. (Page 15)

- The report assumed no added renewable energy from wind or solar even though Virginia's electric utilities expect to comply with the state's 15 percent renewable energy goal either by generating the renewable energy in Virginia or buying it from other states. A conservative estimate puts in-state renew-able generation at around 2,800 gigawatt hours per year by 2030. This doesn't count the purchase of renewables from outside the state, which may be used under some compliance scenarios. (Page 10)

◆ ***M*ade a calculation mistake that cut the estimated benefits of emission reductions by more than 40%.** CCER discounted the future benefits twice, a conceptual error that understates the benefits of emission reductions. It also neglected to adjust 2011 dollars into 2012 dollars to account for inflation. Both of these mistakes understate the estimated benefits of reducing carbon dioxide emissions. (Page 33)

◆ ***O*verstated estimates of the negative economic effects of the regulations by mischaracterizing Virginia coal markets.** The study implicitly assumes that most coal mined in Virginia is used for electricity generation and would have no market other than Virginia power plants. This is incorrect. As of 2011, only about a third of Virginia coal was used in electricity generation in Virginia. In 2013, over 45% of Virginia-mined coal was exported to foreign countries. (Page 27)

◆ ***U*sed inappropriate and incomplete economic analysis in estimating total economic costs and associated job losses, inflating costs and job losses.** The economic analysis in the report implicitly assumes that people do not make sensible adjustments to changes in economic circumstances and assumes that there are no economic benefits elsewhere in the economy. Both of these assumptions are incorrect. (Page 29)

◆ ***A*ssumes unrealistically low capacity factors for Virginia's new natural gas power plants in Warren and Brunswick counties.** A considerable portion of this power would offset higher emitting coal plants and would reduce the compliance gap relative to CCER's assumption. The difference is on the order of 6 million tons of CO_2 per year that would not add to compliance costs, but these emissions are included in compliance cost estimates in the study. (Page 18)

◆ ***F*ails to provide a full analysis of the option of building the third reactor at the North Anna Nuclear Power Station.** Building this plant, with its 11,000 gigawatt hours of non-fossil electricity annually, would bring Virginia into compliance with the federal regulations on greenhouse gas emissions. Since the building of this plant figures prominently in Dominion Power's resource planning and in the assumptions of the regional electricity transmission organization, the building of the reactor should have been included in at least one baseline scenario. (Page 15)

- ***O*verestimated the rate of growth in electricity demand.** CCER assumes a 1.51% annual growth rate in electricity demand. Recent experience has seen much slower growth in demand, and this should have factored into the analysis. At a minimum, CCER should have noted recent lower growth rates and carried out a sensitivity analysis of their high growth rate assumption. (Page 11)
- ***D*oes not analyze any cases of cooperation between states, even though such cooperation is a known way to lower compliance costs.** In its brief discussion of this issue, CCER provided an incomplete and unbalanced treatment of options for multi-state cooperation. This analysis does not reflect the large scientific literature on low-cost emission compliance options. (Page 36)
- ***M*isinterpreted, on at least two occasions, analysis provided by the EPA in the EPA's regulatory impact analysis of its proposed rule.** These mistakes demonstrate a clear lack of expertise in both economics generally and in the analysis of climate policies in particular. (Pages 23 and 33)
- ***I*ncorrectly characterized the results of a U.S. GAO report on EPA's use of "social cost of carbon" estimates.** The CCER report represents the GAO as being critical of EPA's methodology, when actually the GAO found that EPA followed the appropriate guidelines for using the "social cost of carbon" in its analysis. (Page 32)

Once corrected for double counting, the analysis shows positive net benefits of reducing CO_2 emissions. This is true in spite of the overestimation of compliance costs.

A disturbing fact about this list of errors and inappropriate assumptions is that they all tend to overstate the likely cost of emission reductions and, in turn, the cost of compliance with the new rules limiting emissions of greenhouse gases. Decision makers in the Commonwealth will need to look elsewhere than this report for guidance on best strategies for complying with the new rules.

To avoid such mistakes in the future, agencies with responsibilities related to compliance with these regulations should subject their analysis to peer review by outside experts in the field and should consider whether there would be value in forming a technical advisory committee to help ensure that any analysis done is both unbiased and methodologically sound.

Forward

The University of Virginia's Weldon Cooper Center for Public Service provides objective information, data, applied research, technical assistance, and practical training to state and local officials, community leaders, and members of the general public. The Center traces its history to the Bureau of Public Administration, created at the University in 1931. The Center leverages the resources of the University to provide the best available technical assistance in the areas of public policy and public administration. The Cooper Center's economic analysis division, the Center for Economic and Policy Studies (CEPS), specializes in the use of economic analysis to assist public decision making.

This report is intended to add to the policy conversation concerning Virginia's energy future and, in particular, the Commonwealth's response to increased concerns about greenhouse gases and climate change. Pending federal regulations bring this issue to the center of energy policy issues in Virginia. Crafting an effective policy response to the federal proposal and to concerns about climate change generally requires that we bring the very best information and analysis to bear on the problem. In providing this review of the part of the Virginia Energy Plan that addresses compliance with the federal rules, we hope to move the policy discussion towards a constructive discussion of compliance options.

This report would not have been possible without the able research assistance of Christopher Haberland. Helpful comments and suggestions were provided by Annie Rorem. Any errors are the responsibility of the author alone. The cover photo of a combined cycle natural gas power plant is courtesy of Panda Power Funds.

Introduction

A path forward What should Virginia do to respond to the Environmental Protection Agency's new regulations limiting greenhouse gas emissions from existing power plants? The EPA is about to publish its final rule, and Virginia will have to begin in earnest the process of deciding its best course. Since controlling power plant emissions can be an expensive undertaking, it is critical that state policy makers have the highest-quality analysis on which to base their choices. They need accurate information about current resources, the application of the federal rules to Virginia's particular circumstances, a robust menu of policy options, and a fair evaluation of the costs and benefits of each of those options. It is unfortunate then, that one of the key sources of information provided to state policy makers, the Virginia Energy Plan, does a poor job of evaluating implications and opportunities associated with the expected final rules that EPA will publish later in 2015. Consequently, the Virginia Energy Plan report on compliance with federal greenhouse gas regulations may seriously misdirect policy discussions about how to comply with the EPA proposal.

Amendments to Title 67 of the *Code of Virginia*, require the Department of Mines, Minerals and Energy (DMME) to evaluate state policy options in response to any federal regulations that would be promulgated under Section 111(d) of the Clean Air Act (42 U.S.C. § 7411(d)). DMME contracted with the Center for Coal and Energy Research (CCER) at Virginia Tech to prepare the analysis required by the amendments to 67-202. On September 26, 2014, the Center delivered its analysis entitled *Virginia Energy Plan Item 8:*

Impacts of Proposed Regulations under Section 111(d) of the Clean Air Act. The report, which is published on DMME's website as Appendix A-1 of the Virginia Energy Plan focuses on the proposed regulations under 111(d) published by the U.S. Environmental Protection Agency (EPA) in June of 2014.

While the CCER report contains some helpful information about the method EPA used for establishing its reduction requirements for the states, and contains some helpful information about the current state of energy technology and infrastructure serving the Commonwealth, our review indicates that the report is characterized by mistakes, inaccuracies, and unbalanced presentation.

1. The report contains numerous errors in its calculations of the costs and benefits of compliance, including at least one very extreme case of double counting of compliance costs, leading to a near doubling of cost estimates.
2. The report fails to establish a reasonable baseline for its analysis, again inflating compliance costs.
3. The report is based on a number of questionable judgments about costs, benefits, and possible policy responses, nearly all of which tend to make compliance appear more costly or more difficult than it needs to be.
4. The report misinterprets EPA's regulatory impact analysis of the proposed rule.
5. The report mixes inflation-adjusted and non-inflation-adjusted measures.
6. The analysis in the report does not correctly model the <u>economic</u> effects of compliance, and substantially overestimates likely job losses.
7. The report does not provide adequate analysis of alternative compliance approaches that could lower compliance costs.
8. The report mentions, but does not properly address, an obvious, low-cost compliance option.
9. The report is slanted in its presentation and does not provide an even-handed treatment of various important issues.

At an absolute minimum, the report overstates direct compliance costs by 50 to 90 percent, depending on the scenario. With a set of reasonable, yet still conservative, adjustments to CCER's assumptions, the report overestimates by more than 100 percent. The conclusion that costs in this study are overstated is bolstered by more sophisticated modeling exercises undertaken by other organizations, including PJM, the regional transmission organization to which Virginia belongs. CCER also mischaracterizes the available alternative compliance pathways and doesn't even undertake an evaluation of well-known likely alternatives but dismisses them in a backhanded fashion. This combination leaves the reader with a seriously skewed perception of how Virginia might best respond to new federal rules on controlling greenhouse gases.

We undertake a detailed assessment of the CCER study partly because of the weight likely to be placed by policy makers on elements of the Virginia Energy Plan and partly to point out the need for a technically sophisticated approach to solving this problem. The mistakes in the report reflect a misunderstanding of some important aspects of the policy analysis of emission controls and of Virginia energy markets as well. To improve the level of the policy discussion concerning compliance alternatives, Virginia needs a coordinated plan for developing the necessary modeling and expertise.

In the future, DMME should subject any analysis under Section 67-202(D) to external peer review. This will help ensure that the Virginia Energy Plan provides helpful analysis for guiding the state's response to federal regulation of greenhouse gases.

The Baseline

First principles Effectively evaluating future policy options requires a baseline with which you can compare policy alternatives. Establishing a baseline requires constructing the counterfactual: what you think would have occurred in the absence of the policy event under consideration. This is, of course, a matter of judgment as well as a matter of probabilities. There are often wide ranges of reasonable future paths that might have occurred absent the policy event. Nevertheless, the baseline, or set of baselines, must be established for the evaluation of policy alternatives to have any meaning. Important unknowns may be subjected to sensitivity analysis to see how different outcomes for those factors would change the costs and benefits of various policy options. It would not be correct to take current values as baseline values if you had reason to believe that these values were likely to change under the no-policy event path. A correct baseline must fairly assess the likelihood of changes in current values that were likely to take place anyway.

The study baseline The baseline for the analysis is established in Section 5: Study Approach, Assumptions, and Limitations and on pages 102-108 in Section 6: Power Generation Scenarios.

Key assumptions made for Scenario 1 appear in Section 5:

- Baseline capacity factors for operating plants continue at their 2012 levels (p. 96)
- Dispatch is determined by the "relative cost of generation" without including the shadow price of CO_2 emissions (p. 97)

- "Electricity demand" will grow at 1.51%, as specified in Dominion Power's 2013 Integrated Resource Plan (p. 100)
- Additional generation (not covered by this particular rule but adding up to 11.5 MWh annually) will be built (p. 100):
    - Small coal-fired units
    - Additional small biomass units
    - "New generation that commenced construction after January 8, 2014

Scenario 1 is not used in the analysis but is rather a step to building the main baseline, which is Scenario 2. The only difference between these scenarios is the addition of six percent of existing nuclear capacity (p. 108). The key assumptions of Scenario 2 are as follows (pp. 105-108):

- The base year for the analysis is 2012.
- Existing generation is adjusted for:
    - Announced retirements: Bremo Bluff, Chesapeake, Clinch River, Glen Lyn, Potomac River and Yorktown
    - Two new natural gas/combined cycle (NGCC) plants: Warren County and Brunswick County
    - Conversion of units at Clinch River and Bremo Bluff to natural gas
- Preserved nuclear is included as part of the compliance units:
    - It is assumed that the nuclear generation replaces generation at the new NGCC plants
    - This generation substitutes for output from the newest, most efficient new NGCC units
- Renewables remain at 2012 levels.
- No conservation or energy efficiency is included.

There is no assumption listed about the expected path of the price of natural gas. Our repeated searches of the report found no mention of the price of natural gas used in the analysis for any year or scenario. Since this is a key variable in determining marginal dispatch of capacity, this variable should have been subjected to sensitivity analysis. The authors did report how much higher costs would be if natural gas prices rose by 50 percent from their assumed base but did not change anything else. This is not a correct comparison, since both dispatch choices and demand for electricity would respond to such a change. Furthermore, the treatment of natural gas prices is not symmetric: there was an estimate for unexpectedly high prices but not unexpectedly low ones. A shock to the low side is, in fact, what has occurred thus far in 2015. With the exception of brief periods of pipeline capacity constraints in exceptionally cold winter months, natural gas prices have remained low. The Henry Hub futures price in April of 2015 was $2.60 per million Btu, about $1.50 less than the same time the previous year. Price surprises should be treated symmetrically.

Renewables The very first thing to notice about these baseline assumptions is that they are internally inconsistent with respect to biofuels. First, the authors assume that biofuel generation remains the same as in 2012 for the entire policy horizon. Then they assume that some share of increased generation in the state will come from biofuel-powered plants (p. 100). The only way to reconcile these things is to assume that other biofuel combustion is scaled back to match exactly the increase in the new plants. In fact, biofuel generation increased 23% by 2013 and another 29% in 2014 (Energy Information Administration, 2014). Increased biofuel combustion was anticipated in Dominion Virginia Power's IRP (Dominion Virginia Power, 2013, p. xii), and data on actual biofuel combustion was available for all of 2013 and part of 2014 at the time the authors made their assumption of no growth in biofuels. (Energy Information Administration, 2014)

According to EPA's proposed rule, the additional biofuel-fired generation reduces the fossil emission reductions needed to meet the new standards. When biofuel use rises, compliance becomes easier. Biofuel use has risen from 2012 levels and, even if we assume no further increase in biofuels over the entire policy horizon, the growth in biofuels combustion from 2012 to 2014 amounts to around 1,377 GWh per year. This improvement in the emission rate belongs in the baseline from 2015 forward, thereby reducing the cost of compliance.

The authors also assume zero additions to other renewables including wind and photovoltaic solar power; this, in spite of the published schedule of additions to wind and solar generation in Dominion's 2013 IRP and even more additions in the 2014 IRP. At the time the CCER report was submitted, Dominion had more than 800 MW of nameplate capacity in wind and solar generation by 2029 in its "Fuel Diversity" resource plan and more than 200 MW in its "Base" plan. Since Dominion clearly stated that it would continue development of options under the Fuel Diversity plan (Dominion 2014 Cover Letter, p. 3), it was incorrect for the authors to choose zero as their solar and wind baseline. Using a 38% conversion from nameplate to firm capacity and a 21% capacity factor, the minimum solar capacity one should put in the baseline is about 370 GWh/yr for the 200 MW assumption. A figure that should be considered in any reasonable set of baseline scenarios would be Dominion's figure of just under 800 MW nameplate with about 1,400 GWh/yr. Given the rapid reductions in the cost of both PV solar and battery storage technology, this would seem a rather conservative baseline figure. Dominion's plans for solar are something of a moving target, with increasing plans for solar in the last two IRPs. Any balanced analysis must account for the possibility that solar penetration will continue to grow even within 2030 planning horizon.

That there was zero solar and wind in the baseline is now outdated by a substantial margin since the announcement in early 2015 that Dominion had agreed to accelerate its solar installation plans and have 400 MW nameplate installed by 2020 (~735 GwH). There was more than enough announced future solar and wind development so that these things belonged in the baseline scenario.

The offshore wind resource available to Virginia is very large, but the likelihood that offshore wind will be much of a factor by 2030 seems quite low. That said, Dominion's IRP anticipates about 200 MW (nameplate) of installed wind power by 2030. It is a significant addition to the renewables that would be available for compliance.

In its IRP, Dominion states that it expects to meet the state's voluntary renewable portfolio standard by a combination of in-state generation and the purchase of renewable power and the purchase of renewable energy certificates created by renewables generation elsewhere. There is reason to believe that, under EPA's proposed rule, the purchasers of renewable energy certificates will be able to credit this renewable generation against the fossil generation in state. This possibility should have been acknowledged as it would add considerably to the expected renewables available for use in compliance.

Even without counting any contribution from wind power, the CCER baseline should have included on the order of 1,377 GWh/yr of biofuels and 1,400 GWh/yr of solar. The 2,777 GWh/yr in renewables reduces the changes required in coal and natural gas generation in order to achieve compliance. As the costs of solar photovoltaic generation continues to fall, it seems highly unlikely that the state would choose less than this amount, and more likely that the solar contribution could be substantially higher.

Growth in electricity sales The baseline assumption that sales of electricity will increase at 1.51% per year is taken from the Dominion Power 2013 IRP. This was not a reasonable benchmark to take as an unvarying factor in modeling compliance. There are two reasons why 1.5% is not a reasonable growth benchmark: (1) growth in electricity sales has been slowing for quite some time and (2) the demand for electricity is responsive to price, so increased compliance costs will lead to lower sales of electricity than we would have without the change in compliance costs. The first of these points justifies the consideration of a range of estimates for the growth rate, especially including lower ones. The second point means that the growth in sales should not be an assumption at all. It is something that changes as costs change. Assuming that people and businesses will consume exactly as much electricity at higher prices as they do at lower prices is incorrect and works to raise the estimated compliance costs because the higher growth necessitates the building of additional capacity. Substitution away from electricity as price rises is one of the essential ingredients of any policy attempting to control the side-effects of the generation of electricity. Including the costs of those side-effects in the electricity price induces efficient shifts away from electricity towards other goods. The demand elasticity of electricity is small but significant, on the order of -0.1 to -0.2 in the short run and maybe -0.3 to -0.5 in the longer run (Bernstein & Griffin, 2006). Given the kinds of cost increases that the CCER study implies, it is not appropriate to assume that sales rise by a relatively high and constant rate, even as the cost rises. This assumption inflates compliance cost estimates.

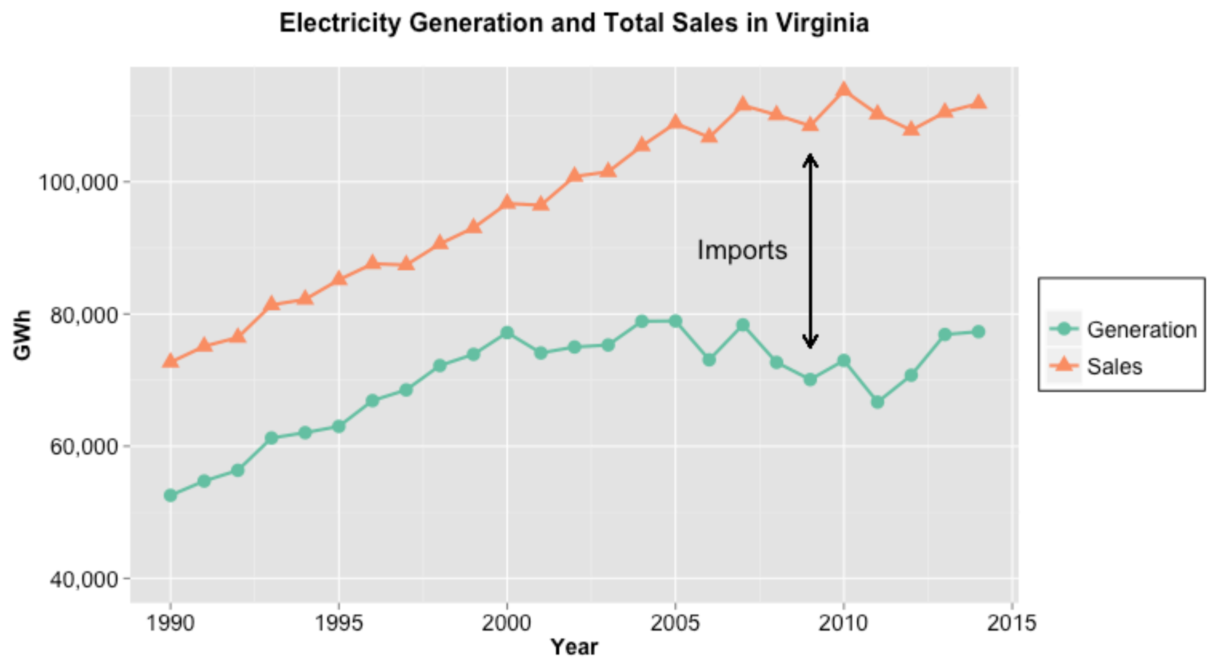
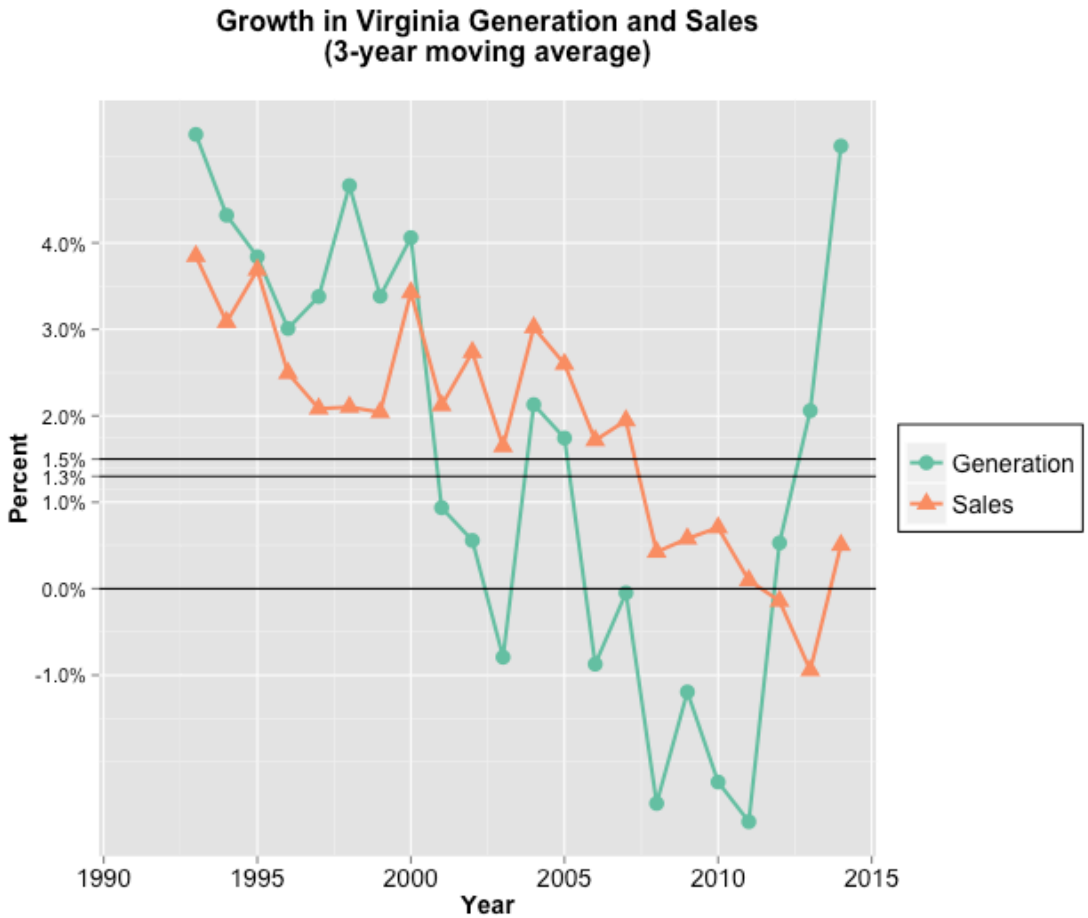
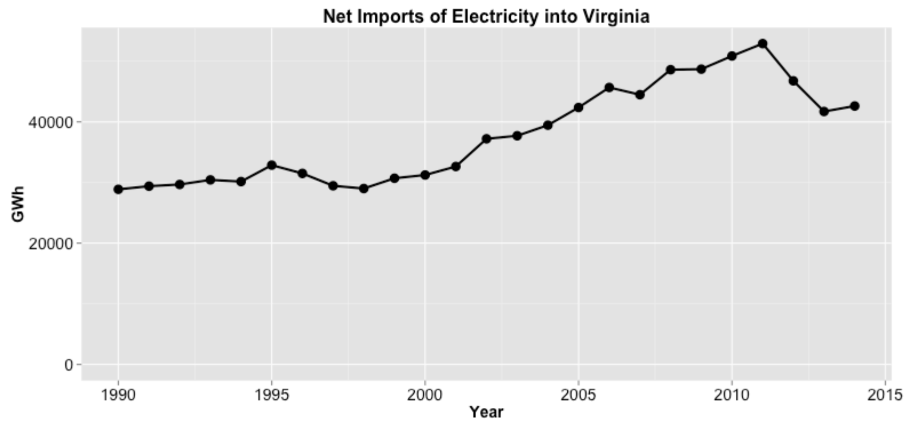


Figure 1 shows electricity sales (triangles) and generation (circles) in Virginia since 1990. The difference between these two lines (except for a few insignificant items) is equal to imports of electricity into the state. Notice that the amount of electricity generated in Virginia has been level since 2000. Also note that sales growth has been slowing gradually since 1990, but that the decline in the rate of growth accelerated about the time of the Great Recession and has never returned to its previous pace. Figure 2 shows the growth rates for the data from Figure 1. The data are presented as a three-year moving average to smooth out some of the yearly variation due to factors such as weather. The rate of growth in the amount of electricity sold in Virginia has been on a steady downward path since 1990. In fact, the three year moving average of the rate of growth in electricity sales has been less than 1 percent since 2008. This has continued even as the economy has begun growing again after the recession.



Generation growth, on the other hand, has taken a huge leap from a decline at more than 1 percent to the recent surge of over 5 percent growth per year. This has occurred because of the recent construction of new power plants in Virginia and comes at the expense of imported power, as is clear from Figure 3, which shows imported power. This trend will continue for a year or two as power plants under construction are completed. The increase in generation in Virginia does not imply a likely return to higher rates of growth in consumer demand, although the level of domestic generation relative to imports will interact with other elements of a compliance plan.

EPA's proposed rule does not credit states for reducing their imports, and thus reducing emissions in other states. So, as it stands, reducing imports by increasing the amount of generation within Virginia from sources covered by 111(d) makes compliance in Virginia more difficult while making compliance in other states less difficult. For example, suppose Virginia were to bring new capacity, such as the new NGCC plant in Warren County, under the current compliance umbrella. There are good reasons why the state might want to do this, but the current proposed rules discourage such a move since they would treat the added capacity as new emissions in Virginia and less in the state from which we previously imported the power, say West Virginia. So, even though the shift from West Virginia coal plants to Virginia NGCC facilities would reduce net emissions, the credit would go to West Virginia instead of Virginia. Depending on how EPA's final rule treats imports, emission growth and load growth will be decoupled. Simply treating generation growth as the same as growth in demand is an oversimplification that does not correctly characterize the choices the state will have to make.



Under the CPP, fossil-fired generation in both states will be more expensive due to the implicit or explicit price placed on CO_2 emissions. If Virginia is likely to choose a more cost-effective compliance plan than West Virginia, then it will be profitable to shift some amount of marginal generation to Virginia. If, however, reducing imports is discouraged, overall efficiency will suffer. States operating under a regional cap and trade organization would not see overall emission caps change due to changing trade in power, but the net trade of emission allowances across state lines would shift as the generation balance shifted.

The continued low rates of growth in Virginia electricity demand may be attributed to many causes, any number of which may continue into the indefinite future, for example, the decline of manufacturing as a share of state economic activity, increased efficiency in buildings and appliances, the aging of the population, and others. Any baseline measure of growth should reflect current circumstance. Even as the CCER report was being drafted, Dominion was finalizing its 2014 IRP (Dominion Virginia Power). Its assumed rate of increase in sales out to 2029 fell from 1.51% to 1.3%. Since their chosen rate is obviously on the high side given current circumstances, the authors should have explored the likely consequences of a lower growth rate, or at least mentioned the possibility. As it stands, the high assumed growth rate adds to the growing list of assumptions that tend to overstate the cost of compliance.

Under these circumstances, it would have been appropriate at least to subject the 1.5 percent growth rate assumption to sensitivity analysis. Even the small change in the growth rate from 1.51% to 1.3% results in lower 2030 generation by 888 GWh, given the study's 2012 baseline generation. Once again, this choice of baseline gives higher apparent compliance costs than the somewhat more modest rate that would appear justified by recent experience. This conclusion is complicated by the treatment of imported power, but this should be addressed directly rather than as lumped in with demand growth.

Demand-side management The assumption of a high rate of growth in electricity sales is compounded by the assumption that there would be zero energy conservation relative to the 2012 rate. This is not a case of bad judgment; rather it is an incorrect setting of the baseline. Dominion's 2013 IRP (Dominion Virginia Power) includes two separate assumptions about its own energy conservation activities, called demand side management (DSM). First, there are the DSM activities that have already been approved by the State Corporation Commission. These amount to 442 GWh in 2028. Second, Dominion has a number of proposed but not-yet-approved energy conservation initiatives in both its Base and Fuel Diversity plans. These initiatives amount to a total of 2,707 GWh/yr by 2028 *in addition* to the already approved DSM efforts. These two published schedules for DSM add to 3,149 GWh/yr less generation subject to compliance. Not to include any DSM is a mistake, a mistake that artificially raises the apparent cost of compliance with EPA's proposed rule because it assigns the costs of these DSM measures to the CPP even though they predate the policy, in some cases by several years. A better approach would be to assume a more realistic amount of energy savings and then subject this assumption to sensitivity analysis.

North Anna 3 Dominion has, for some years now, been actively pursuing the option of building a third reactor at the North Anna nuclear plant. North Anna 3 (NA3) has figured prominently in Dominion's IRP and is included in the preferred Fuel Diversity plan. In the 2013 IRP Dominion showed NA3 coming online in 2025. This schedule has been pushed back to 2028 in the 2014 plan. PJM, Virginia's regional transmission organization, includes NA3 in its baseline models of future supply adequacy in its territory. The CCER authors mention the possibility of a third unit at North Anna in a few places in their report and even point out that completing North Anna would almost certainly bring Virginia into compliance with the CPP. They do not, however, include NA3 in any baseline or any scenario. They do refer to a Scenario 3a that includes NA3, but that scenario never made it into the report. Dominion began the process of seeking permits for NA3 in 2003. Efforts to construct a new nuclear plant reflected a general regulatory climate of the mid-2000s in which Dominion sought to comply with EPA regulations of pollutants that did not yet include CO_2 (Haberland, 2015). It is significant that the PJM load planning includes the introduction of NA3 between 2025 and 2029 in its basic planning model, signaling that industry experts at PJM expect the plant to be built regardless of whether the CPP is promulgated. Completing NA3 should have been included in a baseline scenario.

It would be reasonable to argue that the likelihood of controls on greenhouse gas emissions makes it more likely that NA3 will be built. In that case, it would be appropriate to treat any added cost as shared between the baseline and the compliance scenario. The CCER study does not do this but, instead, simply does not evaluate the NA3 option.

Page 121 of the report, in considering whether NA3 could be used for compliance, states that "[t]here is currently nothing in the EPA CPP [proposed] regulation that will allow use of <u>proposed</u>, but not yet permitted, nuclear facilities." This is incorrect. The EPA proposed rule clearly anticipates the possibility of converting the rate-based limits to a mass cap and operating either independently or with other states under a joint cap. Under this compliance option any non-fossil generation, including new nuclear, will "count" toward compliance. The report unwisely discounts the value of a mass cap compliance option and fails to provide any substantial analysis of the tradeoffs relative to rate-based compliance. And even under rate-based compliance, new nuclear would have displaced fossil generation and facilitated compliance.

North Anna 1 and 2 were not built because they are free of greenhouse gas emissions. They were built because Dominion believed that it was in its interest as the primary provider of electricity in the Commonwealth. And the North Anna units have been reliable workhorses in serving baseload generation needs in Virginia. There are, of course, many people in Virginia who would prefer not to have another nuclear plant built here, but this is not relevant to whether NA3 should be included in some baseline scenario for future electricity supply. It is a path we may choose not to take, but it is inappropriate not to evaluate it as an option for compliance.

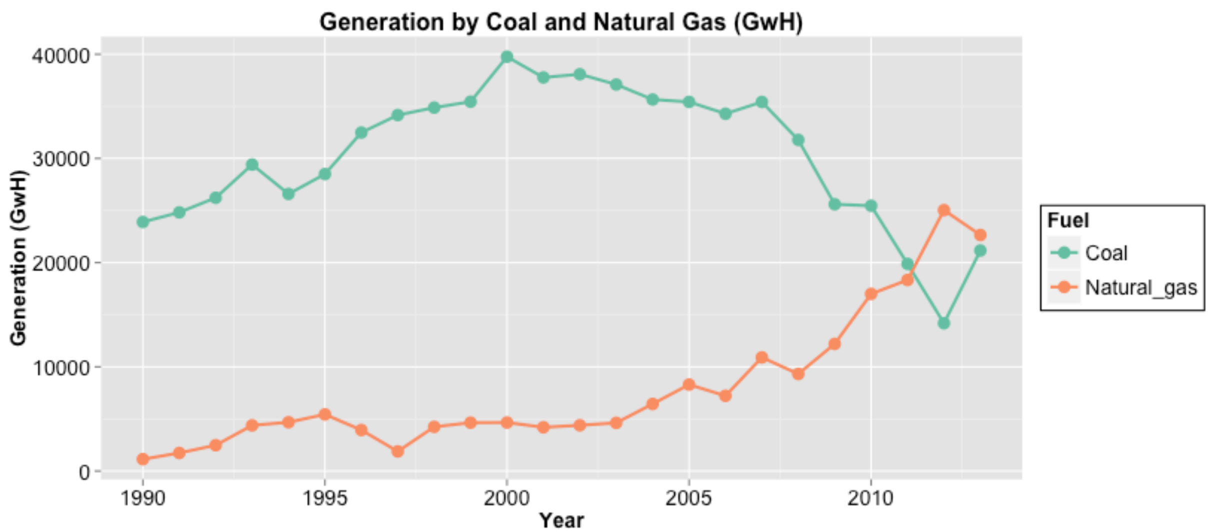
NA3 would supply 11,455 GWh/yr of baseload generation. Every reasonable scenario including the addition of this amount of non-fossil generation brings Virginia into compliance with the CPP rules by 2030. There is a sense in which the completion of NA3 is actually better than zero-cost. If Virginia joins any interstate compliance group, say joining the Regional Greenhouse Gas Initiative (RGGI) then completing NA3 would leave the state with a surplus of emission reductions, which could be sold to emitters in other states, supplementing state revenues.

The scheduling of the completion of NA3 is a bit up in the air. Dominion has pushed the operational date into the future in both of its last two IRPs. Presumably, at least part of the reason for this is the recent slower growth in sales. Insofar as this is the reason for the delay, it is good news for compliance because it means slower emission growth even without NA3.

It was a major error of omission to leave analysis of the NA3 option out of the report.

Current trends, capacity factors and the baseline

The fuel mix of the electricity generation fleet in Virginia has been moving away from coal since around 2003. This trend is illustrated in Figure 4.



The report notes this trend (p. 80):

> *...[T]he composition of fossil fuel sources has changed dramatically. Most notably, much of the coal generation capacity, which comprised 52% of the in state generation in 2002 has shrunk to 20.5% in 2012, while natural gas rose from 6% to 32.5% (Figure 4-2 and Figure 4-3). The switch from a coal dominated energy mix to one of greater reliance on natural gas is mostly due to a decrease in natural gas prices. This trend is likely to continue mostly due to expected favorable natural gas prices and also EPA regulations, such as CSAPR, MATS and the new proposal for reducing CO2 emissions.*

While the report points out that the downward trend in coal generation is bound to continue in the short run because a number of further retirements of coal units have already been announced, it makes the unjustified implicit assumption that, as soon as the current round of retirements is complete, the trend stops immediately and no more coal units are retired before 2030 in the base case. This implies that any further retirements of coal units or, indeed, any further reductions in their capacity factors, and any costs associated with retirements or reductions, are due only to greenhouse gas regulations (p.

103). If natural gas prices stay fairly low, there could easily be more transition to natural gas and away from coal but CCER simply assumes that this will not happen. To include the abrupt end of a current trend as part of a baseline assumption requires clear and convincing justification. In this case, no reason is given. This stacking of the baseline with high coal use inflates estimated compliance costs.

Lost plant capacity: This baseline stacking is made worse by the assumption that, under Scenario 2, the brand new NGCC units at Warren and Brunswick are operated at unrealistically low capacities. This assumption is introduced as if it is just a matter of arithmetic convenience:

> *The generation added by including nuclear must be compensated for by a reduction in generation from other sources. The newest NGCC units were selected for decreased generating rates, consistent with the Scenario 1 assumption. As a result, the generating capacity for Warren and Brunswick County units were operated at 7 percent and 5 percent, respectively. (p. 117)*

This has the effect once again of inflating baseline emissions and, hence, raising the costs of reducing them. The baseline is inflated because any generation not taking place at the NGCC units will be dispatched form coal-fired plants, which have emission rates more than twice has high as NGCC units. That these new, highly efficient plants would be operated at such low capacity factors strikes us as a wildly unrealistic assumption and one for which no explanation is provided except for the following explanation given on page 108:

> *Announced additions at Warren and Brunswick are included in the scenario and assumed to operate at the floating capacity factors necessary to achieve the total baseline generation for Virginia defined in the EPA's proposed rules.*

With a nameplate capacity of 1,329 MW, a more reasonable 60% capacity factor would mean roughly 7,000 GWh of generation. Even if you assume a lower capacity factor you would still be displacing considerable coal generation and reducing baseline emissions accordingly. If we add back in the 60% of capacity factor assumed away by CCER and if we use a reasonable estimate of the emission difference between coal and NGCC units of 1,000 lbs/MWh, this amounts to about 3 million tons of CO_2 that we would not need to reduce in order to achieve compliance. Keep in mind that this is for the Warren County facility alone. The Brunswick County facility is slightly larger and would have somewhat greater savings.

Non-comparable scenarios: The only difference between Scenarios 1 and 2 is supposedly that 1,645 GWh of nuclear generation is included and the capacity factors at the new NGCC units is cut back to make up for the included nuclear. The report does not explain why Scenarios 1 and 2 have different amounts of "Other" generation and differences in the total amount of electricity generated. The explanation given in the text is either incomplete or inaccurate. The authors give no explanation as to why the total amounts generated can't match up. Without a match in the amount of electricity generated, the scenarios do not seem directly comparable.

The difference in electricity generated is not just a feature of Scenarios 1 and 2. In fact, the actual amount of electricity generated is different in every scenario in every year. Each compliance scenario is based on a different amount of generation. Said another way, you are comparing compliance costs not just for different policies, but also for different levels of output.

Finally, nowhere does the report indicate how a 1.51% growth rate from the 2012 base can result in different generation outcomes across scenarios. In fact, in Scenario 2 the growth in generation by the units covered in the scenario occurs at 1.5006% up to 2020 and then at 1.3166% from 2020 to 2030. The reduced generation implied by this smaller rate does not constitute generation offset by expanded renewable capacity or energy conservation; these are held constant. If the difference is that some generation is moving to or from units outside of the purview of the CPP, then the different scenarios are not actually properly comparing compliance costs since some costs and benefits are unreported.

The distant baseline The baseline established in this report substantially inflates estimates of compliance costs when compared with the compliance scenarios that the authors chose to analyze.

- At a minimum, at least one baseline should have included renewables and demand side management from Dominion's preferred resource plan. This subtracts 5,926 GWh/yr from the generation that must be adjusted to comply with the CPP.
- Sensitivity analysis for this baseline should have included low natural gas price and low growth rate outcomes. As it stands, the report uses only a high gas price outcome and does not consider the possibility of a lower rate of growth in retail sales.
- The report makes an unrealistic assumption of low capacity factors at new NGCC units, which shifts from 6,000 to 7,000 GWh from low emission NGCC units to other higher emitting units, primarily coal. *Raising these capacity factors back to more reasonable levels is treated in the study as a cost of compliance.*

- Finally, the report mentions but does not analyze the automatic-compliance baseline case of the completion of North Anna 3, with its expected 11,455 GWh/yr of non-emitting generation. The completion of NA3 is in Dominion's preferred resource plan and is included in baseline generation in PJM modeling. Not to have a baseline case that includes NA3 undermines the credibility of the report.

Mis-estimating costs

Estimating costs of compliance Making useful estimates of the cost of complying with a regulation requires three things: (1) a reasonable baseline, (2) scenarios that capture the range of possible compliance options, and (3) a correct method for estimating costs for each scenario. We have already described ways in which CCER failed to establish a correct baseline. In every case where it was possible to sign the misestimation, CCER baselines overestimated the likely cost of compliance. In this section, we will look at whether the report authors chose a balanced set of scenarios that illustrate the likely range of policy options. Then we will take a look at how the compliance cost estimates were actually calculated.

Choosing scenarios It is clear from the outset that CCER did not choose a set of scenarios exemplary of the policy choices available to the Commonwealth. Two entire classes of scenarios are completely omitted: mass-cap based compliance and multi-state options, the latter of which may be either mass-based or rate-based. The mass-based approach is important to analyze because it makes the NA3 option available regardless of how EPA ultimately decides to treat new nuclear units under a rate-based approach and because it reduces administrative costs and facilitates multi-state cooperation. The failure to consider important compliance options limits the usefulness of the report in guiding policy discussions.[2]

The omission of multi-state approaches, or more accurately their dismissal by the report, is also an obvious and unfortunate choice. There is a large body of theory, modeling, and empirical analysis demonstrating the benefits of increasing compliance flexibility by expanding the number of generators that can exchange compliance obligations. To treat this, as the report clearly does in Section 7, as an issue of secondary importance is at complete variance with everything we have learned about emission controls since EPA's first experiments with compliance "bubbles" in the 1970s. The omission inflates the likely low range of compliance costs. It is extremely unlikely that Virginia would find a single-state solution to its advantage because the costs of doing so would be too high relative to regional compliance. The EPA proposed regulations clearly anticipate the trading of compliance obligations across state lines.

The omission of multi-state and mass-based options means that CCER limits its analysis to the highest cost options and ignores, at least in its scenarios, the cost-saving opportunities of these two approaches, separately or combined. This is probably a key reason why the compliance cost estimates are so much higher than other, more complete, analyses, such as that by PJM, where the achievable costs per short ton of CO2 reduced is at or under $20 in 2029. The consequence of this choice by the authors is to skew the policy debate by presenting as realistic compliance cost estimates that are unrealistically high and by inferring that flexible compliance options may not be worth pursuing. This is a clear disservice to the public debate.

Even within the context of the chosen scenarios, the compliance costs are substantially overstated. First, the authors make a large double counting error. Second, their choice of how to model dispatch to achieve compliance, as best we can understand it, almost certainly overstates the cost of compliance, even confining the analysis to in-state, rate-based options.

Another indication that the range of scenarios chosen by CCER is not sufficiently wide comes from examining the "Efficiency" column of the different scenarios. As we have already noted, Dominion's own 2013 resource plan includes over 3,000 GWh/yr of demand side reductions (read: efficiency improvements) in 2028. But the most aggressive conservation scenario considered by CCER, Scenario 5, includes only 2,397 GWh/yr. Earlier, we argued that Dominion's proposed DSM belonged in at least one baseline. In that

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2. EPA did not publish its own mass equivalents for the states in time for those numbers to be used in this report, but it would have been possible to make estimates based on the documentation accompanying the proposed rule and to construct a useful compliance scenario.

case, Scenario 5, would require zero additional expenditures on efficiency to achieve compliance.

Double counting Using the report's baseline, the estimated annualized compliance costs are given in Table 8-3 of the report. We already know that these estimates are too high because of the unfortunate choices made in setting the baseline. But setting that aside for now, the table shows the various elements of savings and costs that are used to calculate the total incremental costs of changing capacity and dispatch to achieve compliance. These costs include both operating and capital expenditures. (One thing that immediately catches your eye about this table is the large costs per unit of emission reduction. These estimates are much larger than those made by modelers using much more sophisticated tools. We will come back to this later).

Now looking at Table 8-5, the authors present calculations of "Estimated Costs to Consumers and Businesses." These are quite different than the estimates in Table 8-3. These numbers are based on estimates by EPA of the percentage increases in electricity prices that would occur in the various states if the CPP as proposed were implemented. These estimates are presented by EPA in Tables 3-21 through 3-23 of its regulatory impact analysis (RIA) for the proposed CPP regulations. EPA describes these estimates on page 3-39 of the RIA:

> *Retail electricity prices embody generation, transmission, distribution, taxes, and utility demand-side EE program costs. IPM modeling projects changes in regional wholesale power prices and capacity payments related to imposition of the represented policy that are combined with EIA regional transmission and distribution costs to calculate changes to regional retail prices.*

What this means is that EPA estimates of price increases are the costs of compliance that get passed through to electricity customers. The first mistake that CCER makes with respect to these EPA estimates is to treat them as if they were EPA's estimates of compliance costs. They are, as EPA explains in its RIA, that portion of compliance costs that gets passed through to consumers of electricity. How much of the cost gets passed through depends on many specific features of the local electricity market. In particular, it depends on whether electricity providers in the state are regulated utilities or not. So CCER is mistaken in interpreting these price increase estimates as full measures of compliance costs.

The authors then make a mistake by inflating the nominal electricity prices before increasing them by the EPA estimated compliance cost factor of three percent. Then they present these estimates as being in 2012 dollars, which they are not, and make the mistake of adding 2030 dollars to 2012 dollars in the results. To show how much of a difference this makes, take the figures for Scenario 3 in the year 2030. If you discount the 2030 values of $221.1 and $205.7 back to the appropriate 2012 dollars, the cost figure falls from a total of $426.8 to just over one half that amount, $242. In the end, this mistake wouldn't matter because these costs should not have been included in the cost estimates however they were calculated.

CCER commits a double counting mistake when, in Table 8-9, it adds its measure of compliance costs to EPA's measure of the same thing; a clear case of double counting of costs. The lines in Table 8-9 labeled "Electricity Cost" are based on EPA's measure of compliance costs, and the lines labeled "Compliance Cost (100% pass-through)" are DMME's measure of exactly the same thing. In the line labeled "Total Costs to Customers" they add these two things together. Every calculation based on that last line is about 60% too large just due to double counting including Table 8-10, the economic impacts generally, and the job losses in particular.

Even if you ignore all of the errors in setting the baseline and give the DMME cost estimates the benefit of the doubt, you can see that the cost of compliance for Scenario 3 in 2030 is half of their estimate in Table 8-9. **Focusing only on the year 2030, the double counting overstates costs of compliance by $427 million, $434 million, $382 million, and $382 million respectively for Scenarios 3,4,5 and 6.**

Least-cost reductions On page 97, the authors of the report describe in general terms their method for assigning generation to units:

> *The present study did not use an LPM-enabled approach because of the time constraints for completion of this report. As an alternative, this study relied upon significant data collection and the experience of the contributors to identify units that would be included in a Virginia generating portfolio to satisfy the mandates of the Clean Power Plan (CPP), while generating adequate, least cost power. The relative cost of generation of various units reflects the coal-fired, oil- and gas- fired boilers, and NGCC units, enabling generating units to be ranked in approximate order of least to highest generating cost. In general, this ranking demonstrated that coal-fired units were least cost, followed by NGCC units. Finally, oil- and natural gas-fired steam generating units, with higher costs, are also considered.*
>
> *...*
>
> *The capacity factors were assigned by ranking units in terms of generating cost from lowest to highest under the constraint of meeting the CO_2 emissions rate. The complicating factor is that a ranking of units by generating cost is inverse to the ranking of units by CO_2 emissions. Typically, state-of-art NGCC facilities rank lowest in CO_2 emissions, followed by existing earlier-generation and smaller NGCC facilities, then oil-fired and gas-fired steam boilers, with coal-fired units ranking highest in emissions.*

> *The challenge is to construct a portfolio of generating options that balances meeting power requirements against complying with the required overall CO_2 emission rates.*
> *...*
> *Notably, all coal units emitted CO_2 at a rate greater than 2,000 lbs per MWh; therefore, these units were forced to accept relatively low capacity factors. As a result, the overall generation that coal contributes to the total is relatively low in each scenario.*

The description given is not complete because it does not how units are chosen to achieve the next unit of emission reduction. It sounds, from the description, like the CCER algorithm is to cut back high emitting units first in order to achieve compliance. Such a rule, if this is what they did, is not likely to identify the lowest-cost allocation of generating units given that we face a constraint on CO_2 emissions because it does not adequately account for the different profitability of different units before the emission charge. One possible method that the authors could have used in their spreadsheet model would be to include the shadow price of emissions as a component of production cost and then to find the shadow price of emissions that just achieved compliance with the regulations. If you do not do this, then emission-rate-based generation assignment will generally result in inefficient production plans.

The shadow price of emissions is just the cost of the cheapest next unit of emission reduction you can get from any of your sources. If you subtract the shadow price from the net value of running a unit and the unit is still profitable to run, then you run it because it is cheaper than to arrange the reductions elsewhere. If the unit net value is negative after subtracting off the shadow price, then this unit is the cheapest way of achieving the reduction. Finding the CO_2 price that just achieves compliance will induce cost minimizing dispatch. This is essentially what the more sophisticated models do, but the process can be implemented in a simplified version in a spreadsheet.

We cannot tell from the description in the report whether the authors used a cost-minimizing strategy to assign generation. At a minimum, they should provide a clear description of the mechanism they used so that the reader can tell whether they implemented a cost-minimizing strategy.

Economic effects and jobs

Model inputs Since we have already demonstrated that the compliance cost estimates are too high (first, because of a simple double counting mistake; second, because of an incorrectly set baseline, and third, because of poorly chosen scenarios), then it follows that any estimates you might get of economic impacts of effects on jobs would be accordingly overstated. Unfortunately, setting aside the problem with model inputs, the CCER does rather a bad job of calculating economic impacts.[3] As with the rest of the report, these mistakes all go in one direction, that of inflating cost estimates.

Static economic models The authors give their assumptions about how the southwest Virginia coal industry operates on page 169:

> *National data indicate that 93 percent of coal output was sold to electricity producers as of 2014 (EIA, 2014a). As a result, any reduction in coal-powered electricity will have a sizable impact on this industry. As Table 8-13 shows, under the scenario where all coal-fired plants are retired (Scenario 5), Virginia coal mining industries would lose 3,305 jobs, or approximately 70 percent of direct coal mining jobs (2012) in Virginia. Based on typical indirect and induced employment multipliers for coal mining jobs of about 4, this would potentially create indirect and induced job losses of over 12,000 jobs, for a total of over 15,000 jobs impacted.*

[3] According to the DMME report, the economic analysis was performed by Chmura Economics and Analytics. As of the time of this writing, CCER had not provided any of the Chmura analysis for our review.

First, we ask whether it is reasonable to take the national figure for the share of U.S. coal used by the electric power sector and apply it to the Virginia coal sector and implicitly assume that this percentage is fixed. Figure 5 shows the history of coal-fired generation and direct coal mining employment in Virginia since 1990. As coal-fired generation nearly doubled, employment in mining coal dropped by more than 50%. Then in 2000, as coal-fired generation started falling, employment in the mines stopped dropping. Finally, when the Great Recession hit and coal generation dropped from 40,000 GWh to 15,000 GWh, coal mine employment actually bottomed out and started to rise again.

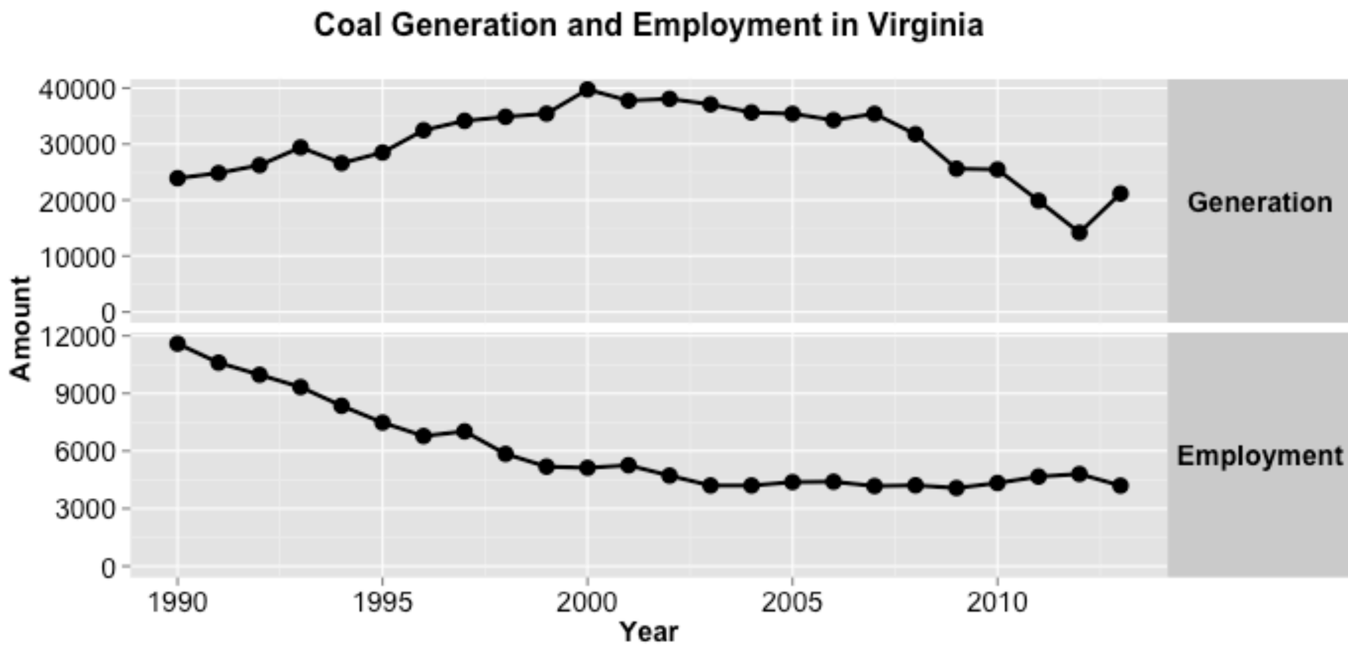
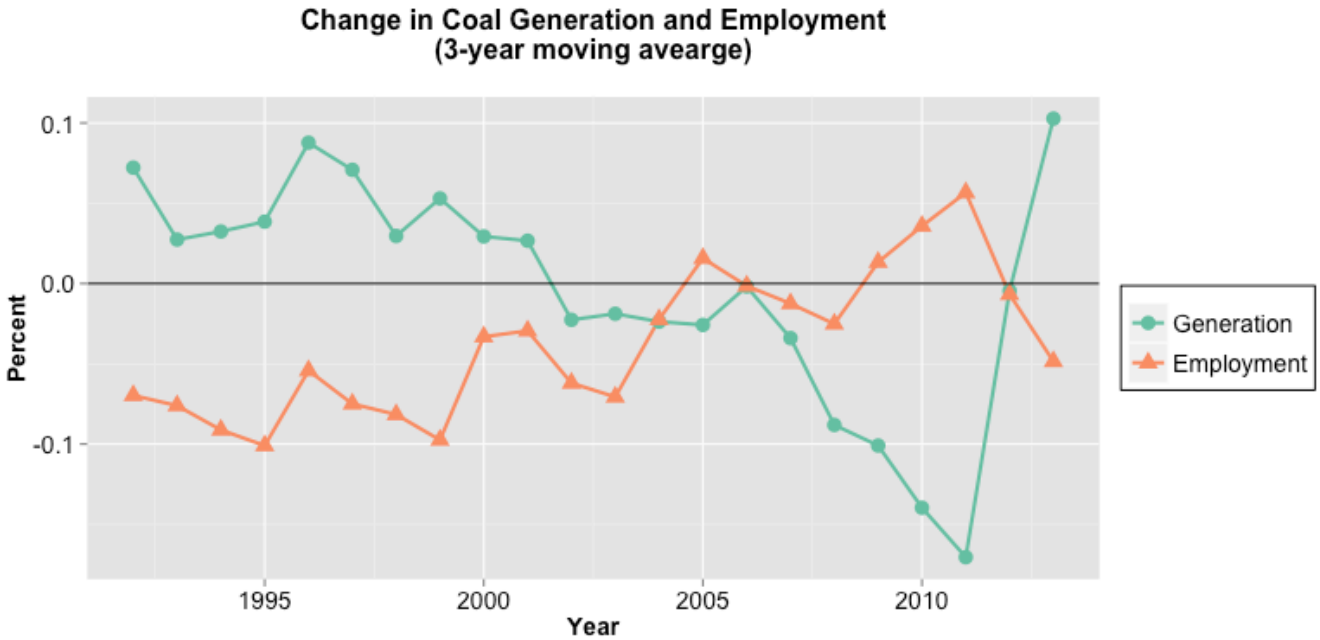


Figure 6 shows the percent growth rates in generation and employment on the same graph. High rates of generation growth are associated with high rates of job loss in the mines, just the opposite of what is asserted in the CCER report.



The CCER model gives poor results because a number of the assumptions about Virginia coal markets are inaccurate. The economics and jobs components of the analysis do not use an appropriate methodology, failing to capture how important aspects of the Virginia coal industry has changed in the past and how it would likely change in response to a lower demand for coal by Virginia power plants.

As of 2011, only 32 percent of coal mined in Virginia was sold for domestic electricity generation (McIlmoil, Hansen, Askins, & Betcher, 2013). In fact, metallurgical coal comprised 58 percent of total Virginia coal shipments in that year. In 2013, over 45 percent of Virginia-mined coal (both met coal and steam coal) was exported to foreign countries, and of the remainder, 25 percent was sold for coke, 75 percent for electric power (Energy Information Administration, 2015). These facts alone are enough to call into question the relevance of the analysis provided to DMME. These facts are a matter of public record and should have been used to inform the economic analysis of reductions in coal-fired generation in the state. As it stands, the analysis by CCER overstates the likely effects of future reductions in steam coal use in Virginia.

The persistent recent trend toward lower productivity and higher price for central Appalachia coal means that coal production will continue to shift away from Virginia mines and toward Powder River Basin coal. The drop in productivity could actually mean an increase in coal employment in the state even as production drops. This can happen as long as the price increases implied by the falling productivity are not enough to cause substantial drops in sales of metallurgical coal or sales for export.

The economic model used in this study cannot account for changes in worker productivity, prices, changes in international circumstance and many other factors that are important in the market for coal. It is a kind of back-of-the-envelope calculation based on current conditions. It implicitly assumes that, if one market for their product dries up coal companies won't lower their price to attract new business. It assumes yesterday's productivity and that this productivity does not change. If productivity does change, making the fuel cheaper, power plants do not respond by buying more. Simple, static models of the sort used in this report cannot account for the large, long-run changes occurring in Virginia's coal market.

Additional job losses: The quote from the report also asserts that a loss of 3,305 jobs (already a large overestimate, as we have shown) would result in 12,000 other jobs being lost. Here is how this works:

Suppose a coal miner loses his or her job due to a regulation. (Forget for the moment whether someone else is gaining because of the regulation, say due to lower medical bills.) The way the model works, this worker doesn't just stop working, but actually disappears from the economy. No more spending on food, gas, roof-over-the-head. The unemployed miner doesn't even get to hire a U-haul truck to move out of town. Other things the worker definitely **does not do**, in the static models used this report, is to find another job, move to another part of the state, take retirement and go on pension, go on Social Security, spend savings or any of the other things real people do when they lose jobs. None of these things could happen, or you wouldn't get the BIG job loss numbers. If the unemployed coal miner gets some money to get training for a different job, this would spoil all the CCER estimates. Then there would be spending on community college, on books, on food, on gas. If the added training happens to raise the worker's productivity, the economy could actually grow as a result of the shift, and there *are* programs to help miners who lose their jobs. Whether they are adequate is not a question we need to answer here but that Virginia *will* need to address as future reductions in the demand for coal (from whatever source) play out.

The model used in this report makes an implicit assumption that people do not respond to circumstance by taking their next best alternative. If they do, then the loss is actually the difference between what they had before and what they have now - a much smaller loss, or even a gain.

None of this should be taken to trivialize the harm done when someone, anyone loses a job, for whatever reason. It is an unhappy event for that person and their family. The problem with the old-fashioned kind of model used in this report is that it doesn't actually treat people like people and so gives the wrong answer about the consequences of changes in an industry: in this case a drop in the local demand for coal.

<ins>Gains elsewhere:</ins> There is another, more subtle, issue; what if compliance activities do harm some jobs but create benefits as well? For example, all those mining jobs lost in the 1990s reflect rising productivity in coal mining, which ultimately results in some combination of higher profits for mine owners, higher wages for the workers who keep their jobs, and lower prices for coal. This, in turn, makes electricity cheaper. When jobs are lost because of higher productivity, other parts of the economy will grow faster, even though some workers lost their jobs.

In the case of the CPP regulations, there is also a case to be made that other parts of the state will receive some benefits, and probably greater benefits for children and for the poor, on average. In fact, there is evidence that lower exposure to some of the pollutants from coal-fired power plants can improve productivity (Chang, Graff Zivin, Gross, & Neidell, 2014). The actual size of these gains is subject to high statistical variation, but the effects are measurable and substantial (Deschenes, Greenstone, & Shapiro, 2012). The reduction in coal related emissions can be expected to improve economic outcomes elsewhere in the state economy. None of this was entered into the calculations presented in this report. In estimating the economic consequences of compliance, the CCER only considers harm and ignores potential gains. As a result, not only is the size of the effect incorrect; the estimated distributional effects are also incorrect. This is a mistake. And once again, it works to inflate the loss measures given in the report.

<ins>Failure to give measures of statistical uncertainty:</ins> Later in the report, the authors emphasize the statistical variability of the estimates of health benefits from emission reductions. To be consistent, their economic analysis should also provide a range of estimates based on the statistical reliability of the estimates given. Emphasizing the statistical uncertainty of benefits but not costs provides a one-sided analysis.

The key problem the kind of mistakes made here is that they misdirect the policy debate and may lead policy makers to make expensive mistakes.

Benefits

Environmental benefits After spending 30 pages repeatedly overestimating the costs of compliance with the CPP, the CCER authors finally get around to discussing the environmental and health benefits of the regulations as something of an afterthought, with about two pages on each. Unfortunately, in doing so, the authors misinterpret EPAs regulatory impact analysis, mis-apply the social cost of carbon by double discounting it, and misrepresent the conclusions of a report from the U.S. Government Accountability Office (GAO).

On page 117, the report gives the authors' interpretation of the social cost of carbon (SCC):

> *The EPA quantifies the impacts of CO_2 emissions using an economic valuation of the Social Cost of Carbon (SCC). SCC is a metric that can be used to estimate, in monetary terms, the marginal changes in CO_2 emissions on an annual basis. According to the EPA, it is based on consideration of anticipated global climate impacts, including agricultural, human health, property damage, and energy systems costs. Their rationale for using this metric and development of the number are given in another EPA publication from 2010 (EPA, 2010a). It should be noted that the Government Accountability Office and a number of other entities have criticized the EPA's methodology (GAO, 2014).*
>
> *Using a 3 percent discount rate, the EPA estimates the global SCC for CO_2 emissions as averaging \$39/metric ton in 2015; \$46/metric ton in 2020; and, \$55/metric ton in 2030. Discounting the 2015 value to 2012 yields an SCC for Virginia's CO_2 emissions of*

\$36/per metric ton or approximately \$940 million in that year (EPA, 2014g). Using the estimated CO2 emissions in 2030 under Scenario 6, which corresponds to EPA's Option 1 and requires an emissions rate of less than 810 tons of CO2 per megawatt hour, the projected SCC in Virginia is approximately \$780 million, a reduction of \$160 million.

First, EPA did not come up with the estimate for the SCC. As reported in the GAO (2014, pp. 23-26) report cited in the quote:

A federal interagency working group, co-led by OMB [Office of Management and Budget] and the Council of Economic Advisers, developed social cost of carbon estimates in a technical support document produced in 2010 and updated in 2013.

The SCC was developed with the input of numerous academic economists working in this field.

The statement that the GAO was critical of "EPA's methodology" is both wrong and disingenuous. It is wrong, because it is not EPA's methodology, and it is disingenuous because what the GAO said was that EPA was correctly following the guidance from the interagency task force.[4] The headline quote from the report is:

EPA Used Current Guidance to Estimate the Value of Carbon Dioxide Emission Reductions (p. 23)

In their discussion of the social benefits of reducing CO_2 emissions, the authors start off with a mis-quote from EPA's RIA. They describe the SCC as "measuring the marginal changes in CO2 emissions on an annual basis." Here is what EPA actually says:

We also provide information regarding the economic valuation of CO_2 using the Social Cost of Carbon (SCC), a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. (U.S. Environmental Protection Agency, 2014)

The paraphrase in the DMME report misconstrues the EPA language, making important changes in its meaning.

The SCC is an estimate of the marginal damage curve for CO_2 emissions. As more emissions enter the atmosphere, the additional units actually cause more damage than the ones before. This is very common in the economic analysis of damaging emissions. Because the damages happen in the future, today's valuation of those damages must be discounted, which denominates those future marginal damages in terms of today's dollar values. So, the

[4] The GAO report may be found here: http://www.gao.gov/assets/670/664872.pdf

SCC table gives a marginal damage curve with increasing damages, where each year's marginal damage value is stated in current year dollars. In the case of EPA's RIA, the SCC is given in 2011 dollars (p. 4-12). As is standard practice, EPA presented a range of SCC values based on different assumptions about the appropriate interest rate. It then settled on a central estimate of 3 percent, a value well within the range used by practitioners in this field.

Although the EPA RIA clearly labels the SCC estimates as in 2011 dollars, the authors of the DMME report discount the values as if they were in 2020 and 2030 dollars respectively. So, for example, the 2030 marginal damages are incorrectly discounted 18 years at 3.2 percent, reducing the 2030 SCC from $55 to $32.31. The correct calculation would have been to multiply the $55 by 1.021, which is the conversion rate for converting 2011 dollars into 2012 dollars. This would have given $56.16 of benefit per ton of CO_2 emissions instead of DMME's $32.31.

It does not appear that the authors converted metric tons in the EPA report to the short tons used in their report, although this is not clear from the text. The authors only refer to "tons".

The final misunderstanding of the EPA RIA comes at the top of page 178 of the DMME report:

> *Since the EPA agrees that the SCC is only a partial accounting of the total climate impacts, they developed another monetized metric of "estimated global climate benefits of CO2 reductions" for the proposed rule. These values differ by year and also include the use of various discount rates to monetize the benefits. The EPA's values are national, based on total tonnage reductions projected under the various options identified in the proposed rule.*

This quote refers to Tables 4-3, 4-4 and 4-5 in the EPA RIA. These are not, as the quote asserts, a different monetized metric. These tables simply give the aggregate damage figures you get when you multiply the expected reductions by the social cost of carbon given in the immediately preceding table, Table 4-2. To see this, take Table 8-22 from the DMME report and divide the U.S. benefits by the U.S. reductions. This just returns the EPA values for the SCC (not the values as double discounted by DMME). *The authors have mistaken this for a different way of calculating damages.* The dollars-per-ton estimates given after Table 8-22 are the result of multiple mistakes and need to be recalculated before the results can be useful.

Health Benefits The authors express considerable suspicion about EPA's estimates of health benefits (p. 179). They claim that "a number of organizations have criticized EPA's approach" but give neither examples nor citations. They note that the estimates have significant statistical uncertainty especially when applied to local geographies, as acknowledged by EPA.[5] This is necessarily true, given the difficulty in isolating the effects of pollution from other contributions to sickness and death. That said, there is a substantial body of modern statistical evidence indicating that the co-benefits of emission reductions from coal-fired power plants may be large (Bharadwaj, Gibson, Graff Zivin, & Neilson, 2014; Chang et al., 2014; Deschenes et al., 2012; Parry, Veung, & Heine, 2014). In the end, the variability in health estimates does not affect the outcome. Once you eliminate the double counting of compliance costs from Table 8-22 by eliminating the "Increased Cost to customers [sic]" column, then every scenario has unambiguously positive benefits even if you only count half of the health benefits as estimated by EPA. This implies that all CCER scenarios give unambiguously positive net benefits for reducing CO_2 emissions, even for the inflated cost estimates in Scenarios 4 through 6.

On page 180, the report infers that the cost estimates are understated:

> *Table 8-23 combines the costs and benefits discussed above. It should be noted that the methodology for determining cost and benefit numbers are not the same and these numbers may not be have similar levels of accuracy or confidence. The cost numbers do not include the cost of raising capital and supporting interest on bonds or loans, capital costs associated with infrastructure (such as natural gas pipelines) and some other unquantifiable capital and O&M costs borne by utilities in fuel switching and building new generating plants. Capital costs are levelized over a 30 year period. Although it anticipated that utilities will pass costs to consumers, this is not reflected in the table, due to uncertainties in the timing of approval for cost recoveries.*

While it is correct to say that the benefit estimates and cost estimates will not have the same "accuracy," *the report never discusses the statistical variability of its cost estimates and does not provide a range of estimates*. The presentation is unbalanced, emphasizing the variability of benefit estimates but not estimates of costs or of economic impacts.

The quote also mischaracterizes the cost estimates as not including "the cost of raising capital." Capital costs are included in their cost estimates (p. 149). It is not at all clear what the authors are referring to here.

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5. As we noted earlier, the same is true for economic analysis, and this point should have been raised by the authors concerning their own cost estimates.

Finally, electric utilities in Virginia are rate-regulated public utilities. This means that, for all practical purposes, the costs of approved activities are automatically passed through to customers.

This is not to say that there are necessarily net benefits from the CPP emission reductions. This depends on uncertain health benefits and an uncertain social cost of carbon estimate. But CCER's analysis does not provide evidence that the net effect of the CPP would be negative for Virginia under the scenarios it offers.

Flexibility mechanisms

Regional cooperation In section 7 of the report, the authors seem not only unaware but almost uninterested in the enormous academic literature on flexibility mechanisms for reducing compliance costs with environmental regulations in general and CO_2 emissions in particular. The lessons from both theory and empirical studies are so well established that they are frequently taught in introductory microeconomics classes. A simple Google Scholar search on related terms turns up 30,700 sources on "emission trading", 5,530 on RGGI (the Regional Greenhouse Gas Initiative), 19,100 on "EU ETS" (the European Union CO_2 trading program), 1,440 on "NOx budget", and 5,360 on "Pigouvian tax".

What little text the authors do provide is either simplistic descriptive information, such as the three paragraphs on the now famous SO_2 trading program under the acid rain provisions of the Clean Air Act. The third paragraph is intended to leave you with the impression that the SO_2 trading program was a failure, while most analysts, including Robert Stavins, considered one of the top experts in the field, are on record as arguing that the SO_2 emission trading program was extremely successful in both protecting the environment and lowering the costs of compliance. The SO_2 trading program has now been effectively superseded by stricter standards under other provisions of the CAA where emission trading was not a legal option. The program is essentially at its end after a long and successful run. The authors insinuate otherwise, against all available evidence.

Virginia, incidentally, has already participated in two successful emission trading regimes: the SO_2 program already mentioned and the NO_x budget rule, which helped lower compliance costs with the EPA rules limiting interstate pollution from NO_x emissions. This program has also been effectively superseded by stricter rules. The authors seem unaware of the NO_x budget rule, even though, as we have already noted, there are more than 1,000 citations on Google Scholar that could have helped them in this regard.

The authors move on to a description of the Regional Greenhouse Gas Initiative and, once again, appear anxious to give a very negative impression of the program. It is worth an extended quote (pp. 141-142) to demonstrate this:

> *...Regionally the initial cap was set at 165 million tons for the period 2009 through 2014, but after a review of criticism of over-allocation in the program, the regional cap was lowered by 45 percent to 91 million tons in 2014.*
>
> *Electricity generators in the RGGI states must purchase needed allowances from quarterly auctions, but, unlike the US Acid Rain Program, compliance is measured on a three-year basis rather than annually. Because of over-allocation, allowance prices in the first phase of the program hovered just below $3 per ton. Today, even with the lower overall allocation levels, offers to sell RGGI allowances were at $4.90 in late July 2014. One major issue the designers of RGGI had to contend with was the concept of how to deal with power being generated outside the RGGI footprint and brought into RGGI with no associated CO2 penalty. This was called "leakage" by the RGGI group, and continues to be an issue when considering CO2 emissions for power imports into RGGI states.*
>
> *A wide array of opinions have been offered regarding RGGI's success. According to some, the program has been very effective in meeting its goals. Others (Stavins in Legrand, 2013) have noted, "what RGGI is today is a relatively modest electricity tax that is being used to fund energy efficiency programs in the states." However, RGGI indicates that the auction proceeds to date have resulted in a return of "more than $2 billion in lifetime energy bill savings" to regional electric customers (RGGI, 2014). RGGI indicates that the investments offset 8.5 million MWh of electrical generation and reduce* CO_2 *emissions by 8 million tons.*
>
> *Like the US Acid Rain Program, the RGGI program has encountered changes in mid-stream through allowance reallocations, discounting of banked allowances, and states withdrawing from the program. These types of occurrences do not contribute to overall market confidence for long term compliance assurance.*

First, the revision of the cap was part of periodic program review that was established as part of the program design from the very beginning. All the participants knew that, if the initial setting of the cap turned out, after experience, to be too high or too low, that adjustments would likely be made. The RGGI program started up immediately before the Great Recession and coincident with the dramatic drop in natural gas prices and, as a result, had based the cap on assumptions that quickly became outdated. It is actually a credit to the RGGI states that they were able to respond to new circumstances by adjusting the cap so that the new cap reflected the lower-than-anticipated costs of achieving reductions.

The price of allowances in the first compliance period did not "hover around $3." In fact they drifted down to the auction reserve price, which was just below $2 and stayed there until the cap was lowered. And while the authors seem to insinuate that $4.90 is a bad price for allowances, it is actually a very good signal about the cost of complying with the EPA rule. To see this, you have to know that on the current path, RGGI will probably comply with the EPA rule (possibly with very marginal adjustments). Since there is a bank of unused allowances in private hands, we can use this price to make a rough estimate of what market participants view as likely compliance costs in 2030.

It is well-known that assets like RGGI allowances, if they are held by private parties, must have an expected future price path that is rising at the private discount rate (private cost of capital adjusted for inflation). If you take today's real price and raise it by the private interest rate between now and 2030, you get an estimate of what market participants expect the price to be at that time (again, adjusted for inflation). Reasonable guesses about the private interest rate put 2030 compliance costs in RGGI at less than $20 per ton of CO_2 emissions. This should be taken as very good news by the authors, who have estimated compliance costs in Virginia at many times that amount. It immediately raises the prospect that Virginia could save many millions of dollars by joining RGGI and trading emission reduction responsibilities with states who have figured out much cheaper ways to lower emissions than the authors were able to imagine in writing this report.

A third note about the above quote is that the authors misuse a quote by Robert Stavins to insinuate that he is disapproving of RGGI. They quote from a student-authored law review article that is summarizing the comments of a panel commenting on RGGI. Comments that Stavins has made about RGGI paint a very different picture. For a sample of Stavin's writing on RGGI and on other emission trading programs, see his 2012 post: *Low Prices a Problem? Making Sense of Misleading Talk about Cap-and-Trade in Europe and the USA* (http://www.robertstavinsblog.org/2012/04/25/low-prices-a-problem-making-sense-of-misleading-talk-about-cap-and-trade-in-europe-and-the-usa/). Just to be clear, this post was written *before* the RGGI states successfully agreed to lower their cap to a level that essentially achieves compliance with the CPP.

Finally, the last paragraph of the quote must be classified as innuendo, without evidence or analysis. It flies in the face of the vast amount of rigorous research that carefully examined the effects of program design, program review, regulatory uncertainty and other factors on emission market performance. It is not even clear what the authors mean by the phrase "overall market confidence for long term compliance assurance." No credible analyst has suggested that RGGI sources will not be in compliance, and we have no reason to believe that the authors of this report can measure "market confidence," whatever they mean by it.

The discussion of the potential for multi-state collaborations is insubstantial and offers no guidance to policy makers. Nearly all credible observers find that there are very substantial cost savings available when states collaborate (PJM Interconnection, 2015). PJM points out that a shift from regional to state-by-state compliance doubles the amount of capacity at risk of retirement.

Most models show that aggregate costs of compliance for everyone are lowest when all states choose to be part of a multi-state emission trading program (Palmer & Paul, 2015).

So, not only is Section 7 misleading in its treatment of emission trading options, but it fails to provide any substantive analysis of multi-state compliance options, the approach most likely to achieve the lowest practicable compliance costs.

Mass-based compliance The CCER focuses solely on compliance with the emission rates specified in EPA's proposed rule. EPA's approach to the regulations in defining each state's obligations on emission rate performance was necessitated by the statutory language in the Clean Air Act. But EPA clearly anticipated the likely benefits of using a mass cap rather than a restricted set of emission rate improvements such as those specified in its proposed rule. EPA, in its proposal, outlined how the conversion from emission rates to emission caps would work and has since published mass caps both for existing sources alone as well as for all sources, both covered and non-covered.

Using a mass cap rather than an emission rate to determine compliance raises the number of options for achieving compliance, and this can only lower costs. The cost advantages of mass-based compliance are well understood and have been so for many years. The savings can be substantial. In PJM's analysis (PJM Interconnection, 2015) the marginal cost of region-wide reductions in CO_2 emissions under a mass-based approach in 2029 is $31.9 per short ton, while under a rate-based approach the costs more than double to $79.2 per short ton. Not analyzing the mass-cap approach overestimates compliance costs and shifts policy focus away from the clear benefits of region-wide, mass-cap approaches to compliance. The decision about whether to use a cap for covered units only or for all units is a complicated one and depends in part on what other states do. It is important that this analysis be done if Virginia is to take advantage of the compliance flexibility offered under the EPA regulations.

Conclusions and Observations

Raising the quality of the discussion about compliance There are billions of dollars on the line as the Commonwealth decides on how to comply with the anticipated federal rules limiting greenhouse gas emissions from existing power plants. Because of the importance of this issue, DMME was required to submit a supplement to the Virginia Energy Plan analyzing compliance options and estimating the likely effects of effective compliance strategies.

The large amounts of money involved in making adjustments to our existing electricity infrastructure and to our dispatch of production from that infrastructure means that a mistake concerning the approach to compliance can have a large effect on electricity rates and state fiscal policy, and even on the state's competitive position. Without effective advice on these questions state policy makers and the public do not have the guidance needed to make choices that are fair and cost-effective.

It comes as a serious disappointment, then, that DMME has submitted an analysis that is both in error in its own analysis and one-sided in its approach. The study that the CCER submitted to DMME contains so many mistakes that it is not possible to estimate the full implications of the errors, since in some cases multiple errors are compounded together. In addition to the basic factual errors, the report makes a series of questionable and one-sided assumptions that all lead to an overestimation of the costs of complying with the proposed federal rule. The economic analysis in the study is incorrect because it is based on a series of inaccurate assumptions about Virginia's coal industry. Furthermore, the type of economic analysis used is simply not appropriate to a policy change that will likely drive changes in both prices and productivity. What we can say is that the costs are almost certainly less than half of what CCER presents, maybe much less than half. Other, more credible, estimates, such as those by the regional transmission organization to which Virginia belongs, are indeed much lower.

The key underlying problem is the lack of expertise within state agencies to carry out the needed studies, or in the case of this study, even to evaluate contracted work for the most basic methodological flaws. A first step toward a solution would be for the agencies involved, DMME, DEQ and the State Corporation Commission, to submit their analysis or analysis done for them for peer review by experts in the field. This doesn't eliminate the possibility of error, but it helps insure against obvious mistakes and it helps prevent the use of inappropriate methodology, such as that applied in this study. Peer review also helps ensure even-handedness in the analysis and helps the agency in correctly interpreting the results.

If done correctly, even relatively simple spreadsheet analyses can provide helpful perspective about compliance options. In light of the complications involved, Virginia should also consider investing in modeling exercises by the well-established consulting firms and think tanks in this field. These exercises could be reviewed and supplemented by experts from universities around the state in consultation with state agencies, power companies, and the regional transmission organization, PJM.

Virginia will have to invest resources to raise the bar in its analysis of climate change policy, especially given that DMME, DEQ and the State Corporation Commission, the agencies most directly involved, lack the expertise to do the necessary studies internally. The Commonwealth of Virginia deserves a better foundation on which to base its necessarily momentous choices about compliance with the Clean Power Plan.

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