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The Potential Impact of Rate-based or Mass-based Rules on Coal-Producing States under the Clean Power Plan: Implications for Wyoming

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Executive Summary:

Under the final Clean Power Plan (CPP) rules, among the first decisions states will have to make is whether to adopt CO_2 rate- or mass-based standards. The incentives under each type of standard are quite different and the implications for regional economic impacts may also be quite different. A rate-based standard defines an intensity of emissions per megawatt hour, and can dynamically adjust as changes in demand occur. Under a mass-based standard, each state has an allowable level of total emissions defined in tons of CO_2 a state can emit from its generating sector regardless of demand. The definition of rate- and mass-based rules creates potential incentives that, combined with the recent extension of renewable energy investment incentives by Congress, could greatly affect capacity investment decisions, generation outcomes and therefore coal production outcomes if states use credit trading to meet the regulations.

Specifically, under mass-based standards, there may be an incentive for a larger natural-gas combined-cycle build out in generation capacity that reduces future coal generation substantially. Under a rate-based plan, however, renewable generation may be encouraged because renewable sources can sell emissions reduction credits to CO_2 emitters such as coal-fired power plants. Revenues from these sales could create an incentive to build out significantly more renewable generation, which may displace investment in new NGCC plants, and leave more coal-fired generation operating. This could preserve greater demand for coal-production.

This paper investigates the potential implications of choosing rate-based or mass-based standards on coal producing states using a series of proprietary simulations. These results suggest that coal producing states should have a clear preference regarding which type standard to prefer. Rate-based outcomes appear to have a greater chance of preserving of coal production than mass-based standards. This occurs because under rate-based standards a larger build-out of wind generation displaces new investment in natural gas-fired generation and allows more coal-fired generation to be preserved. In effect, wind and coal generation become strange bedfellows - the existence of greater wind generation actually protects coal-fired generation relative to outcomes under a mass-based standard. In Wyoming, the difference in adopting rate-based over mass-based standards could preserve over 50 million tons of coal production annually by 2030. This could result in the potential saving of over 2,300 jobs in the state in 2030 relative to levels in 2012.

Many coal-producing states such as Wyoming should also realize that it will not be their own choice regarding rate- or mass-based standards that matters, but what customer states choose to do. Given the simulation results presented it would seem that coal-producing states could have an interest in emphasizing coordination among as many states as possible, especially those using their coal, to ensure that rate-based standards are adopted.

The Potential Impact of Rate-based or Mass-based Rules on Coal-Producing States under the Clean Power Plan: Implications for Wyoming

Introduction

Under the Clean Power Plan (CPP) rules, among the first decisions states will have to make is whether to adopt CO_2 rate- or mass-based standards when adopting an implementation plan to control greenhouse gas (GHG) emissions from existing natural gas or coal-fired power plants. Under a rate-based plan, states adopt emissions standards defined as a limit on CO_2 emissions per unit of electricity produced at regulated generators within a state. Under a mass-based plan, CO_2 limits are defined as a finite total mass of emissions allowed across covered facilities within a state and covered generators must hold allowances to emit, where the total allowances available to firms sum to the state cap. The Environmental Protection Agency (EPA) has allowed states to choose either rulemaking standard and has defined CO_2 limits in each case in the final CPP rules for existing plants released on August 3rd, 2015.[1]

The EPA has encouraged states to allow emissions trading to meet the limits of the CPP, however, states submitting to regulation under rate- or mass-based plans may only trade or cooperate with other states that choose to regulate under the same type of emissions standards. Historically, under Section 111(d) of the Clean Air Act, existing sources of emissions for other pollutants have been regulated using emissions rates. States regulating and trading emissions, however, have decades of experience regulating conventional pollutants under a mass-based standard, and previous CO_2 trading programs like the Regional Greenhouse Gas Initiative also define standards using mass-based limits.[2] The EPA claims that under their analysis, limits using rate or mass-based standards should lead to achieving an equivalent emissions goal. The choice of how to regulate, however creates different incentives for states regarding compliance strategies, and EPA analysis indicates that mass-based standards may result in a lower total national cost of emission control. Other analyses differ, including one described here. Actual costs of pollution control will depend on how states choose to regulate, what standards states choose, and whether states themselves prefer regulating under standards they are more familiar with.

The incentives under each type of standard are quite different and the implications for regional economic impacts may also be quite different. A rate-base standard defines an intensity of emissions per megawatt hour (MWh), and can dynamically adjust as changes in demand occur. For example, if demand increases, requiring greater generation, the actual emissions rate experienced will depend on how new generation is met. If the new load is met with low-emissions generation, the rate occurring could fall despite an increase in emissions. Under a rate-based standard low-emissions generation may also allow other higher-emissions sources to continue operation through the creation of emission reduction credits. Under a mass-based standard, the emissions cap would be unaffected and this is not possible. This could have implications for coal production and the economic costs of the CPP regulation for coal producing states. This paper investigates this possibility and the potential implications of choosing rate-based or mass-based standards on coal producing states using a series of proprietary simulations based upon the National Energy Modeling System (NEMS) performed by the Rhodium Group.[3]

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[1] See the Clean Power Plan website maintained by the EPA at https://www.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants. This includes the references the Federal Register citations relevant to the program.
[2] The Regional Greenhouse Gas Initiative is the first mandatory market-based greenhouse gas emissions control program in the United States, and includes Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont. The program website can be found at www.rggi.org.
[3] Additional results from the simulations reported here can be found in Larsen et al. (2016 a, b, and c), and Larsen and Herndon (2016).

Background

Final Clean Power Plan rules for existing power plants were announced on August 3rd, 2015. If upheld, these rules aim to reduce U.S. greenhouse gas emissions from the power sector by 32 percent from 2005 levels by 2030.[4] The final rule changed several areas of the 2014 proposal, and a review of all the changes is outside the scope of this paper.[5] Two principles, however, are important to note here. First, the final 2015 rules streamlined the ability of states to engage in regional cooperative strategies to reduce the costs of implementing the new regulations, and the final rules attempt to encourage such actions. Second, changes to the final rule also made it more consistent with other stationary source regulations under the Clean Air Act (CAA). For example, the original 2014 proposal potentially allowed states to decide the compliance entity accountable for ensuring regulations are met. In the proposal the responsible entity could have ranged from individual sources, to utilities and their fleet of sources, to state agencies overseeing all sources within a state's borders. The 2015 rule makes the individual emitter solely responsible, which is consistent with other CAA regulations. This also simplifies the rule-making for emissions trading and other market-based strategies for compliance by allowing trade to more easily be defined between sources. The final rule also includes model trading rules to help facilitate and coordinate the development and organization of such trading efforts.

Importantly, to ensure consistency with other CAA regulations which have historically been defined in terms of emission rates, but also with the fact that existing trading efforts in GHGs define mass-standards, targets for states were defined under both rate- and mass-based standards. Among the first decisions states will have to decide is whether to adopt CO_2 rate- or mass-based standards when formulating their state implementation plans (SIPs).[6] In the final rule, these are due by September 6, 2016 unless an extension is requested, in which case states may have until 2018 to develop their respective plans, including multistate cooperative plans such as emission trading across state lines.[7] If states do not submit such a plan a Federal Implementation Plan (FIP) will be imposed within two years of non-compliance. Currently a final FIP is not defined, however, two proposals currently exist – one a mass- and the other a rate-based

[4] These rules are currently under a stay by the U.S. Supreme Court pending the resolution of legal challenges to the rule. The stay was granted February 9, 2016 and the notice of stay can be found at http://www.supremecourt.gov/orders/courtorders/020916zr3_hf5m.pdf. A summary of the

[5] For a review of changes written shortly after the final rule was announced, see Ramseur and McCarthy (2015). Also, see Larsen et al. (2015) for a summary discussion.

[6] Under the mass-based standards, states will also have to decide whether to cover (i) only existing fossil-fuel generators while adopting a specific allowance distribution approach defined by the EPA in its model rules, or (ii) to cover both existing and new generation under a slightly higher cap defined by the EPA. This additional decision was necessitated by the fact that the rules for existing generators fall under the Clean Air Act's 111(d) portion of the rule, while new generators fall under separate 111(b) rules in the Clean Power Plan, which define emissions rates for new sources. Capping the emissions mass from existing power plants only could result in an incentive to build new fossil-fuel generators to avoid the rule's emission mass constraint, shifting generation to these new plants and thereby increasing total emissions beyond what the 111(d) rule intends. This is termed as "leakage" by the EPA and to avoid this incentive these additional considerations have been imposed on states opting for a mass-based plan to ensure that outcomes are broadly consistent with incentives and outcomes under a rate-based approach. For a deeper discussion and analysis of the potential impacts of leakage on CPP outcomes under a mass-based approach, see Larsen et al. (2016a).

[7] The U.S. Court of Appeals, D.C. Circuit will hear the appeal on September 27, 2016. Since this is after the official deadline for states to submit initial implementation plans, the timetable of the rule will have to be delayed regardless of the appeal's outcome.

plan.[8]Importantly, states adopting mass- or rate-based standards will only be allowed to create such trading plans with other states adopting regulation under a similar standard.

Under both a mass- or rate-based rules, the EPA originally estimated that the choice of regulation would not fundamentally change emissions outcomes, however, their simulations did indicate that this choice could alter the total incremental cost of the rule, and costs faced by consumers. Modeling the 2015 rules assuming a national-wide trading regime and single mass- or rate-based choice by all states, the EPA estimated the incremental cost of the CPP above a business as usual (no-CPP baseline) of between $5.1 billion under a mass-based approach to $8.4 billion under the rate-based approach. Despite these added costs, the EPA (2015) estimated that the average consumer's electricity bill would decrease by between 7% and 7.7% respectively by 2030 due to reduced power consumption and energy efficiency measures, while retail electricity rates were nearly unchanged from their business as usual projections.[9]

The emphasis on emissions trading in final 2015 CPP rules is consistent with several modeling results for rules under the 2014 proposal, which found that wider trading reduced significantly the potential cost of meeting the CO_2 standards of the CPP.[10] Reduced costs of implementation also reduce the impact of the rules on coal-producing states like Wyoming as shown in Godby et al. (2015 a,b)and Godby and Coupal (2016). Those results, using simulation results from Larsen et al. (2014) and the EIA (2015) to estimate state impacts as well as state revenue outcomes for the implementation of the 2014 CPP rules showed that wider trading could reduce such impacts by 7 to 8 percent in the case of employment losses for Wyoming, the nation's largest coal-producing state.[11]

Previous simulations on the originally proposed rules have also indicated the sensitivity of potential outcomes to assumed conditions in the natural gas and coal markets, and on changes in assumptions regarding renewable costs. Some of these are described in Godby and Coupal (2016). In particular, earlier simulations like those used in Larsen et al. (2014) and across the results reported in Hopkins (2015) generally identify displacement of coal with natural gas generation as the predominant means of meeting new CO_2 regulations. These simulations used the EIA's Annual Energy Outlook 2014 (AEO2014) modeling assumptions. Higher natural gas prices and lower coal production costs, along with lower renewable cost assumptions embodied in the EIA's AEO2015 assumptions, however, lead to a different outcome, and result in EIA (2015) finding renewables, particularly wind generation, the most important means by which the proposed CO_2 limits would be met in the 2014 CPP proposal. In these projections, natural gas plays a less prominent role and displaces less coal-fired generation. This difference in conclusions highlights the sensitivity of potential CPP outcomes to changes in energy markets.

More recently, additional changes to the economic landscape have potentially altered possible outcomes of the CPP and how it may be implemented. In addition to the final rule changes in August 2015, the U.S.

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[8] A summary of the rule and its implications for state action can be found in Durkay (2016).

[9] Mass-based outcomes were modeled presuming only existing sources were covered, and that 5 percent of emissions allowances were set-aside to recognize and support the deployment of new renewable capacity. This is consistent with choice (i) in note 6.

[10] Larsen et al. (2014) consider the impact or regional versus national trading on 2014 CPP proposal outcomes using their version of the National Energy Modeling System (NEMS-RHG), while Hopkins (2015) describes the results of several simulations across a variety of models. EIA (2015) also estimated costs of the 2014 proposed rules under three trading scenarios.

[11] Godby et al. (2015a,b) describes results for Wyoming for output, employment and income as well as revenue outcomes. Godby and Coupal (2016) compares results for coal production in and revenue outcomes using both Larsen et al. (2014) and and EIA (2015) projections.

Congress made unanticipated and significant changes to renewable incentives in late December 2015.[12] Specifically, this action restored previous incentives to develop new renewables and guaranteed such assistance until at least 2020. The wind production tax credit (PTC), which previously expired in 2014 was reinstated. It will now pay 2.3 cents per kilowatt hour generated for the first ten years of output for all new wind projects begun in 2015 and 2016. It will then drop to 80 percent of this value in 2017, 60 percent in 2018 and 40 percent in 2019 before ending in 2020. Similarly the investment tax credit for solar projects, which was set to drop to 10 percent of project costs in 2016, will now decline from 30 percent to 12 percent by 2020 in 6 percent increments annually starting in 2017, before finally dropping to 10 percent in 2021. Overall, after years of inconsistent policy causing significant investment uncertainty for renewable energy sources, these new rules allow a much more favorable and predictable environment in which to develop such projects.

Given the more favorable conditions for renewable energy projects, this could further alter energy market outcomes and the impacts regulations like the CPP have on energy dependent economies, especially those that produce coal. Additionally, the new CPP rules introduced in 2015 potentially create incentives that could cause the impacts experienced by such economies to be altered by the states' choices regarding how they choose to be regulated. The following sections describe how the state choice between rate- and mass-based regulations could impact generation mixes and resultant demands for coal, and describes simulation outcomes that attempt to quantify these results.

Incentives matter

As described, among the first choices states must make under the CPP is whether to be regulated by mass- or rate-based standards. While estimated emissions impacts for states universally choosing one or the other type of standard have been estimated to be nearly identical by the EPA under the final CPP rules, how these choices affect the method of delivering these reductions may be markedly different. Added to that, newly reinstated tax credits potentially increase the competitiveness of renewable generation and may alter investment decisions to meet potential CO_2 targets.

With respect to incentives, consider how a rate-based standard expressed in pounds of CO_2 emitted per megawatt hour (lbs. CO2/MWh) could affect generation decisions under an emission trading system. Any existing fossil-fuel generator with an emission rate higher than the standard set by the EPA must either reduce their emissions to the rate required through plant modification, or acquire enough emission rate credits (ERCs) denominated in MWh to bring their emission rate into compliance. Such credits can be created under the 2015 CPP rules by any existing fossil-fuel generator with an emission rate below applicable standards, or by any new zero-emitting source such as renewable or nuclear generation built after 2012, and sold directly or through third parties to initially non-compliant sources. Revenues from such sales effectively reduce the net cost of operation of credit generating sources, making them more competitive in electricity markets, while increasing the costs (through permit purchases) and reducing the competitiveness of those sources that do not meet the EPA's performance standards, altering the generation mix. These incentives may also alter the investment decisions made with respect to new generation choices in the future to comply with regulations or to accommodate new load growth. Since only zero-emission generation built after 2012 is eligible to create ERCs there is an increased incentive under rate-based regulation to build

[12] See H.R.2029 - Consolidated Appropriations Act, 2016 https://www.congress.gov/bill/114th-congress/house-bill/2029/text#toc-H99A78113D3B9438997E3FAAB274EAA22 (accessed May 2, 2016).

new renewable (and new nuclear to a lesser degree) generation. New load growth allows dynamic adjustment of the power system to accommodate such growth while potentially allowing the regulatory impact on coal fired generation to be reduced by the creation of credits.

Under a mass-based standard, each state has an allowable level of total emissions defined in tons of CO_2 it can emit from its generating sector. These are allocated by states to generators. All fossil-fueled generators must hold emission allowances to cover their operating emissions. If these allowances are allocated in an allowance auction, these sources all see their costs rise, and the higher the emissions of any given source, the greater the cost incurred to purchase allowances. Less emissions-intensive sources such as natural gas combined-cycle (NGCC) power plants face reduced cost increases relative to more emissions-intensive technologies such as traditional coal-fired plants, resulting in greater NGCC relative market competitiveness than without such regulations. Absent any other incentives this would result in greater use and deployment of NGCC technologies and less coal generation. Note that zero-emitting sources do not have to hold allowances, but they also do not create allowances for resale and therefore while NGCC and coal-fired generators see increased costs, non-emitting sources do not see the additional cost improvements available to such generators under the rate-based alternative. The result then is potentially less incentive for investments in new renewable capacity under a mass-based scheme than under a rate-based one, while new NGCC plants may have increased investment incentives relative to other forms of generation.

For coal-fired generation, and by extension, suppliers of coal for such plants, these incentives have important implications. Coal under any CO_2 control policy will be challenged due to the emissions intensity of that fuel, however, under a rate based scheme new renewables can create the credits that may allow some coal-plants to remain in operation, especially in the presence of greater load growth. Rate-based schemes may also alter the rate of load growth if they result in lower electricity prices than under a mass-based alternative. Under a mass-based scheme, load growth does not alter the emissions mass cap, thus a relative advantage will always exist between coal and natural gas generation due to the relative emissions intensity of the two fuels, creating a greater incentive to replace coal-fired with gas-fired generation. By implication then, a rate-based scheme could preserve greater coal generation and reduce the impact of carbon regulations on coal-mining states. New renewable incentives in the form of production and investment tax credits could further reinforce the incentives to build additional renewable generation and magnify the potential advantages of states choosing a rate-based regulation for coal-producers under the CPP.

Simulation Results

To estimate the potential impact of both the new CPP rules changes and the tax credit changes recently passed by Congress, Rhodium Group performed a series of simulations using their implementation of the EIA's NEMS model (RHG-NEMS).[13] Simulations assumed the AEO2015 assumptions, adding the newly passed 2015 tax credit extensions without the CPP as a reference scenario, and implemented either rate or mass based rules assuming all states chose either a rate or mass based regime imposing CPP standards as defined in the 2015 rule. In both CPP scenarios a nation-wide trading market was assumed also. The mass-based scenario was implemented assuming all existing and new fossil-fueled generators are covered and allowance auction revenues were not returned to consumers or the power sector, or used to pursue any other policy goal.[14] Results illustrate the effects of all states implementing rate- or mass-based programs in a model-consistent context. To be consistent with the 2015 CPP rules that use the year 2012 as a baseline,

[13] Larsen et al. (2016c) describes the specific simulation parameters assumed in the Appendix while broad results of the simulations are reported in more detail in Larsen et al. (2016 a, b and c).
[14] Revenues were presumed to be kept by government and not recycled in any way. Assume these revenues were added to state operating budgets. See Larsen et al. (2016c).

results are shown from that year and run through 2030, the year final CPP standards are required to be achieved.[15]

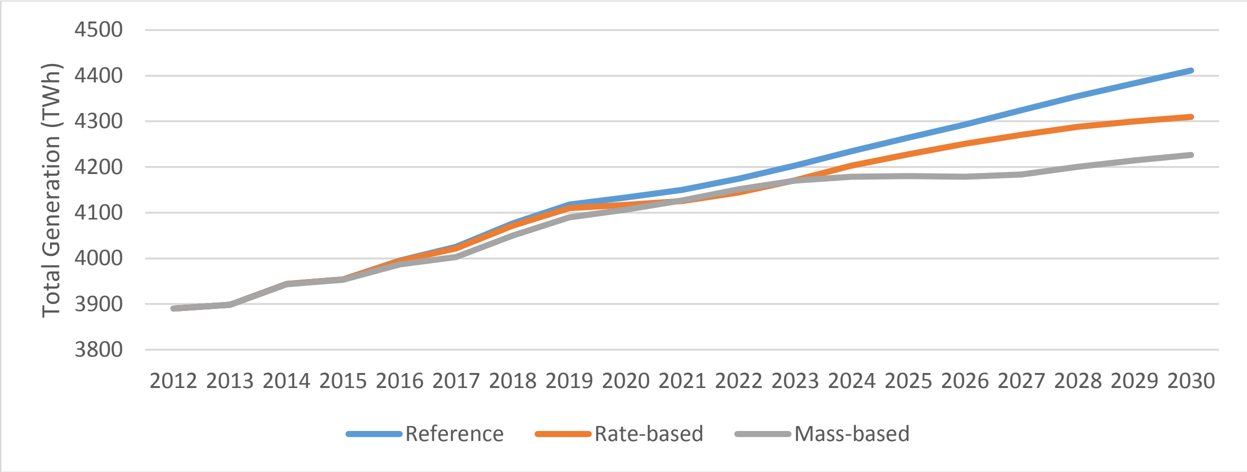

Figure 1: Total Generation Outcomes from 2012 to 2030.

Generation outcomes under the scenario are shown in Figure 1. Without the CPP imposed, but including the newly passed renewable tax credit extensions and assuming market conditions and assumptions consistent with the EIA's AEO2015, projected electricity sales by 2030 would increase by 13.4 percent relative to those in 2012. As reported in Larsen et al. (2016c), implementing the CPP results in electricity rates rising and reduced consumer sales due to additional investment and control costs necessary to meet the rules. This occurs regardless of a rate- or mass-based choice by states. The mass-based scenario assumes auctioned permits raise costs at all fossil-plants, while zero-emissions plants are unaffected, raising rates. In the rate-based system the cost of ERCs reduce zero-emission sources' costs while increasing fossil-fueled sources thus the rate impact is not as severe.[16] The overall result is that in the mass-based case the reduction in electricity demand due to higher rates is more significant relative to the reference case, dampening predicted electricity growth to 8.6 percent between 2012 and 2030. In the rate-based case it grows by 10.8 percent. As reported in Larsen et al. (2016c), overall expenditures for electricity in the mass-based case rise by 11 percent relative to the reference case by 2030 and only 1.1 percent in the rate-based scenario.

As described previously, the choice of rate- or mass-based policy potentially has significant impact on predicted generation investment and generation mix. Under the assumed conditions, simulations confirm this. Capacity additions by scenario are shown in Figures 2, 3 and 4 for coal, NGCC, nuclear and fossil with carbon capture, wind, solar, and all other generation. In the reference case without the CPP, coal retirements total 48 GW by 2030 and occur by 2025. Wind increases by 67 GW and solar by 12 GW by 2030 relative to 2012 levels, while NGCC generation increases by 42 GW over the same period. Both CPP scenarios result in greater retirement of coal-fired generation than under the reference case - in the mass-based case 81 GW is retired by 2030 while in the rate-based case retirements total 73 GW. How this is replaced by new NGCC and renewable build-out differs in each case.

[15] As in AEO2015, model results are calibrated to actual outcomes through 2013, with results after that year reflecting simulation results.

[16] In the mass-based case, allowance costs raise all fossil-fuel generator costs, while trade in the rate-based case transfers costs among emitters. Both types of regulation would result in other costs to meet the regulation.

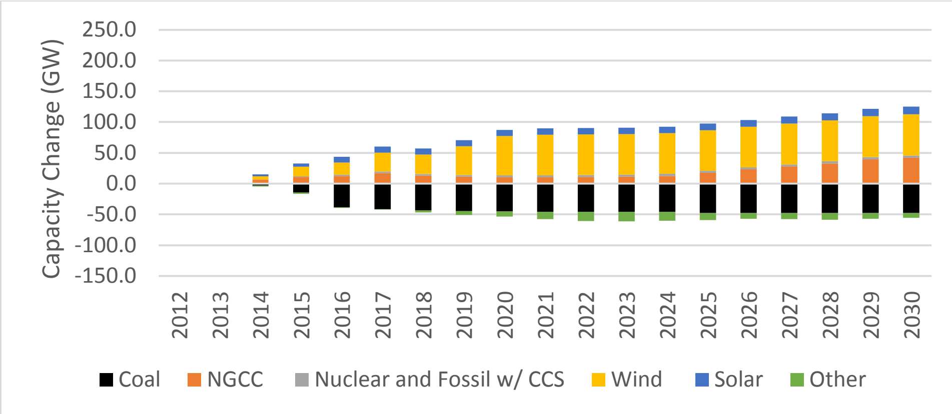

Figure 2: Reference Scenario – Cumulative Capacity Changes by Generation Type Relative to 2012

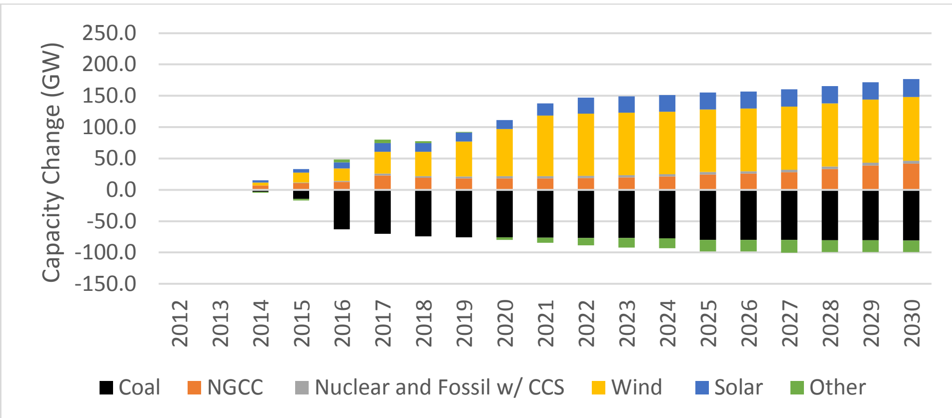

Figure 3: Mass-based Scenario - Cumulative Capacity Changes by Generation Type Relative to 2012

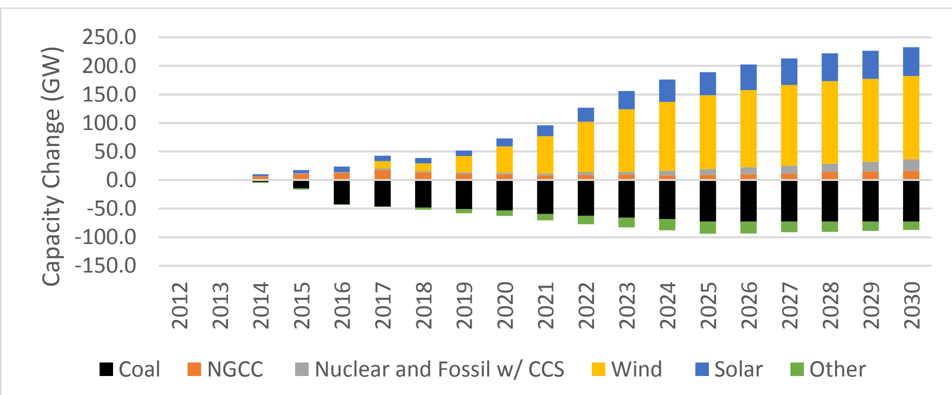

Figure 4: Rate-based Scenario - Cumulative Capacity Changes by Generation Type Relative to 2012

Under the mass-based scenario, NGCC additions total 42 GW by 2030, virtually the same as that projected in the reference case. Wind and solar increase relative to reference with a total of 102 GW of wind and 29 GW of solar added by 2030. Under rate-based regulation, however, NGCC additions at 16 GW are over 60 percent less than the reference and mass-based cases, while wind additions are more than double the reference and over 40 percent more than the mass-based case at 146 GW. Solar additions are over four times the reference outcome at 50 GW. Overall, new capacity additions in both CPP scenarios occur relative to the reference case to make up for lost coal generation, but because rate-based rules allow only generation built after 2012 to generate ERCs, there is a significantly greater incentive to build out new renewable generation. Conversely the incentive to exploit natural gas is reduced under rate-based relative to mass-based regulation.

Generation production outcomes also indicate how the choice of rate or mass-based regulation leads to different outcomes. Figures 5, 6 and 7 show the change in generation relative to 2012 for coal, NGCC, nuclear and fossil with carbon capture, renewables and all other sources of generation.[17] In the reference case, renewable generation increases by 332 TWh in 2030 relative to levels in 2012, while coal increases by 160 TWh and NGCC by 79 TWh. Introduction of the CPP dramatically changes these results. In both cases total coal generation declines significantly; by 207 TWh by 2030 relative to 2012 levels in the rate-based case, compared to 302 TWh in the mass-based case. By 2030 the mass-based case results in a 20 percent loss in coal-fired electricity production compared to 2012, while the rate-based case declines by 13.7 percent over the same period.[18] In the mass-based case, the relative improvement in NGCC competitiveness caused by the incentives this regulation choice creates causes NGCC generation in 2030 to rise by 204 TWh relative to the 973 TWh produced in 2012. In the rate-based case, however, NGCC generation in 2030 declines by 166 TWh relative to 2012. Renewable generation outcomes are also dramatically different by scenario. In the mass based case, renewable generation is 481 TWh higher in 2030 than 2012 levels, while the rate-based scenario results in a 730 TWh increase over the same period.[19] Again, this reflects the difference in incentives for renewable use caused by the rate-based regulation. Together, under rate-based regulation, greater renewable generation, combined with higher load growth due to electricity rates allows greater coal generation to survive given the introduction of the CPP.

Generation and capacity outcomes by scenario have significant implications for coal demand over time as well, as shown in Figure 8. Panels in Figure 8 describe the projected time-paths of coal production from 2012 through 2030 in the reference case and in the rate- and mass-based scenarios.[20] As can be seen in the Figure, the no-CPP reference baseline would predict all regions shown except the Southwest and Appalachia to increase production. Appalachian production, however, declines due to increased coal competition from elsewhere in the United States, particularly the Wyoming Powder River Basin (PRB) and Midwest as relative costs increase over time to mine in Appalachia, and customer's coal-fired power plants are retired due to age in these regions. Reinvestment occurs with other forms of generation as noted when describing projected capacity changes.

[17] Renewables in this case include wind, solar and geothermal/hydrothermal. Geothermal/hydrothermal were included as "Other" in Figures 2, 3 and 4. Overall impact of "Other" sources is very small in both sets of figures.
[18] In 2012, 1511 TWh of electricity were produced from coal.
[19] In 2012, 468 TWh of electricity were produced from renewables.
[20] In Figure 8, Appalachian outcomes represent the sum of production in Pennsylvania, West Virginia, Kentucky, Ohio, Maryland, Virginia, Tennessee, and Alabama and include metallurgical coal production. Midwest/Interior/Gulf production includes Illinois, Indiana, Mississippi, Western Kentucky, Iowa, Missouri, Kansas, Oklahoma, Arkansas, Texas and Louisiana outcomes. Wyoming PRB includes only production located in Wyoming, while Great Plains production includes Wyoming PRB and non-PRB, Montana and North Dakota production. Alaskan and Washington coal production, which sum to less than 3 million tons per year between 2012 and 2030 is not shown.

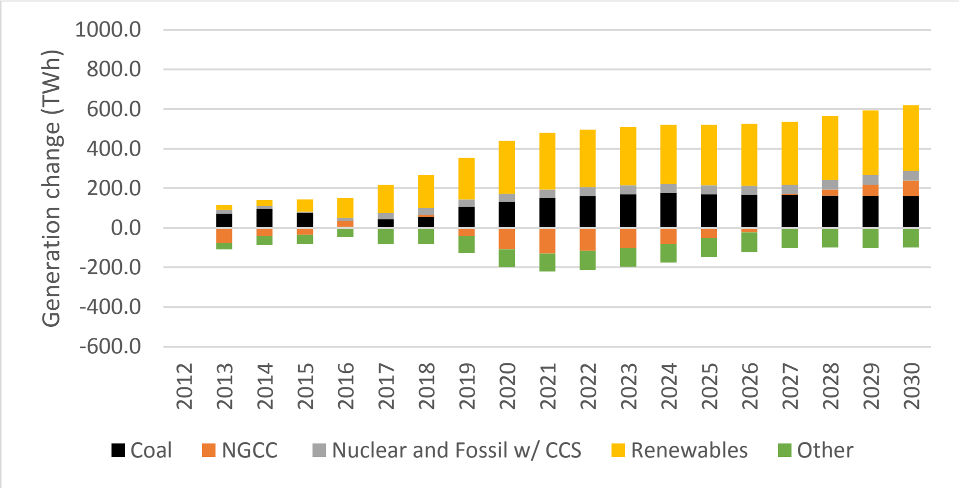

Figure 5: Reference Scenario – Generation Changes from 2012 by Fuel Type

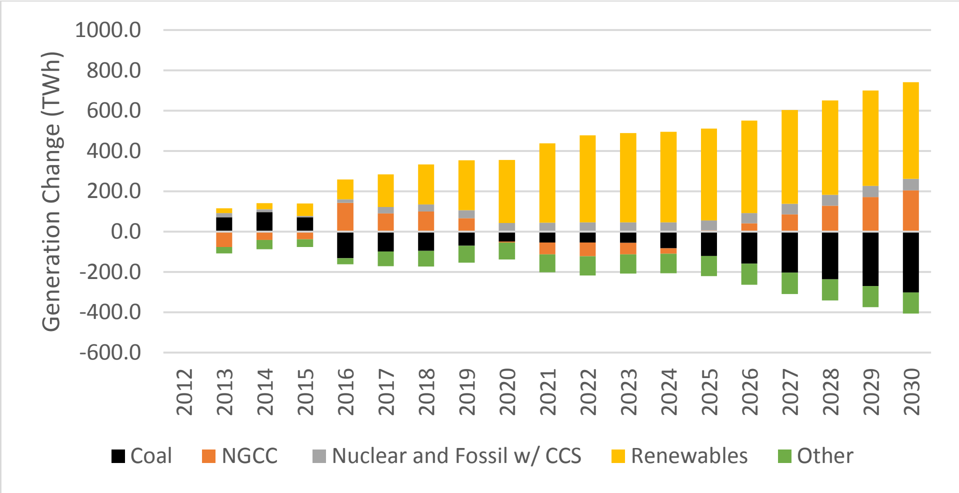

Figure 6: Mass-based Scenario – Generation Changes from 2012 by Fuel Type

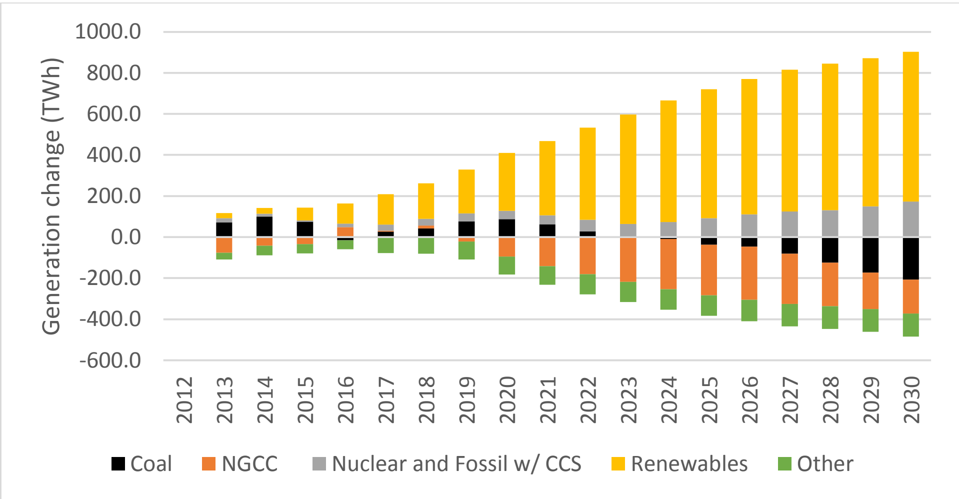

Figure 7: Rate-based Scenario – Generation Changes from 2012 by Fuel Type

The remainder of the country in the reference forecast would be predicted to see a resurgence in coal through at least 2022, with Midwestern coal competitiveness increasing through the entire forecast period.[21] Midwestern coal growth comes primarily at the expense of Wyoming Powder River Basin output, which peaks in the reference projection in the mid-2020s. Midwestern production improvements occur due to relative cost improvements caused by technologies such as longwall mining, while PRB costs increase as overburdens increase and PRB mining reserves are reduced in quality. Adding to this cost increase is an increase in coal transportation costs due to the AEO2015 assumption of rising oil prices over time.[22] Both effects limit the size of the PRB market after 2025, along with changes in the coal market as retirements occur in PRB-fueled plants. Still, despite these changes in relative market size between Midwestern/Interior/Gulf producers and PRB producers, the Powder River Basin remains the largest coal producing region in the country throughout the forecast period, producing 40.5 percent of the nation's coal in 2030, an increase over its 38.2 percent share in 2012. The Interior/Midwestern/Gulf share of output rises to 22.8 percent of national output in 2030, an increase over its 17.7 percent share in 2012.

The imposition of the Clean Power Plan causes several effects. First, regardless of scenario the CPP results in significant declines in projected coal production for all regions and nationally relative to the reference case. These declines though, reflect the sensitivity of generation and new capacity outcomes to the rate- or mass-based case assumed to occur. In the mass-based case U.S. total coal production declines by 21.4 percent from the level produced in 2012. In a rate-based setting, however, this is reduced to a 13 percent decline by 2030. Under a rate-based setting, national coal production remains higher than the mass-based case throughout the projection period, peaking in 2020, while in the mass-based case the decline occurs immediately upon the imposition of the CPP in 2016, with some recovery in coal production nationally through 2023, and declines occurring afterward. Overall, by 2030 under the rate-based case national coal production is 10.6 percent greater than the mass-based case.

Impacts of the CPP are relatively unequal across the regions shown in Figure 8. In Appalachia, projected declines in coal production accelerate due to the CPP. In the Interior/Midwest and Gulf, projected increases in coal production are mostly halted by 2020, and production remains relatively constant thereafter. In the Southwest, coal production declines begin with the program introduction when without the regulation they were projected to remain relatively constant. In the Great Plains region, which is dominated by Wyoming PRB production, the outcome is somewhat similar to the outcome in the Interior/Midwest/Gulf as a projected increase in coal output through the next decade in the reference case becomes a decline. Generally, however, impacts on regional and national coal production are worsened under a mass-based standard relative to rate-based outcomes in all regions but the Southwest by the time the CPP is fully implemented in 2030. Southwestern outcomes are dependent on local market outcomes and production after 2025 between rate- and mass-based outcomes differs by only between to two to three million tons of production per year.

[21] Midwestern growth is primarily due to increases in production in the region including Illinois and Indiana.

[22] AEO2015 assumptions with respect to PRB production costs and oil prices are discussed in Godby and Coupal (2016). Midwestern production increases also occur as Mercury and Air Toxics Standards go into effect in 2016, causing a reduction in low-sulfur coal demand from the PRB due to induced plant retirements and reinvestments.

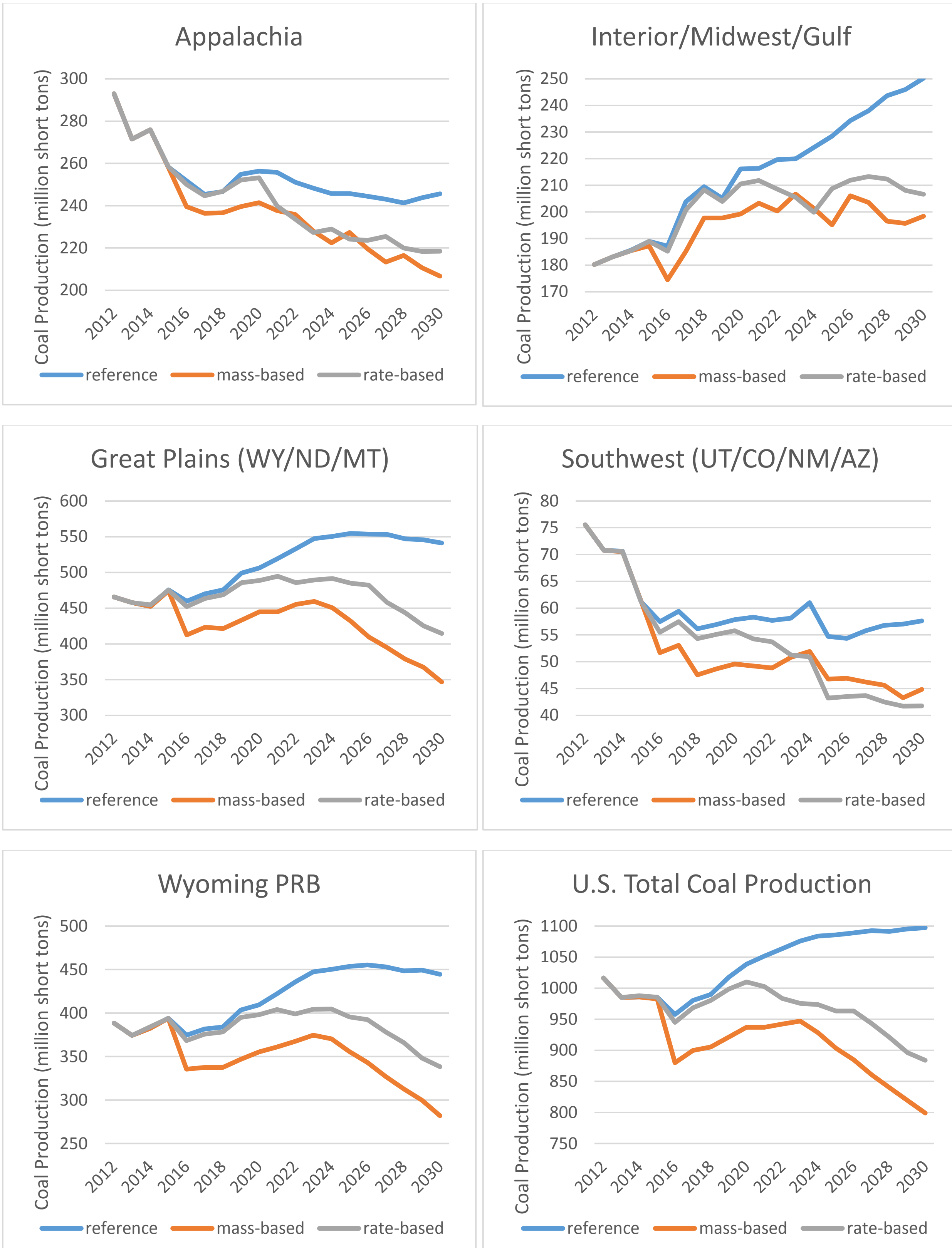

Figure 8: Coal Production by Region and Simulation Scenario (2012 to 2030)

With respect to production differences between rate and mass-based outcomes, the primary areas benefiting from the choice of rate-based regulation are the Wyoming Powder River Basin (and by extension the northern Great Plains states), and the Interior/Midwest/Gulf producers. In the former case, the choice of rate-based regulation allows coal production levels to avoid declines until after 2025. In the Interior/Midwest/Gulf case, increases in production in the period between 2016 and 2020 are larger and these production levels are then largely preserved through the rest of the projection period. Scenario-specific trends and outcomes are not as distinct in the other regions in terms of production volumes, and in Appalachia there is little difference between the rate- or mass-based outcomes until the late 2020s.

Coal production outcomes in Figure 8 show how different generation and investment incentives affect coal production. Under mass-based regulation, NGCC generation investment is incentivized and given retirement decisions present in the period from 2016 through 2025, this leads to greater coal retirement. More dispatch substitution from coal to gas and a much larger build-out of the NGCC fleet also occurs. Under the rate-based alternative, higher demand for electricity coupled with the subsidy effect of a trading system that allows renewables to exploit the creation of ERCs to lower their costs, causes more renewables to be built instead of NGCC plants in anticipation of the CPP requirements. This creates less coal displacement in dispatch, fewer coal retirements, and creates credits that allow many coal-fired generators to remain in production longer or more intensely in the period from 2016 to 2025 than under the mass-based standard. These effects lead to higher coal demand in all regions under the rate-based case. Over time, however, as the stringency of the CPP standards increase, the presence of wind ERCs is not enough to forestall coal retirements and they accelerate in the period from 2025 to 2030. This impacts Appalachian and Southwestern coal-producers most. Overall though, across all regions the projection outcome is the same, more coal production is preserved under rate-based regulation over the period from 2016 to 2030. Less NGCC generation is built, coal generation is able to benefit from the creation of ERCs greater renewable investment allows, thus greater amounts of coal generation stay in operation longer, creating greater coal production.

The impact of the rate- vs. mass-based choice has important economic consequences on coal-producing states. For example, using the employment impact model described in Godby and Coupal (2016), Wyoming employment in the coal sector under the mass-based alternative is estimated to be almost 6,600 positions lower than under the reference case. Rate-based rules reduce this loss to 4,300 fewer jobs. Relative to 2012 employment levels in the Wyoming coal economy, overall losses under the mass-based rules represent 1.7 percent of state jobs, and in the rate-based case 1.1 percent. These losses are much lower than those shown in Godby and Coupal (2016) where losses were in the 2 percent to 2.5 percent range by 2030.

Conclusions

Changes to the Clean Power Plan in August 2016 allow states to define their implementation plans under mass- or rate-based standards. Based on simulations by the EPA and by Rhodium Group, whose National Energy Modeling System simulation results are used here, the choice of standard should not dramatically affect emissions outcomes. The choices could, however affect system costs and electricity rates. The EPA has also championed the use of allowance trading and regional cooperation to reduce the costs of compliance to these rules. The definition of rate- and mass-based rules in such trading schemes creates potential incentives that, combined with the recent extension of renewable energy investment incentives could greatly affect capacity investment decisions, generation outcomes and therefore coal production outcomes. Specifically, under mass-based standards, there may be an incentive for a larger natural-gas combined-cycle build out in generation capacity that reduces future coal generation substantially. While renewables are also encouraged by these regulations, they cannot offset the NGCC build-out nor can they offer help for coal-fired plants in meeting EPA regulations. The result is greater coal production declines.

Under a rate-based plan, however, renewable generation is encouraged because renewable sources can sell emissions reduction credits to CO_2 emitters such as coal-fired power plants. Revenues from these sales create a subsidy and incentive to build out significantly more renewable generation, especially wind plants, which displaces investment in new NGCC plants. Less coal-fired generation is potentially displaced and the combination of greater renewable generation and greater coal-fired generation allows the system to meet required emissions outcomes. This preserves greater demand for coal-production. Renewables, in particular wind, and coal become in effect strange bedfellows. Both enable the other in a rate-based regime.

Regardless of rate- or mass-based implementation, any GHG standards will be detrimental to coal production. These results suggest that coal producing states, while very likely not enthusiastic about the CPP, should have a clear preference regarding which type standard to prefer. Rate-based outcomes appear to have a greater chance of reducing this impact and greater preservation of coal production than mass-based standards. Many coal producing states such as Wyoming should also realize that it will not be their own choice regarding rate- or mass-based standards that matters, but what customer states choose to do. Given the simulation results presented it would seem that coal-producing states therefore should emphasize coordination among as many states as possible, especially those using their coal to ensure that rate-based standards are adopted.

There are some caveats to this analysis. First outcomes shown are best-case scenarios that occur under ideal conditions. For example, all states choose rate- or mass-based regulation and national trading occurs in both cases. This maximizes trading and cooperative opportunities. In all likelihood, a patchwork or regional groupings of states will emerge that make similar regulatory choices. How such patterns occur with respect to choice of standard could determine the trading opportunities available and this could affect generation and capacity choices in ways not foreseen. These could alter the results reported, and could worsen the impacts on coal production while increasing costs of compliance. Given this risk, it should be in the national interest to try to coordinate rate- or mass-based choices to minimize such inefficiencies.[23]

Second, changes modeling assumptions made here could undermine the advantages of rate-based regulation for coal producers. AEO2015 assumptions and estimates of natural gas prices have proven much higher than actual outcomes in 2015 and 2016. Much lower gas prices than foreseen in this analysis could lead to the natural gas generation being more cost-competitive than assumed here, which could reduce renewable investment and undermine rate-based results that favor greater coal use.

Thirdly, in the modeling presented here it is assumed allowance auction revenues in the mass-based case are not used to achieve specific energy outcomes such as subsidizing renewable generation, or as consumer rebates that could reduce electricity rates and increase generation demand. In the mass-based case, using allowance auction revenues in this way could reduce the impacts on coal production for that regulatory choice. The assumption that allowances are not used in that way could exaggerate the differences between mass- and rate-based outcomes.

Finally, retirement decisions made in the simulations may not reflect considerations made in reality. For example, because NEMS assumes perfect foresight, modeled MATS retrofit decisions are made foreseeing CPP rules that will occur in the future. In the mass-based simulations, the combination of MATS retrofits

[23] It could be the case that some coal-producing states might find it to their advantage to adopt mass-based rules if nearby states who share the same electricity markets also do to maximize the ability of their utility sectors to exploit regional cooperation. Simultaneously however, these same states may prefer their coal customer states adopt a rate-based standard based on the results presented here to minimize the impact on their coal production sector. This could put a coal-producing state in the awkward position of conflicting interests – a "do as I say, not as I do" if they tried to influence coal-customer states' choices on rate- or mass-based regulation.

and then anticipated high future CPP operating costs could cause firms to be projected to retire more coal-fired generation than may actually occur. In reality, MATS compliance choices have had to be made without knowledge of future CPP rules. This could cause the modeled mass-based decisions to be biased towards less coal-use than has actually occurred in reality.[24] Conversely though, in the actual world the uncertainty regarding GHG rules at the time MATS decisions were made could have increased retirement over the model predictions, thus results under mass-based regulation presented could understate those that will eventually happen. The impacts of uncertainty regarding future GHG regulations have had in reality are difficult to know and quantify. This could also be true in the rate-based cases – conditions in reality may lead to larger coal-retirements than the simulation scenarios predict.

Overall, however, regardless of the limitations of using simulation results, the results clearly show that the choice of rate- or mass-based standards potentially creates significant differences in incentives regarding investments in natural gas and renewable generation, and therefore the preservation of coal generation. Simulation modeling suggests these incentives could have significant effects on coal generation outcomes, and by implication coal production in the future. States attempting to minimize the cost of the CPP, and in particular, those states that are major coal-producers might consider that how their customer states choose to implement CPP rules could have major impacts on their coal production. For this reason it may be in their interests to attempt to ensure such decisions are as coordinated as possible and that rate-based regulation is given maximum consideration.

Implications for Wyoming

A comparison of Wyoming coal production outcomes relative to those in previous projections of the CPP is shown in Figure 9. The figure includes the reference and four projections from Godby *et al.* (2015) based on the Rhodium Group's modeling of the original CPP proposal (dashed lines), the reference and two projections described in Godby and Coupal (2016) and taken from the EIA (2015) analysis of the CPP proposal (dotted lines), and the projections described in this paper (solid lines). All projections used a version of the EIA's NEMS model and differences between projections are model-consistent effects due to changes to reference and scenario assumptions.

Note that the references in each set of projections change. Godby *et al.* (2015) described projections based on a previous Rhodium Group set of projections used in that study, which used AEO2014 assumptions. Reference projections describe outcomes predicted if the CPP were not implemented. Comparison of this reference to the reference outcome if AEO2015 assumptions are used (these were used in the EIA projections shown) shows that coal production in Wyoming absent the CPP was projected to improve based on changes in the AEO assumptions between 2014 and 2015. Primarily, this occurred because of updates in AEO2015 that improved projected Wyoming coal production costs, and updates to oil and natural gas assumptions based that included recent declines in both sets of prices. These were described in Godby and Coupal (2016). The reference case presented in this paper takes the AEO2015 assumptions and updates them for the impact of the production and investment tax credits for renewables passed by Congress in late 2015. The result of these congressional actions reduces coal production in Wyoming relative to the AEO2015 projection, due to a projected increased use of renewables in electricity generation over time, which lowers Wyoming coal demand somewhat, though not to the levels the AEO2014 projection had predicted. Overall, the new reference is within 10 million tons (or less) in annual production levels of the previous references for the years between 2020 and 2030 thus the impact of these assumption changes can be considered relatively minor.

[24] We thank John Larsen at Rhodium Group for this observation.

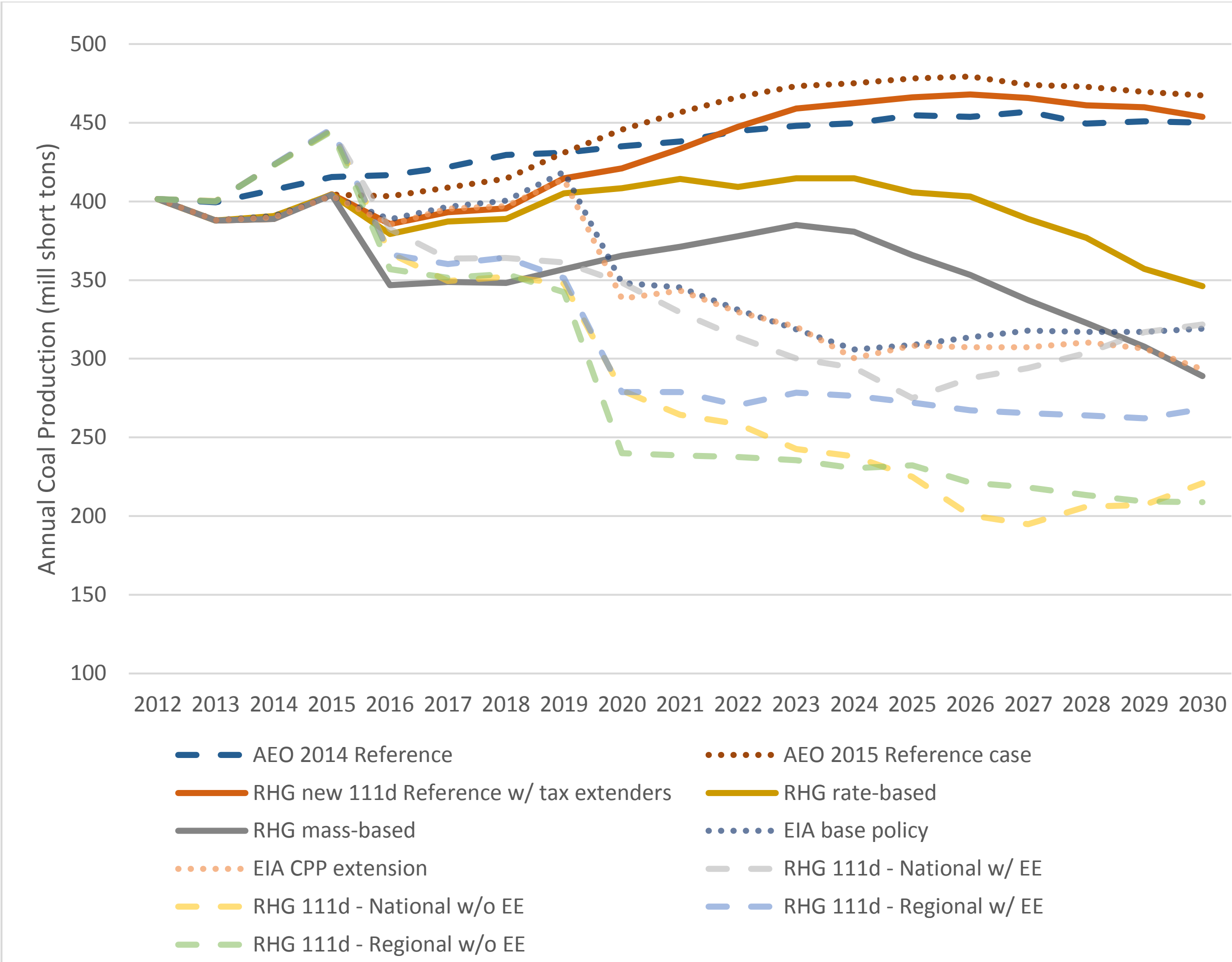

Figure 9: Projected Wyoming Coal Production Outcomes: current and past studies

The previous projections of CPP impact based on the originally proposed rules in 2014 indicated a significant reduction in Wyoming coal production. The original projections described in Godby *et al.* (2015) suggested the potential impact of the proposed CPP rules could result in coal production being reduced by approximately 80 to 210 million tons per year relative to production levels in 2012, depending on the implementation assumptions made. As previously noted, later EIA projections suggested improved Wyoming coal production outcomes for the 2014-proposed CPP rules relative to those originally projected in the RHG simulations and described in Godby *et al.* (2015), in part due to basic market assumptions changes. The EIA projections also used a more likely set of scenario implementations regarding how the rules would be implemented than the original RHG simulations. The result was a narrower range of outcomes regarding projected Wyoming coal production that reduced coal output by approximately 80 to 100 million tons per year relative to the 2012 production level of 401 million tons. Projected Wyoming coal production improves still further based on the final 2015 CPP rules shown by the rate- and mass-based cases described in this paper and shown in Figure 9. Mass-based outcomes are broadly similar to the worst of the previous EIA projections and result in a decline of 108 million tons of Wyoming coal production relative to 2012 levels by 2030. The projected rate-based outcome by 2030 for Wyoming coal production is significantly better than any of the previous studies', with a decline of 55 million tons relative to the 2012 production level. Further, both the rate- and mass-based projections suggest significantly less decline in Wyoming coal production in the years between 2020 and 2030 relative to previous studies.

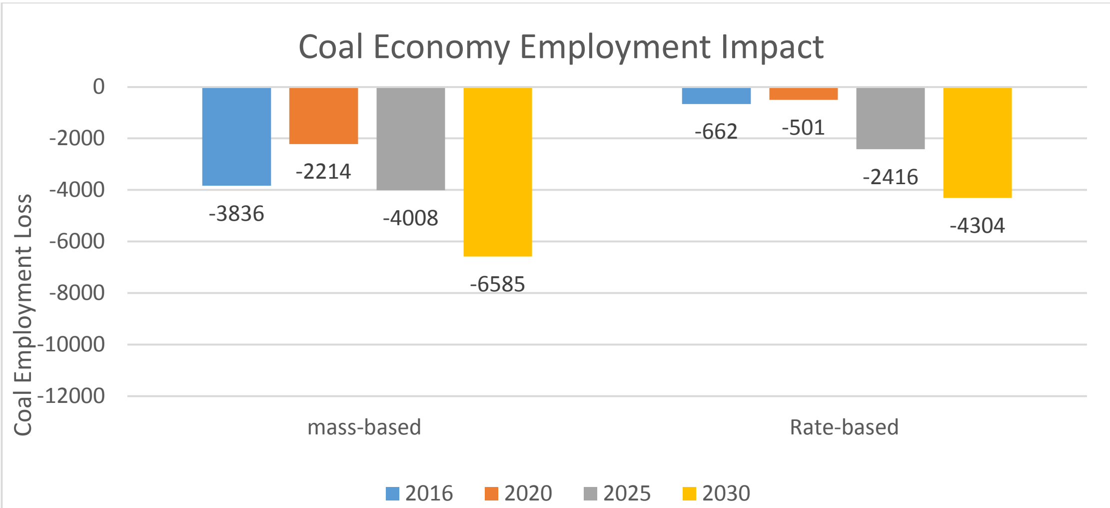

Figure 10: Projected Wyoming Coal Employment Impacts by Scenario

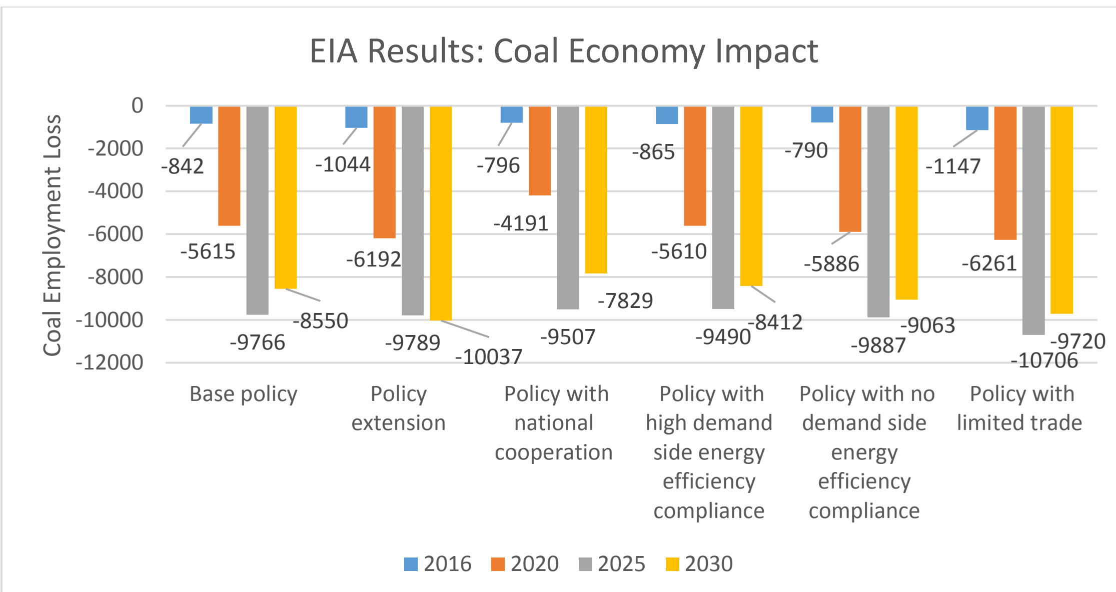

Figure 11: Godby and Coupal (2016) Coal Employment Impacts based on EIA (2016) Projections

The implication of the production projections shown in Figure 9, and employment outcomes in Figure 10 is that the new 2015 CPP rules could result in less hardship on Wyoming's coal economy than projected in previous studies. Consider employment impacts implied by the newest projections relative to earlier estimates.[25] Estimates of the employment impact of the final CPP plan based on projections presented and using the impact model described in Godby *et al.* (2015) suggest that by 2030 coal employment impacts could be approximately half of those estimated earlier in Godby and Coupal (2016), which in turn are

[25] The "coal economy" of Wyoming refers to activity due to coal mining, including rail transport and electricity generation using coal in Wyoming. Economic impacts include not only the direct impacts of coal mining, rail transport services and generation, but also the associated activities that support these industries (referred to as indirect impacts), and the induced economic activities due to additional expenditures generated by incomes in these sectors. The "coal economy" is explicitly described in Godby *et al.* (2015).

somewhat less than those found in Godby *et al.* (2015).[26] These projected employment impacts on Wyoming's coal economy using rate- and mass-based projections are shown in Figure 10. Figure 11 presents the Wyoming coal employment impacts from Godby and Coupal (2016) for comparison. Employment impact estimates from the simulations presented in this paper range from approximately 4,300 job losses to over 6,600 by 2030. Note that the previous projections predicted a larger impact of the CPP in 2025 than 2030, consistent with the production outcomes shown in Figure 9. New projections suggest a smaller decline in Wyoming coal employment that occurs more slowly over time than previous studies predicted. Further, as shown with the production outcomes, results are now very sensitive to the choice of whether a rate- or mass-based standard is chosen.

Comparison of employment and coal production impacts should be tempered by some caveats:

(i) The simulations shown assumed nation-wide trading. It is highly unlikely that the entire country will choose rate or mass-based regulation. States may only trade with states under the same regime – and smaller markets increase the costs of the regulation to states like Wyoming by reducing the means of achieving emissions reductions available to states using coal generation and buying coal. This implies impacts shown are likely low estimates relative to what actually would happen in either rate- or mass-based cases. Especially in coal regions producing lower outputs, specific market changes could have significant effects on whether rate- or mass-based regulation is preferred if national implementation does not occur under one rate- or mass-based regulation.

(ii) AEO2015 price assumptions have proven to be high relative to actual energy market outcomes. Had such prices been used in the analysis and if they persist could significantly change projected investment and capacity changes, generation and coal production results. Figure 9 plots Wyoming total coal production as projected in the simulations presented and actual coal production outcomes through mid-2016, including projected outcomes in 2016 and 2017 using the EIA's Short Term Energy Outlook (STEO). Recent declines have been driven by natural gas price outcomes significantly below the levels AEO2015 assumed. It could be the case that should such natural gas prices persist, that at such low prices renewables may be far less competitive than presumed in the simulations presented. In such a case the reductions in coal output could be far more dramatic. Note that Figure 12 shows current coal outcomes to be at levels comparable to the worst mass-based outcomes of the CPP and these reductions have occurred in less than two years, versus the 15 years anticipated to reach the CPP outcomes projected.[27] Alternatively, AEO2015 assumptions regarding cost improvements for renewables are considered by many to be pessimistic relative to other sources (see Larsen *et al.* (2016c)) and therefore simulation results could understate the levels of renewable development that may occur under either rate- or mass-based choices.

[26] Godby and Coupal presented coal employment estimates based on EIA (2015a) forecasts of the 2014 CPP proposal. The analysis presented here does not include natural gas impacts, which were included in Godby and Coupal (2016) and (Godby et al. (2015).

[27] The coal production decline that has occurred in 2015-2016 will result in an estimated loss of over 1,300 jobs in coal mining alone. To date only approximately 600 job losses have occurred in coal mining thus the state may expect under current conditions an additional 700 lost jobs in just coal mining alone. Overall impact across the Wyoming coal economy for the current coal downturn could be expected to destroy over 3,800 jobs in the state using the impact model in Godby *et al.* (2015).

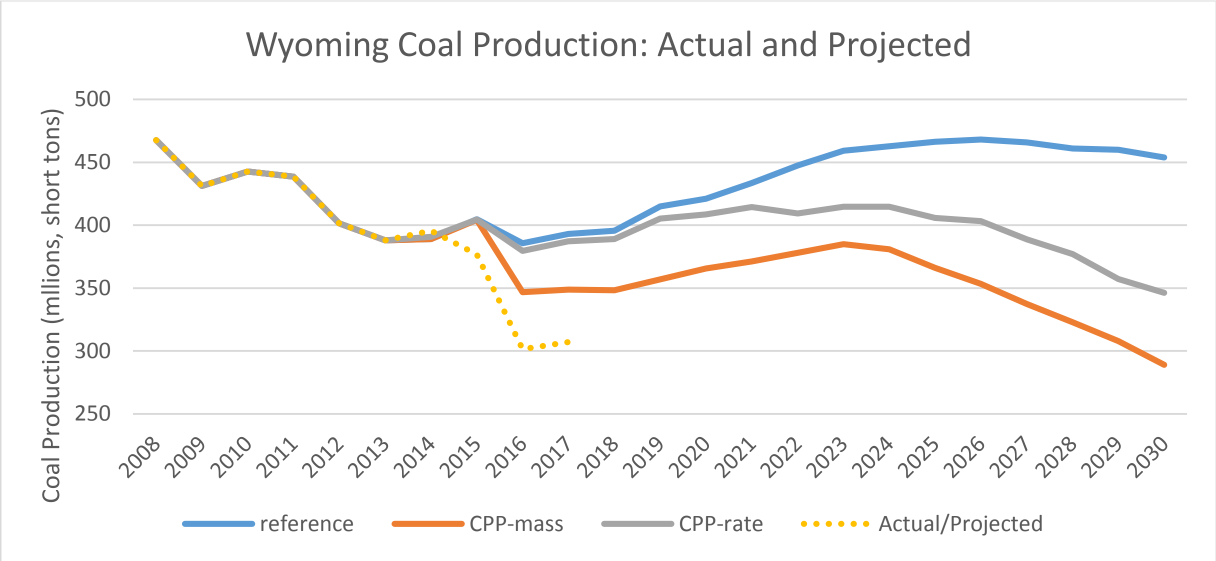

Figure 12: Projected coal production outcomes for Wyoming, including more recent actual levels and recent short-term projections.

(iii) Allowance distribution: the simulations presented assumed that allowances were auctioned in the mass-based scenario and revenues were not used for any energy-related purpose, nor were revenues returned to taxpayers. If these revenues were used to incentivize renewable production, results could differ. Similarly, if the revenues were returned to households the demand impact under the mass-based standard could be reduced, thus potentially reducing the impact on coal production.

The choice of rate or mass-based standard that is important to Wyoming is not the choice the state makes itself, but the choice its customer states make since approximately 93 percent of Wyoming coal is exported out of the state. As described earlier in the paper, the incentives created by rate- versus mass-based standards could be significant for Wyoming coal production outcomes and a clear preference should exist regarding which outcome the state would prefer. Coordinating such a choice across states could be important for the Wyoming, and it would be beneficial if Wyoming has any influence locally, that other surrounding states are coordinated similarly for the benefit of the Wyoming utility sector.

Insights from this Analysis for Wyoming: A Possible Action Plan:

From the previous analysis the following six actions could be beneficial to the state in minimizing the impact of the CPP on the Wyoming economy:

1) Based on these results Wyoming should adopt a rate-based standard in its own state implementation plan (lead by example).
2) Wyoming should be attempting to ensure through lobbying or other cooperative and coordinating efforts that at least the 30+ states that use Wyoming coal also adopt a rate-based standard to maximize the trading opportunities available to these states and to minimize impacts to Wyoming on its coal exports.
3) Wyoming should similarly be attempting to lead neighboring states to adopt a rate-based plan to ensure that the state is able to exploit trading opportunities nearby. Several neighboring states are coal-producers thus adopting such a plan could be in their interest also.

4) Wyoming should be promoting wide emission reduction credit trading plans among rate-based states to maximize the ability of states to take advantage of cost-reducing activities.

As noted in the paper, wide development of wind generation under a rate-based standard could allow the least impact to coal-producing states like Wyoming. This occurs because of the reduced build-out of NGCC generation that displaces coal, and because wind generators create emission reduction credits that coal generators can use to meet CPP standards. Wyoming could become a potentially large wind-generation state due to the natural weather conditions within its borders. This could allow Wyoming to both benefit from wind generation through its coal industry, and also through the creation of emission reduction credit revenues.

5) Wyoming should also promote the development of wind generation within its borders. As noted previously, rate-based standards potentially allow wind and coal generation to become "strange bedfellows". Wind generation in Wyoming could both support its existing coal generation industry through selling such credits, and also create a lucrative area of economic development that could offset some of the economic effects of reduced coal production under the CPP.

Wyoming has recently considered raising its wind-production tax to offset revenue losses from the recent energy downturn. These ideas may be ones that Wyoming will wish to thoroughly consider, to avoid deterring such development.[28]

6) In addition to promoting wind development, Wyoming could also continue to promote the building of additional transmission access out of the state. This has previously been identified as a problem for wind development in Wyoming (see Godby, Coupal and Torell (2014)).

[28] Wyoming is currently the only state in the nation to tax wind production on a per MWh basis. Presentations at the Wyoming Joint Revenue Committee meetings in Douglas, Wyoming on May 11-12 included proposals to increase the wind-generation tax in Wyoming. See http://legisweb.state.wy.us/interimCommittee/2016/03MIN0511.pdf .

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