

## Federal Coal Program Reform, the Clean Power Plan, and the Interaction of Upstream and Downstream Climate Policies<sup>†</sup>

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*Can supply-side environmental policies that limit the extraction of fossil fuels reduce CO<sub>2</sub> emissions? This paper studies interactions between a specific supply-side policy—a carbon surcharge on federal coal royalties—and regulation of emissions from the power sector under the Clean Air Act. Estimates from a detailed dynamic model of the power sector suggest that, absent new downstream regulation, a royalty surcharge equal to the social cost of carbon would generate three-quarters of the emissions reductions originally projected for the Clean Power Plan (CPP), with an average abatement cost roughly equal to the social cost of carbon. Were the CPP in place, the royalty surcharge would reduce emissions by reducing leakage and causing the CPP to be nonbinding in some scenarios. (JEL Q35, Q38, Q48, Q54, Q58)*

Environmental policies that aim to limit emissions of carbon dioxide (CO<sub>2</sub>) by restricting the supply of fossil fuels are controversial. Proponents argue that fossil fuel reserves are so vast that burning them all would lead to catastrophic climate outcomes, so government policies that directly restrict supply—“keep it in the ground”—are in order. Opponents argue that partial supply-side, or upstream, policies can fail to reduce overall emissions because alternative sources of fossil fuels will replace the restricted ones and, moreover, upstream policies can interact perversely with downstream policies that directly regulate CO<sub>2</sub> emissions.

In the United States, federal coal policy provides a prominent example of the debate over supply-side policies. Approximately 40 percent of the coal consumed in the United States is mined on federally managed land under a mineral leasing program administered by the US Department of the Interior (US DOI). Burning this

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federal coal to generate electricity accounts for approximately 11 percent of all US energy-related emissions of carbon dioxide.

Both upstream policies on federal coal leasing and downstream policies on power sector emissions are in flux. In 2015, the Obama administration used administrative authority under the Clean Air Act to propose the Clean Power Plan (CPP), a cap-and-trade program for CO<sub>2</sub> emissions from the power sector (Carbon Pollution Emission Guidelines 2015). The CPP was withdrawn by the Trump administration, which in 2018 proposed in its place a limited command-and-control regulation, the Affordable Clean Energy (ACE) plan (Emission Guidelines for Greenhouse Gas Emissions 2018).<sup>1</sup> Concerning federal coal policy, in 2016, the DOI announced the first programmatic review of the federal coal leasing program since the 1980s and, for the duration of the review, a moratorium on new and renewed federal coal leases.<sup>2</sup> Both actions were reversed under the Trump administration,<sup>3</sup> which instead made increased federal mineral leasing a priority for the Bureau of Land Management (BLM). Because these are all administrative actions taken under existing law, they could be changed again by a future administration or by future legislation.

Given this policy flux, there is surprisingly little analysis of how these upstream and downstream policies interact. This paper aims to fill this gap by analyzing the effects of a specific supply-side policy: imposing a royalty surcharge on US federal coal to reflect the environmental externalities associated with its combustion. We examine the interactions between a royalty surcharge on federal coal, the availability of nonfederal coal substitutes, and downstream regulation using two distinct modeling strategies. First, we use a stylized static model of the power sector to illustrate these interactions as transparently as possible. For quantitative estimates, we turn to the Integrated Planning Model (IPM), a detailed dynamic structural model of the power sector maintained by ICF International. The IPM is a peer-reviewed<sup>4</sup> proprietary model that is widely used for industry and environmental analysis. We adopt it here because of its granular modeling of the US power sector, which is necessary to quantify the extent to which nonfederal coal and gas are substituted for federal coal, and because the IPM was used by the EPA in its formal economic analysis (“Regulatory Impact Analysis”) of the effects of the CPP (US EPA 2015). By using the EPA’s modeling assumptions as our baseline, we are able to estimate the marginal effects of a royalty surcharge in a way that connects directly with existing official policy analysis.

The upstream and downstream regulations we consider are based on concrete proposals. The upstream policy, a royalty surcharge, is one of the policies proposed for study in the 2016 DOI programmatic review (US DOI 2017).<sup>5</sup> We consider three cases of downstream regulation under the Clean Air Act. The first is no downstream regulation. The second is a cap-and-trade system in which the EPA sets a cap on

<sup>1</sup> See Keyes et al. (2019) for a description and analysis of the ACE.

<sup>2</sup> The Secretarial Order of January 15, 2016 at [http://www.blm.gov/style/medialib/blm/wo/Communications\\_Directorate/public\\_affairs/news\\_release\\_attachments.Par.4909.File.dat/SO%203338%20Coal.pdf](http://www.blm.gov/style/medialib/blm/wo/Communications_Directorate/public_affairs/news_release_attachments.Par.4909.File.dat/SO%203338%20Coal.pdf).

<sup>3</sup> Executive Order 13783, Section 6, at <https://www.whitehouse.gov/the-press-office/2017/03/28/presidential-executive-order-promoting-energy-independence-and-economy-1>.

<sup>4</sup> See, for example, Paul et al. (2014).

<sup>5</sup> In the climate section of the 2017 scoping document for the programmatic review, the first policy listed for consideration is to “account for carbon-based externalities through royalty rate increase or royalty adder” (US DOI 2017, ES-5).

annual CO<sub>2</sub> emissions at the state level and authorizes trading of emission allowances; following standard terminology, we refer to this possibility as mass-based regulation. The third case is a system in which EPA sets a maximum *rate* of emissions, that is, tons of CO<sub>2</sub> per megawatt-hour (MWh) of electricity generated at the state level, and allows trading of emissions rate allowances; we refer to this as rate-based regulation. Any real-world emissions regulation will differ from a stylized textbook system, and the details matter. The specific mass and rate cases modeled here are the two main options laid out in the CPP. In both, we allow for regional trading. Given a downstream regulatory regime, we study the effect of implementing a royalty surcharge on federal coal based on its greenhouse gas externalities when burned. Although our quantitative results narrowly pertain to this mix of policies, those results can be informative for variations of these policies that might be considered in the future. Moreover, our analytical approach can be extended to other settings with interacting upstream and downstream policies.

The IPM simulations provide seven main findings. First, in the absence of downstream regulation, a royalty surcharge applied to federal coal results in substantial emissions reductions: a royalty surcharge equal to the US government estimate of the social cost of carbon (SCC) is estimated to reduce power sector CO<sub>2</sub> emissions by nearly three-quarters of the estimated reduction from the CPP without the royalty surcharge. Second, even with the mass-based CPP in place, a royalty surcharge drives additional emissions reductions because, in some regions, the IPM simulations indicate that by 2030 the CPP would not be binding, and in the regions in which the CPP does bind, the CPP does not cover some sources and the royalty surcharge has the effect of reducing generation at those uncovered sources. In technical terms, the royalty surcharge reduces leakage in the CPP.<sup>6</sup> Third, in all cases, there is only partial substitution of nonfederal for federal coal. The reason for incomplete substitution is the combination of potentially expensive plant-level switching costs and the fact that the surcharge boosts demand for nonfederal coal, increasing its price and thus making it less competitive with gas and renewables. For this latter reason, the greater the surcharge, the *less* substitution there is of nonfederal for federal coal. Fourth, the per-ton abatement cost of a royalty surcharge, holding constant the downstream regulation, is comparable to or less than the SCC in the no-CPP or rate regulation case; however, it is roughly twice the SCC in the mass-based case (the surcharge induces less emissions reductions in the mass- than rate-based case). That said, comparing the royalty-only policy to the CPP-only policy, both relative to a no-policy baseline, the CPP is more efficient in the sense that the royalty surcharge has a higher average abatement cost than the CPP, as would be expected because the downstream regulation covers emissions from all fossil fuels, not just from federal coal. Fifth, the price of tradable emissions allowances falls as the surcharge increases under both rate- and mass-based CPPs, so the royalty surcharge decreases the cost of compliance with the CPP. Sixth, under mass-based regulation, the wholesale electricity price *falls* as the surcharge increases: the surcharge induces switching to gas, which means greater generation for the same emissions cap, and

<sup>6</sup>In the context of air emissions regulation, the term leakage refers to the possibility that some types of emissions are not covered by a regulation and the regulation incentivizes more of those emissions.

thus a lower price of electricity. Seventh, total royalty receipts increase sharply with the royalty surcharge, even though federal coal production declines.<sup>7</sup>

This paper contributes to a large theoretical literature on instrument choice and overlapping policies. Holland (2012) studies the relative efficiency of mass- and rate-based regulation and shows that emissions leakage can provide an efficiency rationale for rate-based regulation. Mansur (2012) uses a theoretical model to highlight the key factors that determine optimal vertical targeting of regulation (i.e., upstream or downstream). Goulder and Stavins (2012) assesses the effects of overlapping state and federal cap-and-trade policies. They highlight the potential for stringent subnational policies to induce emissions leakage to covered sources in other states, compromising national cost-effectiveness without inducing any net emissions reductions.<sup>8</sup> Goulder, Jacobsen, and van Benthem (2012) demonstrates the relevance of these theoretical points in a study of the vehicle market. Fischer and Newell (2008) and Fischer, Preonas, and Newell (2017) investigate the welfare impacts of introducing alternative regulatory instruments that overlap with comprehensive greenhouse gas regulation but have the potential to address additional market failures (e.g., innovation market failures).<sup>9</sup> Horowitz and Linn (2015) highlights the potentially perverse impact of technological change in the presence of rate-based regulation, where cost reductions for clean energy can lead to increases in total emissions. In contrast to these previous papers, we study the interaction of overlapping upstream and downstream policies, both with partial coverage, with a particular focus on the effect of leakage on electricity market and emissions outcomes. This paper is also related to Harstad (2012) in that both consider supply-side policies in the presence of downstream policies; however, Harstad's (2012) focus is on supply restrictions for unregulated fuels, whereas we consider supply-side policies for fuels whose emissions are regulated.<sup>10</sup>

This paper also contributes to the literature on the economics of the CPP. Bushnell et al. (2015) looks at interactions between rate and mass plans under the proposed CPP, and we return to their work in Section V. The literature on the federal coal program is small. Krupnick et al. (2015) examines the legal framework for a carbon charge on federal coal. Hein and Howard (2015) considers both fair return and climate concerns about the federal coal program. In this literature, the paper most closely related to ours is Haggerty, Lawson, and Percy (2015), who use a partial equilibrium model of the coal market to estimate the effect on coal revenues and prices of changing the method for computing coal revenues to include transport costs.

Finally, and perhaps most importantly, this paper contributes to our understanding of the extent to which a partial supply-side policy could substitute for more comprehensive emissions regulation. We find that the abatement cost of the royalty surcharge is higher than the more comprehensive CPP, which is unsurprising given that the royalty surcharge does not equalize marginal abatement costs across fuels used for electricity generation. Yet what is striking is that we estimate the royalty

<sup>7</sup> Additional simulation results are presented in Vulcan (2016).

<sup>8</sup> Fankhauser, Hepburn, and Park (2010) makes similar points with an emphasis on the European policy context.

<sup>9</sup> See Fischer and Preonas (2010) for a review of further literature on this topic.

<sup>10</sup> In Harstad (2012), the unregulated fuels are fossil fuels in countries not participating in an international climate agreement.

surcharge would generate three-quarters of the emissions reductions originally projected for the CPP at a cost roughly equal to the SCC. Thus, while implementing a royalty surcharge would not be as efficient or efficacious as comprehensive regulation of the electric power sector, the surcharge could provide meaningful and fairly cost-effective emissions reductions. Our results also highlight some potentially surprising advantages of such a supply-side policy, chief among them that, unlike the CPP, it would not induce leakage through coal exports.

The remainder of the paper is organized as follows. Section I provides a brief summary of the federal coal program and the CPP. Section II presents the comparative statics. Section III lays out the research design using the IPM, and Section IV presents the IPM results. Section V concludes.

## I. Institutional Context

### A. *The Federal Coal Program*<sup>11</sup>

In 2017, US coal production was 775 million short tons, 42 percent of which was mined on federally managed lands.<sup>12</sup> Approximately 93 percent of coal consumption in the United States is used to generate electricity.<sup>13</sup> Burning coal (both federal and nonfederal) accounted for approximately 1.3 billion metric tons (MT) of CO<sub>2</sub> emissions in 2017, roughly one-fourth of all CO<sub>2</sub> emissions from fossil fuels.<sup>14</sup> As shown in Figure 1, US coal production has trended downward since 2008, and total coal production fell by 23 percent from 2014 to 2017. However, the US Energy Information Administration (EIA) projects that the recent decline in coal production will stabilize absent new regulation (EIA 2019b).

Wyoming, Montana, Colorado, and Utah collectively account for 94 percent of coal mined on federal and Indian lands (Table 1). The single largest basin for US coal production is the Powder River Basin (PRB) in Wyoming and Montana (Figure 1). In 2017, 88 percent of coal mined on federal lands was produced in these two states.<sup>15</sup>

Powder River Basin coal is primarily low-sulfur subbituminous coal. PRB coal enjoys a considerable price advantage over coal from other basins, especially Appalachia. For example, in 2017, the average price of coal sold at the mine was \$13 per short ton in Wyoming, \$52 in Kentucky, and \$82 in southern West Virginia (EIA 2018, Table 28). One reason for this difference in prices is extraction costs. Most Eastern coal is mined underground, which is labor intensive: average productivity for West Virginia mines in 2017 was 3.0 short tons per worker-hour. In contrast, PRB coal is surface-mined using massive dragline excavators, and in 2017

<sup>11</sup> For more details on the federal coal program, see US DOI (2013) and Council of Economic Advisers (2016).

<sup>12</sup> Total production in 2017 was 774.6 million short tons (US Energy Information Administration (US EIA) 2018, Table ES1). Federal coal production in 2017 was 326 million short tons (US Office of Natural Resources Revenue Form ONRR-4430, accessed via <https://revenuedata.doi.gov/explore/#federal-production>).

<sup>13</sup> US Energy Information Administration (2018, Table 26).

<sup>14</sup> US Energy Information Administration (2019a, Table 12.1).

<sup>15</sup> Coal production on federal lands in Wyoming and Montana in 2017 was 273 and 14 million short tons (US Office of Natural Resources Revenue Form ONRR-4430, accessed via <https://revenuedata.doi.gov/explore/#federal-production>).

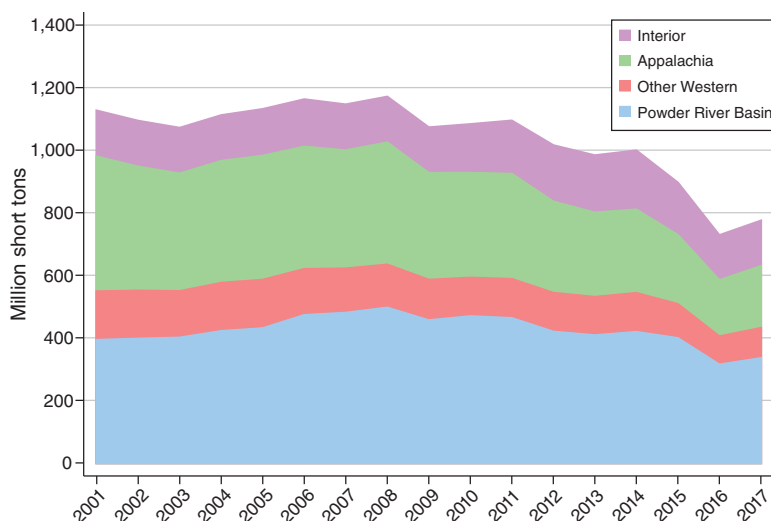


FIGURE 1. US COAL PRODUCTION BY REGION, 2001–2017

Source: US Energy Information Administration

TABLE 1—ANNUAL FEDERAL AND NONFEDERAL COAL PRODUCTION (MILLIONS OF SHORT TONS)

State	Total, 2013	Total, 2014	Federal only, FY2014	Federal percent
Wyoming	388	396	337	86%
Montana	42	45	27	61%
Colorado	24	24	17	71%
Utah	17	18	14	79%
Other	512	516	26	5%
Total	983	998	421	42%

Notes: Federal percent is computed as the ratio of FY production to the weighted average of calendar year 2013 and 2014 production, weighted by the fraction of the calendar year in the fiscal year. Excludes refuse recovery.

Source: US EIA (2015b, 2016)

produced 26.8 short tons of coal per worker-hour—an order of magnitude higher than Appalachian coal mines.<sup>16</sup> Another, quantitatively less important reason for the difference is that coals differ in their thermal content, and central Appalachian coal has about 40 percent more thermal energy per ton than does PRB coal.

*Federal Leasing Program.*—Federal revenues from its coal leases derive from three sources: land rental payments, which are negligible (\$3/acre annually), bonus bids from auctions of the right to mine coal on a given tract, and royalties paid as a fraction of the price of the coal at the mine.

Federal coal lease auctions have little competition. According to the Government Accountability Office (GAO 2013), from 1990 to 2013, DOI leased

<sup>16</sup>Source for the productivity data is EIA, Coal Data Browser at <http://www.eia.gov/beta/coal/data/browser/>.



107 coal tracts, of which 96 had a single bidder. The Bureau of Land Management (BLM) sets a confidential minimum value for the bonus bid for a tract, however through repeated interactions, bidders can estimate BLM bonus bid floors.<sup>17</sup> From 2006–2015, the average bonus bid in the PRB was \$0.91 per ton of recoverable reserves. As a practical matter, encouraging competitive bidding in the PRB is difficult because new tracts are typically nominated by the mining companies and are extensions of existing mines, and the fixed cost of a competitor setting up a new dragline are prohibitive compared with the existing mine operator following the seam onto the new tract using its existing dragline. The 1976 Federal Coal Leasing Act Amendments require competitive bidding in coal-producing regions; however, the BLM has decertified the PRB as a coal-producing region, thereby exempting the PRB from this requirement (Squillace 2013).

The DOI collects royalties on production of coal and other minerals on federal land and forwards approximately half of these royalty revenues to states. The DOI has broad statutory discretion in setting royalty rates for new or renewed leases, although they cannot be changed on existing leases.<sup>18</sup> The minimum royalty rate on surface-mined coal is 12.5 percent of the sales price by law, and the royalty rate on underground mines was set by regulation at 8 percent in 1990. The BLM typically sets royalties at the minimum rate prescribed by law (US GAO 2013) and frequently exercises its authority to issue partial royalty waivers. Reviews by the US government suggest that actual royalty payments are further reduced by failure to report coal prices accurately (US GAO 2013, US DOI 2014). Headwaters Economics (2015a) estimates the effective royalty rate on federal coal to be as low as 5 percent.<sup>19</sup> In 2016, the DOI finalized a rule reforming the computation of royalties to require, among other things, that the royalty be based on the first arms-length transaction,<sup>20</sup> however this rule was repealed by the Trump administration in 2017.<sup>21</sup>

The federal government holds most but not all of the mineral rights in the PRB. State, tribal, and private mineral rights are typically checkerboarded inholdings surrounded by land with federal rights.<sup>22</sup> When coal seams cross property boundaries, mines are consolidated into an officially designated “logical mining unit” that allows for continuity of operations across the federal and nonfederal tracts.

Federal coal leases cover an initial period of 20 years and are thereafter subject to renewal every 10 years. Figure 2 presents the cumulative distribution of lease expiration dates, based on BLM data compiled by Headwaters Economics (2015b), both

<sup>17</sup> For example, Cordero Mining (Cloud Peak) nominated a 446-acre tract adjacent to the Cordero-Rojo mine for leasing. In the October 2007 sale, the firm offered a bonus bid of \$0.38/ton, which was rejected. In March 2008, they offered \$0.80/ton for the same tract, which was also rejected. In January 2009, they made a third offer for the same tract, \$0.88/ton, which was accepted. In the accepted bid, Cordero Mining was the sole bidder; data are not available on the number of bidders for the failed bids.

<sup>18</sup> Title 30, Section 207(a) of the US Federal Code states conditions on federal leases; also see Krupnick et al. (2015).

<sup>19</sup> As discussed in CEA (2016), coal companies use various methods to achieve these low effective rates. For example, some sales are to subsidiaries of the parent mining company, which resell the coal with a substantial marketing markup; the parent company uses the sales price to its subsidiary to compute royalties.

<sup>20</sup> [http://onrr.gov/laws\\_r\\_d/fnotices/pdfdocs/433530.pdf](http://onrr.gov/laws_r_d/fnotices/pdfdocs/433530.pdf).

<sup>21</sup> <https://www.federalregister.gov/documents/2017/08/07/2017-16571/repeal-of-consolidated-federal-oil-and-gas-and-federal-and-indian-coal-valuation-reform>.

<sup>22</sup> See Luppens et al. (2015), Figure 20 for a map of PRB mineral rights.

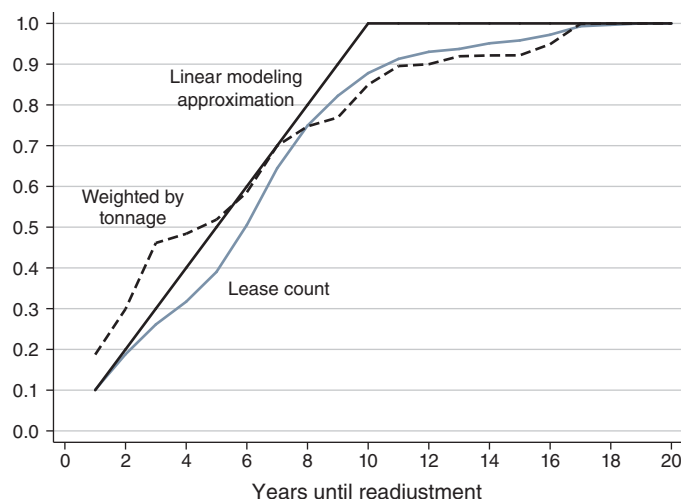


FIGURE 2. FEDERAL LEASE RENEWAL PROFILE AS OF JANUARY 2016

*Notes:* The chart plots the cumulative distribution of years until lease readjustment (typically renewal), as of January 1, 2016, for all federal leases in Wyoming, Montana, Colorado, and Utah (surface and underground combined). The linear modeling approximation is discussed in Section IIIC.

*Source:* Headwaters Economics (2015b) and authors' calculations

by lease count (unweighted) and weighted by the tonnage of the original lease. The piecewise linear approximation in the figure is discussed in Section IIIC.

### B. Power Sector CO<sub>2</sub> Emissions Regulation under the Clean Air Act

A 2007 US Supreme Court ruling, combined with the EPA's 2009 finding that greenhouse gases endanger public health and welfare, require EPA to regulate greenhouse gas emissions.<sup>23</sup> In 2015, EPA finalized the Clean Power Plan (CPP), which used Section 111 of the Clean Air Act to regulate CO<sub>2</sub> emissions from the power sector.<sup>24</sup> The Trump administration withdrew the CPP and proposed to replace it by the ACE, however that action too could be reversed by a future administration. Because our simulations use the CPP as the template for downstream regulation, we briefly describe the CPP here.

The CPP was structured around state emissions targets specified by the EPA; implementing those targets was left to the states, as dictated by the Clean Air Act. States' implementation options included both a mass-based and a rate-based approach. The mass-based approach is a cap-and-trade system in which states are provided with a CO<sub>2</sub> emissions mass cap (tons CO<sub>2</sub> annually) that must be achieved

<sup>23</sup> For the legal history of greenhouse gas regulation under the Clean Air Act, see National Association of Clean Air Agencies (2011).

<sup>24</sup> The CPP has been extensively described elsewhere; see the Congressional Research Service summary by Ramseur and McCarthy (2016) and the 2015 EPA summary of the final rule (archived at [https://19january2017snapshot.epa.gov/cleanpowerplan/fact-sheet-overview-clean-power-plan\\_.html](https://19january2017snapshot.epa.gov/cleanpowerplan/fact-sheet-overview-clean-power-plan_.html)). The CPP final rule is published in the Federal Register, vol. 80, No. 205, 64661–65120. The state plan options are summarized on pages 64, 832–64, 843.



by 2030. The mass cap applies to existing fossil fuel sources, with the exception of simple-cycle natural gas combustion turbines (peakers) and small units.<sup>25</sup> EPA provided the option of including new sources under this trading cap (“compliance option 1”), in which case the cap is increased.<sup>26</sup> Under the rate-based approach, states were provided with a rate cap (pounds CO<sub>2</sub> per MWh) for existing sources. New and modified fossil-fuel generators are excluded from this cap and are regulated instead under the new source performance standard, and peakers and small units are not regulated. States with rate-based regulation are encouraged to participate in multistate trading pools, as are states with mass-based regulation, but trading is not allowed between mass and rate systems.

The CPP has several possible sources of leakage, depending on the details of the implementation. Small units and peakers are exempted, although together these generators comprise a small fraction of total emissions. Both rate and mass implementations have potential leakage through exports: the CPP reduces demand for coal and thus its price, making US coal more competitive abroad. As discussed in Bushnell et al. (2015), there is also leakage arising from cross-state electricity sales under rate-based regulation and in mixed mass- and rate-based systems.

## II. Comparative Statics of Partial Upstream and Downstream Regulation

We begin our analysis of the effects of a carbon surcharge on federal coal with a static partial equilibrium analysis of electricity production. We examine the effect of the surcharge on the electricity price, production by source, total electricity production, emissions, and the price of tradable emissions permits. The static analysis in this section serves to develop intuition for understanding the more complicated results from the dynamic IPM model presented below.

In our static model, electricity can be generated by federal coal, by nonfederal coal, or by other sources. Federal and nonfederal coal are assumed to have the same CO<sub>2</sub> emissions rate per MWh of generation, whereas the other sources are assumed to have a lower emissions rate (e.g., combined cycle natural gas). To allow for downstream regulation with partial coverage, we introduce a fourth unregulated generation source that has an emissions rate lower than coal but possibly different than other covered sources (for example, simple-cycle combustion turbines). Once generated, electricity is treated as homogeneous.

Analytic results for the model are provided in online Appendix A. Here, we summarize those results in the four diagrams in Figure 3, which depict supply and demand for electricity under various special cases of the results in online Appendix A. The carbon surcharge on federal coal is denoted by  $r$ , which we treat as shifting supply up by  $r$ .<sup>27</sup>

<sup>25</sup> Units with capacity less than 25 MW, modified units, and some other units are also excluded (see 80 FR 64716).

<sup>26</sup> Because new sources are regulated under §111(b) of the Clean Air Act and existing sources are regulated under §111(d), the EPA cannot compel states to create a mass cap that covers both existing and new sources. Compliance option 1 in the final rule envisions that states adopt additional legislation or regulation that allows them to place both existing and new sources under the same mass cap and, if that is done, expands the mass cap to include new sources.

<sup>27</sup> We abstract from the upstream coal market for simplicity but assume throughout that an increase in the per-ton coal royalty will (weakly) increase prices for coal mined under federal leases. In the case of a perfectly

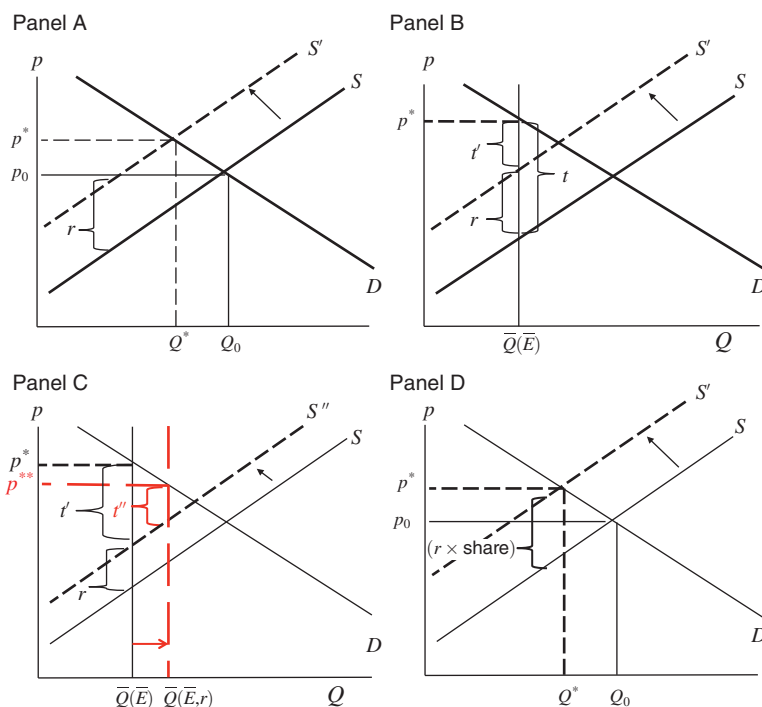


FIGURE 3. ELECTRICITY SUPPLY AND DEMAND:  
INTERACTION OF CARBON SURCHARGE WITH DOWNSTREAM REGULATION

Notes: Panel A: only fuel is federal coal. Carbon surcharge  $r$ , no emissions regulations. Panel B: only fuel is federal coal. Carbon surcharge  $r$ , mass-based cap-and-trade with emissions cap  $\bar{E}$  and tradable permit price  $t$ . Panel C: fuels are natural gas and federal coal. Carbon surcharge  $r$  on federal coal, mass-based cap-and-trade with emissions cap  $\bar{E}$  with tradable permit price  $t$ . Panel D: fuels are natural gas and federal coal. Carbon surcharge  $r$  on federal coal, rate-based emissions regulation with tradable allowances.

When federal coal is the only fuel and there is no downstream regulation, the royalty surcharge is equivalent to a carbon tax. In this familiar case, under a royalty surcharge the price of electricity rises, the quantity demanded falls, and emissions fall (Figure 3, panel A).

Figure 3, panel B depicts one fuel, federal coal, with a binding mass-based emissions limit  $\bar{E}$  and a system of tradable allowances. Because there is only one source, the emissions limit implies a binding generation limit  $\bar{Q}(\bar{E})$ . Without a royalty surcharge, the allowance price  $t$  is the difference between the demand and supply prices at  $\bar{Q}(\bar{E})$ . When the surcharge  $r$  is introduced, the supply curve shifts up by  $r$ ; as long as the cap still binds, however, production, price, and emissions remain unchanged. The price of the tradable allowance falls one-for-one with the royalty surcharge, so that the new allowance price is  $t' = t - r$ . Thus, compliance cost of the cap-and-trade system is partially shifted to the royalty surcharge. If the carbon surcharge is sufficiently large

competitive upstream coal market with infinitely elastic supply and homogeneous generation and transportation costs,  $r$  would be equal to the royalty surcharge in \$/MWh. Alternatively,  $r$  can be thought of as the royalty surcharge if it were charged directly to electricity generators (rather than mines).

that  $r > t$ , then the cap and trade system ceases to bind and the binding policy is the carbon surcharge. Because federal coal is the only fuel, this situation is the same as the familiar case of a carbon tax coexisting with a cap-and-trade system.

The comparative statics become more interesting when generation can also be from natural gas, which has lower emissions than coal and which is not subject to the royalty surcharge. Figure 3, panel C considers this case with a binding cap-and-trade emissions limit  $\bar{E}$ . Again, the royalty surcharge shifts up the electricity supply curve. But because federal coal becomes relatively more expensive, firms shift generation from federal coal to gas. Because gas has a lower emissions rate than coal, this shift in the generation mix increases total generation for a given binding emissions cap. The price of electricity falls to clear the market. The allowance price falls by more than it would were there no shift from coal to gas, in fact it falls by more than does the electricity price. If the royalty surcharge increases sufficiently, then the supply curve shifts to the point that the cap-and-trade system is no longer binding.

The situation under rate regulation is different (Figure 3, panel D). Under an emissions rate regulation, the emissions per MWh is fixed. In a system with only gas and coal, this fixes the shares of gas and coal in the system independent of the level of production. With these fixed shares, a royalty surcharge increases the price of coal generation by  $r$ , which shifts the supply curve up by  $r$  times the (fixed) share of federal coal. Thus, the royalty surcharge increases the price and reduces total generation and (because of fixed shares) reduces emissions. Under the rate standard, the tradable permits serve to equate the marginal costs of coal and gas generation. With the introduction of the royalty surcharge, the gap between these marginal costs falls, so the price of the tradable permit falls. However, this change in the permit price is a net-zero transfer between coal and gas generation and does not affect the weighted average marginal cost of electricity; thus, it does not have an additional effect on price, generation, or emissions. At a sufficiently high level of the royalty surcharge, the higher cost of coal pushes the coal share below that implied by the rate standard; at this point, the rate standard no longer binds and emissions fall further because of fuel shifting and higher prices.

The model in online Appendix A additionally allows for nonfederal coal and for uncovered sources. If there is nonfederal coal, then the upward shift in the supply curve is less than depicted in Figure 3 because of substitution of nonfederal for federal coal, however the qualitative comparative statics are the same. In particular, without downstream regulation (or if the downstream regulation is not binding), emissions fall under a royalty surcharge both because of substitution toward gas and because of higher electricity prices; the magnitude of this fall depends on how much nonfederal coal is substituted for federal coal.

If there are sources not covered by downstream regulation, then the effect of the carbon surcharge depends on the case. If the electricity price falls (rises) with the surcharge, then the return from uncovered generation falls (rises) and uncovered generation decreases (increases). The royalty surcharge therefore decreases leakage in a binding mass-based system with uncovered sources.

Finally, we note that the comparative statics shown in these figures are the same if federal coal generation (i.e., the mining of federal coal) is subject to a quantity limit. A quantity limit for federal coal that induces a given value  $r$  of the shadow

price shifts up the electricity supply curve by the same amount as would imposing a royalty surcharge of that value.

### III. The Integrated Planning Model and Research Design

We use ICF International's Integrated Planning Model (IPM) to obtain quantitative estimates of the effects of implementation of various possible reforms to the federal coal program.

#### A. The IPM

The IPM is a disaggregated dynamic perfect-foresight optimization model of the US electric power sector.<sup>28</sup> The IPM combines plant-level information on existing and potential future electricity generating units, regional fuel supply curves based on engineering and geological data, and existing and potential fuel transportation networks to compute the least-cost way to meet regional and national electricity demand. Stated in terms of supply and demand, IPM uses engineering (not economic) fuel supply curves, and fuel demand is computed endogenously by linear programming minimization of the net present value of production costs optimized over fuel supply, transportation, dispatch, and construction and retrofit options, subject to meeting fixed regional electricity demand, reliability, and environmental regulatory constraints.

The fuel supply sector consists of supply curves based on geological assessments using private and public data. In the case of coal, mine-level supply curves are aggregated to 36 coal supply regions and 14 coal qualities, which vary by heat content, sulfur content, mercury content, and other characteristics. A given region can have multiple supply curves, one for each local coal quality. IPM has 81 natural gas supply regions (including conventional and unconventional) and 15 liquefied natural gas (LNG) import facilities. Other fuels include fuel oil, nuclear, biomass, and waste.

The electricity generating sector uses these fuels at model plants, which are constructed using a database of existing plants. The model plants are either individual plants or a composite of technologically similar co-located existing plants. For example, there were 937 coal steam plants in the full existing plant database at the time of our simulations, which were aggregated to 732 model plants. The electricity sector includes all generation units (hydro, solar, imports, etc.).

The transportation sector differs by fuel. For coal, the available transportation modes are rail, barge, truck, ship, and conveyor belt. For a given coal supply region/model plant route, which modes are available depends on physical conditions. Each mode is treated as having a cost per ton-mile and a loading/offloading cost. The cost per ton-mile varies by distance shipped and, for rail, whether there are multiple rail carriers or a single carrier servicing the route (this recognizes the lack of competition

<sup>28</sup>The simulations in this paper use IPM version v.5.15. Full IPM documentation for version v.5.13, and documentation of incremental changes from v.5.13 to v.5.15, are available at <https://www.epa.gov/airmarkets/power-sector-modeling>.

in the rail sector). For natural gas, IPM incorporates existing pipelines and hubs and allows for pipeline expansions and, along certain corridors, new pipelines.

The IPM is closed by a multiyear perfect foresight minimization of discounted electricity production costs by linear programming. Following EPA's use of the IPM in the CPP Regulatory Impact Analysis (RIA), demand for electricity is specified exogenously and is fixed. Optimization is over which fuel is used at which plant, transported by which method, subject to meeting regional demand, capacity, environmental, and other physical constraints. The model can build new capacity in the form of specific generators or gas pipelines, and can retrofit existing generators. For example, the model will retrofit an existing coal plant that burns low-sulfur PRB coal to burn higher-sulfur Eastern coal with a scrubber, if that option is technologically feasible and least-cost. The version of IPM used here allows CO<sub>2</sub> regulation using state-level mass caps or rate standards with regional trading.

*Relevant Predictions of the IPM.*—The IPM is a complex structural model with many parameters, and it is important to assess whether results from the IPM are credible before using them to understand and inform future policy. Two recent studies that are closely related to the topic of this paper suggest they are. First, a recent ex post analysis of coal plant retirements corroborates the ex ante predictions of the IPM. In 2011, the EPA used the IPM to estimate that the Mercury and Air Toxics Standards (MATS) would lead to 4.7 gigawatts (GW) of coal power plant retirements (US EPA 2011). The MATS rule had been long delayed and the timing of its announcement, as well as its details, were unexpected. The proposed rule, comment period, and final rule all fell between the EIA's annual survey of generators, which asks, among other things, about retirement plans. Coglianese, Gerarden, and Stock (forthcoming) exploits this timing to conduct an ex post event study analysis (i.e., a difference-in-differences controlling for coal and gas price changes) to quantify the impact of the MATS rule using data on coal plant retirements planned for the effective date of the rule. They estimate that the MATS rule led to a planned reduction in coal power plant capacity of 5.2 GW, only slightly greater than the IPM estimate.

A second piece of evidence comes from Jordan, Lange, and Linn's (2018) econometric study of historical coal mine closures. They find that federal coal from the Powder River Basin and nonfederal coal from Appalachia are weak substitutes. Their estimates are short-run responses, and are smaller than the longer run responses estimated here, which allow for plant conversion between PRB and non-PRB coal.<sup>29</sup>

## B. Base Cases

The six base cases used in this study use two sets of underlying economic assumptions and three sets of CO<sub>2</sub> regulatory assumptions.

*Economic Assumptions.*—The primary base case approximates the economic assumptions in the EPA's final Regulatory Impact Analysis of the Clean Power Plan

<sup>29</sup> Because PRB coal is more friable and liable to spontaneous combustion than Eastern coal, coal handling and burner machinery differ for PRB and non-PRB coal (Khambekar and Barnum 2013).

(US EPA 2015). The secondary base case employs the same assumptions concerning total demand and energy efficiency, but has different fuel cost assumptions than the primary base case, mainly lower costs of coal and higher costs of renewables.<sup>30</sup> The secondary base case provides a sensitivity check. The policy and legal assumptions for both the primary and secondary base cases are those of October 2015 upon the publication of the CPP final rule. In particular, in all cases, regional power sector emissions programs remain in place, as do regional clean energy standards, renewable portfolio standards, etc. Coal export terminal capacity is frozen at current levels. Because of limitations of the IPM, total national coal exports were exogenously set to EIA Annual Energy Outlook projections.<sup>31</sup>

*Assumptions about CPP Implementation.*—We consider three variations of power sector regulation under the Clean Air Act:

- (i) “No CPP”: no federal power sector CO<sub>2</sub> emissions regulation. Electricity demand projections are from the 2015 Annual Energy Outlook (US EIA 2015a).
- (ii) “CPP-mass” assumes that all states use mass-based standards with regional emissions allowance trading to comply with the CPP. The CPP-mass scenario covers existing and new fossil fuel sources, with the exception of the exempted sources discussed in Section IB. The mass-based scenario is Compliance Option 1 in the CPP final rule, in which the mass cap is extended by state legislation or regulation to cover both existing and new sources.<sup>32</sup> In its RIA for the final CPP rule, EPA made an exogenous downward adjustment to energy demand to reflect energy efficiency induced by the CPP. For comparability, the CPP-mass base case electricity demand projections are from the 2015 Annual Energy Outlook (US EIA 2015a), exogenously adjusted down by the EPA’s energy efficiency estimates.
- (iii) “CPP-rate” assumes that all states use CPP rate-based standards with regional trading as the compliance mechanism.<sup>33</sup> Rate-based regulation excludes all new and modified fossil sources, although those new sources must meet the new and modified source standards under §111(b). Electricity demand projections are the same as in the CPP-mass base case.

<sup>30</sup>The primary base case uses the publicly available assumptions of EPA Base Case v.5.15, which was used in the final CPP RIA. The secondary base case uses load growth and natural gas production assumptions from EPA Base Case v.5.15, with other cost assumptions taken from EPA Base Case v.5.13, which was used in the June 2014 draft CPP RIA; however, the coal supply curves for the alternative base case were based on ICF internal assumptions and have lower costs than EPA’s v.5.15.

<sup>31</sup>Most US coal exports are metallurgical coal (US EIA 2018). In 2017, Montana and Wyoming together exported 4 million tons of coal (all steam coal), all through West Coast coal export terminals. The capacity at those terminals is limited and constrains access of PRB coal to Asia. There are proposals for new or expanded export terminals, but all face considerable local opposition. The mix of exports was solved endogenously based on regional prices subject to fixing total exports. As discussed in Section VB, exogenously fixing total exports is a conservative assumption from the perspective of modeling the effect of the royalty surcharge, holding constant the CPP scenario.

<sup>32</sup>The state caps used in the simulations are the “new source complements” in Table 14 (80 FR 64888).

<sup>33</sup>The state rate-based standards are the emissions performance goals in the final rule, Table 12 (80 FR 64824).



The allowance trading regions are the six regions used in the EPA's RIA of the CPP proposed rule.<sup>34</sup>

### *C. Policy Scenarios*

The policy scenarios incorporate royalty surcharges assessed at the mine in dollars per short ton of coal. The results presented here calibrate the royalty surcharges to 20 percent, 50 percent, and 100 percent of the US government's central estimate of the SCC.<sup>35</sup> The effect of each of these policy scenarios was assessed separately against the primary and secondary base cases. These surcharges are assessed on top of the existing ad valorem federal royalty rate of 12.5 percent.

The surcharge was incorporated into the IPM by modifying the mine-level supply curves. For a mine that produces solely federal coal, this modification entails shifting the supply curve up by the per-ton surcharge. For mines that have both federal and nonfederal coal, the surcharge was computed using current practice for assessing federal royalties, that is, for the logical mining unit in proportion to its fraction of coal resources.<sup>36</sup> State and private royalty rates are modeled as remaining unchanged if federal royalties are increased to incorporate a royalty surcharge. The adjusted mine-level engineering supply curves were aggregated in the IPM coal supply module to regional supply curves.

Royalties can only be changed when leases come up for renewal or for new leases. It was infeasible to incorporate mine-level renewal decisions within the IPM, so instead we modeled this restriction as phasing in the royalty surcharge linearly for all leases, ramping up over a ten-year period from 2016 to 2026. As seen in Figure 2, this linear schedule approximates the actual lease expiration date distribution. The values of the royalty surcharge on federal coal, adjusted for the ten-year phase-in and computed for typical PRB subbituminous coal, are given in Table 2. This schedule in Table 2 was adjusted at the mine level to reflect the fraction of coal in each logical mining unit, at each step in the mine supply curve. Because the SCC schedule varies over time and the surcharge is ramped up over ten years, the regional

<sup>34</sup>The six regions are: West (WECC), North Central (MRO), South Central (SPP + ERCOT), Southeast (SERC + FL), East Central (RFC), and Northeast (NPCC). These regions are state-level aggregates constructed to encompass the NERC interconnection regions in parentheses. See US EPA (2014), Figure 3-3 for which state is in which region.

<sup>35</sup>The SCC is the monetized present value of damages from emission of an additional metric ton of CO<sub>2</sub>. The US government estimate of the SCC used here is the November 2013 update (US IWG on Social Cost of Carbon 2013). There is significant variation in estimates of the SCC around this central estimate, which is constructed by averaging estimates of the SCC from three different integrated assessment models using five reference scenarios and a discount rate of 3 percent. Alternative discount rates and summary statistics presented in US IWG on Social Cost of Carbon (2016) range from under one-third to over five times the central estimate during the time period we study.

<sup>36</sup>We consulted industry experts as to whether a large royalty surcharge would incentivize mining only the state and private inholdings and were advised that even at high royalty rates this would not be economically feasible given the large fixed cost of dragline mining and the relatively small size of each inholding. Furthermore, Haggerty, Lawson, and Percy (2015) reports that states in which mineral rights ownership is predominately federal—including Colorado, Montana, and Wyoming, which comprise 90 percent of coal mined on federal and Indian lands—usually adopt federal rules and royalty policies on state land. Even if this practice were to change in response to the royalty surcharge, as our modeling approach assumes in order to be conservative, there is limited potential for substitution from federal to nonfederal coal within a mine or even within a state or basin: in the four Western states that comprise 94 percent of all coal mined on federal and Indian lands, 82 percent of all production occurs on those federal and Indian lands (calculated using numbers in Table 1).

TABLE 2—SIMULATED PHASED-IN ROYALTY SURCHARGES FOR FEDERAL COAL INDEXED TO SCC WITH 10-YEAR LINEAR PHASE-IN (US 2012 DOLLARS)

Year	20% SCC	50% SCC	100% SCC
2016	\$1.47	\$3.68	\$7.37
2018	\$4.65	\$11.63	\$23.27
2020	\$8.34	\$20.84	\$41.68
2025	\$18.22	\$45.56	\$91.12
2030	\$20.16	\$50.41	\$100.82

Notes: Computed for subbituminous coal (heat content 9,130 Btu/lb). The SCC is the 2013 US government estimate (IWG on SCC 2016).

supply curves are actually a sequence of supply curves over time that incorporate the time-varying royalty surcharge.

We also consider two policy cases that provide quantitative limits on coal production. The first, “No New Permits or Renewals,” models making the moratorium on federal coal leasing permanent. The second, “50 percent Cap,” constrains total PRB production to be 50 percent its level in 2013. Both quantity restriction policies are phased in over 20 years.<sup>37</sup>

Following the EPA’s CPP RIA, electricity demand is exogenous and fixed across all policy cases to match the respective base case. These demand levels were set by EPA outside the IPM using additional modeling and judgement about energy efficiency improvements under the CPP. In general, this implies that changes due to the royalty surcharge can be compared to the corresponding CPP case without a surcharge, but results are not necessarily comparable across CPP base cases because of different demand and energy efficiency assumptions.

#### IV. IPM Results

This section summarizes the IPM results on wholesale electricity and tradable permit prices, fuel substitution, total emissions, abatement costs, and royalties. We focus on results for 2030 because it is the full compliance deadline for the CPP and the modeled royalty surcharge would be fully phased in. Prices and costs are in 2012 dollars.

##### *A. Electricity and Allowance Prices*

Generation-weighted national average wholesale electricity prices in 2030 are shown in Figure 4 as a function of the royalty surcharge for the three CPP implementation cases. In this and subsequent figures, the horizontal axis is the royalty surcharge

<sup>37</sup> For the “No New Permits or Renewals” scenario, it was assumed that commingled mines would cease production as it would not be economically or technically feasible to extract only nonfederal coal. The “50 percent Cap” scenario could be implemented by administrative means or by a market mechanism (tradable extraction permits), but we do not model those details.

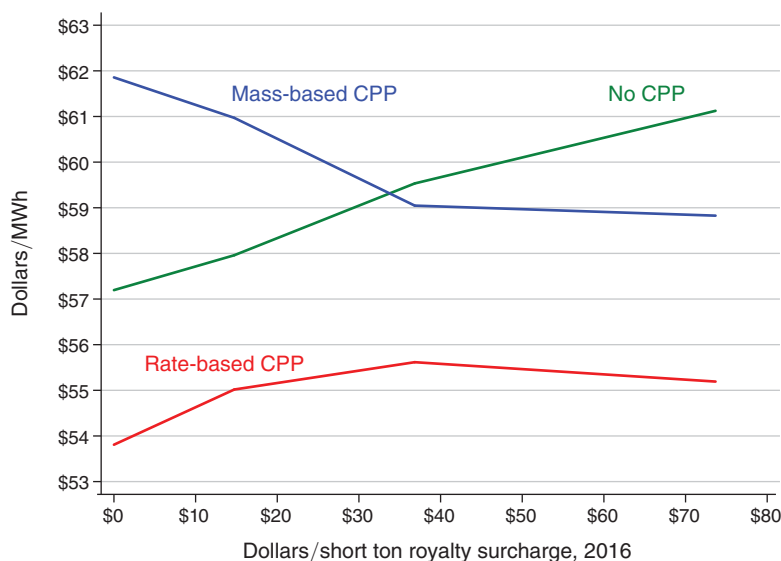


FIGURE 4. WHOLESALE ELECTRICITY PRICES IN 2030 (NATIONAL AVERAGE): EFFECT OF FEDERAL COAL ROYALTY INCREASE UNDER VARIOUS CLEAN POWER PLAN IMPLEMENTATIONS

*Notes:* The lines present the average wholesale price of electricity in 2030 under the no CPP, mass-based CPP, and rate-based CPP case, in 2012 dollars. The horizontal axis is the dollar value of the relevant percent of the SCC in 2016, in 2012 dollars.

*Source:* Based on IPM simulations by ICF

for a new lease issued in 2016 (in 2012 dollars/short ton).<sup>38</sup> Figure 5 plots tradable allowance prices for the regions in which they are nonzero: south central, east central, the Southeast, and north central regions.<sup>39</sup> Values of these prices are given in Table 3.

In the no-CPP case, a royalty surcharge increases fuel prices and consequently increases wholesale electricity prices. Wholesale electricity prices rise by 7 percent under the no-CPP/100 percent SCC case relative to the no-CPP/no-surcharge case. Note that this increase would be less, were electricity demand endogenous.

In the mass-based CPP case, including a royalty surcharge results in a decline in wholesale power prices and tradable allowance prices. This finding in IPM accords with the static model.<sup>40</sup> The amount of the decline in the permit price varies regionally under the regional trading regime, depending on the amount of federal

<sup>38</sup> As discussed in Section III, turnover of new leases subject to the royalty surcharge is modeled as ramping in linearly over 10 years and increasing according to the SCC schedule.

<sup>39</sup> Allowance prices for the Northeast are zero in all cases with the CPP. In the West, allowance prices are less than \$5 under the mass-based CPP, and zero under the rate-based CPP, with no royalty surcharge, and they are zero in all CPP cases with positive royalty surcharges.

<sup>40</sup> The strong form of the comparative static for electricity prices we derive in online Appendix A—that the price of electricity is strictly (not weakly) decreasing in the royalty surcharge—holds even with perfectly inelastic electricity demand, provided that the supply curve of other sources of electricity generation is strictly upward sloping. This can be seen graphically in Figure 3, panel C by thinking of the downward sloping demand curve as not market demand but instead residual demand for electricity from natural gas and federal coal, after accounting for the supply of unregulated sources (renewables and unregulated fossil fuel generators).

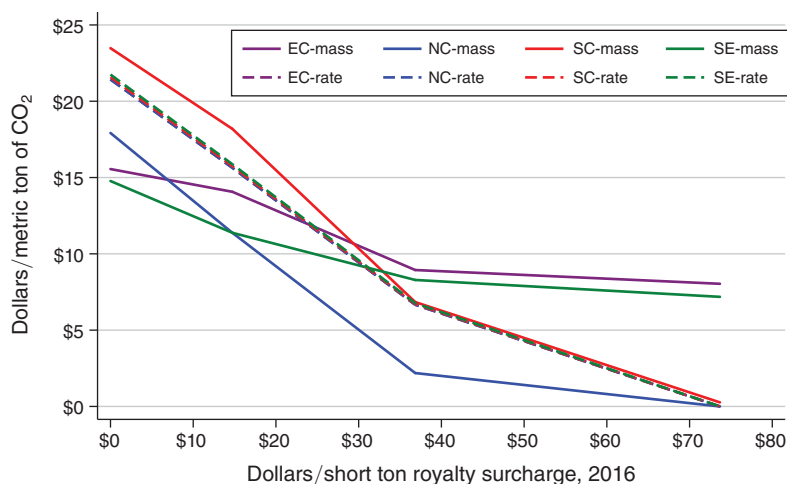


FIGURE 5. TRADABLE ALLOWANCE PRICES IN 2030: EFFECT OF FEDERAL COAL ROYALTY INCREASE UNDER VARIOUS CLEAN POWER PLAN IMPLEMENTATIONS

*Notes:* EC = East Central, NC = North Central, SC = South Central, SE = Southeast. The lines present the prices of tradable allowances in 2030 by trading region under the no CPP, mass-based CPP, and rate-based CPP case, all in 2012 dollars. Prices for the Northeast in 2030 are zero in all cases, and in the West are less than \$5, and are not shown. The horizontal axis is the dollar value of the relevant percent of the SCC in 2016, in 2012 dollars.

*Source:* Based on IPM simulations by ICF

TABLE 3—IPM RESULTS: ELECTRICITY AND ALLOWANCE PRICES

Case	Electricity price (\$/MWh)	CO <sub>2</sub> allowance prices (dollars/MT CO <sub>2</sub> )					
		East Central	North Central	Northeast	South Central	Southeast	West
No CPP, no royalty surcharge	57.20						
No CPP, 20% SCC	57.96						
No CPP, 50% SCC	59.53						
No CPP, 100% SCC	61.12						
CPP mass case, no surcharge	61.86	15.56	17.92	0	23.48	14.77	4.27
CPP mass case with 20% SCC	60.97	14.07	11.38	0	18.19	11.38	0
CPP mass case with 50% SCC	59.05	8.94	2.19	0	6.84	8.29	0
CPP mass case with 100% SCC	58.83	8.04	0	0	0.27	7.18	0
CPP rate case, no surcharge	53.81	21.43	21.43	0	21.58	21.75	0
CPP rate case with 20% SCC	55.02	15.64	15.64	0	15.75	15.87	0
CPP rate case with 50% SCC	55.62	6.67	6.67	0	6.71	6.77	0
CPP rate case with 100% SCC	55.19	0	0	0	0	0	0

*Note:* Prices are 2012 dollars and are generation-weighted averages.

*Source:* IPM simulations by ICF and authors' calculations

coal used. In the Northeast and the West regions, for all values of the royalty surcharge, the tradable allowance price is zero, so the binding policy in those regions is the surcharge, not the CPP.

In the rate-based CPP case, a royalty surcharge increases the electricity price, as expected, although there is a slight drop in the wholesale price at the highest value

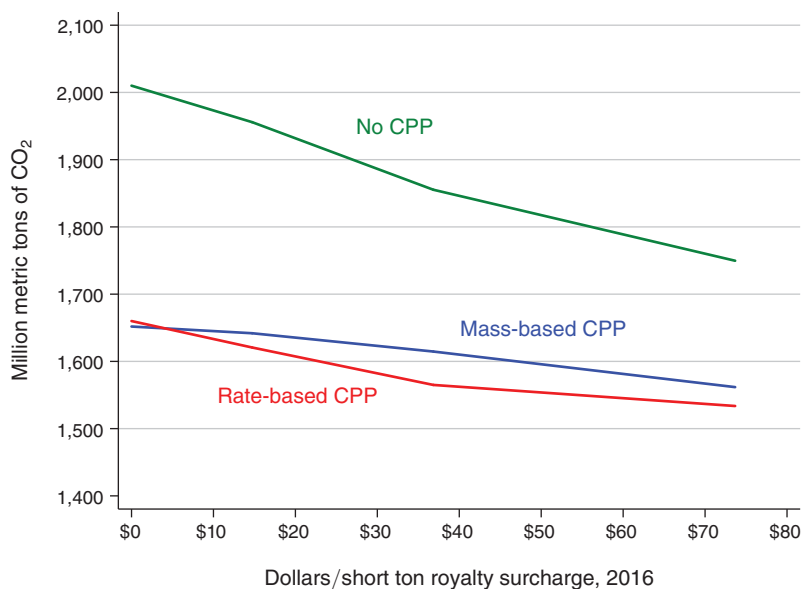


FIGURE 6. NATIONAL CO<sub>2</sub> EMISSIONS FROM THE POWER SECTOR IN 2030: EFFECT OF FEDERAL COAL ROYALTY INCREASE UNDER VARIOUS CLEAN POWER PLAN IMPLEMENTATIONS

*Notes:* The lines present power sector emissions in 2030 under the no CPP, mass-based CPP, and rate-based CPP case. The horizontal axis is the dollar value of the relevant percent of the SCC in 2016, in 2012 dollars.

*Source:* Based on IPM simulations by ICF

of the royalty surcharge. With a 100 percent SCC surcharge, the surcharge, not the CPP, is the binding policy in all regions.

### B. Emissions Reductions

Power sector CO<sub>2</sub> emissions are shown in Figure 6 and tabulated in Table 4 (the final columns of Table 4, abatement costs, are discussed in Section IVE). In all CPP cases, the royalty surcharge lowers 2030 CO<sub>2</sub> emissions. In the no-CPP scenario, the emissions reductions are large. Absent the CPP, the 100 percent SCC royalty surcharge on federal coal results in a 260 million metric ton (MMT) emissions reduction in 2030. This decline in emissions is 73 percent of the estimated 358 MMT reduction under the mass-based CPP (with no surcharge), relative to the no-CPP, no-surcharge base case.

Emissions also fall when a royalty surcharge is introduced under the mass-based CPP implementation, but the decline is much smaller than without downstream regulation. There are two reasons for these emissions reductions. First, as just discussed, the mass-based CPP is nonbinding in the Northeast, becomes nonbinding in the West with a 20 percent SCC surcharge, and becomes nonbinding in the north central with a 100 percent SCC surcharge. In those regions, the royalty surcharge is binding and spurs fuel switching, thereby reducing emissions just as if there were no downstream policy in place.

TABLE 4—IPM RESULTS: EMISSIONS AND ABATEMENT COSTS OF ROYALTY SURCHARGE

	CO <sub>2</sub> emissions in 2030 (MMT)	Emissions in 2030 relative to no CPP/no surcharge case		Cost per ton CO <sub>2</sub> avoided, relative to no-surcharge case within CPP implementation (US\$(2012)/MT)	
		MMT	Percent	2025	2030
No CPP, no royalty surcharge	2,010				
No CPP, 20% SCC	1,956	−54	−2.7%	\$31	\$39
No CPP, 50% SCC	1,855	−155	−7.7%	\$58	\$60
No CPP, 100% SCC	1,750	−260	−13.0%	\$56	\$63
CPP mass case, no surcharge	1,652	−358	−17.8%		
CPP mass case with 20% SCC	1,642	−368	−18.3%	\$67	\$126
CPP mass case with 50% SCC	1,615	−395	−19.7%	\$104	\$104
CPP mass case with 100% SCC	1,562	−448	−22.3%	\$90	\$85
CPP rate case, no surcharge	1,660	−350	−17.4%		
CPP rate case with 20% SCC	1,621	−389	−19.4%	\$33	\$24
CPP rate case with 50% SCC	1,565	−445	−22.1%	\$56	\$49
CPP rate case with 100% SCC	1,534	−476	−23.7%	\$64	\$55
Memo: SCC (US 2012 dollars)				\$51	\$57

*Notes:* Abatement cost is the increase in the total cost of power production, net of the federal royalty, relative to the zero-surcharge CPP case, as a ratio to emissions reductions. Prices are 2012 dollars. The SCC values in the memo line are the values for emissions in 2025 and 2030 in US 2012 dollars.

*Source:* IPM simulations by ICF and authors' calculations

Second, in regions where the CPP binds, the royalty surcharge leads to a decline in the electricity price, so uncovered sources produce and emit less. Put another way, the royalty surcharge lowers the tradable permit price, making the covered natural gas sources (existing and new natural gas combined cycle generators) relatively more attractive than uncovered sources (simple-cycle natural gas generators) at a given electricity price. Thus, new builds and generation are shifted from uncovered sources to covered sources and are brought under the mass cap, leading total emissions to fall.

The incremental emissions reductions from the royalty surcharge are larger under the rate than the mass-based CPP. One reason for this is that, at the 100 percent SCC surcharge, the rate-based CPP is not binding in any region, so the national binding policy is the surcharge; in the mass-based case, the surcharge is the binding policy at 100 percent SCC in only three regions. Second, even when each state's emission rate is binding at the CPP standard, the change in relative prices induces shifts in production across states, both within permit trading regions and across regions: because the relative price of coal generation increases with the surcharge, generation shifts from coal-using states (with high CPP rate standards) to states with renewable and gas generation. This compositional shift toward lower rate states further reduces emissions. Third, even when the CPP is binding, the royalty surcharge slightly reduces total electricity generation, so emissions fall.<sup>41</sup> The second and third channels are not present under the mass-based CPP.

<sup>41</sup> Although final electricity demand is constant, cross-region exports of coal-fired power declines, reducing transmission losses, and more hydropower is imported from Canada; the decline in generation reduces emissions



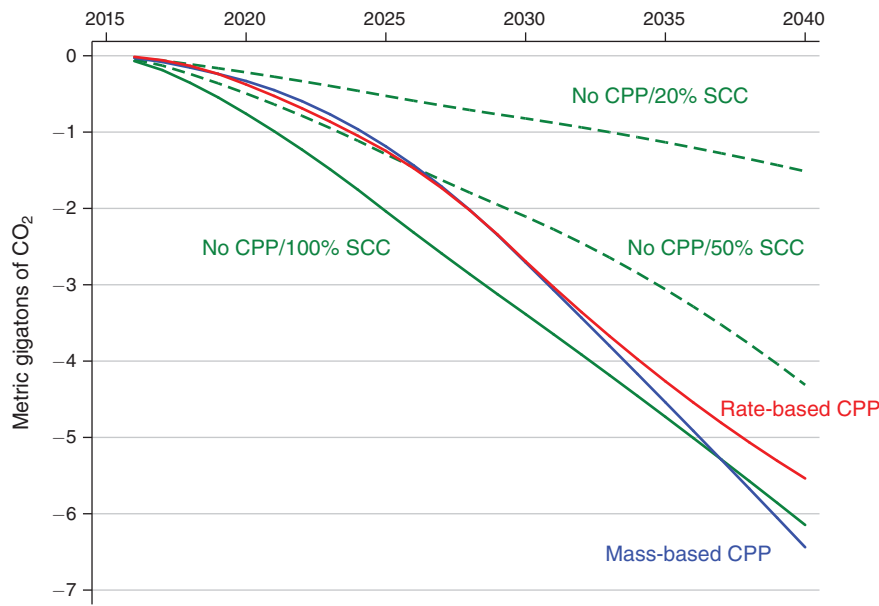


FIGURE 7. CUMULATIVE EMISSIONS REDUCTIONS: NO CPP/SURCHARGE CASES AND CPP/NO SURCHARGE CASES RELATIVE TO THE NO CPP/NO SURCHARGE CASE

Notes: The lines present cumulative power emissions reductions by year, starting in 2016, relative to the no CPP/no surcharge baseline.

Source: Based on IPM simulations by ICF

Figure 7 plots cumulative emissions reductions over time for five policy combinations, relative to the business-as-usual baseline. According to these estimates, the emissions reductions from the royalty surcharge occur sooner than those from the CPP, so that cumulative emissions reductions by 2030 are greater under the 100 percent SCC royalty surcharge with no CPP than under either the mass- or rate-based CPP with no royalty surcharge. The reason for this acceleration of emissions reductions is in part that the phased-in royalty surcharge provides greater incentives for building new NGCC under the royalty surcharge/no-CPP scenario than under the mass- or rate-CPP/no royalty surcharge scenarios. The 20 percent and 50 percent SCC royalty surcharges lead to more modest, but still significant, cumulative emissions reductions.

C. Coal Production by Region and Fuel Substitution

Figure 8 plots the generation mix in 2030 as a function of the royalty surcharge; numerical values are given in Table 5. This figure, along with tradable permit prices shown in Figure 5, illustrate the mechanism whereby the royalty surcharge

under a rate standard but not under a mass standard. This channel would be more important if total demand had been modeled as price sensitive.

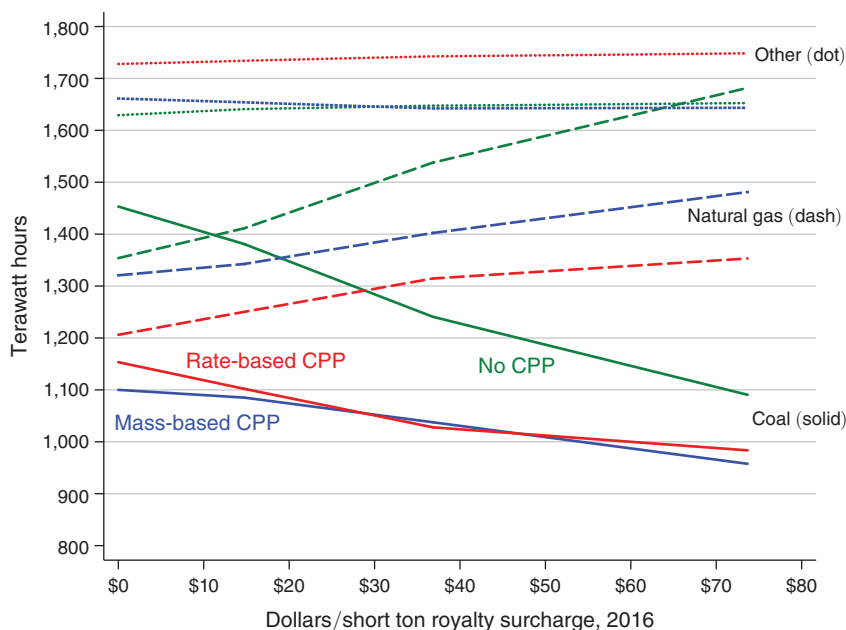


FIGURE 8. GENERATION MIX IN 2030: EFFECT OF FEDERAL COAL ROYALTY INCREASE UNDER VARIOUS CLEAN POWER PLAN IMPLEMENTATIONS

*Note:* The lines present electricity generation by fuel source in 2030 under the no CPP, mass-based CPP, and rate-based CPP case. The horizontal axis is the dollar value of the relevant percent of the SCC in 2016, in 2012 dollars.

*Source:* Based on IPM simulations by ICF

TABLE 5—IPM RESULTS: GENERATION MIX AND PRB COAL PRODUCTION

	Generation (TWh)			New gas generation (TWh)	PRB coal production (m short tons)	Change, PRB coal, relative to no-surcharge case within CPP implementation	
	Coal	Gas	Solar and wind			(m short tons)	(Percent)
No CPP, no royalty surcharge	1,453	1,354	378	339	318		
No CPP, 20% SCC	1,381	1,411	382	388	242	−76	−24.0%
No CPP, 50% SCC	1,241	1,538	389	500	110	−208	−65.4%
No CPP, 100% SCC	1,091	1,682	394	642	11	−308	−96.7%
CPP mass case, no surcharge	1,100	1,321	410	255	264		
CPP mass case with 20% SCC	1,085	1,343	402	266	172	−92	−35.0%
CPP mass case with 50% SCC	1,038	1,402	388	318	71	−193	−73.1%
CPP mass case with 100% SCC	958	1,481	388	402	9	−255	−96.6%
CPP rate case, no surcharge	1,153	1,206	460	113	281		
CPP rate case with 20% SCC	1,102	1,250	445	167	173	−107	−38.3%
CPP rate case with 50% SCC	1,028	1,315	431	266	63	−218	−77.7%
CPP rate case with 100% SCC	984	1,353	430	334	9	−272	−96.8%

*Notes:* Results are for 2030.

*Source:* IPM simulations by ICF and authors' calculations

reduces emissions. Regardless of the CPP case, the higher delivered price of coal shifts generation away from coal. In the CPP cases, the surcharge increases the

effective carbon price on coal, but not on gas; moreover, as the surcharge increases, the tradable allowance price falls, making gas more attractive relative to both coal and renewables. Thus, in the CPP mass and rate cases, as the royalty surcharge increases, generation is shifted to gas, and solar and wind generation decreases as the allowance price falls.

A similar dynamic can be seen by comparing the no-CPP/100 percent surcharge case and the mass-based CPP/no surcharge case. In the no CPP/100 percent SCC surcharge case, the amount of coal generation is essentially the same as in the mass-based CPP/no surcharge case; however, emissions reductions are only 73 percent those of the mass-based CPP. The reason for the higher emissions, but same coal combustion, is that the surcharge only applies to coal, not gas, so in the no-CPP/100 percent SCC case there is more gas generation and less renewables than in the mass-based CPP/no surcharge case.

Under all CPP variants, coal production in the PRB falls as the royalty surcharge increases (Table 5). Figure 9 plots the degree of substitution of nonfederal for federal coal when a surcharge is introduced, computed as the ratio of the increase in nonfederal production to the decrease in federal production, relative to the same CPP policy without a royalty surcharge. For the 20 percent SCC surcharge, the average substitution rate is large: with no CPP, one ton of federal coal is replaced by 0.47 tons of nonfederal coal, while under the mass- and rate-based CPPs the replacement rate is 0.69 and 0.53, respectively. As the surcharge increases, this replacement rate declines. In the no-CPP case, the replacement ratio is 0.01 for a 100 percent SCC surcharge. The mechanism driving the decline in the replacement ratio is that a higher surcharge makes federal coal less attractive, driving up demand for, and thus the price of, nonfederal coal. But an increase in the price of both federal and nonfederal coal provides an additional incentive to use noncoal generation. Thus, the degree of substitution has a self-limiting feature: the higher price of nonfederal coal ultimately drives substitution to noncoal fuels.

#### *D. Royalties*

Total royalties increase substantially as the surcharge is phased in (Figure 10).<sup>42</sup> In the no-CPP case, the 20 percent SCC surcharge increases annual royalties in 2025 by \$3.7 billion. In the 20 percent SCC case, increases in royalty receipts in Wyoming, Montana, and Utah are sustained through 2050. Under current law, 48 percent of these royalties go to the states and the rest goes to US government general revenues. In the 100 percent SCC surcharge case, royalty receipts initially increase but as production falls to near zero, receipts eventually fall below what they would be in the no-surcharge case.

<sup>42</sup>These royalty receipt calculations were computed under the secondary base case.

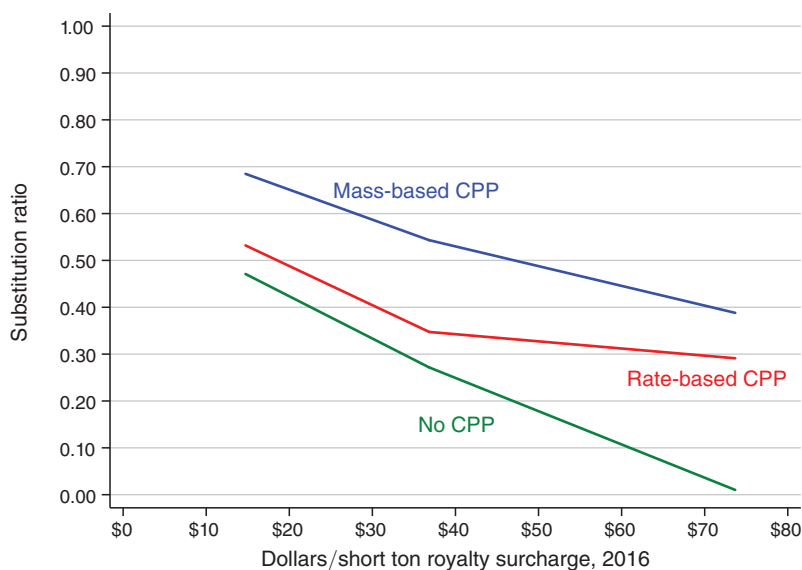


FIGURE 9. AVERAGE NONFEDERAL-FEDERAL COAL SUBSTITUTION RATIO:  
TONS OF NONFEDERAL COAL INCREASE PER TON FEDERAL COAL DECREASE IN 2030

*Notes:* The lines plot the ratio,  $(\Delta \text{ nonfederal coal production})/(\Delta \text{ federal coal production})$  for the surcharge on the horizontal axis, where  $\Delta$  is the difference between production given the surcharge and production with zero surcharge in the same CPP case. The horizontal axis is the dollar value of the relevant percent of the SCC in 2016, in 2012 dollars.

*Source:* Based on IPM simulations by ICF

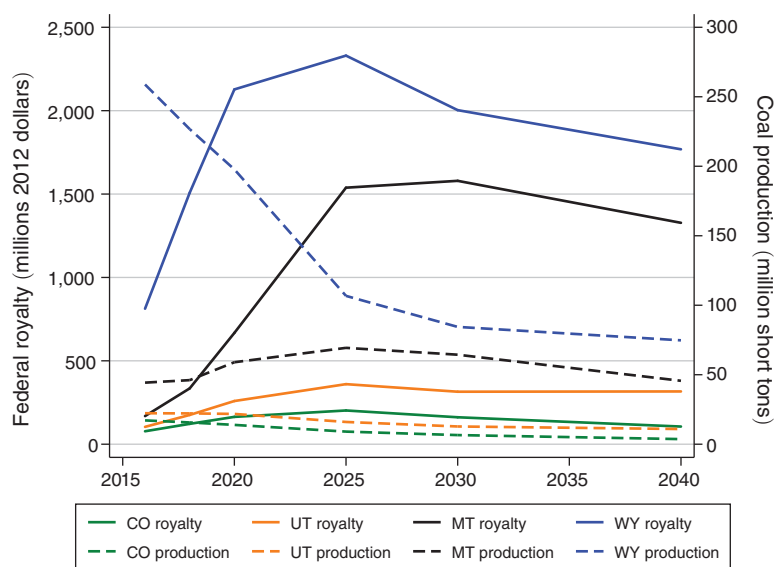


FIGURE 10. FEDERAL ROYALTIES AND COAL PRODUCTION ON FEDERAL LANDS IN WESTERN STATES:  
NO DOWNSTREAM REGULATION, WITH 20 PERCENT SCC SURCHARGE

*Notes:* Royalties are plotted in solid lines on the left scale. Production is plotted in dashed lines on the right scale. Royalties are federal ad valorem plus carbon surcharge.

*Source:* Based on IPM simulations by ICF and authors' calculations

### *E. Abatement Costs*

The final two columns of Table 4 reports an estimate of the average abatement costs in 2025 and 2030 arising from imposing a royalty surcharge. The total abatement cost is calculated as the increase in the cost to society to produce power for a given surcharge, relative to the same CPP case with no surcharge. We compute the cost to society of generating the power as the electricity generators' total production cost, minus coal royalty revenues. Total production cost is the sum of fuel costs, variable operating costs, fixed operating costs, and capital costs, all computed at the model plant level. The capital costs are computed based on the new construction and retrofits endogenously put in place in the dynamic optimization. The delivered price for fuel is the fuel cost, which is part of variable operating costs. Because the delivered price is gross of royalties, total production costs include coal royalties. Because coal royalties are a transfer within society, from ratepayers to taxpayers, we net out this transfer. The per-ton abatement cost is thus computed as the ratio of the electricity production cost increase, net of royalties, per ton of emissions decline, where changes are measured against the corresponding CPP base case.

First consider the abatement costs in 2030. For the no-CPP and the rate-based CPP, the abatement costs are substantially less than the SCC for the 20 percent SCC surcharges (\$39/MT in the no-CPP case and \$24/MT in the rate case) and are in the vicinity of the SCC for the 50 percent and 100 percent SCC surcharges.<sup>43</sup> For the mass-based case, the abatement costs are substantially higher, roughly twice the SCC. This reflects the smaller emissions reductions from the surcharge under the mass-based CPP than under the rate-based CPP, as discussed in Section IVB, while for both CPP variants the net production cost increases due to the surcharge are similar.

For the no-CPP and rate-based CPP cases, the average abatement cost increases as the stringency of the policy increases. We interpret this as indicating that relatively inexpensive substitutes for Western coal, such as gas, are available for small royalty surcharges, but at larger surcharges the marginal generation substitute is more expensive. This increasing marginal cost of substitutes drives an abatement cost that increases with stringency. In contrast, under the mass-based CPP, the average abatement cost decreases with stringency. For the smaller values of the surcharge, the CPP continues to bind in most regions, so emissions fall only modestly but costs go up. For larger values of the surcharge, the CPP ceases to bind and the surcharge is the binding policy. Accordingly, the absolute value of the (numerical) derivative of emissions with respect to the surcharge is increasing under the mass case, but is decreasing under the no-CPP and rate case.

A natural question is how a pure supply-side approach compares to a pure demand-side approach, specifically, how do the abatement costs for a 100 percent SCC royalty surcharge absent the CPP compare to abatement costs for the mass-based CPP, absent a royalty surcharge? Unfortunately, this comparison requires additional

<sup>43</sup> Recall that the SCC schedule increases with the date of emissions. The abatement costs in 2025 (2030) should therefore be compared to the value of the SCC for emissions in 2025 (2030), which is \$51/metric ton (\$57/metric ton) in 2012 US dollars.

assumptions beyond those embedded in the IPM due to the role of energy efficiency in the EPA's modeling of the CPP. Specifically, the no-CPP and CPP base cases have different total electricity demand because (as described in Section III) EPA modeled energy efficiency induced by the CPP outside of the IPM.<sup>44</sup> By incorporating EPA's energy efficiency assumption into the CPP base cases, EPA's policy case becomes our base case, but at the cost of being able to compare the CPP base cases to the no-CPP base case. Still, it is informative to compare EPA's estimates of the average abatement costs for the mass- and rate-based CPP in 2030, which are \$25/MT and \$15/MT, to the estimate for the 100 percent SCC royalty surcharge in the absence of the CPP, which is \$63/MT. The higher cost of the royalty-only approach is consistent with economic theory, as the royalty approach does not equalize marginal abatement costs across fuels, underscoring the benefits of using a broad-based policy to target environmental externalities. That said, these estimates are not strictly comparable because the CPP estimate incorporates benefits from energy efficiency, estimated outside the IPM, whereas our analysis of the coal royalty holds demand fixed and thus omits the ability to reduce costs through energy efficiency.

#### F. *Quantity Limit Policy Scenarios*

We also consider policies in which federal coal leases were subject to tonnage production caps but no royalty surcharge. This analysis was conducted under the secondary base case. Table 6 compares the results for the two production cap cases to the 20 percent and 100 percent SCC royalty surcharge cases with no downstream regulation (first block of rows) and in the presence of the mass-based CPP (second block). The comparisons are for 2040 because of the longer ramp-in time used in the production limit scenarios. As can be seen in Table 6, the results for the no new leases case and the 100 percent SCC case yield similar long-run prices (wholesale electricity prices and tradable permit prices) and quantities (emissions, coal production, and generation mix); also, the results for the 50 percent production cap and the 20 percent SCC surcharge are similar. This is consistent with the results from the static model in online Appendix A that indicate that price and quantity regulation achieve similar results absent uncertainty. An important difference between the production cap and royalty surcharge policies is that the royalty surcharge generates substantial additional royalties, but the production cap does not.

#### G. *Sensitivity Analysis*

The results for the royalty surcharge under the secondary base case are broadly similar to those under the primary base case, as summarized in Table B.1 in the online Appendix. Baseline emissions are higher in the secondary base case, so the reductions arising from the CPP (without upstream regulation) are larger than in the

<sup>44</sup> The EPA estimated the level of energy efficiency improvements induced by the CPP and their cost, and then used the level to exogenously change demand in the IPM simulations and the associated cost to compute average abatement costs based on a combination of the IPM results and the separate energy efficiency analysis. We follow their approach to facilitate comparisons, as discussed in Section III.



TABLE 6—IPM RESULTS: COMPARISON OF ROYALTY SURCHARGE AND QUANTITY LIMIT CASES

		Royalty surcharge		Tonnage production cap	
	No surcharge	20% SCC	100% SCC	50% cap	No new leases or renewals
<i>Panel A. No CPP</i>					
Emissions (MMT)	2,476	2,410	2,074	2,417	2,100
PRB production (MST)	439	335	20	233	42
Total coal production (MST)	1,244	1,177	878	1,184	895
Wholesale electricity price (\$/MWh)	\$56.27	\$56.59	\$59.32	\$56.55	\$59.85
Allowance price					
North Central	—	—	—	—	—
South Central	—	—	—	—	—
Southeast	—	—	—	—	—
Generation (TWh)					
Solar + Wind	323	325	356	323	342
New NGCC	942	1,021	1,485	1,015	1,449
<i>Panel B. Mass-based CPP</i>					
Emissions (MMT)	1,672	1,653	1,622	1,665	1,631
PRB production (MST)	266	171	20	232	42
Total coal production (MST)	763	730	661	756	678
Wholesale electricity price (\$/MWh)	\$68.67	\$67.97	\$65.08	\$68.42	\$64.83
Allowance price					
North Central	\$29.42	\$22.53	\$9.03	\$27.13	\$7.81
South Central	\$29.68	\$22.07	\$4.41	\$27.39	\$5.21
Southeast	\$31.24	\$31.09	\$29.67	\$30.88	\$29.17
Generation (TWh)					
Solar + Wind	466	433	373	456	393
New NGCC	1,184	1,280	1,472	1,215	1,400

Notes: All results are for 2040, computed under the secondary base case. The tonnage production caps assume a 20 year linear phase-in.

Source: IPM simulations by ICF

primary base case. Similarly, emissions reductions arising from upstream regulation (without the CPP) are larger in the secondary than primary case. In the presence of the CPP, the additional effect of the royalty surcharge on emissions and coal production is somewhat smaller under the secondary base case than under the primary base case. The mechanisms driving this are that in the secondary base case, the cost of coal including the surcharge is less than in the comparable primary base case so that there is somewhat less substitution away from federal coal; and the CPP tends to bind in more regions and under higher surcharges under the secondary base case relative to the primary base case.

#### H. The CPP versus Generic Mass-Based Regulation

The downstream emissions regulations considered here are modeled on the CPP. A natural question is which results hinge on specific features of the CPP, as compared to a more generic “textbook” regulation that is not subject to political constraints or constraints of the Clean Air Act. We focus on mass-based regulation because that is the standard cap-and-trade framework.

The main departures of the CPP (as modeled here) from a generic mass-based regulation are: the use of state-level caps, the exemption of small generators, and

regional rather than national allowance trading. Under the mass-based CPP, the royalty surcharge leads to emissions reductions even if the mass-based regulation is binding because it reduces leakage; however, under a binding generic national mass-based plan there would be no leakage and thus no emissions reductions from the royalty surcharge. National trading would alter the regional impact of the surcharge and of the regulation, so that either it is binding for all regions (nationally) or it is not. Other results, however, would be expected to apply to generic mass-based regulation: the royalty surcharge would reduce tradeable allowance prices, increase generating costs, encourage a shift to nonfederal coal (with only partial substitution) and to gas and renewables, and generate sizable additional royalties. If the royalty surcharge is sufficiently large and/or the generic mass-based caps are sufficiently high, then the royalty surcharge would be the binding policy and the IPM simulation results in the nonbinding cases would apply.<sup>45</sup>

## V. Discussion

### A. Caveats

The quantitative estimates produced by the IPM deserve several caveats. First, the economic and policy assumptions are those in place in October 2015. There have been and will be departures of actual prices, demand, and policy from those modeled. For example, these assumptions do not include the five-year extension of the wind production tax credit and the solar investment tax credit passed at the end of 2015, and therefore arguably understate likely new wind and solar capacity in the 2016–2021 period, and thus likely overstate both baseline coal demand and baseline allowance prices. Some observers have suggested that those policy developments, along with declining wind and solar costs, would make the CPP nonbinding by 2030, in which case the effects of the royalty surcharge under the CPP would look more like the no-CPP results.

Second, the simulations fix total electricity demand to be that in the corresponding CPP base case, a decision made both for technical reasons within the IPM and to align comparability of this study and the EPA's Regulatory Impact Analysis of the CPP. In the cases of no downstream regulation, rate-based regulation, and mass-based regulation when the CPP is not binding, allowing for some demand elasticity would result in lower emissions, smaller electricity price increases, and lower abatement costs for each scenario relative to the results presented here. In the mass-based case, the electricity price would fall by less, demand would increase, and the reduction in emissions would be less than when demand is fixed.

Third, the study considered mass-based systems and rate-based systems, but not hybrid systems in which some states choose mass and others choose rate regulation. As discussed in Bushnell et al. (2015), leakage of downstream regulation can occur within rate systems when states with different rates standards either trade

<sup>45</sup> Another difference between the CPP and generic regulation is that, under the actual CPP, states could choose between rate- and mass-based regulation, whereas a single approach would be used for generic national regulation; however, our simulations do not allow for that choice so this distinction is not relevant.

allowances or are interconnected. That leakage is modeled in the IPM results, however additional leakage can occur in hybrid systems in which mass- and rate-based states are interconnected but do not trade. Whether the surcharge would mitigate or exacerbate this leakage of the downstream regulation depends on details of the generation fleet in the different states and the standards adopted, and more study of this issue is warranted.

### B. Additional Considerations

There are several relevant considerations that are not addressed in the static or IPM modeling. All these issues merit further study.

*Exports.*—As discussed in Section IIIB, the IPM simulations hold coal exports constant. Because downstream regulation would reduce the price of coal and make it more competitive internationally, this assumption misses a channel whereby steam coal exports would increase under the CPP, inducing leakage in the CPP/no surcharge base cases. While CO<sub>2</sub> emissions are a global problem, we do not include non-US emissions in any calculations in this paper because the IPM does not model endogenous changes in total coal exports. Conditional on the CPP case, however, the royalty surcharge would increase the price of both federal and nonfederal coal, thus reducing exports and providing upward pressure on international coal prices. Thus, the royalty surcharge would mitigate this source of leakage in the CPP.

*Stockpiling.*—The announcement of higher royalties upon lease renewal would provide an incentive for increased mining and stockpiling prior to expiration (the green paradox). This mechanism is not incorporated into the IPM, however practical considerations suggest that this effect might be limited. Once mined, PRB coal is subject to partial oxidation and spontaneous combustion, so that the coal heat rate is reduced by storage. This effect would serve to increase PRB usage during the phase-in of the surcharge, relative to the simulation results, but given physical limitations on stockpiling, we consider this mechanism unlikely to affect the results for 2030 that are the focus of Section IV.<sup>46</sup>

*Leakage Through Bonus Bids and Royalty Evasion.*—In principle, a royalty surcharge could result in lower bonus bids. There are three reasons this is unlikely to undermine the effect of the surcharge. First, the royalty surcharge would increase the marginal cost of extraction from a given lease irrespective of the response of bonus bids to the surcharge because bonus bids are a fixed cost. Second, as discussed in Section I, bonus bids appear to be near the minimum set by the BLM. Finally, even if the BLM were to lower the minimum bonus bid to zero, this change would be swamped by the size of the surcharge: bonus bids are currently around \$1 per ton of recoverable coal, a small amount compared to the per-ton surcharges in Table 2. The inability of firms to lower bonus bids enough to offset the cost of the royalty

<sup>46</sup> See Nalbandian (2010) for a discussion of stockpile management methods to reduce partial oxidation. These methods include using smaller stockpiles, coal pile design, and periodic compaction.

surcharge could affect the extensive margin and result in fewer leases. We model the surcharge as shifting the supply curve in a somewhat continuous way because of commingling, the 10-year phase-in, and aggregation to a regional supply curve. If the surcharge were to lead instead to new mines not opening and nonrenewal of existing leases, this could make the supply curve steeper than is modeled here, in which case the IPM results would understate the impact of the royalty surcharge.

*Noncompetitive Rail Transport.*—The IPM treats transport prices as a fixed markup, so the royalty surcharge is fully passed through to the generator. Rail transport is not competitive, however, with just one or two railroads for PRB coal depending on the destination. Busse and Keohane (2007) provides evidence that rail transport prices adjusted to exploit market power as the market shifted to low-sulfur coal in the early 1990s. Thus, a royalty surcharge could be partially absorbed by lower rail rates. This is more likely relevant at low values of the surcharge since high values could not be profitably absorbed.

*Noncompetitive Generation Sector.*—The IPM treats the power sector as cost-minimizing and competitive. In reality, much of the electricity generation sector is comprised of regulated utilities, and where there are wholesale electricity markets, there is evidence of market power in at least some regions.<sup>47</sup> If regulated utilities exercise market power and can pass through costs, they might choose to continue to use PRB coal instead of switching to a cheaper generation option. If so, that would reduce the effectiveness of the royalty surcharge. However, the Averch and Johnson (1962) effect suggests that a regulated utility might choose a more costly investment in natural gas, wind, or solar than a less-costly retrofit that enabled a PRB-fired plant to switch to Eastern or Midwestern coal, which would lead to greater emissions reductions from a surcharge than estimated by the IPM.

*Cost-Benefit Analysis.*—It is tempting to use the per-ton abatement costs summarized in Section IVE and the SCC to undertake a cost-benefit analysis. However, the data needed to evaluate the health co-benefits of the surcharge policy for such an analysis are not available. We expect that the co-benefits would be substantial and positive, as they are in the EPA's RIA of the CPP, because of reductions in particulates,  $\text{NO}_x$ , and  $\text{SO}_x$ . In principle, these health co-benefits could justify a surcharge even before accounting for climate change mitigation benefits. However, the sign of the effect of the surcharge on  $\text{SO}_x$  is ambiguous a priori because substitution from low-sulfur PRB coal to higher-sulfur Eastern coal could increase  $\text{SO}_x$  emissions. We do not have the criteria pollutant emissions data necessary to compute the health co-benefits, so a full cost-benefit analysis is outside the scope of this study. Undertaking a full cost-benefit analysis that permits comparisons of combinations of upstream and downstream policies is an important project for future research.

<sup>47</sup> See, for example, Borenstein, Bushnell, and Wolak (2002) and Wolak (2003).

### C. Conclusions

We reach two main conclusions about the policy of a royalty surcharge. First, the royalty surcharge without downstream policy reduces emissions: at a 100 percent SCC royalty, it achieves nearly three-quarters the emissions reductions projected for the CPP, and does so with an average abatement cost roughly equal to the SCC. This by itself is noteworthy, given that partial upstream policy is often viewed as ineffective because of the possibility of fuel substitution. But unique features of the US coal sector make the upstream policy effective: federal coal is less costly to extract than nonfederal coal; it comprises a large fraction of US coal production; and the surcharge increases demand for and the price of nonfederal coal, incentivizing a shift toward gas.

Second, the royalty surcharge on top of the CPP reduces leakage of the downstream policy, particularly in the rate-based case. Moreover, and in our view more importantly, it serves as a backstop to weak downstream policy. In our simulations, the CPP is not binding in some regions without the surcharge, so that the surcharge becomes the binding federal emissions policy.

Together, these two findings provide evidence on the extent to which a partial supply-side policy could substitute for or complement more comprehensive emissions regulation. We conclude that, in the absence of ideal, economically efficient emissions regulation, a carbon surcharge on federal coal royalties could provide meaningful, cost-effective emissions reductions.

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